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**Transcript Exhibit(s)**

**Docket #(s):** WS-02676A-09-0257

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To: Docket Control

Date: April 6, 2010

Re: Rio Rico Utilities / Rates
WS-02676A-09-0257
Volumes I through V, Concluded
March 10 through 30, 2010

## STATUS OF ORIGINAL EXHIBITS

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Rio Rico Properties (I Exhibits)

I-1, I-3, I-4, I-5

Rio Rico Utilities (A Exhibits)

A-1 through A-28

Residential Utility Consumer Office (R Exhibits)

R-1 through R-5, R-7 through R-15, R-17, R-18, R-19

Staff (S Exhibits)

S-1 through S-14

## *EXHIBITS NOT OFFERED BY DESIGN OR OVERSIGHT*

Residential Utility Consumer Office (R Exhibits)

R-6
R-16 Returned to RUCO

## *EXHIBITS NOT UTILIZED*

Rio Rico Properties (I Exhibits)

I-2

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Ms. Jane L. Rodda, Administrative Law Judge
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Mr. Daniel Pozefsky – RUCO
Mr. Tim Sabo – Rico Rico Properties
Ms. Robin Mitchell - Staff

FENNEMORE CRAIG, P.C.
Jay L. Shapiro (No. 014650)
Todd C. Wiley (No. 015358)
3003 N. Central Ave.
Suite 2600
Phoenix, Arizona 85012
Attorneys for Rio Rico Utilities, Inc.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF RIO RICO UTILITIES, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER AND WASTEWATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON. | DOCKET NO: WS-02676A-09-0257 |

**REJOINDER TESTIMONY OF**

**THOMAS J. BOURASSA**

**(COST OF CAPITAL)**

**March 9, 2010**

EXHIBIT
A-9
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY ..... 1

I. SUMMARY OF REBUTTAL TESTIMONY AND THE PROPOSED COST OF CAPITAL FOR THE COMPANY ..... 1

A. Summary of Company's Final Position ..... 1

B. Summary of the Final Positions of Staff and RUCO. ..... 2

II. REJOINDER TO STAFF'S COST OF CAPITAL ANALYSIS, TESTIMONY AND RECOMMENDATIONS ..... 8

A. Staff's Financial Risk Adjustment ..... 8

B. Firm Specific Risk ..... 11

C. Estimates of Growth ..... 14

III. REJOINDER TO RUCO'S COST OF CAPITAL ANALYSIS, TESTIMONY AND RECOMMENDATIONS ..... 14

A. Use of Southwest Water to Develop Cost of Equity ..... 14

B. Use of Publicly traded Gas Utilities ..... 15

C. RUCO's Purported Generosity ..... 17

D. RUCO's Implementation of the CAPM ..... 20

E. RUCO's Hypothetical Capital Structure ..... 28

F. RUCO's Unrealistic Cost of Debt ..... 34

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## I. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Thomas J. Bourassa. My business address is 139 W. Wood Drive, Phoenix, Arizona 85029.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS CASE?**

A. On behalf of the applicant, Rio Rico Utilities, Inc. ("RRUI" or the "Company").

**Q. ARE YOU THE SAME THOMAS J. BOURASSA THAT FILED DIRECT AND REBUTTAL TESTIMONY IN THIS DOCKET?**

A. Yes. I am submitting separately bound rejoinder testimony on rate base, income statement, revenue requirement and rate design, along with this rejoinder testimony on the cost of capital.

## I. SUMMARY OF REBUTTAL TESTIMONY AND THE PROPOSED COST OF CAPITAL FOR THE COMPANY

### A. Summary of Company's Final Position

**Q. WHAT IS THE COMPANY'S FINAL POSITION ON THE COST OF CAPITAL?**

A. The Company's position regarding the cost of equity has not changed since my rebuttal testimony was filed on February 1. The Company's proposed capital structure is its actual capital structure, which consists of 100 percent common equity. I continue to recommend a cost of equity of 11.7 percent, which results in a weighted cost of capital ("WACC") of 11.7 percent.

As I explained in my rebuttal testimony, I believe that a return on equity of 11.7 percent is fair and reasonable, and properly takes into account RRUI's financial and business risk. It is based on applying the Discounted Cash Flow ("DCF") model and the Capital Asset Pricing Model ("CAPM") to the sample group of publicly traded water utilities normally used by Staff and approved by the



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Commission in setting rates for numerous water and wastewater utilities, including affiliates of RRUI. The return produced by those models is adjusted downward by 100 basis points to account for the absence of debt in the Company's capital structure and then upward by 50 basis points to account for the Company's extremely small size, lack of investment liquidity, and the additional risk that results from the particular rate-making methods employed in Arizona. The table below summarizes the Company's final position:

| Method | Low | High | Midpoint |
|---|---|---|---|
| Range DCF Constant Growth Estimates | 10.8% | 12.2% | 11.5% |
| Range of CAPM Estimates | 10.3% | 15.6% | 13.0% |
| Average of DCF and CAPM midpoint estimates | 10.6% | 13.9% | 12.2% |
| Financial Risk Adjustment | -1.0% | -1.0% | -1.0% |
| Specific Company Risk Premium | 0.5% | 0.5% | 0.5% |
| **Indicated Cost of Equity** | **10.1%** | **13.4%** | **11.7%** |

The schedules containing the cost of capital analysis are attached to my cost of capital rebuttal testimony. There have been no significant changes in the financial markets that affect that analysis, which was performed approximately five weeks ago.

**B. Summary of the Final Positions of Staff and RUCO.**

**Q. PLEASE SUMMARIZE THE COMPANY'S FINAL POSITION REGARDING STAFF'S RECOMMENDED EQUITY RETURN AND WACC.**

A. Staff's cost of capital witness, Mr. Manrique, continues to recommend that RRUI's actual capital structure be used.[1] He also continues to propose a return on equity of 9.2 percent. That return is based on the average cost of equity produced by its DCF and CAPM models – 10.3 percent – and a 110 basis-point downward adjustment for RRUI's financial risk.[2] Based on its 100 percent equity capital structure, he is again proposing the WACC for RRUI to be 9.2 percent.[3] The most serious problems with Staff's recommendation, in summary, are:

(1) Staff's downward adjustment for financial risk is overstated. First, Mr. Manrique has misapplied the Hamada formula by using the book value of the sample utilities' equity rather than the conceptually correct market value of their equity. Moreover, he has assumed that the average beta of the sample utilities can be applied to RRUI, even though RRUI is much smaller and is riskier than the publicly traded utilities.

(2) Staff ignores the fact that RRUI is riskier than the publicly traded utilities in the sample group, despite RRUI's small size, lack of liquidity and Arizona's unfavorable regulatory climate. No rational investor would agree with Staff's position, which violates the comparable earnings standard.

(3) Staff improperly double-counts historic growth rates in estimating the future dividend growth rate – *g* – in the DCF model, and fails to properly utilize the best estimate of expected dividend growth, analysts' forecasts. Historic growth is already reflected in the current stock prices of the publicly traded sample utilities and is considered by analysts in developing their growth rate forecasts. This error depresses the result produced by the DCF model.

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[1] Surrebuttal Testimony of Juan C. Manrique ("Manrique Sb.") at 2.

[2] *Id.*

[3] *Id.*

**Q. PLEASE SUMMARIZE THE COMPANY'S FINAL POSITION REGARDING RUCO'S RECOMMENDED EQUITY RETURN AND WACC.**

A. RUCO did not revise its cost of equity recommendation or its recommended WACC – 7.9 percent – in its surrebuttal testimony.[4] As I discussed in my rebuttal testimony, RUCO's witness, Mr. Rigsby, estimated that the cost of equity for its sample utilities is only 7.9 percent, based on the results of its DCF and CAPM methods.[5] RUCO's cost of equity is driven by its extraordinarily low CAPM estimate, 6.1 percent, which is lower than the current yield on an investment grade bond and, moreover, lower RUCO's own hypothetical debt cost. Mr. Rigsby obviously utilized techniques that greatly bias downward his cost of equity estimates and, for this reason, has actually recommended a cost of equity that is 9.0 percent – 110 basis points greater than the results produced by his models. The most serious errors in RUCO's cost of equity estimate, in summary, are:

(1) RUCO relies on a sample group of publicly traded gas utilities to estimate RRUI's cost of equity, and estimates that this industry's group's cost of equity is only 7.6 percent. In contrast, the Commission recently authorized a 10.0% return on equity for Southwest Gas Corporation.[6] The water industry sample group has significantly more market risk than the gas industry sample group, as estimated by each industry group's beta, and therefore has a significantly higher cost of equity than 10.0%.

(2) RUCO used a sample of only four water utilities when useful data for three other water utilities that Staff includes in its sample group are available.

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[4] Surrebuttal Testimony of William A. Rigsby ("Rigsby Sb.") at 2 – 3.

[5] Direct Testimony of William A. Rigsby Dt. ("Rigsby Dt.") at 4 – 5.

[6] *Southwest Gas Corporation*, Decision No. 70665 (December 24, 2008).



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Moreover, RUCO included Southwest Water Company in its water sample group, despite the fact that less than 50% of Southwest Water's revenues are derived from regulated activities. In addition, Southwest Water is a financially distressed company and should not be considered in determining RRUI's return on equity.

(3) RUCO erroneously relies on geometric annual averages in his CAPM estimates instead of conceptually correct arithmetic annual averages to compute the historic market risk premium.

(4) RUCO did not compute a current risk premium in estimating the cost of equity using the CAPM, notwithstanding the fact that Staff has consistently presented, and the Commission has consistently approved, CAPM estimates that rely on a current market risk premium.

(5) RUCO erroneously uses total returns on Treasury securities to estimate the historic market risk premium in its CAPM estimates, rather than the conceptually correct income returns.

(6) RUCO erroneously uses the yield on a 5-year Treasury note as the risk-free rate in its CAPM estimates rather than the conceptually correct expected yield on a long-term Treasury bond.

This unrealistic result is exacerbated by RUCO's use of a hypothetical capital structure of 40 percent debt and 60 percent equity.[7] This results in an effective overall return on equity of **only 6.9 percent** when RUCO's fictitious income tax deduction is considered. A similar RUCO proposal was rejected by the Commission as "results-oriented" in Black Mountain's recent rate case.[8] The most serious problems with RUCO's hypothetical capital structure, in summary, are:

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[7] *Id.*

[8] *Black Mountain Sewer Corporation*, Decision No. 69164 (December 5, 2006) at 19 – 20.

(1) RUCO effectively reclassifies 40 percent of RRUI's equity investment into debt.

(2) RUCO provides a low debt cost of just 6.26 percent on 40 percent of RRUI's equity investment.

(3) RUCO imputes fictional interest expense into its income tax computation which penalizes RRUI by a loss of operating expenses of nearly $100,000.

**Q. MR. BOURASSA, STAFF AND RUCO BOTH HAVE RECOMMENDED A DISALLOWANCE OF VIRTUALLY THE ENTIRE AMOUNT OF CENTRAL OFFICE COSTS INCURRED BY APT AND ALLOCATED TO RRUI. IF ADOPTED BY THE COMMISSION, WOULD THAT DISALLOWANCE OF THE APT CENTRAL OFFICE COSTS HAVE ANY IMPACT ON THE COST OF EQUITY FOR RRUI AND, IF SO, PLEASE EXPLAIN.**

A. Yes, a denial of the APT Central Office Costs would deprive RRUI of the opportunity to earn the rate of return as set by Staff and RUCO based on the sample group of publicly traded utilities. Specifically, Staff and RUCO have disallowed the costs incurred by APIF, through APT, as a publicly traded income fund, including costs for escrow fees, shareholder communications, securities filings, Board of Director/Trustee fees, auditing and financial requirements imposed on publicly traded companies (such as Sarbanes-Oxley or its Canadian equivalent), and other similar costs. In disallowing those costs, however, Staff and RUCO have failed to address the impact of denying the APT costs on their cost of capital analyses.

**Q. HOW SO?**

A. In developing information on cost of equity, both Staff and RUCO rely on data from publicly traded companies in deriving their cost of equity calculations. Those companies include San Jose Water, Connecticut Water, American States, Aqua America, California Water and Middlesex Water, among others. Essentially, Staff and RUCO use financial information from Value Line, which is based on the annual reports filed by the various companies in the sample group. In those annual reports, the companies in the sample group report the various costs of being publicly traded on their respective exchanges as expenses, including director fees, taxes and audits. For example, companies such as San Jose Water, Connecticut Water, American States, Aqua America, California Water and Middlesex Water incur expenses associated with boards of directors, audit fees, and tax services as a result of being publicly traded. Unfortunately, however, Staff and RUCO do not adjust for denial of those expenses in their cost of capital analyses.

It is arbitrary and unfair for Staff and RUCO to set RRUI's cost of equity based on net earnings of the sample companies, which reflect corporate expenses of being publicly traded, but disallow RRUI from recovering those costs in this case. Staff and RUCO have not produced any evidence showing that the regulatory jurisdictions for the sample companies have disallowed those corporate costs from inclusion in operating expenses of those companies. If those jurisdictions allow recovery of such corporate costs as operating expenses for the sample companies, then, by denying those same costs for RRUI, Staff and RUCO would prevent RRUI from earning its authorized rate of return. In fact, I am aware that the California PUC has authorized recovery of these types of expenses.[9]

[9] *See, e.g., In Re San Jose Water Co.*, 2004 WL 1947074 at ¶4.8 (Cal. P.U.C. 2004) (approving settlement which "includes an additional $141,000 for 2004 and $143,000 for 2005 for expenses related to compliance with the Sarbanes-Oxley Act. In 2002, Congress enacted the Sarbanes-Oxley Act. Among other things, section 404 of the Act requires companies to establish and certify their internal financial control systems by developing risk assessments and an internal audit plan....The new requirements of the

## II. REJOINDER TO STAFF'S COST OF CAPITAL ANALYSIS, TESTIMONY AND RECOMMENDATIONS

### A. Staff's Financial Risk Adjustment

**Q. PLEASE COMMENT ON STAFF'S FINANCIAL RISK ADJUSTMENT?**

A. Because Staff incorrectly uses book values in its Hamada approach, for the reasons set forth in my direct testimony[10], Staff's recommended surrebuttal financial risk adjustment of 110 basis points is overstated by at least 50 basis points. Accordingly, Staff's cost of equity estimate would increase from 9.2% to at least 9.7% if market values rather than book values were used in the Hamada method.[11]

**Q. WHAT REASON DOES STAFF GIVE TO SUPPORT THE USE OF BOOK VALUES?**

A. Rather than providing any authoritative support for using of book values in the Hamada method, Staff simply claims that the use of book values is "prudent and reasonable in a regulatory environment".[12] Following Staff's reasoning it should also be prudent and reasonable in a regulatory environment to use current book values rather than current stock prices in the DCF model to determine the dividend yield and the cost of equity. After all, we are applying a return to an original cost rate base (book value) for the determination of the return dollars available to investors.

**Q. WHAT WOULD BE THE RESULTS OF STAFF'S MODELS IF BOOK VALUES ARE USED RATHER THAN STOCK PRICES?**

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Sarbanes-Oxley Act also have increased the audit fees associated with the standard financial auditing required of a publicly traded company.")

[10] Direct Testimony of Thomas J. Bourassa (Cost of Capital) ("Bourassa COC Dt.") at 8 – 12.

[11] Staff unadjusted cost of equity of 10.3% less 50 basis points.

[12] Manrique Sb. at 3.

A. If book values are used rather than stock prices, Staff's dividend yield increases to 6.3% and Staff's cost of equity estimate for the DCF constant growth method would increase from 9.4% to 12.0%. Further, Staff multi-stage DCF estimate would increase from 10.3% to 12.6%. The average of Staff's DCF method would increase to 12.3% from 9.9%.

**Q. WHY IS IT REASONABLE TO USE BOOK VALUES RATHER THAN STOCK PRICES IN THE DCF?**

A. As I pointed out in my direct testimony, the application of the DCF model produces estimates of the cost of equity that are consistent with investor expectations only when the market price of a stock and the stock's book value are approximately the same. The DCF model will understate the cost of equity when the market-to-book ratio ("M/B") exceeds 1.0 and conversely will overstate the cost of equity when the M/B is less than 1.0.[13] Staff has not disputed this point.

Dr. Morin points out that one of most important reasons for caution and skepticism in the application of the DCF model is that it "produces estimates of common equity cost that are consistent with investors' expected return only when stock price and book value are reasonably similar, that is, when the M/B is close to unity".[14] In fact, Dr. Morin provides an illustration which shows that when a market based return is applied to a book value figure it will produce insufficient earnings necessary to provide the indicated dividend and indicated growth.[15] Over time, earnings will be insufficient to pay dividends and both earnings and book value will necessarily decline.

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[13] Bourassa COC Dt. at 27.

[14] Roger A. Morin, *New Regulatory Finance* 223-24 (Public Utility Reports, Inc. 2006) ("Morin") at 434-436.

[15] *Id.* at 434.

**Q. IS THERE A WAY TO RESTATE STAFF'S CAPM RESULTS IN TERMS OF BOOK VALUE?**

A. Yes. A book value return from the CAPM can be obtained using a derivation of the DCF model.[16] The equation is

$$r = M/B(k-g) + g$$

Where r = book return on equity
M/B = the market-to-book ratio
k = market cost of equity
g = growth rate

Using the average of Staff's CAPM results of 10.6% as k, the average M/B ratio of 1.7 for Staff sample group as M/B, and an implied growth rate of 6.9%[17] as g, the indicated book equity return for Staff's models using the equation above is 13.2% and is computed as follows:

$$13.2\% = 1.7(10.6\% - 6.9\%) + 6.9\%$$

Thus, Staff's CAPM estimate would increase to 13.2% from 10.6%.

**Q. WHAT WOULD BE STAFF'S OVERALL COST OF EQUITY ESTIMATE USING THE BOOK VALUE BASED DCF AND CAPM DESCRIBED ABOVE?**

A. The average of Staff's DCF and CAPM estimates would increase to 12.8% from 10.3%. Applying Staff's book value based financial risk adjustment of 110 basis

[16] Morin at 364.

[17] Solving for g (growth rate) in the DCF equation, $g = k - D_1/P_0$ where K = return on equity and $D_1/P_0$ = expected dividend yield. The average of Staff's CAPM estimates is 10.6% and Staff's dividend yield is 3.7%, thus the implied growth rate in 10.6% less 3.7% or 6.9%.



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points to Staff's book value based cost of equity estimate would result in an indicated cost of equity of 11.7% as shown below:

| DCF Method | $D_1/B_0$ | + | $g^1$ | = | k |
|---|---|---|---|---|---|
| Constant Growth DCF estimate (book value) | 6.3% | + | 5.7% | = | 12.0% |
| Multi-stage DCF estimate (book value) | | | | | 12.6% |
| Average of DCF estimates | | | | | 12.3% |
| **CAPM Method** | | | | | k |
| CAPM (book value) | | | | | 13.2% |
| | | | | Average | 12.8% |
| | | | | Financial Risk Adjustment[1] | -1.1% |
| | | | | Total | 11.7% |

[1] From Staff Surrebuttal Schedule JCM-3

**Q. WHAT IS THE AVERAGE PERCENTAGE PROJECTED RATE OF RETURN ON BOOK COMMON EQUITY FOR THE WATER UTILITIES SAMPLE MR. MANRIQUE USES TO DETERMINE BENCHMARK COSTS OF EQUITY ESTIMATES?**

A. Based Mr. Manrique's water industry sample and for which Value Line provides projected book returns, the average ROE is 12.0% It is found as the average of Value Line's projected ROEs for American States of 12.0%, for Aqua America of 12.0% and California Water of 12.0%.[18] This compares favorably with the 11.7% estimate shown above and like the 11.7%, it is much higher than the 10.3% estimate of Staff.[19]

**B. <u>Firm Specific Risk</u>**

**Q. PLEASE RESPOND TO MR. MANRIQUE'S TESTIMONY ON PAGE 3 THAT YOU HAVE "CHERRY PICKED" CERTAIN ASPECTS OF OTHER**

[18] Value Line Investment Survey, January 22, 2010.

[19] The unadjusted average of Staff's DCF and CAPM results as shown on Staff Surrebuttal Schedule PCM-3 is 10.3%.

**REGULATORY ENVIRONMENTS TO DISPUTE HIS TESTIMONY THAT DOING BUSINESS IN ARIZONA IS NO LESS RISKY THAT OTHER STATES.**

A. The accusation that I "cherry picked" certain attributes of other regulatory environments is simply not true. Mr. Manrique has not provided specific examples of attributes of other regulatory jurisdictions that I have over looked nor has he disputed my testimony concerning the attributes of other regulatory environments that reduce regulatory and investment risk.[20] I could similarly accuse Mr. Manrique of "cherry picking" his so-called "attractive" Arizona regulatory attributes that he cited in his testimony.[21] The important difference between Mr. Manrique and me is that I addressed and refuted each one of the Arizona attributes he cited with specific responses and examples as to why they did not make Arizona more attractive than other jurisdictions.[22] Mr. Manrique has not disputed that testimony. Consequently, Mr. Manrique fails to support his assertion that Arizona is no different than other jurisdictions because as he states, "it is the overall effect that is relevant".[23]

**Q. PLEASE RESPOND TO MR. MANRIQUE'S TESTIMONY ON PAGE 4 THAT REGULATORY RISK IS A FIRM-SPECIFIC RISK AND INVESTORS CANNOT EXPECT TO BE COMPENSATED FOR FIRM-SPECIFIC RISKS.**

A. Mr. Manrique's assertion is undermined by the fact that the *Bluefield* standard requires the return on equity be commensurate with returns on enterprises with

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[20] Rebuttal Testimony of Thomas J. Bourassa (Cost of Capital) ("Bourassa COC Rb.") at 18 – 20.

[21] Direct Testimony of Juan C. Manrique ("Manrique Dt.") at 41.

[22] Bourassa COC Rb. at 14 – 18.

[23] Manrique Sb. at 3.

comparable risks (the "comparable earning standard"). The impact of the various factors on investment risk that I have discussed throughout my testimony, such as small size, construction risk, regulatory risk, lack of diversification, small customer base, liquidity risk, etc., are factors which make RRUI more risky and therefore not comparable to the large publicly traded water companies.

Mr. Manrique admits, for example, that smaller companies tend to have higher betas than larger companies making smaller companies more risky.[24] It stands to reason that RRUI would have higher beta than the sample water companies.[25] Yet, Mr. Manrique blindly accepts that the average beta of the much larger publicly traded water utilities as the beta for RRUI.[26] Further, Mr. Manrique does not dispute the data contained in Morningstar supporting small company risk premiums.[27] Yet again, Mr. Manrique ignores this evidence.

The only firm-specific risk Staff acknowledges is financial risk. Other risks that would obviously be considered by any rational investor are simply ignored. Would a rational investor really regard an equity investment in RRUI as presenting less risk than an equity investment in Aqua America or in Connecticut Water Services, which have AA- and AAA bond ratings, respectively, for example, notwithstanding the lack of debt in RRUI's capital structure? The answer is a resounding "no".

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[24] Manrique Dt. at 42.

[25] Bourassa COC Rb. at 8.

[26] Manrique Dt. at 28.

[27] Small company risk premiums are the risk premiums not explained by the higher betas for small companies.

### C. Estimates of Growth

**Q. ON PAGE 4, MR. MANRIQUE STATES THAT YOU MAKE THE ASSERTION THAT THE ONLY FACTOR INVESTORS LOOK AT IS ANALYSTS' ESTIMATES OF GROWTH. DO YOU HAVE A COMMENT?**

A. Yes. First, let me state that I do not use analyst estimates exclusively in my cost of capital analysis.[28] Second, Mr. Manrique has misunderstood my testimony and misses the point. That is, if analysts' estimates already consider past growth, then Staff vastly overstates the impact of past growth rates in its DCF model.[29] And, because Staff overstates the impact of historical growth rates in its estimate of growth, Staff's models reflect a type of "double-counting" that produces extremely low results.[30] And, as I have stated, Staff gives less weight to what is arguably the best estimate of growth.[31]

## III. REJOINDER TO RUCO'S COST OF CAPITAL ANALYSIS, TESTIMONY AND RECOMMENDATIONS

### A. Use of Southwest Water to Develop Cost of Equity

**Q. MR. RIGSBY CLAIMS THAT IT IS APPROPRIATE TO INCLUDE SOUTHWEST WATER IN HIS SAMPLE, WHILE EXCLUDING THE REMAINING THREE PUBLICLY TRADED WATER UTILITIES USED BY THE COMPANY AND STAFF. HOW DO YOU RESPOND?**

A. As I have explained in my rebuttal testimony, Southwest Water is not comparable to RRUI. Southwest Water derives less than 50 percent of its revenues from regulated utility services, while the other three utilities on average derive nearly 89

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[28] Bourassa COC Dt. at 28 – 29.

[29] Bourassa COC Rb. at 24.

[30] *Id.*

[31] Bourassa COC Rb. at 23.

percent of revenues from regulated activities.[32] The fact that some of the unregulated services are "closely related" to the water industry doesn't change the fact that these activities aren't regulated. Although the other utilities are engaged in some unregulated activities, they still derive most of their revenues from activities that are regulated.

**Q. MR. RIGSBY CLAIMS THAT SOUTHWEST WATER'S POOR EARNINGS HISTORY AND OTHER FINANCIAL PROBLEMS SHOULD BE IGNORED BECAUSE ALL COMPANIES HAVE VARIATIONS IN THEIR EARNINGS. IT THAT A LEGITIMATE BASIS TO USE UTILITIES IN A WEAK FINANCIAL CONDITION?**

A. No. While it is certainly true that earnings fluctuate, Southwest Water's earnings have been consistently poor and its dividends have been reduced. Southwest Water's equity returns for the period 2004 through 2008 averaged 3.6 percent, and Value Line projects earnings of 3.5 percent in 2009. None of the utilities have had this sort of earnings history, nor do they have C+ financial strength ratings.

**B. Use of Publicly traded Gas Utilities**

**Q. DOES THE COMPANY OBJECT TO THE USE OF THE PUBLICLY TRADED GAS UTILITIES TO ESTIMATE THE COST OF EQUITY, AS MR. RIGSBY CLAIMS IN HIS TESTIMONY?**

A. No. Mr. Rigsby has misunderstood my rebuttal testimony. The point is that the sample gas utilities are less risky and therefore not comparable to water utilities. The gas utilities can be used if the results produced by the DCF and CAPM models are adjusted upward to reflect the water utilities' additional risk. Mr. Rigsby made no such adjustment.

[32] Based on information contained in AUS Utility Reports (January 2010).

However, the gas sample does provide useful information, which demonstrates that RUCO's recommended return on equity is unfair and unreasonable.

**Q. HOW DO THE GAS UTILITIES SUPPORT A HIGHER EQUITY RETURN FOR RRUI?**

A. The Commission recently authorized a 10.0 percent return on equity for Southwest Gas Corporation, based on the recommendation of Staff's cost of capital witness, Mr. Parcell.[33] Moreover, in August 2009, Mr. Parcell provided cost of capital testimony for Staff in the pending rate case for UNS Gas, Inc., again recommending a 10.0 percent return on equity.[34] A decision should be used in the UNS Gas case in the next 60 days. While I don't know what equity return will be approved for the utility, I expect that it will be approximately 10 percent.

Based on these cases, we know that a return on equity of 10 percent is just and reasonable for an Arizona gas utility. As I explained in my rebuttal testimony, Mr. Rigsby's water industry sample has a beta of 0.83, while his gas industry sample has a beta of just 0.67.[35] That means that the equity cost for a water utility is greater than a gas utility, based on their relative riskiness. In my rebuttal testimony, I estimated that the cost of equity for the water industry sample should be 120 basis points greater than the gas industry sample, using the methodology employed by Staff in the Arizona Water Company Eastern Group case.[36] Consequently, if gas utilities are used, a significant upward adjustment above the

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[33] Decision No. 70665.

[34] *See* Direct Testimony of David C. Parcell, filed June 8, 2009 in Docket No. G-04204A-08-0571.

[35] *See* RUCO Schedule WAR-7, page 1 of 2.

[36] In that case, Staff estimated that the cost of equity for the gas utilities was 10.4% using the CAPM, while the cost of equity for the water utilities was 9.4% – a difference of 100 basis points. *See* Direct Testimony of Joel M. Reiker, filed July 8, 2003 in Docket No. W-01445A-02-0619 ("Reiker Dt."), at Schedule JMR-7 and JMR-18.

10 percent floor established in the Southwest Gas case must be made to properly reflect the water industry's higher risk.

**Q. SO THE POINT IS NOT WHETHER IT'S IS APPROPRIATE TO USE A SAMPLE OF GAS UTILITIES, BUT HOW THEY ARE USED?**

A. Exactly. Mr. Rigsby has failed to properly use the gas industry sample by ignoring the differences in risk between the water and gas industries, as estimated by beta. It is a simple matter to adjust the 10 percent return on equity for an Arizona gas utility upward to account for the additional risk associated with a water utility, as Staff has done in previous cases. With this adjustment, the indicated cost of equity for an Arizona water utility (unadjusted for other risks) is 11.2 percent, not 7.9 percent, as Mr. Rigsby has estimated.

**C. <u>RUCO's Purported Generosity</u>**

**Q. MR. RIGSBY TESTIFIES ON PAGE 6 OF HIS SURREBUTTAL TESTIMONY THAT RUCO'S RECOMMENDED RETURN ON EQUITY OF 9.0 PERCENT "IS ACTUALLY GENEROUS." DO YOU AGREE WITH THIS CHARACTERIZATION OF RUCO'S POSITION?**

A. It is preposterous. But we all need a good laugh now and then, and Mr. Rigsby's testimony kept me laughing out loud for several minutes.

**Q. WHY IS MR. RIGSBY'S TESTIMONY PREPOSTEROUS?**

A. For a number of reasons. First, Mr. Rigsby is not proposing a return on RRUI's equity of even 9.0 percent. When RUCO's hypothetical capital structure is considered, the resulting return on equity is only 6.9 percent – a return that is very nearly equal to an investment grade bond. Such a return would be confiscatory, not generous.

Second, the Commission has consistently relied on market-based finance models such as the DCF and CAPM models to estimate the current cost of equity,

with adjustments for firm-specific risk. For example, in a recent decision setting rates for Arizona Water Company, the Commission stated:

> In estimating its cost of equity, Arizona Water relied on a risk premium analysis methodology used by the [California] PUC staff, which uses comparisons to actual or authorized returns on equity. This sort of "comparable earnings" analysis has long been discredited for several reasons, … . Market-based methods like the DCF model and the CAPM provide more reliable estimates of equity cost, because it is capital markets, not regulatory commissions that determine the cost of equity. Use of the risk premium analysis urged by the Company would circumvent the market forces that regulation attempts, as much as possible, to replicate. … The risk premium analysis methodology erroneously assumes that accounting-based "actual" ROEs are equal to the cost of equity.[37]

In this case, all of the parties relied on the DCF and CAPM models to estimate RRUI's cost of equity, using as proxies much larger, publicly traded utilities. The results of the parties' models are:

| Party | DCF | CAPM | Average |
|---|---|---|---|
| RRUI | 10.1% | 13.4% | 11.7% |
| Staff | 9.9% | 11.0% | 10.5% |
| RUCO | 9.7% | **6.10%** | 7.9% |

RUCO's extremely low estimate is obviously driven by its 6.1 percent CAPM estimate. If that estimate is excluded – as it must be, given that it is less than the cost of debt – the average of the parties' DCF estimates is 9.9 percent, while the average of their CAPM estimates is 11.1 percent, resulting in an average equity cost of 10.5 percent. I believe that 10.5 percent is too low for RRUI. But 10.5 percent is certainly greater than RUCO's 9.0 percent equity cost for the sample utilities and RUCO's effective return of 6.9 percent for RRUI.

[37] *Arizona Water Company (Western Group)*, Decision No. 68302 (November 14, 2005) at 37 – 38.

Third, as I just discussed, the equity returns being authorized for Arizona gas utilities is approximately 10 percent. Water utilities are riskier and have a higher cost of equity than gas utilities. This indicates that RRUI's cost of equity is much higher than either 6.9 percent or 9.0 percent.

Finally, Mr. Rigsby's contention that RRUI's cost of equity should be less than the DCF and CAPM models indicate because water utilities are viewed as "safe investments for income oriented investors" ignores the fact that water utility stocks are nevertheless a risky investment at present. For example, Value Line's water utility industry analyst, Andre J. Costanza, recently warned investors that the "risk profiles of [the water utility stocks] are higher than one might think," and stated that investors "with a more conservative bent and an affinity for income can do better by looking elsewhere, specifically the Electric Utility segment."[38] This indicates that the water utility industry is currently viewed by investors as being riskier than both the electric and gas utility industries, and requires higher equity returns to compete for investor capital. Yet RUCO's effective return for RRUI is approaching the current yield on investment grade bonds. Obviously, RUCO's approach fails to recognize the risk inherent in an investment in the common stock of a publicly traded water utility, and would produce a return for RRUI that is unlawful.

**Q. DID MR. RIGSBY EVALUATE THE COST OF EQUITY FOR ELECTRIC UTILITIES?**

A. No. I suspect he did not do so because it would have supported an even higher cost of equity. He selected the gas industry because its beta is lower and, therefore, the gas industry produces a lower CAPM estimate. It is important to remember that

[38] Value Line, Water Utility Industry (January 22, 2010).

RUCO's goal is to force the cost of equity as low as possible, and a fair and honest assessment of the cost of equity for companies than are truly comparable to RRUI is not consistent with that goal.

**D. <u>RUCO's Implementation of the CAPM</u>**

**Q. PLEASE SUMMARIZE YOUR CONCERNS WITH MR. RIGBY'S CAPM ANALYSIS.**

A. In my rebuttal testimony, I described five problems with Mr. Rigsby's CAPM analysis. Perhaps most importantly, three out of four of Mr. Rigsby's CAPM estimates (one for the water industry and two for the gas industry), as well as his overall CAPM result, are at or below the current cost of Baa investment grade bonds, which is approximately 6.3 percent.[39] The following are the results of Mr. Rigsby's CAPM as shown on WAR-1, page 3 of 3:

| | |
|---|---|
| Geometric mean CAPM estimate - water industry | 5.72% |
| Arithmetic mean CAPM estimate - water industry | 7.29% |
| Geometric mean CAPM estimate - gas industry | 5.05% |
| Arithmetic mean CAPM estimate - gas industry | 6.32% |
| Overall CAPM result | 6.10% |

In contrast, the Company's CAPM estimates average 13.4 percent, while Staff's CAPM estimates average 11.0 percent. Clearly, something is wrong with the methods and inputs Mr. Rigsby has selected. The most serious problems with RUCO's CAPM, in summary, are

(1) RUCO uses geometric means to estimate the market risk premium which are conceptually incorrect and result in very low CAPM estimates.

[39] Federal Reserve, January 15, 2010.

(2) RUCO uses conceptually incorrect 5 year U.S. Treasuries for its risk-free rate.

(3) RUCO's CAPM results of RUCO's are at or below the cost of investment grade bonds.

**Q. AT PAGE 9 OF HIS TESTIMONY, MR. RIGSBY ARGUES THAT BOTH THE GEOMETRIC AS WELL AS THE ARITHMETIC ANNUAL AVERAGES SHOULD BE CONSIDERED WHEN ESTIMATING THE MARKET RISK PREMIUM. DO YOU HAVE A RESPONSE?**

A. I addressed this in my rebuttal testimony.[40] I also attached an excerpt from Dr. Morin's textbook in my Exhibit TJB-COC-RB3 to that testimony to show why no weight should be given to geometric annual averages when computing the market risk premium ("MRP"). At page 8, lines 22-24, Mr. Rigsby says that consideration of geometric annual averages is "particularly relevant in the case of the return on the stock market, which has had its share of ups and downs." He is correct that the stock market has been volatile. In fact, the stock market has been unusually volatile in the past 5 years. But such volatility is only recognized by the arithmetic annual average. By contrast, the geometric annual average simply compares two observations – the one at the start of the period and the one at the end of the period. It ignores the variability in returns that occurred between the beginning and ending points, and therefore understates the risk associated with the market. A good illustration of this point is found in Dr. Morin's textbook on page 134, attached to my rebuttal testimony as Exhibit TJB-COC-RB3, which compares the historical returns of two stocks calculated using arithmetic and geometric averages.

[40] Bourassa COC Rb. at 36 – 37.

**Q. DOES MR. RIGSBY'S EXAMPLE ON PAGES 10 AND 11 OF HIS SURREBUTTAL TESTIMONY JUSTIFY USING GEOMETRIC ANNUAL AVERAGES TO FORECAST THE FUTURE?**

A. No. His example correctly shows that the geometric annual average is the best way to describe what has happened in the past, but our goal is to forecast what may happen in the future. When we are determining a forecast of the future from past data, we never know what the final outcome will be when we hold risky assets. Therefore, we look at an average of all of the annual returns from the past to try and glean what may happen. If we actually know what is going to happen – as Mr. Rigsby assumes – the asset would be risk-less and not a risky asset like a common stock.

**Q. AT PAGE 12, MR. RIGSBY CITES A BOOK BY COPELAND, KOLLER AND MURRIN ("CKM") TO SUPPORT HIS CLAIM THAT A TRUE MARKET RISK PREMIUM MAY LIE SOMEWHERE BETWEEN THE ARITHMETIC AND GEOMETRIC ANNUAL AVERAGES. DOES IT?**

A. No. At page 219, the authors state:

> The arithmetic average is the best estimate of future expected returns because all possible paths are given equal weighting. The simple geometric average return is 0 percent [in exhibit 10.6], but this is the historical return along a single path that was realized by chance. Although the geometric return is the correct measure of historical performance, it is not forward-looking.

**Q. AT PAGE 12, LINES 18-22, MR. RIGSBY ALSO CLAIMS THE CKM BOOK SHOWS THAT YEAR-TO-YEAR RETURNS ARE NOT INDEPENDENT, WHICH MEANS THAT THE ARITHMETIC AVERAGE BASED ON AN AVERAGE OF ANNUAL RETURNS HAS LESS CREDENCE. WHAT DOES CURRENT RESEARCH SHOW ON THIS POINT?**

A. Morningstar provides updated evidence on this point. Morningstar has determined that the yearly difference between the stock market total return and the income return on long-term Treasury securities in any particular year is random, i.e., there is no serial correlation.[41] Therefore, the arithmetic average of those annual returns provides the best estimate of the average of all "possible paths" of concern to CKM. Also, if annual returns are independent of each other, it is appropriate to use annual periods, rather than a longer period such as two years or three years, as is suggested by Mr. Rigsby at page 13, to compute arithmetic averages.

**Q. AT PAGE 13 OF HIS TESTIMONY, MR. RIGSBY ALSO DISCUSSES OTHER POTENTIAL DATA PROBLEMS RAISED BY CKM AND STATES THAT AFTER CKM CONSIDERED THOSE PROBLEMS, THEIR ESTIMATE OF THE MRP WAS IN THE RANGE OF 4.0% TO 5.5%. IS HE CORRECT?**

A. No. Based on the data in CKM Exhibit 10.8, they determined that the MRP based on arithmetic annual averages was 7.5%, which is consistent with Morningstar, Morin and other reliable sources. They then arbitrarily substitute an average based on two-year periods, 6.5%, and combine that average with a negative adjustment of 1.5% to 2.0% to account for their subjective view that U. S. stock markets will not do as well during the next 100 years as they have in the past, to determine a MRP range of 4.5% to 5.0%. Given the updated analysis in Morningstar, which shows that annual market returns are random and are not influenced by returns in the prior year, the correct MRP estimated by these authors is 7.5% if we do not apply their subjective downward adjustment. Mr. Rigsby should have relied upon the 7.5% MRP in his CAPM estimate.

[41] Morningstar, Ibbotson SBBI 2009 Valuation Yearbook, p 60.

**Q. ARE THERE OTHER PROBLEMS WITH MR. RIGSBY'S CALCULATIONS AT PAGE 13?**

A. Yes. He adds the risk premium range determined by CKM to a 5-year Treasury bond rate, when the MRP range computed by CKM was based on differences between returns for large company stocks and long-term government bonds. This inconsistency must be corrected if data from CKM are used to make the CAPM estimate. Without the correction, his choice of a 5-year Treasury bond rate biases downward the equity cost range.

**Q. WHAT HAPPENS TO HIS CAPM EQUITY COST ESTIMATE AT PAGE 13, LINE 17 IF YOU MAKE THE TWO CORRECTIONS YOU HAVE IDENTIFIED?**

A. It increases the equity cost, which Mr. Rigsby determined to fall in a range of 6.26% to 7.76%[42], to 11.9%. The 11.9% is found by adding together a current long-term Treasury rate of 4.4% and the 7.5% MRP actually estimated by CKM. Mr. Rigsby notes that since utilities are generally somewhat less risky than the market as a whole and suggests his 9.0% cost of equity is too high.[43] If we combine his beta of 0.83[44] to account for this lower utility risk, his revised CAPM indicates the cost of equity for a typical water utility is 10.6%, found as

$$\text{Equity cost} = 4.4\% + (0.83 \times 7.5\%) = 10.6\%$$

**Q. ON PAGE 14 OF HIS TESTIMONY, MR. RIGSBY SUGGESTS THAT YOU WERE INCORRECT IN YOUR CRITICISM OF HIS USE OF TOTAL RETURNS ON BONDS TO COMPUTE HIS MARKET RISK PREMIUM. PLEASE COMMENT.**

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[42] Rigsby Sb. at 13.

[43] *Id.*

[44] *See* RUCO Schedule WAR-1, page 3 of 3.



FENNEMORE CRAIG
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A. As I testified, if the total return on a Treasury security is used, additional risk from capital loss or gain is injected into the CAPM estimate, which is inconsistent with treating the Treasury security as a riskless asset.[45] Thus, income returns rather than total returns should be used in the estimation of the equity risk premium.[46] Mr. Rigsby admits that Treasury security income returns ignore the fluctuations in the price of the bonds - which is exactly what is required for treating the security as a riskless asset. I would note that, in the instant case, Staff does not use a MRP based upon total returns in its CAPM estimates, presumably for the same reasons.[47]

**Q. DOES THE FACT THAT UTILITY RATES ARE NOT SET EVERY THIRTY YEARS HAVE ANYTHING TO DO WITH THE PROPER CHOICE OF THE LENGTH OF THE TREASURY THAT SHOULD BE USED IN THE CAPM AS SUGGESTED BY MR. RIGSBY ON PAGE 14 OF HIS TESTIMONY?**

A. No. This is nonsense. As I explained in my rebuttal testimony, the expected stock return is based upon long-term cash flows, regardless of an individual's holding period.[48] Moreover, short term rates are volatile, fluctuate widely, and are subject to more random disturbances leading to volatile and unreliable equity returns.[49]

**Q. DOES THE ARGUMENT THAT THE ECONOMY IS IMPROVING MAKE THE USE OF A CURRENT MARKET RISK PREMIUM PASSE?**

A. Again, no. I find it odd that Mr. Rigsby now seeks to dismiss any consideration of the current economic conditions. After all, he acknowledges the importance of

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[45] Bourassa COC Rb. at 37 – 38.

[46] Id. at 38.

[47] Manrique Dt. at 29. Staff uses historical market risk premium calculated from Ibbotson Associates SBBI 2009 Yearbook data.

[48] Bourassa COC Rb. at 38 – 39.

[49] *Id.* at 39.

considering current economic conditions.[50] As I have testified, changes in the current market risk premium have been a significant factor in the cost of equity authorized by the Commission in the past.[51] And, the current market risk premium has had impact on the cost of equity in both directions over the years.[52] My current market equity risk premium of 13.1% in the instant case is no larger than current market risk premiums employed by Staff and relied upon when adopting Staff cost of equity in the past.[53] Further, while economic conditions have improved since the start of the recession in 2008, unemployment remains high and the economic outlook is still uncertain. Value Line recently commented that "the strength and sustainability of the economic recovery are open questions at this time".[54]

**Q. ON PAGE 15 AND 16, MR. RIGSBY STATES HIS RECOLLECTION OF COMMENTS MADE BY PROFESSOR DAMODARAN AND PROFESSOR MARSTON AT A 2007 CONFERENCE HE SAYS HE ATTENDED. DO STUDIES MADE BY THOSE PROFESSORS LEAD YOU TO QUESTION WHETHER THEY WOULD ENDORSE A RANGE OF MRPS OF 4.0% TO 5.5% IN 2010?**

A. Yes. I was not at the 2007 conference and do not know what was actually said and in what context. I am also not aware of the studies upon which the panelists relied. I am aware of a 2009 estimate of the current MRP estimated by Professor Damodaran and I am also aware of a paper written by Dr. Marston which suggests these two would not say the current MRP fails in a range of 4.0% to 5.0%. First, with respect to Professor Damodaran, I am aware that his current estimate of the

[50] Rigsby Dt. at 38 – 39.

[51] Bourassa COC Rb. at 41 – 42.

[52] *Id.* at 42.

[53] *Id.* at 40.

[54] Value Line *Selection and Opinion*, February 26, 2010.



FENNEMORE CRAIG
PROFESSIONAL CORPORATION
PHOENIX

MRP is 6.43%. Work papers supporting that estimate were provided by Department of Ratepayer Advocates witness Professor J.R. Woolridge in California PUC Application 09-05-001, et al., which went to hearing in August 2009. I was a witness in that case for Valencia Water (Application 09-05-002) and reviewed the work papers supporting the Damodaran estimate. It is possible that Professor Damodaran presented a lower MRP estimate in 2007.

Second, with respect to Professor Marston, I am aware of a paper, "Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice between Global and Domestic CAPM, published in Financial Management (Autumn 2003), co-authored with Robert Harris, Dev Mishra and Thomas O'Bien, Professor Marston estimated the MRP to be 7.3% based on data for a 16 year period ending in 1998. Given her past published study, I am puzzled she would state that the MRP has dropped to less than 5.5% at a conference. As with Professor Damoradan, it is possible that Professor Martson presented a lower estimate in 2007, but I am not sure on what basis Professor Martson would have based her opinion.

**Q. WERE CURRENT MARKET RISK PREMIUMS LOWER DURING THIS TIME PERIOD?**

A. As I discussed in my rebuttal testimony, during the Black Mountain Company rate case in 2006, Staff computed a current MRP of 5.7%, which was much lower than earlier estimates which over 13%.[55] The 5.7% is near the range allegedly offered by the panelists mentioned by Mr. Rigsby.

**Q. DO YOU HAVE ANY RESPONSE TO THE CAPM CALCULATIONS PRESENTED AT PAGE 16 AND 17 BY MR. RIGSBY?**

[55] Bourassa COC Rb. at 40.

A. Yes. These calculations are simply mechanical applications of the simple version of the CAPM. They rely on the wrong interest rate concept and MRPs attributed to someone who is not a witness in this case. There is no reason to believe the 4% or the 5% MRPs are reasonable at this time. Notwithstanding the fact that there is no support for either of these calculations, there are serious problems with Mr. Rigsby's claim that equity cost estimates of 5.58% and 6.41% are reasonable when the cost of Baa bonds was 6.48%. A reasonable estimate of the cost of equity must be higher than the cost of Baa bonds.

**E. <u>RUCO's Hypothetical Capital Structure</u>**

**Q. PLEASE SUMMARIZE THE FINAL POSITIONS OF THE PARTIES CONCERNING THE COMPANY'S CAPITAL STRUCTURE AND WHAT, IF ANY ADJUSTMENTS TO THAT CAPITAL STRUCTURE ARE APPROPRIATE FOR RRUI.**

A. RRUI's actual capital structure consists of 100 percent equity. RRUI and Staff propose the use of the Company's actual capital structure to develop the WACC and required rate of return on rate base, which is consistent with RRUI's prior rate case and other water and wastewater utility rate cases in this jurisdiction. Staff proposes a direct, downward adjustment to the cost of equity of 110 basis points in order to account for the Company's reduced financial risk that is calculated using the Hamada formula. I also propose such a reduction, but of a smaller magnitude. As I have explained, Staff's adjustment is incorrectly calculated and erroneously assumes the RRUI would have the same beta as the water utility sample.

RUCO, however, has taken a much different tack, and argues that a hypothetical capital structure should be imputed to RRUI, containing 40 percent hypothetical debt at a hypothetical interest rate of 6.26 percent. This produces a



ENNEMORE CRAIG
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WACC of 7.9 percent (which happens to also equal the cost of equity produced Mr. Rigsby's DCF and CAPM models). In his direct testimony, Mr. Rigsby justified this unusual regulatory treatment by claiming it is necessary to properly account for RRUI's lower level of financial risk, resulting from the absence of debt in RRUI's capital structure as compared to the amount of debt in the capital structures of the large, publicly traded utilities used in the his DCF and CAPM models.[56] Now, in his surrebuttal testimony, Mr. Rigsby has brought out a new argument: A hypothetical capital structure is needed to reduce the Company's earnings. In other words, RRUI should be punished for not having a capital structure that is similar to the capital structure of a large, publicly traded utility.

As I stated in my rebuttal testimony, this is unfair and confiscatory. Mr. Rigsby effectively turns 40 percent of the investor's equity investment into debt and then provides a return on that equity investment equal to only 6.26 percent. Moreover, Mr. Rigsby creates fictional interest expense resulting from fictional debt with a fictional interest rate to eliminate income tax expense and, ultimately, lower RRUI's test year operating expenses by nearly $100,000. That reduction reduced the Company's actual rate of return on rate base to approximately 6.9 percent – a return that is hundreds of basis points less than the cost of equity indicated by the parties finance models.

**Q. WHY IS THE REGULATORY TREATMENT ADVOCATED BY RUCO UNUSUAL, MR. BOURASSA?**

A. In recent decisions involving water and sewer utilities, the Commission has used the utility's actual capital structure and, in some cases, has adjusted the return on equity to account for financial risk. When it has made an adjustment for financial

[56] Rigsby Dt. at 54 – 55.

risk, the Commission has done so by adding or subtracting basis points from the cost of equity. The use of a hypothetical capital structure has been rarely used, and normally only in unusual cases such as the Tucson Electric Power Company case, discussed in Mr. Rigsby's surrebuttal testimony, where the utility was insolvent and had a capital structure consisting of 100 percent debt.[57]

For example, in a recent rate case for Arizona-American Water Company's ("Arizona-American") Paradise Valley District, the Commission adopted Staff's 10.4 percent return on common equity, which included an upward adjustment of 50 basis points to account for the high percentage of debt in that utility's capital structure.[58] In approving this approach, the Commission explained: "RUCO and Staff appropriately addressed the Company's higher debt ratio *by the generally accepted regulatory means of accounting for financial risk*, adding basis points to the results of their CAPM and DCF analyses."[59] Notably, in that case, Mr. Rigsby "added 50 basis points to his cost of equity estimate to account for the increased financial risk faced by Arizona-American as a result of the Company's debt-heavy capital structure," just as he did in Arizona-American's prior rate case, decided in 2004.[60] RUCO did not propose a hypothetical capital structure.

In other recent cases involving larger-sized Arizona water and wastewater utilities, the Commission has made an adjustment for financial risk in some cases but not in others.[61] In RRUI's previous case, for example, the utility had a capital

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[57] Rigsby Sb. at 21 – 22.

[58] *Arizona-American Water Company*, Decision No. 68858 (July 28, 2006) at 28.

[59] *Id.* (emphasis supplied).

[60] *Id.* at 25.

[61] *See, e.g.*, Decision No. 68302 at 30, 34 – 36 (73.4 percent equity; no financial risk adjustment); *Chaparral City Water Company*, Decision No. 68176 (September 30, 2005) at 16, 25 – 26 (58.7 percent equity; no financial risk adjustment); *Arizona Water Company* (Eastern Group), Decision No. 66849 (March 19, 2004) at 23 – 24, (66.2 percent common equity; Staff's 20 basis point downward adjustment for financial risk rejected).

structure consisting of 100 percent equity and no debt, but no adjustment was made for financial risk.[62] More recently, in Black Mountain Sewer Corporation's rate case, the utility and Staff recommended the use of the utility's 100 percent equity capital structure, while RUCO proposed a hypothetical capital structure containing 57 percent equity and 43 percent debt.[63] The rationale provided by RUCO for using a hypothetical capital structure in Black Mountain's case is the same rationale that RUCO provided in this case:

> The water utilities in my sample, from which I derived an estimated cost of common equity of 9.49 percent, would be considered as having a higher level of financial risk (i.e. the risk associated with debt repayment) because of their higher levels of debt. The additional financial risk due to debt leverage is embedded in the cost of equities [sic] derived for those companies through the DCF analysis. Thus, the 9.49 percent cost of equity derived in my DCF analysis is applicable to companies that are more leveraged and, theoretically speaking, riskier than a utility with no debt in its capital structure.[64]

The Commission rejected RUCO's proposed hypothetical capital structure, concluding that a capital structure comprised of 100 percent equity should be used in calculating Black Mountain's cost of equity. The Commission stated: "We believe RUCO's hypothetical capital structure recommendation *is results oriented and is not consistent with the Company's actual capital structure*."[65] Instead, the Commission adopted the utility's actual capital structure containing 100 percent equity, and explained "that adoption of Staff's recommendation results in a just and reasonable return for [Black Mountain]."[66]

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[62] *Rio Rico Utilities, Inc.*, Decision No. 67279 (October 5, 2004) at 11.

[63] Decision No. 69164 at 19.

[64] Direct Testimony of William A. Rigsby, filed March 9, 2006 in Docket No. SW-02361A-05-0657, at 52.

[65] Decision No. 69164 at 20 (emphasis supplied).

[66] *Id.* at 27, 39 (finding of fact 19).

In short, as these examples show, the Commission does not consider using a hypothetical capital structure to account for financial risk, absent unusual circumstances, such as the Tucson Electric case and, in fact, does not always adjust the utility's cost of equity, even when its capital structure contains no debt.

**Q. IF, AS THE COMMISSION HAS STATED, THE "GENERALLY ACCEPTED REGULATORY MEANS OF ACCOUNTING FOR FINANCIAL RISK" IS ADJUSTING THE CAPM AND DCF ANALYSES, HOW DO YOU EXPLAIN THE COMMISSION'S DECISION IN THE GOLD CANYON SEWER COMPANY RATE CASE?**

A. I can't. That decision[67], which is discussed in Mr. Rigsby's direct testimony[68], is best viewed as outlier. It conflicts with the decisions described above and contains no explanation of why the Commission rejected use of the Hamada formula, which, as explained, is the method normally used to account for financial risk.[69] That is one of the reasons why the utility appealed the Commission's decision. Given the lack of any explanation or reasoning for what the Commission did, it certainly doesn't alter the fact that the Commission normally adjusts the cost of equity upward or downward to account for financial risk and, in a number of cases, has made no adjustment at all.

**Q. SINCE WE ARE DEALING IN HYPOTHETICALS, IF A FICTITIOUS CAPITAL STRUCTURE WITH FICTITIOUS DEBT WERE IMPUTED TO RRUI, DOES THAT MEAN THAT RRUI'S INCOME TAX EXPENSE SHOULD BE REDUCED?**

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[67] *Gold Canyon Sewer Company*, Decision No. 70624 (November 9, 2008).

[68] Rigsby Dt. at 54 – 55.

[69] Decision No. 70624 at 14 (finding of fact 32).

A. Absolutely not. As Mr. Rigsby explained in his direct testimony, the purpose of using a hypothetical capital structure is to account for financial risk, not as an excuse to lower operating expenses.[70]

However, in his surrebuttal testimony, Mr. Rigsby now contends that the Hamada formula should not be used because it fails to produce a weighted cost of debt that can be used in an interest synchronization calculation.[71]

**Q. I AM CONFUSED, MR. BOURASSA. WHAT DOES INTEREST SYNCHRONIZATION HAVE TO DO WITH WHETHER AN ADJUSTMENT TO COST OF EQUITY IS APPROPRIATE TO ACCOUNT FOR FINANCIAL RISK?**

A. I understand your confusion. Interest synchronization has nothing to do with developing an appropriate cost of equity. It is instead intended to match a utility's interest expense with the portion of the utility's rate base financed by debt. RRUI, however, has no debt in its capital structure and thus has no interest to synchronize with its rate base. RUCO's adjustment is entirely fictitious and, frankly, punitive in nature.

**Q. WHY IS IT PUNITIVE?**

A. Because as Mr. Rigsby's surrebuttal testimony shows, RUCO is actually using its recommended hypothetical structure to lower RRUI's operating expenses, not to develop an appropriate cost of equity. In effect, RRUI and its shareholder are being punished because they have financed their plant with equity. The penalty being imposed is the loss of almost $100,000 of operating expenses, in addition to having the WACC reduced by the imputation of fictional debt at an unrealistic cost. This penalty will discourage investment in Arizona, and ensure that RRUI cannot

[70] Rigsby Dt. at 54 – 55.

[71] Rigsby Sb. at 20.

earn a reasonable return on its invested capital. Thus, it is both bad policy and unlawful.

The new argument presented by Mr. Rigsby also cannot be squared with the Commission decisions I discussed earlier. In the Black Mountain rate case, for example, Staff's cost of capital witness, in explaining why no adjustment to the utility's return on equity was appropriate, stated:

> Staff's ROE recommendation does not reflect a financial risk adjustment due to the lower financial risk reflected in the Applicant's capital structure in relation to that of the sample companies because *the Applicant's capital structure is reasonable and the Applicant should be encouraged, not discouraged, to maintain a healthy capital structure.*[72]

As I stated, in that case, the Commission adopted Black Mountain's actual capital structure containing 100 percent equity, and explained that adoption of Staff's recommendation results in a just and reasonable return.

The bottom line is that both the Hamada formula and a hypothetical capital structure are tools to develop an appropriate cost of equity. Neither is intended to be used to manipulate a utility's income tax expense, and thereby prevent the utility from actually earning its authorized rate of return.

**F. <u>RUCO's Unrealistic Cost of Debt</u>**

**Q. PLEASE COMMENT ON MR. RIGSBY'S HYPOTHETICAL COST OF DEBT.**

A. As already mentioned, Mr. Rigsby's hypothetical cost of debt, applicable to 40 percent of his hypothetical capital structure, is 6.26 percent. He bases this debt cost on the average weighted cost of debt for the large, publicly traded water utilities in his water proxy group. As I previously discussed, those water utilities

[72] Surrebuttal Testimony of Pedro M. Chaves, filed May 4, 2006 in Docket No. SW-02361A-05-0657, at 2 (emphasis supplied).



ENNEMORE CRAIG
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have, on average, net plant of $1.47 billion and revenue of $488 million. Moreover, because of their size and the fact that they issue debt in the public markets, these utilities have published bond ratings. Mr. Rigsby assumes that RRUI could raise debt capital at the same cost as these entities. I seriously doubt that it could, and note that Mr. Rigsby has presented no evidence to support his assumption.

**Q. DO YOU HAVE ANY ADDITIONAL COMMENTS ON MR. RIGSBY'S UNREALISTIC HYPOTHETICAL DEBT COST?**

A. Yes. Mr. Rigsby continues to assert that because the Company's parent has access to the capital markets, the Company can obtain debt financing at a cost of 6.26 percent per annum, i.e., the current yield on a Baa bond. This debt cost is based on the average weighted cost of debt for the large, publicly traded water utilities in his water proxy group. As I have discussed in my previous testimony, those water utilities have, on average, net plant of $1.47 billion and revenue of $488 million. Moreover, because of their size and the fact that they issue debt in the public markets, these utilities have published bond ratings. They are much different from RRUI in terms of operating income, cash flow, investment in plant, and other criteria that would be considered by a lender.

Mr. Rigsby apparently acknowledges that RRUI could not borrow the equivalent of 40 percent of its capitalization – about $4.5 million – at an interest rate approaching 6.26 percent. He argues instead that the Company's parent should obtain debt financing for the Company. This is illogical. An equity investor is not required to provide debt financing to the firm by virtue of holding the firm's common stock. To my knowledge, the shareholders of Aqua America and California Water Service aren't required to secure debt financing for those utilities.

If that were the case, the return on equity would have to be increased substantially in order to compensate shareholders for acting as lenders.

**Q. HAS MR. RIGSBY PROPOSED TO ADD A PREMIUM TO THE AUTHORIZED RETURN ON EQUITY TO COMPENSATE FOR THE ADDITIONAL RISK OF PROCURING DEBT FINANCING FOR RRUI?**

A. No. The authorized return on equity must compensate investors for the risks they have assumed by investing their capital in the enterprise. If those risks also include providing debt financing, a higher return on equity is required. Yet RUCO proposes an effective return on equity of 6.9 percent for RRUI, which is barely above an investment grade bond and far less than equity return estimated by the parties for the industry sample groups. Again, RUCO's recommendations are punitive and should be rejected.

**Q. DOES THAT CONCLUDE YOUR REJOINDER TESTIMONY ON COST OF CAPITAL?**

A. Yes.

FENNEMORE CRAIG, P.C.
Jay L. Shapiro (No. 014650)
Todd C. Wiley (No. 015358)
3003 N. Central Ave.
Suite 2600
Phoenix, Arizona 85012
Attorneys for Rio Rico Utilities, Inc.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF RIO RICO UTILITIES, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER AND WASTEWATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON. | DOCKET NO: WS-02676A-09-0257 |

**REBUTTAL TESTIMONY OF**

**PETER EICHLER**

**February 1, 2010**

EXHIBIT
A-10
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY ..... 1

II. SUMMARY OF TESTIMONY ..... 2

III. ALGONQUIN/LIBERTY WATER SHARED SERVICES MODEL AND AFFILIATE COST ALLOCATION METHODOLOGY ..... 3

IV. REBUTTAL TO STAFF AND RUCO ADJUSTMENTS TO CENTRAL COST ALLOCATIONS ..... 19

A. Rebuttal to Staff. ..... 19

B. Rebuttal to RUCO ..... 32

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## I. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Peter Eichler. My business address is 2~~4~~85 Bristol Circle, Oakville, Ontario L6A 7H7.

**Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?**

A. I am providing this rebuttal testimony on behalf of Rio Rico Utilities, Inc. ("RRUI" or the "Company").

**Q. DID YOU PREVIOUSLY PROVIDE TESTIMONY ON BEHALF OF THE COMPANY IN THIS CASE?**

A. No.

**Q. BY WHOM ARE YOU EMPLOYED AND IN WHAT CAPACITY?**

A. Currently, I am employed by Liberty Water Canada as Manager of Financial Planning & Analysis.

**Q. PLEASE SUMMARIZE YOUR WORK RESPONSIBILITIES?**

A. I am in charge of financial planning for Liberty Water, including ensuring overall accountability for rate cases. I am also responsible for analyzing regulatory related accounting and finance issues and responding to related discovery issues.

**Q. WHAT IS YOUR EDUCATIONAL AND EMPLOYMENT EXPERIENCE?**

A. I have been employed at Liberty Water for approximately 6 months. Prior to my employment at Liberty Water, I spent 4 years at regulated electrical utilities in Ontario, Canada, working in the areas of Corporate Finance, Ratemaking and Regulatory Affairs.

I am a designated accountant, having received the Certified Management Accountant (CMA) designation in Canada. That designation is similar to a Certified Public Accountant designation in the United States. In addition, I have completed a Masters of Business Administration degree from the University of



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Windsor in Ontario, Canada, and have a Bachelor of Commerce degree with a specialization in Finance from Ryerson University, in Toronto, Canada.

**Q. DO YOU HAVE ANY SPECIALIZED TRAINING RELATED TO UTILITY RATEMAKING?**

A. In addition to my work experience, I have also completed NARUC's Utility School in November, 2009.

## II. SUMMARY OF TESTIMONY

**Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?**

A. The purpose of my rebuttal testimony is to provide a detailed explanation of Liberty Water's affiliate cost allocation methodology in response to the direct testimonies of Mr. Gerald W. Becker on behalf of Commission Staff and Mr. Timothy J. Coley on behalf of RUCO relating to Liberty Water's affiliate cost allocations to RRUI.

Based on my review of Staff's and RUCO's testimony, it appears that Staff and RUCO do not fully understand our affiliate cost methodology and the benefits provided to RRUI and our other regulated utilities in Arizona through services provided by Algonquin Power Trust ("APT") and Algonquin Water Services d/b/a Liberty Water ("Liberty Water"). Both Staff and RUCO seem intent on opposing RRUI's affiliate cost allocations from APT, irrespective of the undisputed evidence that RRUI provides high quality utility service at a reasonable cost. In this rebuttal testimony, I provide a detailed explanation of the affiliate cost allocation methodology used by the regulated utility affiliates of Liberty Water Company, Inc. ("LWC") including RRUI, Litchfield Park Service Company, Black Mountain Sewer Company, Gold Canyon Sewer Company, Bella Vista Water Company, Northern Sunrise Water Company, and Southern Sunrise Water Company

(collectively the "Regulated Utilities"). The Regulated Utilities are wholly-owned subsidiaries of LWC, which is owned by Algonquin Power Income Fund ("APIF").

We have prepared a detailed paper entitled "Liberty Water Affiliate Cost Allocation Methodology," which is attached to my testimony as **Exhibit PE-RB1**. That paper explains in detail all of the affiliate cost allocations to the Regulated Utilities by Liberty Water and APT. That paper also demonstrates the substantial benefits that RRUI and its customers receive from the services provided by APT. This document was previously disclosed in this case in response to data request GWB 4.2.

## III. ALGONQUIN/LIBERTY WATER SHARED SERVICES MODEL AND AFFILIATE COST ALLOCATION METHODOLOGY

**Q. PLEASE EXPLAIN APIF'S CORPORATE STRUCTURE AND BUSINESS MODEL.**

A. APIF's primary business is ownership of generating and infrastructure facilities through investments in securities of subsidiaries. APIF owns 46 electric facilities and 17 water distribution and wastewater treatment facilities in Canada and the United States. APIF also owns an electric facility that was not active during the test year and is not expected to be active in the foreseeable future. Finally, APIF has an operating interest in seven other facilities, but does not own them. As such, these facilities do not receive the same benefits as those both owned and operated by the APIF group of companies and are not therefore allocated APIF/APT costs in the same manner.

**Q. PLEASE SUMMARIZE THE SHARED SERVICES MODEL AND THE RELATIONSHIP BETWEEN RRUI, LIBERTY WATER, AND ALGONQUIN POWER TRUST (APT).**

A. There are two main components to this shared services model. First, Liberty Water provides the day to day operating services and costs associated with the operations of all its utilities including our RRUI facility. You could call these direct costs. These costs include operations labor costs charged directly based on timesheets; customer service and finance wages allocated based on customer count; and other administration costs related to the day to day operations of the facility allocated based on a four-factor formula which uses revenue, cost, capital, and customer count as the four drivers of cost. RUCO and Staff generally do not have any objections to the cost allocations from Liberty Water.

Second, APT provides the corporate administration costs associated with the running of a company, including costs associated with being a publicly traded company, to support all of its power generation and infrastructure facilities (including utilities). These are indirect costs, including the rent for the central office where all the staffing works, strategic planning costs, audit, tax services, unit holder communication, trustee fees, and other costs. These costs are allocated to Liberty Water based on the relative number of utilities to total facilities and then further allocated by Liberty Water to each utility based on customer count.

**Q. IS THAT APPROACH CONSISTENT WITH THE NARUC GUIDELINES ON COST ALLOCATION?**

A. Yes. Staff and RUCO have criticized the APT allocations for not conforming to the NARUC guidelines because costs that can be directly charged should be directly charged. Our methodology does exactly that. APT costs are all indirect costs, whereas Liberty Water (AWS) costs are mostly direct costs. Therefore, where appropriate, costs have been directly charged.

**Q. ON PAGES 46-47 OF HIS TESTIMONY, RUCO WITNESS MR. COLEY ASSERTS THAT RRUI HAS FAILED TO REPORT THE APT**



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**ALLOCATED COSTS AS DIRECT OR INDIRECT COSTS. IS THAT CRITICISM ACCURATE?**

A. No. RRUI has complied with the terms and conditions set forth in the NARUC Guidelines for Cost Allocations and Affiliate Transactions. As noted above, RRUI has reported all of the APT costs as indirect costs. Under the NARUC Guidelines, "indirect costs" are defined as "costs that cannot be identified with a particular service or product. This includes, but is not limited to, overhead costs, administrative and general, and taxes." Further, RUCO and Staff ignore the definition of "common costs" in the NARUC Guidelines, which provides (on page 2) that common costs are "costs associated with services or products that are of joint benefit between regulated and non-regulated business units." The Guidelines provide that "cost allocations" "can be based on the origin of the costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators)." The cost allocation methodology used by APIF and Liberty Water for RRUI and the other Arizona subsidiaries follows these NARUC Guidelines.

We also have allocated direct costs to RRUI "to the maximum extent practicable." The APT central office cost pool simply cannot be allocated directly as a practical matter. In turn, the NARUC Guidelines provide that the "general method of allocating indirect costs should be on a fully allocated basis." We have done exactly that by allocating direct costs from Liberty Water and indirect costs from APT.

**Q. WHY ARE STAFF AND RUCO CONCERNED WITH COMPLIANCE WITH A GUIDANCE DOCUMENT?**

A. Staff's and RUCO's primary concern with our cost allocation model seems to be potential subsidization by RRUI's ratepayers for business operations by



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unregulated entities. As stated in the NARUC Guidelines, the "objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers..." Here, there is no evidence of subsidization by RRUI's ratepayers. Rather, approximately 73% of the entire Central Office Cost pool is allocated to unregulated electric facilities. Only 27% of the cost pool is allocated to regulated utilities, such as RRUI. In fact, RRUI only gets 3.49% of the total APT cost. The APT costs are allocated to RRUI based on customer count, which is a reflection of RRUI's use and need for those services provided by APT.

**Q. DO YOU HAVE ANY OTHER COMMENTS ON THE NARUC GUIDELINES?**

A. Yes. While the Company is in general conformance with the guidelines, I would like to note that the guidelines themselves state that: "These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled." Further, the Guidelines go on to state that "The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight." These statements clearly indicate that while the Company does subscribe to the Guidelines, they are and always were meant to be a set of *guiding* principles, and not a set of rules or laws prescribing allocation methodologies.

**Q. PLEASE CONTINUE.**

A. The NARUC Guidelines also make a very clear statement that "Too much flexibility will lead to subsidization, however, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged." Clearly, disallowing almost all of the indirect costs, as Staff and RUCO have done, heavily discourages APT, Liberty Water and RRUI to undertake what are otherwise

economic transactions and such prohibition by Staff/RUCO does not comply with the NARUC Guidelines.

**Q. DOES APIF'S BUSINESS MODEL PROVIDE BENEFITS TO REGULATED UTILITIES SUCH AS RRUI?**

A. Yes. APIF is publicly traded on the Toronto Stock Exchange. APIF's structure as a publicly traded income fund provides substantial benefits to its Regulated Utilities through access to capital markets, strategic management, professional administrative staff, strong corporate governance and financial controls. As APIF has a duty to its shareholders to act in accordance with laws and regulations in areas in which it operates, the very nature of APIF requires the utilities to be run prudently with a keen eye on cost control in order to ensure that costs are justifiable to regulators. Further, as I mention below, APIF's business model allows utilities such as RRUI to operate efficiently and with reduced operating costs. Essentially, APIF's business model allows RRUI and the other Arizona utilities to provide high quality utility service at low costs.

**Q. DOES APIF GENERATE REVENUES FROM THE COSTS INCURRED BY APT?**

A. The costs, absent the utilities and facilities owned by APIF, would not generate any revenues if incurred on a standalone basis. In other words, APIF has no business other than operating the utilities and facilities it owns.

**Q. WHO ARE APIF'S UNIT HOLDERS?**

A. The Shareholders are both institutional and retail investors. Approximately 20% of Algonquin's shares are held by institutions, and are included as part of various pension funds, mutual funds, and monthly dividend and income funds, all of which appeal to long term investors looking to invest for savings and retirement purposes. Approximately 80% of Algonquin's shares are held directly by retail investors



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(individuals) who look for a stable, sustainable level of income in the form of dividend payments. Approximately 30% of Algonquin's shares are held by investors in the United States.

**Q. THANK YOU, MR. EICHLER. CONTINUING NOW WITH YOUR DISCUSSION OF THE SHARED SERVICES MODEL, WHAT SPECIFIC SERVICES ARE PROVIDED TO THE REGULATED UTILITIES BY LIBERTY WATER?**

A. RRUI and the other Regulated Utilities in Arizona do not operate as stand-alone utilities. As I testified above, RRUI is operated by Algonquin Water Services, which operates under the name Liberty Water, along with six other regulated Arizona water and sewer utilities, and eleven regulated water and sewer providers located in Texas, Missouri and Illinois. Liberty Water provides all of the day-to-day administration and operations personnel for these regulated utilities.

**Q. HOW ARE COSTS INCURRED BY LIBERTY WATER ALLOCATED TO RRUI?**

A. All operations and engineering labor is directly charged by Liberty Water to RRUI and the other separate Regulated Utilities operated by Liberty Water. Liberty Water charges those labor rates at cost, which is the dollar hourly rate per employee as recorded in Liberty Water's job costing system, grossed up by 35% for burdens such as payroll taxes, health benefits, 401k retirement plans, and other insurance provided to employees. Engineering technical labor, which is mostly capitalized, is charged on the same basis, plus an allocation of 10% for Liberty Water's overheads such as rent, materials/supplies, etc. Liberty Water has its own offices, separate from the offices where I work in Oakville, Ontario.

Other necessary services provided by Liberty Water for the Regulated Utilities cannot be directly charged to RRUI and the other Regulated Utilities.

Labor for health and safety, accounting, billing and customer service, human resources, and corporate finance cannot be directly allocated using timesheets due to the nature of the costs. It simply isn't practical to keep track of time for employees that serve multiple utilities in small time increments during the course of a work-day. A shared call center is the perfect example. A customer service representative at Liberty Water's call center will field calls from customers of RRUI, Black Mountain and Bella Vista in southern Arizona and the three other states. This work directly benefits all of the Regulated Utilities, so the costs need to be allocated to all of them. These costs are allocated based on the relative customer counts of all of the Regulated Utilities. Using customer counts allows Liberty Water to allocate those costs to an individual utility, such as RRUI, based on the relative burden of that utility relating to those services.

Overhead costs, like rent, insurance, administration costs, depreciation of office furniture and computers, also cannot be directly attributed to specific utilities. These costs are allocated to RRUI and its affiliates by use of a "four factor" methodology that considers relative size through four weighted factors – total plant, total customers, expenses and labor. I understand that this type of four-factor methodology has been utilized by other Arizona utilities, including Chaparral City Water Company and Global Water. All of the costs charged by Liberty Water and allocated to RRUI are based on actual costs, either directly charged or through the allocations described above.

**Q. ARE THE CHARGES FROM LIBERTY WATER INCURRED IN US DOLLARS?**

A. Almost all of the costs charged from Liberty Water are incurred in US dollars. This includes payroll for office and field staff in Arizona, benefits, etc. The few costs that are incurred in Canadian dollars are currency translated on a monthly



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basis using the average exchange rate for that month, in accordance with Generally Accepted Accounting Principles.

**Q. HOW ARE OPERATIONS AND ENGINEERING LABOR COSTS ALLOCATED BY LIBERTY WATER?**

A. Those costs are billed directly to the Regulated Utility that required the labor, as documented by time sheets. Appendix 2 of **Exhibit PE-RB1** is an example time sheet used by Liberty Water. Those direct charges are principally direct labor, including operations and engineering. For example, the costs for a plant operator working solely for RRUI will be directly charged to RRUI without any further allocation necessary. Liberty Water directly charges RRUI at cost.

**Q. OKAY. WHAT ABOUT ACCOUNTING, BILLING AND CUSTOMER SERVICE LABOR COSTS INCURRED BY LIBERTY WATER?**

A. Liberty Water also incurs labor costs for accounting, billing, and customer service, human resources, health and safety, and corporate finance, which are necessary for RRUI to provide adequate and reliable water and wastewater service to customers. Those costs, however, cannot be allocated to each Regulated Utility using time sheets due to the nature of the costs. It is not practical to keep track of time for employees that serve multiple utilities during the course of a work day. For example, an accounting analyst may analyze the financial performance of all Regulated Utilities at the same time. Her accounting work benefits all such Regulated Utilities, so her services and costs would be allocated to all Regulated Utilities. Likewise, a customer service representative at Liberty Water's call center will field calls from customers of all Regulated Utilities during a work day. Again, his work directly benefits all such Utilities and his costs should be allocated to all Regulated Utilities. The key metric driver for this cost allocation was determined

to be the customer count. Management believes that most of the customer service and finance functions are driven by the number of customers for each utility.

**Q. FINALLY, HOW DOES LIBERTY WATER ALLOCATE ITS OVERHEAD COSTS TO RRUI?**

A. Costs incurred by Liberty Water for rent, administrative costs, depreciation of office furniture, depreciation of computers, and other labor cannot be directly attributed to a specific Regulated Utility. As such, those overhead and administrative costs are allocated to the Regulated Utilities by use of the "four factor" methodology. Other costs in this category include insurance, janitorial services and other general non-payroll costs.

The "four factor" methodology allocates costs by relative size of the utilities. The methodology used by Liberty Water involves (1) Rate Base, (2) Total Customers, (3) Non-Labor Expenses and (4) Labor as allocating factors, with each factor assigned a specific weight. Liberty Water developed and utilized this methodology, including all 17 of its utilities, to better allocate costs, recognizing that larger utilities require more time and management attention and incur greater costs than smaller ones.

**Q. DOES RRUI AND ITS CUSTOMERS BENEFIT FROM THE SERVICES PROVIDED BY LIBERTY WATER?**

A. Yes, in several ways. To start, customers of Liberty Water receive significant benefits from this cost allocation model, including lower costs incurred by the Regulated Utilities for services that are essential and necessary to the provision of high quality water and wastewater utility service. The benefits of this type of shared service model include savings on labor costs by resource sharing. Since most Liberty Water employees are not dedicated to a specific utility, the utilities do not need to hire their own dedicated staff, thus resulting in significant cost savings.



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Likewise, the four factor allocations allow for utilities to be charged by relative resources and management attention required to operate them. This means customers of smaller utilities do not subsidize costs of larger utilities. Essentially, this allocation methodology allows costs to be allocated based on the relative burdens and costs incurred by individual utilities. Further, because it's scalable, the shared services model allows for increased growth with less than proportional cost increases, meaning the Regulated Utilities can grow without incurring a proportionate or prohibitive increase in the cost of service.

**Q. WHAT SERVICES ARE PROVIDED TO THE REGULATED UTILITIES BY APT?**

A. APT is the affiliate that provides financial, strategic management, compliance, administrative and support services to the Regulated Utilities operated by Liberty Water. The costs incurred are corporate administrative costs; they are not labor costs. As such, these are indirect costs incurred by APT as necessary to run a company that is part of an Income Fund. APIF then allocates a share of the costs incurred by its operating arm APT in providing necessary and required services to the Regulated Utilities. The head office of APT is located in Oakville, Ontario, Canada and provides administrative, technical and management support, regulatory compliance, and oversight of strategic direction, including approvals of budgets and ensuring a strict level of corporate governance for RRUI and all of the utilities operated by Liberty Water. APT's executive management and administrative support includes accounting and finance, human resources, employee benefits, regulatory and information systems services.

**Q. DOES APT CONDUCT ANY OTHER BUSINESS?**

A. No. APT exists solely for the benefit of the utilities and other facilities APIF owns. APT does not have any business, other than to provide administrative services to

the utilities and the other facilities. If those utilities and other facilities did not exist, APT and all of these indirect corporate administrative costs would not exist.

**Q. BUT HOW DO THESE SERVICES PROVIDED BY APT BENEFIT RRUI AND THE OTHER REGULATED UTILITIES?**

A. First, the services provided by APT are necessary to allow RRUI and the other Regulated Utilities to have access to capital markets for capital projects and operations. In today's market place, the importance of ready access to capital can't be understated. Many stand alone Arizona utilities simply do not have the steady access to capital that is available to RRUI under the APIF corporate model. Far West Sewer & Water Company is a perfect example.[1] Absent consistent access to capital, RRUI would not be able to provide a high level of service.

One of the fatal flaws in Staff's and RUCO's comparisons of APIF's cost allocations to stand-alone utilities is the assumption that stand-alone utilities provide the same level and security of service as provided under APIF's business model. That simply isn't true as demonstrated by service and financial problems experienced by various stand-alone utilities including Far West and the McLain utilities.[2] In addition, RRUI receives benefits by having strategic direction, corporate governance, financial controls, and an audit done at the Income Fund level which reduces the audit requirements upon RRUI. All of these costs ensure that the Income Fund has a long term strategic direction and remains healthy. This definitely benefits RRUI's long term health for a fraction of the price. Many small privately run utilities may not have all of these costs, but history has demonstrated that without these strategic corporate administrative costs and costs associated with

[1] *See Far West Water and Sewer Company*, Decision No. 71447 (December 23, 2009).

[2] *See id.; Northern Sunrise Water Company and Southern Sunrise Water Company*, Decision No. 68826 (June 29, 2006), *et. seq.*



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raising capital, the long term well being of the utility is compromised. We and the Commission know too well the real cost of under-capitalized, under-operated stand-alone utilities.

**Q. BUT MR. EICHLER, RRUI IS NOT PUBLICLY TRADED, SO WHY DOES IT NEED THESE SERVICES?**

A. For the reason I just mentioned. RRUI is a healthy utility when viewed on a stand-alone basis because it is part of the Algonquin/Liberty Water shared services model. The same is now true of Black Mountain, Gold Canyon, and we hope soon, the former McLain water companies. While none of these entities is publicly traded, they are part of a structure and model that includes a publicly traded entity at the top. This model works, ratepayers get the service they deserve and, at least in theory, the investors get a return.

I really can't understate how much we believe the Regulated Utilities benefit from strategic direction on long term capital and operational needs and requirements. This type of strategic planning allows for the parent to enable RRUI to plan for future long term capital needs. All of these costs relate to the promotion of long term health of the entire organization, and that is a definite benefit for RRUI and its ratepayers. Besides, whether RRUI is publicly traded or not, it should have proper corporate governance. Good business requires good governance, financial planning, strategic management, audits, tax services etc. It promotes a healthy company with long term objectives and easier access to capital. Even if RRUI was not part of a larger corporation, it should have a board of directors to oversee management with a long term strategic focus. Smaller utilities that are not part of a larger corporation usually do not have good corporate governance. Again, I refer back to the McLain and Far West systems. McLain in particular had poor corporate governance and lacked a long term strategy resulting

in inadequate treatment, storage and an unreliable distribution system. In other words, RRUI being part of a publicly traded company that shares these costs among many facilities reaps the benefits of these services but at a fraction of the price.

**Q. PLEASE PROVIDE FURTHER DETAIL ON COSTS INCURRED BY APT.**

A. As I testified above, there are no direct labor costs included in the corporate administration "Central Office Cost" allocation from APT. Instead, these costs include professional services like third-party legal services, accounting services, tax planning and filings, management and trustee (board of director) fees, and required auditing that are done for the benefit of all of the Liberty Water Regulated Utilities, including RRUI. Other corporate administrative costs include costs for licenses, fees and permits, information technology/systems, payroll, and HRIS maintenance contracts, as well as the rent and depreciation of office furniture and equipment and computers in the central office in Oakville, Ontario.

**Q. HOW ARE THE COSTS INCURRED BY APT ALLOCATED TO RRUI?**

A. Fees for these services are allocated to the Regulated Utilities using generally accepted allocation principles, which are accepted by the audit firm used by Algonquin. These services are routine and recurring in nature and performed on a regular basis in normal business for Liberty Water and its Regulated Utilities.

These indirect administration Central Office Costs are allocated to RRUI in two phases. The first phase involves allocating these costs to each of the facilities, both regulated and unregulated, owned by APIF. That initial allocation is made based on relative size. Specifically, APIF owns and operates 63 total entities, 17 of which are the Regulated Utilities operated by Liberty Water. In turn, 17 of 63 is 26.98%, which means 26.98 percent of the total Central Office Costs are allocated to the Regulated Utilities operated by Liberty Water. The second phase is that



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Liberty Water allocates the Central Office Costs between RRUI and the 16 other Regulated Utilities based on customer counts.

**Q. WHY WEREN'T OTHER ALLOCATION DRIVERS, SUCH AS REVENUE, PLANT, OR EXPENSES USED?**

A. We have analyzed these other drivers, and when weighted equally, the result is usually an allocation of 20-30%, as can be seen in attached **Exhibit PE-RB2**. For the purposes of simplicity, we decided to use facility count. Our allocation methodology complies with the NARUC Guidelines and results in a reasonable allocation of necessary costs to RRUI. Having said that, if the Commission feels that use of a blended allocation methodology, such as the one shown in **Exhibit PE-RB2**, is preferable, the Company would consider adopting the blended methodology.

**Q. WHY NOT JUST USE REVENUE AS THE SOLE ALLOCATION FACTOR?**

A. Because the purpose of the cost allocations is to appropriately apportion costs where they are incurred. Revenue is not directly comparable between the utilities and power generation businesses. For example, in 2008, the utilities division accounted for 29% of the total controllable operating costs of APIF while only producing 17% of the revenue. This indicates that greater levels of input (expenses) are required to drive revenues on the utilities side than the power generation side. Therefore, allocating based on revenue alone is not consistent with the purpose of the allocations.

**Q. PLEASE CONTINUE.**

A. In addition, revenues for the power generation side of the business are highly volatile and fluctuate greatly with economic conditions. As the economy improves the price of electricity generated increases, and vice versa. Due to the nature of the



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commodity, it is too volatile from year to year to be a reasonable allocator on its own.

**Q. WHY DOESN'T LIBERTY WATER ALLOCATE THESE COSTS ON A DIRECT BASIS TO THE REGULATED UTILITIES?**

A. Because there is no specifically identifiable driver. For example, costs such as ERP system consultation, depreciation costs incurred on computer servers and office furniture, as well as the other costs charged from APT, benefit the whole family of companies and cannot be directly charged to each utility on any reasonable driver. These costs are procured collectively and incurred on behalf of all of the assets owned, and while there is a definite benefit to the Regulated Utilities and their customers, directly charging these types of costs to the 63 separate operating assets would not be possible. Both Staff and RUCO incorrectly state that these costs could be directly billed by vendors and allocated to RRUI. That simply isn't true.

Further, the cost allocation methodology ensures that the costs are allocated as closely as possible to the originator of those costs. An entity such as RRUI with 8,300 water and sewer customers benefits more from these costs than BMSC with only 2,000 wastewater ratepayers. RRUI's total of 8,379 customers is approximately 13% of Liberty Water's 17 Regulated Utilities' total of 68,783 water and wastewater customers, which means RRUI is allocated 13% (8,279/64,094) of the Central Office Cost pool. The fundamental principle of this methodology is that RRUI and the other Regulated Utilities should be charged for all costs incurred by affiliates—both Liberty Water and APT—so that the Regulated Utilities can provide a high level of safe and reliable water and wastewater utility service to customers at a very reasonable cost for such service. If Staff and RUCO continue to oppose the cost allocations from APT, then APT may cease providing those



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services to RRUI and the other Arizona utilities, which may cause service quality to decline and operating costs to increase. It also doesn't seem to make sense for Staff and RUCO to encourage Arizona utilities to operate as stand-alone companies given the number of problems and failures that have occurred with stand-alone utilities. Rather, the Commission should be encouraging owners like APIF that will consolidate operations under a shared-services umbrella and who are able to invest capital in this state.

**Q. GIVEN ALL YOU HAVE DISCUSSED SO FAR IN THIS TESTIMONY, MR. EICHLER, IS IT SAFE TO SAY THAT YOU DISAGREE WITH BOTH STAFF AND RUCO THAT MOST, IF NOT ALL, OF THE SERVICES PROVIDED BY APT ARE FOR THE SOLE BENEFIT OF APIF'S UNIT-HOLDERS OR INVESTORS?**

A. I completely disagree. The utility industry is highly capital intensive. How can providing corporate strategic direction, and costs associated with access to capital markets not benefit RRUI? There is tremendous benefit, as seen from the success of our efforts in Arizona in the past decade. And it's immaterial that APIF does all this for a profit. So what? So does RRUI, Black Mountain, APS, Southwest Gas, Arizona American and Chaparral City, and all of their corporate parents. Instead, that APIF is in the business of making a profit provides additional incentive to tightly control these corporate costs, considering that approximately 73% are allocated to the non-regulated business. The bottom line, in our corporate structure, is a healthy "parent" means a healthy "child". Perhaps this is why neither Staff nor RUCO provide any persuasive evidence supporting their claims that RRUI does not benefit from the services provided by APT.

Both Mr. Becker and Mr. Coley generally claim that the services provided by APT are not attributable to RRUI and primarily benefit APIF's shareholders.



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But neither explains the basis for this conclusion. In reality, the services provided by APT are part of the APIF corporate model, which allows RRUI to provide high quality, cost-effective service. The costs incurred by APT are generated solely and exclusively to provide services to RRUI and the other regulated utilities. The notion that APT would incur those costs without RRUI or the other regulated utilities is inaccurate.

## IV. REBUTTAL TO STAFF AND RUCO ADJUSTMENTS TO CENTRAL COST ALLOCATIONS.

### A. Rebuttal to Staff.

**Q. ON PAGE 28 OF HIS DIRECT TESTIMONY, MR. BECKER SAYS THAT "WHEN COSTS INCURRED PRIMARILY FOR THE BENEFIT OF AN UNREGULATED AFFILIATE'S BUSINESS ARE IDENTIFIED AND ALLOCATED AS OVERHEAD/COMMON COSTS, THEN THE COSTS OF THE UNREGULATED AFFILIATE ARE SHIFTED TO THE CAPTIVE CUSTOMERS OF THE REGULATED UTILITY. DO YOU AGREE WITH THAT STATEMENT?**

A. No. As I've mentioned above, APIF would not incur these costs if not for all of the companies, including the utilities, it owned. APIF would not exist. It has no other business than to operate the facilities it owns. Simply put, the cost pool would be significantly lower if Algonquin did not own the utilities division. While the business structure of being a publicly traded company does drive a significant portion of the Central Office costs, these costs are still incurred to the benefit of the utilities it owns. Again, most of these costs are associated with good corporate governance. These costs are to ensure that the entire corporate family remains viable for the long run. Alternatively, if APIF owned only regulated utilities, these same types of corporate costs would be incurred.



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Again, in our view, this Commission should be encouraging larger companies to be acquiring smaller utilities and consolidating operations under shared services models like we have implemented in Arizona. However, Staff's and RUCO's repeated recommendations to deny such costs will have the opposite impact; keeping the water and wastewater industry in Arizona fractured. In addition to access to capital, something increasingly critical in down economies where the need for critical infrastructure remains constant, larger companies provide good corporate governance, reducing the risk of smaller utility financial problems. There are no McLain messes under a corporate structure like ours. But, this has a cost, as I have testified to above, and as our witnesses have tried to explain in their testimonies in this case and the recent BMSC and LPSCO rate cases. However, under our model, there is a shared cost/benefit.

**Q. ON PAGE 28 OF HIS TESTIMONY, MR. BECKER ALSO STATES THAT "THE COSTS OF A REGULATED UTILITY, SUCH AS RIO RICO, SHOULD ONLY INCLUDE THOSE COSTS THAT WOULD HAVE BEEN INCURRED ON A "STAND ALONE BASIS;" IN OTHER WORDS, ONLY THOSE COSTS THAT THE REGULATED UTILITY WOULD HAVE INCURRED BY ITSELF IN THE PROVISION OF SERVICE." HOW DO YOU RESPOND TO THAT TESTIMONY?**

A. As my earlier testimony illustrates, that statement is flawed in several respects. To start, Staff is using that stand-alone comparison as a requirement for cost allocation, even though there is no authority for any such standard. Even worse, Staff has not even applied or investigated its own standard. In other words, Staff has not evaluated how RRUI's operating costs (including Central Office Costs) compare to other Arizona stand-alone utilities. If Mr. Becker's suggestion is adopted, no utilities would be run under Shared Services models, which is contrary

to the Commission's endorsement of such models for other utility companies operating in the state.

**Q. HAVE YOU MADE SUCH A COMPARISON?**

A. Yes, attached as **Exhibit PE-RB3** are charts comparing RRUI's operating costs with the operating costs of various sized Arizona water utilities, some of which are directly comparable to RRUI. The Arizona Water Company divisions, Sunrise Water Company, Rio Verde Utilities, and H20 Inc. are stand-alone water utilities. The Arizona-American divisions, Global Water—Santa Cruz Water Company, Willow Valley Water Company and Chaparral City Water Company are part of affiliate holding company structures. These charts demonstrate that RRUI's operating costs compare very favorably to the operating costs of the 15 other Arizona utilities on a per customer basis. Therefore, Staff's contention that the APT cost allocations artificially inflate RRUI's rates above industry norms simply isn't true.[3] In fact, these charts show that RRUI's operating costs per customer for water are substantially below the other comparable utilities; and for wastewater are within the range of the comparable sewer companies. This is because the APIF corporate model allows RRUI to provide continuing access to capital and high quality services through the economies of scale provided by the services from APT. For water service, it also should be noted that RRUI's operating costs are lower than all of the stand-alone utilities in the comparison.

**Q. PLEASE CONTINUE.**

A. I also want to point out that the Central Costs cannot be picked on a one by one basis as Mr. Becker suggests. That is to say, they are not mutually exclusive. For example, one could not simply say that they do not like the Trustee Fees, because

[3] Direct Testimony on revenue requirement of Gerald W. Becker at 28.

they are required as much for access to capital as Tax Services. The Commission should be looking at APIF's corporate model as a whole, which allows utilities such as RRUI to provide high quality utility service at reasonable costs. On the whole, RRUI's costs and costs per customer compare very favorably to other Arizona utilities, and given the added benefits provided by the APIF corporate model in terms of corporate governance, and access to capital and stability, APIF's corporate model should be approved in the provision of service.

**Q. SHOULD STAFF BE ENCOURAGING UTILITIES TO OPERATE AS STAND-ALONE ENTITIES?**

A. Absolutely not. Staff and RUCO should not force Arizona utilities to operate as stand-alone companies given the number of problems and failures that have occurred with stand-alone utilities. Rather, the Commission should be encouraging owners like APIF who are willing to invest capital in this state with an overriding corporate model of good governance. I can't stress enough that if Staff and RUCO continue to oppose the cost allocations from APT, then APT may cease providing those services to RRUI and the other Arizona utilities, which may cause service quality to decline and operating costs to increase. I do not see how the Commission can expect the Company to obtain these services and at the same time deny cost recovery. And I certainly hope that Staff and RUCO don't complain if their recommendations are adopted and the services cease and quality of service for customers declines.

**Q. ON PAGE 29-30 OF HIS DIRECT TESTIMONY, MR. BECKER GOES ON TO CONCLUDE THAT "BASED UPON A REVIEW OF THE ACTUAL SUPPORTING INVOICES PROVIDED BY THE COMPANY, STAFF CONCLUDED THAT ALMOST ALL OF THE COSTS WERE OBVIOUSLY**

**ATTRIBUTABLE TO THE OPERATIONS OF APIF OR ONE OF ITS AFFILIATES." HOW DO YOU RESPOND TO THAT TESTIMONY?**

A. He is missing the point. If the costs are incurred by APIF or APT, they are attributable to ALL facilities, regulated and non-regulated, including RRUI. The fact that the 3rd party vendor invoice does not list all 63 companies under the APIF umbrella does not in any way mean that the costs and related service do not benefit the customers of RRUI. If Mr. Becker has a specific invoice he questions because it is for XYZ Hydro Facility in New York, he should ask the Company why what appears to be a cost incurred for a specific operating facility was included in the APT allocation pool.

Again, the Central Office administration costs are incurred in order to prudently operate the facilities owned by the Fund. These costs would not be incurred if no facilities were owned. The utility ratepayers are the primary beneficiaries of the cost savings by paying reasonable rates for high quality service. In fact, since these are operating costs, they are flow-throughs in regulated utility ratemaking, which means that shareholders would not benefit in any way shape or form from higher costs. In fact, since higher costs would increase regulatory risk and diminish RRUI's relationship with its ratepayers, incurring these costs strictly to the benefit of shareholders would be contrary to their desire to earn a profit. It is only to reduce overall costs to ratepayers that we operate this model.

I also would note that Mr. Becker and Staff have arbitrarily assigned 90% of the costs to APIF and 10% of the costs to the regulated utilities. Staff then allocates that 10% to the regulated utilities based on the number of facilities, using a total number of facilities owned by APIF as 70. For RRUI, that translates to 1.43% of the Central Costs.

**Q. DID YOU REVIEW THE MATERIALS AGAIN TO VERIFY THAT ALL THE INVOICES ARE APPROPRIATE FOR RIO RICO UTILITIES INC.?**

A. Yes. I reviewed the Company's response to data request GWB 4.2a. Upon my review, I concluded that almost all of the costs were necessary; however, I did find that due to the large volume of transactions, some invoices that could be directly charged to the non-regulated side of the business were erroneously included in the pool. I have removed those costs, totaling $204,508 from the allocation pool and Mr. Bourassa has made a corresponding adjustment.[4] This reduced the amount requested for operating expenses by RRUI by $4,625.

**Q. WHAT ARE THE OPERATIONS OF APIF THAT MR. BECKER ALLUDES TO IN THE PREVIOUS QUESTION?**

A. I am not really sure, mainly because Mr. Becker's statement is illogical. As I've testified, the parent company has no other business than owning these facilities through its subsidiaries. If the Income Fund did not own RRUI and for that matter did not own any facilities, the Income Fund would not have any of these corporate administration costs because the Income Fund would not exist. In short, there are no operations of APIF other than the ownership and management of the utilities and facilities it owns, so I am unsure what operations Mr. Becker is referring to. In response to RRUI DR 2.9, Mr. Becker responded that it is "conceivable" that APIF would require an audit if it were publicly traded prior to owning any facilities.[5] Mr. Becker does not substantiate that statement and I would challenge Mr. Becker to find a Company that has successfully raised capital without owning a single business, or having any operations. The notion that APIF would raise capital by

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[4] *See* Rebuttal Testimony of Thomas J. Bourassa – Rate Base, Income Statement and Rate Design at 24 and 29.

[5] Staff's response to DR 2.9 is attached as **Exhibit PE-RB4**.



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selling shares on the Toronto Stock Exchange before it owned any facilities is not accurate. Money simply does not get invested that way in the capital markets.

**Q. BUT HOW CAN COSTS INCURRED BY APT BENEFIT BOTH SHAREHOLDERS AND RATEPAYERS?**

A. Because a well run utility with access to capital can provide high quality service at a reasonable cost leaving the utility with a fair and reasonable return on its investment after the recovery of the costs needed to provide that level of service. Everyone wins. The fact that RRUI's operating costs compare very favorably to other Arizona utilities demonstrates that APIF's corporate model works for ratepayers. Further, the NARUC Guidelines recognize this joint benefit concept in its definition of "common costs," which provides that common costs are "costs associated with services or products that are of joint benefit between regulated and non-regulated business units."

**Q. OK, TURNING TO THE ALLOCATION METHODOLOGIES, STAFF HAS ALLOCATED COSTS TO RRUI BASED ON APIF'S OWNERSHIP OR OPERATING INTEREST IN 71 FACILITIES, EIGHT MORE FACILITIES THAN RRUI USED IN ITS FILING. PLEASE DESCRIBE APIF'S INTERESTS IN THOSE OTHER EIGHT UTILITIES?**

A. Algonquin owns the debt of 7 companies, and accounts for them separately from the Central Office costs. Those 7 facilities are simply operated by APIF and do not generate costs that are allocated to the APT cost pool. The remaining one facility is a land field gas facility that has not been operational for years.

**Q. ARE THERE ANY PROBLEMS WITH MR. BECKER'S ALLOCATION METHODOLOGY?**

A. Yes, several. To start, Mr. Becker uses a total number of facilities owned by APIF as 70. That simply isn't accurate. As noted above, APIF owns the debt of 7



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facilities, but does not own them. APT is providing operations services to those 7 facilities, but APT does not incur any central office costs or provide capital investment for those 7 facilities. We are essentially an operator/caretaker of those facilities. Thus, Staff is allocating Central Office Costs to 7 facilities that do not use those services, which artificially decreases the cost allocations to those entities actually using the services. Further, Staff has included one additional facility owned by APIF but which has not operated for several years, again meaning that such facility does not incur any APT costs. Also, Mr. Becker blandly assumes that RRUI does not benefit from the various services provided by APT. As I've testified, that is an incorrect assumption. RRUI would not have access to equity capital from APT and APIF if APT did not undertake the various third-party professional and other services, which costs are allocated to RRUI. Certainly no one can dispute that RRUI and its ratepayers benefit by continuing access to capital and strong corporate governance.

**Q. WHAT SERVICES AND COSTS ARE ALLOCATED TO RRUI BY APT?**

A. Appendix 3 to **Exhibit PE-RB1** provides a discussion of these costs. Generally, the services provided by and costs incurred by APT fall into four general categories: (1) Strategic Management, which includes management fees, general legal services and other professional services; (2) Capital Access, which includes licenses/fees/permits, unit holder communications and escrow fees; (3) Financial Controls, which include audit services, tax services and trustee fees; and (4) Administrative/Overhead Costs, which include rent, depreciation and office costs as I testified above. These costs are allocated down as I testified above.

**Q. WHAT ARE THE APT STRATEGIC MANAGEMENT COSTS?**

A. Strategic management decisions are critical for any public utility. The need for strategic management is even more pronounced for RRUI as a regulated utility that

depends on access to capital for ongoing operational and capital needs. APIF seeks to hire talented strategic managers that aid in running each facility owned by the fund, including RRUI, as efficiently and effectively as possible. This ensures the long term health of each utility and ensures that rates are kept as low as possible without compromising the level of service. It also facilitates each Regulated Utility's access to necessary capital funding at reduced costs.

Legal expenses incurred by APT for general legal matters pertaining to all facilities owned by APIF also are included. These legal services are required in order for APIF to provide capital funding to individual utilities, without which the utilities could not provide adequate service. These legal services involve matters not specific to a single facility, including review of audited financial statements, annual information filings, Sedar filings (mandatory filings for companies listed on the Toronto Stock Exchange), review of contracts with credit facilities, incorporation, tax issues, market compliance, and other similar legal costs.

**Q. WHAT ARE THE BENEFITS OF THESE LEGAL SERVICES?**

A. General legal costs are one of the foundations for proper corporate governance. They help ensure that APIF and the Regulated Utilities remain compliant in all aspects of operations and prevent those entities from being exposed to unnecessary risks. These legal services also allow utilities to have continued access to capital markets available to APIF. These legal expenses are critical to utility operations because they ensure APIF's status and viability as a publicly traded income fund and allow the utilities to provide service in a way to ensure continued access to strategic management and capital markets. Unfortunately, Staff has not even attempted to evaluate the benefits of such legal services to RRUI.

**Q. PLEASE CONTINUE.**

A. The final item included in Strategic Management Costs are professional services, including strategic plan reviews, capital market advisory services, ERP System maintenance, benefits consulting, and other similar professional services. These professional services ensure that APIF's strategic plans and initiatives are completed with the highest degree of care and professionalism, which is necessary for the Regulated Utilities to receive debt and equity funding from capital markets. In no uncertain terms, these services allow the Regulated Utilities to have an available source of capital funding for plant and infrastructure in the provision of utility services. In the absence of these services, unit holders would not invest in utility operations of APIF because the utilities would not incur the necessary costs to ensure that the strategic plans are followed as a condition of such funding. Staff's failure to acknowledge the benefits to RRUI from access to equity capital under the APIF corporate model by denying the Central Office Costs associated with that financing may result in withdrawal of equity capital to RRUI, which ultimately could result in a highly leveraged utility. RRUI's only source of equity capital is from sale of units in APIF on the Toronto Stock Exchange.

**Q. YOU ALSO MENTION ALLOCATION OF COSTS RELATED TO ACCESS TO CAPITAL MARKET. PLEASE EXPLAIN THOSE COSTS.**

A. One of APT's primary functions is to ensure that APIF's facilities (including the Regulated Utilities) have access to quality capital. APIF is listed on the Toronto Stock Exchange, a leading financial market. In order to allow the Regulated Utilities to have continued access to those capital markets, APT incurs a variety of costs for the benefit of the Utilities. These services and costs are in line with the companies' corporate governance policies and are a prerequisite to communicate to

all its stakeholders the health and well being of Algonquin and ensuring to the Regulated Utilities' continued access to those capital markets.

To start, APT incurs fees to ensure that APIF can participate in the Toronto Stock Exchange. Many of the services provided by APT and allocated to RRUI are required by the rules of the Toronto Stock Exchange. These licensing and permit fees are required in order to sell units on the Toronto Stock Exchange. The benefit of these costs is undisputed – the ratepayers and Regulated Utilities have access to capital only so long as APIF is able to access capital markets. These license fees allow APIF to sell units on the Toronto Stock Exchange and, in turn, provide funding for utility operations. These license fees incurred by APT are critical to ensure continuing access to capital.

**Q. IS THAT ALSO TRUE FOR ESCROW FEES INCURRED BY APT?**

A. Yes. Unit holders invest in APIF, and, in turn, provide capital funding to the Regulated Utilities by buying units. In making those investments, unit holders expect monthly distributions on the units they own. As such, APT incurs escrow fees in paying such monthly payments to unit holders. Escrow Fees are incurred in order to ensure that unit holders of APIF continue to maintain ownership, and that new shareholders are enticed to invest in the Fund. Those new shareholders are the ones truly investing money for new and future projects the utilities undertake. Without them, there is no money for APIF to invest in the utilities.

**Q. WHAT ABOUT COSTS FOR UNIT HOLDER COMMUNICATIONS?**

A. Similarly, unit holder communication costs are incurred to comply with the filing and regulatory requirements of the Toronto Stock Exchange and meet the expectations of shareholders. These costs include news releases, unit holder conference calls and other similar costs. Unit holder communications costs are incurred by APT for the benefit of the Regulated Utilities to ensure that unit



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holders are fully informed of all operational and strategic decisions. These disclosures are required by law to ensure a level of integrity and rigor is applied to the management of the Regulated Utilities. It can't be stressed enough that in the absence of unit holder communication costs, investors would not invest in the units of APIF, and in turn, APIF would not have capital to invest in the utilities.

**Q. THE THIRD CATEGORY OF APT COSTS YOU IDENTIFIED RELATED TO FINANCIAL CONTROLS. WHAT ARE THOSE COSTS?**

A. Financial Control costs incurred by APT are another integrated piece of corporate governance. Lack of financial controls could lead to improper decision making or even fraud which could lead to bankruptcy. I understand that the owner of the McLain companies took all of his revenue from water sales and instead of paying things like property taxes, he invested in some failed telecom venture. Bankruptcy followed and we had to step in and bail out the Commission and the ratepayers. With proper financial controls, the McLain mess would not have happened.

**Q. DO THOSE FINANCIAL CONTROL COSTS INCLUDE TAX AND AUDIT SERVICES?**

A. Yes. Costs for tax services are incurred to ensure prudent tax filing, planning and management. Taxes are paid on behalf of the Regulated Utilities at the parent level as part of a consolidated United States tax return. Tax services are provided by third parties, including KPMG. The shared cost of such tax services also are lower than the costs of stand-alone tax services, which would otherwise be incurred by the Regulated Utilities. Audit services are likewise necessary to ensure that the Regulated Utilities are operated in a manner that meets audit standards and regulatory requirements have strong financial and operational controls, and that financial transactions are recorded accurately and prudently. Without these

services, the Regulated Utilities would not have a readily available source of capital funding.

**Q. THE LAST CATEGORY OF APT AFFILIATED COSTS IS ADMINISTRATIVE AND OVERHEAD COSTS. PLEASE DESCRIBE THOSE COSTS.**

A. Administrative costs incurred by APT such as rent, depreciation of office furniture, depreciation of computers, and general office costs are required to house all of the services mentioned above. Without these costs, the employees of APT could not perform their work and provide the necessary services to the Regulated Utilities.

**Q. CAN YOU EXPLAIN HOW THOSE SERVICES PROVIDED BY APT BENEFIT RRUI AND ITS CUSTOMERS?**

A. The capital and funds obtained from the sale of units in the Income Fund are used by the Regulated Utilities for capital investments. That capital is made available by APT to the Regulated Utilities, including RRUI. Also, the services provided by APT provide strong corporate governance, which is essential to the health of any organization whether publicly traded or not. Any company that wishes to raise capital at a decent rate must prove proper corporate governance. Less governance means more risk and a higher cost of capital. Most of these indirect corporate costs from APT relate to proper corporate governance and thus ensuring long term access to the capital markets. Therefore, the services provided by APT are critical and necessary to the Regulated Utilities. Put another way, absent the services provided by APT, the Regulated Utilities would be forced to operate as stand-alone utilities with higher costs and operating expenses. In addition, the utilities would bear greater risk due to a potential inability to obtain capital on a stand-alone basis. Operating as a stand alone utility also raises the very real possibility of declining quality of service.

**Q. DO YOU KNOW HOW THE ALLOCATION METHODOLOGY FOR APT COMPARES TO AFFILIATE COST ALLOCATION METHODOLOGIES USED BY OTHER ARIZONA UTILITIES, SUCH AS GLOBAL WATER?**

A. The allocation methodologies are very similar. In our recent Black Mountain rate case, Staff analyst Crystal Brown mentioned that she had no objections to the methodology employed by Global Water. After comparing our methodologies, we have concluded that they are extremely similar.[6] Costs for certain items such as rent and central office costs are allocated almost exactly the same way. Similarly, Global and Algonquin allocate regional costs similarly, as mentioned above, and also allocate other administration costs in a similar manner to Algonquin.[7] We could not decipher major differences between the methodologies; however, we do agree that Global's presentation was a bit clearer than ours. This is precisely the reason that we have created **Exhibit PE-RB1** and why I am testifying in this case.

**B. <u>Rebuttal to RUCO</u>**

**Q. LET'S SWITCH TO MR. COLEY'S TESTIMONY ON BEHALF OF RUCO. ON PAGE 45 OF HIS DIRECT TESTIMONY, MR. COLEY SUGGESTS THAT RRUI DOES NOT NEED THE MAJORITY OF SERVICES PROVIDED BY APT. HOW DO YOU RESPOND TO THAT STATEMENT?**

A. Mr. Coley's "determination" is troubling. It is incomprehensible that RRUI would not need access to capital, would not need to incur audit costs, tax planning costs, strategic management costs, incur depreciation expense on office furniture and software, incur costs for consulting related to Human Resources, Health and

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[6] *See* Direct Testimony of Greg Barber (with attached Appendices 1-3), filed February 20, 2009 in Docket Nos. SW-03575A-09-0077 and SW-20445A-09-0077.

[7] *Id.*



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Safety, ERP systems, etc. It appears that Mr. Coley simply does not understand the nature of the costs, and instead of asking further questions about it, he simply chose to disallow it under the guise of these costs being "unnecessary." I would challenge Mr. Coley to try and operate a well managed utility on a stand alone basis with healthy access to capital, strong corporate governance, and strategic management expertise for similar or lower cost. It also appears that Mr. Coley's testimony is not based on any tangible evidence. Rather, Mr. Coley simply "believes" that the APT services do not benefit RRUI.

If Mr. Coley, or Mr. Becker, needed more descriptions, explanations or other information regarding any of our shared services, he was free to ask during discovery. Or even now, as long as the case stays on the time-clock. They could have flown to Canada at our expense and seen the operation they are now making important and inaccurate judgments about in this rate case. There are hundreds of thousands of dollars at issue in this case and the others pending for Liberty Water utilities, and we will do whatever we need to do to provide RUCO and Staff the information they need to scrutinize our costs.

**Q. WHAT ABOUT MR. COLEY'S CLAIM THAT RRUI HASN'T COMPLIED WITH THE NARUC GUIDELINES?**

A. Mr. Coley is wrong for the reasons discussed above.

**Q. ARE THERE ANY OTHER ASPECTS OF MR. COLEY'S TESTIMONY THAT YOU'D LIKE TO ADDRESS?**

A. Yes. On page 48 of his testimony Mr. Coley does agree with our cost allocation methodology based on facility count. Unfortunately, like Staff, Mr. Coley uses a facility number of 70, which is incorrect for the reasons noted above.



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**Q. DOES RRUI FOLLOW THE NARUC UNIFORM SYSTEM OF ACCOUNTS?**

A. Yes, RRUI complies with the NARUC Uniform System of Accounts.

**Q. MR. COLEY ALSO SUGGESTS (PAGE 46 OF HIS DIRECT TESTIMONY) THAT COSTS SHOULD BE DIRECTLY BILLED INSTEAD OF ALLOCATED. IS THAT FEASIBLE?**

A. When feasible we agree with Mr. Coley. RRUI has done exactly that by directly charging AWS (direct costs) and allocating APT (indirect costs). However, not all costs are "direct."

**Q. WITH RESPECT TO MANAGEMENT FEES ALLOCATED BY APT, MR. COLEY HAS DETERMINED THAT SUCH FEES DO NOT PROVIDE BENEFIT TO RRUI AND IN HIS TESTIMONY (PAGE 49), MR. COLEY CONCLUDES THAT ONLY A SMALL FRACTION OF THE COSTS ALLOCATED BY APT ARE ATTRIBUTABLE TO RRUI. HOW DO YOU RESPOND TO THAT?**

A. I can only reiterate that strategic management decisions are critical for any public utility. The need for strategic management is even more pronounced for RRUI as a larger regulated utility that depends on access to capital for ongoing operational and capital needs. APIF seeks to hire talented strategic managers that aid in running each facility owned by the fund, including RRUI, as efficiently and effectively as possible. This ensures the long term health of each utility and ensures that rates are kept as low as possible without compromising the level of service. It also facilitates each utility's access to necessary capital funding at reduced costs.

The costs included in Strategic Management Costs fall into the following categories. The first category is Management Fees. Those fees incorporate



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management fees paid to Algonquin's management company for strategic management of all APIF facilities. These fees provide for the financial and capital funding services necessary for the Regulated Utilities, including RRUI, to fund utility operations and growth services. Management Fees are charged to APT as a monthly fee which is then allocated to the utilities division (26.98%), and then to each individual utility based on customer count, as I've explained in detail in my testimony.

**Q. HOW DO CUSTOMERS BENEFIT FROM THESE MANAGEMENT FEES?**

A. Ratepayers avoid the burdens of needing senior management staff at each utility by sharing of resources between all utilities, resulting in significant savings. These management services also allow Regulated Utilities to have an available source of capital funding for plant and infrastructure in the provision of utility services at a cost cheaper than what such utilities could obtain on their own.

APT management services are required in the provision of service by Regulated Utilities because the managers oversee utility operations, provide high level approvals for capital and operating budgets, and provide strategic planning services for the utilities. They also develop overall corporate strategies such as long term financial planning and capital needs, negotiate contracts, allocate capital among utilities and approve high level expenditures. These management services are required in order for APIF to provide capital funding to individual utilities, without which the utilities could not provide adequate service. RRUI receives the benefit of having its own highly functioning executive management team at a fraction of the cost of having its own executive management.



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**Q. WHAT ABOUT MR. COLEY'S DENIAL OF COSTS RELATED TO SHAREHOLDER COMMUNICATIONS?**

A. I would ask Mr. Coley if he would purchase shares of RRUI if he received no communications from the company and was entirely deaf to the operations. I would hope his answer is "No." On that note, RRUI's ratepayers receive the benefits of not only access to capital, but also access to those communications as they are publicly available.

**Q. MR. COLEY ALSO DENIES TRUSTEE FEES. WHAT ARE YOUR THOUGHTS ON THAT?**

A. I would respond that whether publicly traded or not, RRUI would likely have a Board of Directors. The Board assures proper corporate governance and thus a level of financial rigor, provides high level operational and financial oversight, and strategic guidance for the long term viability of the company and hence RRUI.

**Q. MR. COLEY MAKES THE SAME CONCLUSION RELATING TO ESCROW FEES (PAGE 46). IS THERE A CONNECTION BETWEEN SUCH ESCROW FEES AND RRUI'S PROVISION OF UTILITY SERVICE?**

A. Yes. The escrow fees are a cost of the business model that RRUI operates in. Shareholders would not invest in the fund if they did not receive distributions. In turn, RRUI would not have capital available to it from its parent company.

**Q. HOW DOES RUCO TREAT COSTS INCURRED BY APT FOR RENT, DEPRECIATION AND OTHER OFFICE COSTS?**

A. The same way Mr. Coley has treated other costs, by denying them. I would also note that this being the 3rd pending Liberty Water rate case to go to hearing, I have seen 3 different positions taken by RUCO on these issues. In BMSC, RUCO supported these costs. In LPSCO, RUCO supported portions of these costs,



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including rent. In this case, RUCO is disallowing rent and related expenses. I would also note that in the prior two rate cases for Liberty Water affiliates, BMSC and GCSC, RUCO did not oppose any of the Central Cost allocations. RUCO's approach seems to be without any discernable methodology as to what is and isn't acceptable to RUCO.

**Q. WHAT ARE THE POTENTIAL CONSEQUENCES TO RRUI AND OTHER REGULATED UTILITIES IN ARIZONA IF THE COMMISSION ULTIMATELY AGREES WITH STAFF AND/OR RUCO AND DENIES ALLOCATION OF AFFILIATE COSTS INCURRED BY APT?**

A. To be frank, Staff's and RUCO's treatment of APT's affiliate costs is nothing more than a rejection of one pillar of the APIF/APT/Liberty Water shared services model. If the Liberty Water's shared services model is not viewed as reasonable because of its costs, then Liberty Water will have to seriously consider operating differently. APIF isn't going to subsidize 90 percent of an over $1 million allocation pool to the seven Arizona utilities. That's simple economics. But one can't help but wonder why Staff and RUCO would reject a shared services model that is designed to deliver high quality utility service at the lowest possible price given numerous failed utility operations in Arizona. The notion, as Staff and RUCO suggest, that these allocated costs from the parent do not benefit the ratepayers is undercut by the very high level of service RRUI is providing to customers in this system. It is further undercut by the fact that RRUI's operating costs compare very favorably to other Arizona utilities.

**Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?**

A. Yes.

**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REBUTTAL TESTIMONY**
**February 1, 2010**

# Exhibit PE-RB1

# *LIBERTY WATER AFFILIATE COST ALLOCATION METHODOLOGY*

## *I. GENERAL STATEMENT OF ALLOCATION METHODOLOGY*

The purpose of this paper is to provide a detailed explanation of the Affiliate Cost Allocation Methodology used by the regulated utility affiliates of Liberty Water Company ("LWC") including Litchfield Park Service Company ("LPSCO"), Black Mountain Sewer Company, Gold Canyon Sewer Company, Rio Rico Utilities, Bella Vista Water Company, Northern Sunrise Water Company, and Southern Sunrise Water Company (collectively the "Regulated Utilities"). The Regulated Utilities are wholly-owned subsidiaries of LWC, which is owned by Algonquin Power Income Fund ("APIF").

### *A. The APIF Corporate Structure.*

APIF's primary business is ownership of generating and infrastructure facilities through investments in securities of subsidiaries. APIF owns a widely diversified portfolio of 46 electric facilities and 17 water distribution and wastewater treatment facilities in Canada and the United States. APIF also has an operating interest in 8 other facilities, but does not own them. APIF is publicly traded on the Toronto Stock Exchange. APIF's structure as a publicly traded income fund provides substantial benefits to its Regulated Utilities through access to capital markets and access to engineers, technicians, professional managers and administrative staff, including trained plant operators and field supervisors.

### *B. Liberty Water Cost Allocations to LPSCO.*

LPSCO and the other Regulated Utilities in Arizona do not operate as stand-alone utilities. LPSCO is operated by Algonquin Water Services d/b/a Liberty Water ("Liberty Water"), along with six other regulated Arizona water and sewer utilities, and eleven regulated water and sewer providers located in Texas, Missouri and Illinois. Liberty Water provides all of the day-to-day administration and operations personnel for these regulated utilities. All operations and engineering labor is charged by Liberty Water directly to LPSCO and the other separate Regulated Utilities operated by Liberty Water. Liberty Water charges those labor rates at cost, which is the dollar hourly rate per employee as recorded in Liberty Water's payroll system, grossed up by 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees. Engineering technical labor, which is capitalized, is charged on the same basis, plus an allocation of 10% for Liberty Water's corporate overheads such as rent, materials/supplies, etc.

Other necessary services provided by Liberty Water for the Regulated Utilities cannot be directly charged to LPSCO and the other Regulated Utilities. Labor for accounting, billing and customer service, human resources, health and safety, and corporate finance cannot be directly allocated using timesheets due to the nature of the costs because it is not practical to keep track of time for employees that serve multiple utilities in small time increments during the course of a work-day. A shared call center is the perfect example. A customer service representative at Liberty Water's call center will field calls from customers of LPSCO, BMSC, Bella Vista Water Company in southern Arizona and the three other states. This work directly benefits all of the Regulated Utilities, so the costs need to be allocated to all of them. These costs are allocated based on the relative customer counts of all of the Regulated Utilities. Using customer counts allows Liberty Water to allocate those costs to an individual utility, such as LPSCO, based on the relative burden of that utility relating to those services.

Overhead costs, like rent, insurance, administration costs, depreciation of office furniture and computers, also cannot be directly attributed to specific utilities. These costs are allocated to LPSCO and its affiliates by use of a "four factor" methodology that considers relative size through four weighted factors – total plant, total customers, expenses and labor. This type of four-factor methodology has been utilized by other Arizona utilities, including Chaparral City Water Company and Global Water. All of the costs charged by Liberty Water and allocated to LPSCO are based on actual costs, either directly charged or through the allocations described above.

### *B. Central Office Cost Allocations from Algonquin Power Trust.*

In addition to the operations and engineering direct costs, and the allocated overhead/administration costs charged by Liberty Water, LPSCO and the other utilities in this shared services model benefit from costs incurred by the Algonquin corporate parent. Specifically, APIF, the shareholder of Liberty Water, allocates a share of the costs incurred by its operating arm Algonquin Power Trust ("APT") in providing necessary and required services to the Regulated Utilities.

APT is the affiliate that provides financial, strategic management, compliance, administrative and support services to the Regulated Utilities operated by Liberty Water, as well as to the numerous unregulated utility assets owned by the corporate parent, APIF. APT does not allocate any labor related costs. The head office of APT is located in Oakville, Ontario, Canada and provides administrative, technical and management support, regulatory compliance, and

oversight of strategic direction, including approvals of budgets and ensuring a strict level of corporate governance for LPSCO and all of the utilities operated by Liberty Water. APT's executive management and administrative support includes accounting and finance, human resources, employee benefits, regulatory and information systems services.

The services provided by APT are necessary to allow LPSCO and the other Regulated Utilities to have access to capital markets for capital projects and operations, and are necessary to allow LPSCO to provide a high level of service at the lowest cost. There are no direct labor costs included in the corporate administration Central Office Cost allocation from APT. Instead, these costs include professional services like third-party legal services, accounting services, tax planning and filings, and required auditing that are done for the benefit of all of the Liberty Water Regulated Utilities, including LPSCO.

These corporate headquarter administrative costs also include costs for licenses, fees and permits, information technology/systems, payroll, and HRIS maintenance contracts, as well as the rent and depreciation of office furniture and equipment and computers in the central office in Oakville, Ontario. Fees for these services are allocated to the Regulated Utilities using generally accepted allocation principles. These services are routine and recurring in nature and performed on a regular basis as part of normal business operations for Liberty Water and its Regulated Utilities.

These administration Central Office Costs are allocated to LPSCO in two phases. The first phase involves allocating these costs to each of the facilities, both regulated and unregulated, owned by APIF. That initial allocation is made based on relative size. Specifically, APIF owns and operates 63 total entities, 17 of which are the Regulated Utilities operated by Liberty Water. In turn, 17 of 63 is 26.98%, which means 26.98 percent of the total Central Office Costs are allocated to the Regulated Utilities operated by Liberty Water.[1]

From there, the second allocation phase is that Liberty Water allocates the Central Office Costs between LPSCO and the 16 other Regulated Utilities based on customer counts. These costs are incurred for the benefit of all of the Regulated Utilities and their customers, but are not capable of being directly charged to the 63 separate operating assets. This cost allocation methodology

[1] For illustrative purposes, if the total Central Office Costs incurred by APT was $4,000,000, then $1,079,200 (4,000,000 x .2698) in Central Office Costs would be allocated to the 17 Regulated Utilities under Liberty Water. The remaining $2,920,800 (73.02%) in Central Office Costs would be allocated to the remaining 46 electric facilities owned by APIF.

ensures that the costs are allocated as closely as possible to the originator of those costs. An entity such as LPSCO with 33,000 water and sewer customers benefits more from these costs than BMSC with only 2,000 wastewater ratepayers. Specifically, LPSCO has 16,037 water customers and 17,068 wastewater customers, for a total of 33,105 customers. In total, Liberty Water's 17 Regulated Utilities have 68,783 water and wastewater customers, which means LPSCO is allocated 48.13% (33,105/68,783) of the Central Office Cost pool.

The fundamental principle of this Cost Allocation Methodology is that LPSCO and the other Regulated Utilities should be charged for all costs incurred by affiliates—both Liberty Water and APT—so that the Regulated Utilities can provide a high level of safe and reliable water and wastewater utility service to customers.

## *II. DETAILED EXPLANATION OF THE SERVICES PROVIDED AND COSTS ALLOCATED TO THE REGULATED UTILITIES.*

The following is a detailed description of how these cost allocation methodologies are applied to the Regulated Utilities, the benefits of the services provided by Liberty Water and APT, the need for such services in the provision of utility services, and the necessity of allocating costs to the Regulated Utilities.

### *A. Liberty Water Services Provided to LPSCO.*

Attached as Appendix 1 is an allocation summary of how costs incurred by Liberty Water are allocated to the Regulated Utilities, including LPSCO. Whenever possible, costs incurred by Liberty Water for a particular Regulated Utility are directly charged to that utility based on time sheets.

#### *1. Operations and Engineering Labor.*

These costs are billed directly to the Regulated Utility that required the labor, as documented by time sheets. Attached as Appendix 2 is an example time sheet used by Liberty Water. Those direct charges are principally direct labor, including operations and engineering. For example, the costs for a plant operator working solely for LPSCO will be directly allocated to LPSCO without any further allocation necessary. Liberty Water direct charges those services to the Regulated Utilities at cost.[2] The labor rate charged by Liberty Water is the dollar

[2] It bears emphasis that the Liberty Water allocations reflect actual costs incurred. Liberty Water now charges based on actual payroll rates, not market based rates.

hourly rate per employee as recorded in Liberty Water's payroll system, grossed up by roughly 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees. Engineering technical labor, which is capitalized, is charged on the same basis, plus a 10% allocation for corporate overheads incurred by Liberty Water, including rent, materials, supplies and other similar overhead costs.

### 2. *Accounting, Billing and Customer Service Labor Costs.*

Liberty Water also incurs additional labor costs for accounting, billing, and customer service, human resources, health and safety, and corporate finance which are necessary for the Regulated Utilities to provide adequate and reliable water and wastewater service to customers. Those costs, however, cannot be allocated to each Regulated Utility using time sheets due to the nature of the costs. It is not practical to keep track of time for employees that serve multiple utilities during the course of a work day. For example, an accounting analyst may analyze the financial performance of all Regulated Utilities at the same time. Her accounting work benefits all such Regulated Utilities, so her services and costs would be allocated to all Regulated Utilities. Likewise, a customer service representative at Liberty Water's call center will field calls from customers of all Regulated Utilities during a work day. Again, his work directly benefits all such Utilities and his costs should be allocated to all Regulated Utilities.

These labor costs incurred by Liberty Water are allocated to the Regulated Utilities based on customer count. The following simplified example demonstrates how a customer service representative's costs would be allocated to LPSCO:

| | |
|---|---|
| Annual Salary | $30,000 |
| Burden (at 35%): | $10,500 |
| Total Labor Cost | $40,500 |

Total Liberty Water Customers: 68,783
LPSCO Water Customers: 16,037 (23.32% of total customers)
LPSCO Wastewater Customers: 17,068 (24.81% of total customers)

Salary Costs allocated to LPSCO Water: $9,444.60 (40,500 x .2332)

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Liberty Water made that change in early 2008, which means that rate cases pending before that change was made have been trued up and adjusted to reflect this actual cost methodology as if it had been adopted at the beginning of the respective test year.

Salary Costs allocated to LPSCO Wastewater $10,049.78 (40,500 x .2481)
Salary Costs allocated to all other Regulated Utilities: $21,005.62

### 3. *Liberty Water Overhead Costs.*

Costs incurred by Liberty Water for rent, administrative costs, depreciation of office furniture, depreciation of computers, and other labor cannot be directly attributed to a specific Regulated Utility. As such, those overhead and administrative Costs are allocated to the Regulated Utilities by use of the "four factor" methodology. Other costs in this category include insurance, janitorial services and other general non-payroll costs.

The "four factor" methodology allocates costs by relative size of the utilities. The methodology used by Liberty Water involves (1) Rate Base, (2) Total Customers, (3) Non-Labor Expenses and (3) Labor as allocating factors, with each factor assigned a specific weight. Liberty Water uses the following weights under this four factor methodology:

| | |
|---|---|
| **UTILITY PLANT** | **50%** |
| **CUSTOMER COUNT** | **40%** |
| **LABOR** | **5%** |
| **EXPENSES** | **5%** |
| **TOTAL** | **100%** |

The following simplified hypothetical example demonstrates how the four factor allocation methodology would be calculated based on ownership of *only* two hypothetical utilities (LPSCO and BMSC):

| FACTOR | LPSCO | BMSC | TOTAL ALL UTILTIES | LPSCO % OF TOTAL | FACTOR WEIGHT | LPSCO ALLOCATION |
|---|---|---|---|---|---|---|
| **UTILITY PLANT** | **727** | **371** | **1098** | **66%** | **50%** | **33%** |
| **CUSTOMER COUNT** | **6000** | **1000** | **7000** | **86%** | **40%** | **34%** |
| **LABOR COSTS** | **57** | **32** | **89** | **64%** | **5%** | **3%** |
| **EXPENSES** | **108** | **41** | **149** | **72%** | **5%** | **4%** |
| **TOTAL ALLOCATION TO LPSCO** | | | | | | **74%** |

As can be seen from these hypothetical numbers, LPSCO would be allocated 74% of total Administrative/Overhead Costs incurred by Liberty Water, based on its relative size and application of the four factors in comparison to BMSC. BMSC would be allocated the remaining 26%. Liberty Water developed and utilized this methodology including all 17 of its utilities to better allocate costs, recognizing that larger utilities require more time and management attention and incur greater costs than smaller ones.

### *4. Customer Benefits of Liberty Water Allocation Model.*

Customers of Liberty Water receive significant benefits from this cost allocation model, including significantly lower costs incurred by the Regulated Utilities for services that are essential and necessary to the provision of high quality water and wastewater utility service. The benefits of this type of shared service model include:

- Savings on labor costs by resource sharing – since most Liberty Water employees are not dedicated to a specific utility, the utilities do not need to hire their own dedicated staff, thus resulting in significant cost savings.

- Four factor allocations allow for utilities to be charged by relative resources and management attention required to operate them. This means customers of smaller utilities do not subsidize costs of larger utilities. Essentially, this allocation methodology allows costs to be allocated based on the relative burdens and costs incurred by individual utilities.

- Because it's scalable, the shared services model allows for increased growth with less than proportional cost increases, meaning the Regulated Utilities can grow without incurring a proportionate or prohibitive increase in the cost of service.

## *B. APT Services Provided to LPSCO.*

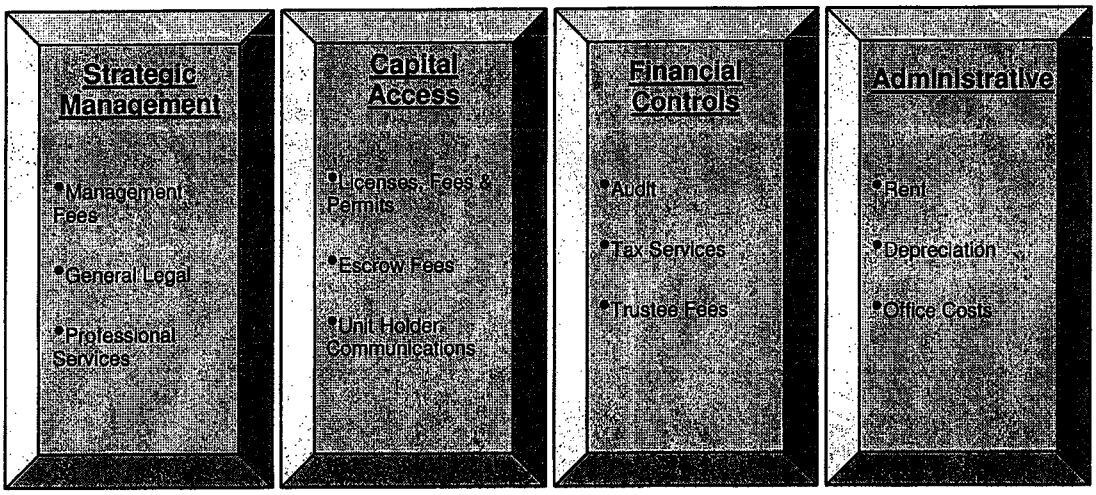
Attached as Appendix 3 is an overview of the services and allocations for APT. As noted above, APT is a wholly-owned subsidiary of APIF. APT is integral to APIF's business structure as a publicly traded income fund on the Toronto Stock Exchange. APIF sells units to public investors in order to generate the funding and capital necessary for the Regulated Utilities to provide utility service. APT provides all of the administrative services for APIF and all of APIF's facilities, including strategic management services, access to capital

markets, corporate governance, and administration and management of the Regulated Utilities.

The capital and funds obtained from the sale of units in the Income Fund are used by the Regulated Utilities for capital investments. That capital is made available by APT to the Regulated Utilities. The services provided by APT are critical and necessary to the Regulated Utilities because without those services the Regulated Utilities would not have a readily available source of capital funding. Put another way, absent the services provided by APT, the Regulated Utilities would be forced to operate as stand alone utilities, with resulting higher costs and operating expenses incurred by customers. In addition, the utilities would bare much greater risk due to a potential inability to obtain capital on a standalone basis.

The services provided by APT optimize performance of the Regulated Utilities, keeping rates low for customers while ensuring access to capital is available. If the Regulated Utilities did not have access to the services provided by APT, then the Regulated Utilities would be forced to incur associated costs for financing, capital investment, audits, taxes and other similar services on a stand-alone basis, which would substantially increase such costs for each Regulated Utility. It bears emphasis that if the costs incurred by APT are not allocated to LPSCO and the other Regulated Utilities, then APT and APIF will have no choice but to cease providing the capital funding and other services to LPSCO and the other Arizona Regulated Utilities.

The services provided by and the costs incurred by APT for the Regulated Utilities fall into four general categories:



All of these costs incurred by APT are calculated and totaled into the administration Central Office Cost Pool. As noted above, that administration Central Office Cost Pool is then allocated to APIF's electrical facilities and water/wastewater facilities based on the number of entities involved. In total, APIF owns 46 electric facilities and 17 water/wastewater utilities. Thus, the Central Office Cost Pools is allocated based on facility count with 73.02% (46/63) of the Pool allocated to the electric facilities and 26.98% (17/63) of the Pool allocated to the Regulated Utilities.

For example, if the total administration Central Office Cost Pool incurred by APT is $4,000,000, then $1,079,200 (4,000,000 x .2698) in administration Central Office Costs would be allocated to the 17 Regulated Utilities under Liberty Water. The remaining $2,920,800 (73.02%) in administration Central Offices costs would be allocated to the remaining 46 electric facilities owned by APIF.

The allocated administration Central Office Cost Pool for the Regulated Utilities then is allocated to each individual utility by customer count. As noted in attached Appendix 3, LPSCO would be allocated 49% of those costs based on customer count. In our hypothetical example, LPSCO would be allocated $518,016 in costs from APT. The following is a detailed description of each cost component within the Central Office Cost Pool, the necessity of allocating such costs to Regulated Utilities in providing services and the associated benefits to ratepayers.

### *1. APT Strategic Management Costs*

Strategic management decisions are critical for any public utility. The need for strategic management is even more pronounced for APIF as a publicly traded income fund, which depends on access to capital funding through public sales of units in the fund. APIF seeks to hire talented strategic managers that aid in running each facility owned by the fund as efficiently and effectively as possible. This ensures the long term health of each utility and ensures that rates are kept as low as possible without compromising the level of service. It also facilitates each Regulated Utility's access to necessary capital funding at reduced costs. The costs included in Strategic Management Costs fall into the following categories.

**MANAGEMENT FEES**

| | |
|---|---|
| Description | Fees which incorporate salaries of senior management staff for strategic management of all APIF facilities. The executives at APT provide the financial and capital funding services necessary for the |

| | |
|---|---|
| | Regulated Utilities to fund utility operations and growth services. |
| Allocation Method | Management Fees are charged by APT as a monthly fee which is allocated to the utilities division (26.98%), and then to each individual utility based on customer count. |
| Ratepayer Benefits | Rate payers avoid the burdens of senior management staff at each utility by sharing of resources between all utilities, resulting in significant savings. These management services also allow Regulated Utilities to have an available source of capital funding for plant and infrastructure in the provision of utility services at a cost cheaper than what such utilities could obtain on their own. |
| Need for Management Services | APT management services are required in the provision of service by Regulated Utilities because the APT managers oversee utility operations, provide high level approvals for capital and operating budgets, and provide strategic planning services for the utilities. They also develop overall corporate strategies, negotiate contracts, allocate capital among utilities and approve high level expenditures. These management services are required in order for APIF to provide capital funding to individual utilities, without which the utilities could not provide adequate service. |

## GENERAL LEGAL SERVICES

| | |
|---|---|
| Description | Legal expenses incurred by APT for general legal matters pertaining to all facilities owned by APIF. These legal services are required in order for APIF to provide capital funding to individual utilities, without which the utilities could not provide adequate service. |
| Services Provided | These legal services involve legal matters not specific to any single facility, including review of audited financial statements, annual information filings, Sedar filings, review of contracts with credit facilities, incorporation, tax issues of a legal nature, market compliance, and other similar legal costs. |
| Ratepayer Benefits | General legal costs help ensure that the APIF and the Regulated Utilities remains compliant in all aspects of operations and prevents those entities from being exposed to unnecessary risks. These legal services also allow utilities to have continued access to capital markets available to APIF. |

| | |
|---|---|
| Need for Legal Services | These legal expenses are critical to utility operations because they ensure APIF's status and viability as a publicly traded income fund and allow the utilities to provide service in a way to ensure continued access to strategic management and capital markets. These legal services also shelter APIF and its Regulated Utilities from operational risks. |

**PROFESSIONAL SERVICES**

| | |
|---|---|
| Description | Professional Services including strategic plan reviews, capital market advisory services, ERP System maintenance, benefits consulting, and other similar professional services. |
| Ratepayer Benefits | These professional services ensure that APIF's strategic plans and initiatives are completed with the highest degree of care and professionalism, which is necessary for the Regulated Utilities to receive debt and equity funding from capital markets. These services allow the Regulated Utilities to have an available source of capital funding for plant and infrastructure in the provision of utility services. |
| Need for Services | These costs are required for the provision of service as the strategic plans are filtered down to the individual utility level. In the absence of strategic plans, the utilities would not be investing to ensure the highest level of service is provided, and would also not be able to strive for continued operational improvements to save ratepayers money in the long run. In the absence of these services, unit holders would not invest in utility operations of APIF because the utilities would not incur the necessary costs to ensure that the strategic plans are followed as a condition of such funding. |

### 2. *Access to Capital Markets.*

One of APT's primary functions is to ensure APIF's facilities (i.e., the Regulated Utilities) have access to quality capital. APIF is listed on the Toronto Stock Exchange, a leading financial market. In order to allow the Regulated Utilities to have continued access to those capital markets, APT incurs the following Costs for the benefit of the Utilities. These services and costs are a prerequisite to the Regulated Utilities' continued access to those capital markets.

## LICENSE FEES AND PERMITS

| | |
|---|---|
| Description | Fees incurred by APT to ensure that APIF can participate in the Toronto Stock Exchange. These licensing and permit fees are required in order to sell units on the Toronto Stock Exchange. |
| Examples | Sedar fees, annual filing fees, licensing fees, etc. |
| Ratepayer Benefits and Need for Services | The ratepayers and Regulated Utilities have access to capital so long as APIF is able to access capital markets. These license fees allow APIF to sell units on the Toronto Stock Exchange and, in turn, provide funding for utility operations. These license fees incurred by APT are critical to ensure continuing access to capital. |

## ESCROW FEES

| | |
|---|---|
| Description | Escrow Fees for payment of dividends to Unit Holders. |
| Examples | Unit holders invest in APIF, and, in turn, provide capital funding to the Regulated Utilities by buying units. In making those investments, unit holders expect monthly distributions on the units they own. As such, APT incurs escrow fees in paying such monthly payments to unit holders. |
| Ratepayer Benefits | Escrow Fees are incurred in order to ensure that unit holders of APIF continue to maintain ownership, and that new shareholders are enticed to invest in the Fund. Those new shareholders are the ones truly investing money for new and future projects the utilities undertake. Without them, there is no money for APIF to invest in the utilities. |
| Need for Services | Escrow Fees are incurred to ensure continued access to capital and ensure continuing and ongoing investments by unit holders. Without such escrow fees, the Regulated Utilities would not have a readily available source of capital funding. |

## UNIT HOLDER COMMUNICATIONS

| | |
|---|---|
| Description | Unit holder communication costs are incurred to comply with filing and regulatory requirements of the Toronto Stock Exchange and meet the expectations of shareholders. |
| Examples | News releases, unit holder conference calls, etc. |
| Ratepayer Benefits | Unit holder communications costs are incurred by APT for the benefit of the Regulated Utilities to ensure that unit holders are fully informed of all operational and strategic decisions. These disclosures are required by law to ensure a level of integrity and rigor is applied to the management of the Regulated Utilities. |

| | |
|---|---|
| Need for Services | In the absence of unit holder communication costs, investors would not invest in the units of APIF, and in turn, APIF would not have capital to invest in the utilities. With such communications services, the Regulated Utilities would not have a readily available source of capital funding. |

### 3. *APT Financial Controls.*

Financial Control costs incurred by APT include costs for audit services, tax services, and trustee fees. These costs are necessary to ensure that the Regulated Utilities are operated in a manner that meets audit standards and regulatory requirements have strong financial and operational controls, and that financial transactions are recorded accurately and prudently. Without these services, the Regulated Utilities would not have a readily available source of capital funding.

**AUDIT FEES**

| | |
|---|---|
| Description | Audits are done on a yearly basis and reviews are performed quarterly on all facilities owned by APIF on an aggregate level. |
| Examples | Audits are provided by KPMG. |
| Ratepayer Benefits | Audits benefit ratepayers by verifying and ensuring that all financial transactions are recorded prudently. Further, financial transactions are scrutinized to ensure that operations are run prudently. Audit fees also ensure that access to capital is available as it is a requirement of financial markets. The aggregate audit again benefits the Regulated Utilities by allowing continued access to capital markets and unit holders. |
| Need for Services | These corporate parent level audits reduce the cost of the standalone audits significantly for utilities such as LSPSCO which must perform its own separate audits. Where standalone audits are not required, rate payers receive benefits of additional financial rigor, as well as access to capital, and financial soundness checks by third parties. Finally, during rate cases, the existence of audits provides Staff and Intervenors additional reliance on the company records, thus reducing overall rate case costs. The aggregate audit is necessary for the Regulated Utilities to have continued access to capital markets and unit holders. |

## TAX SERVICES

| | |
|---|---|
| Description | Tax Services expenses are incurred to ensure prudent tax filing, planning and management. |
| Examples | Taxes are paid on behalf of the Regulated Utilities at the parent level as part of a consolidated United States tax return. Tax services are provided by third parties including KPMG for tax planning and filing. |
| Ratepayer Benefits | Tax services ensure that each utility maintains tax compliance as the parent maintains compliance on their behalf. The shared cost of such tax services also are lower than the costs of stand alone tax services, which would otherwise be incurred by the Regulated Utilities. |
| Need for Services | Tax services are required as each of the utilities would be required to pay taxes on a stand alone basis. Filing tax returns on a consolidated basis benefits each Regulated Utility by reducing the costs that otherwise would be incurred by such Utility in filing its own separate tax return. |

## TRUSTEE FEES

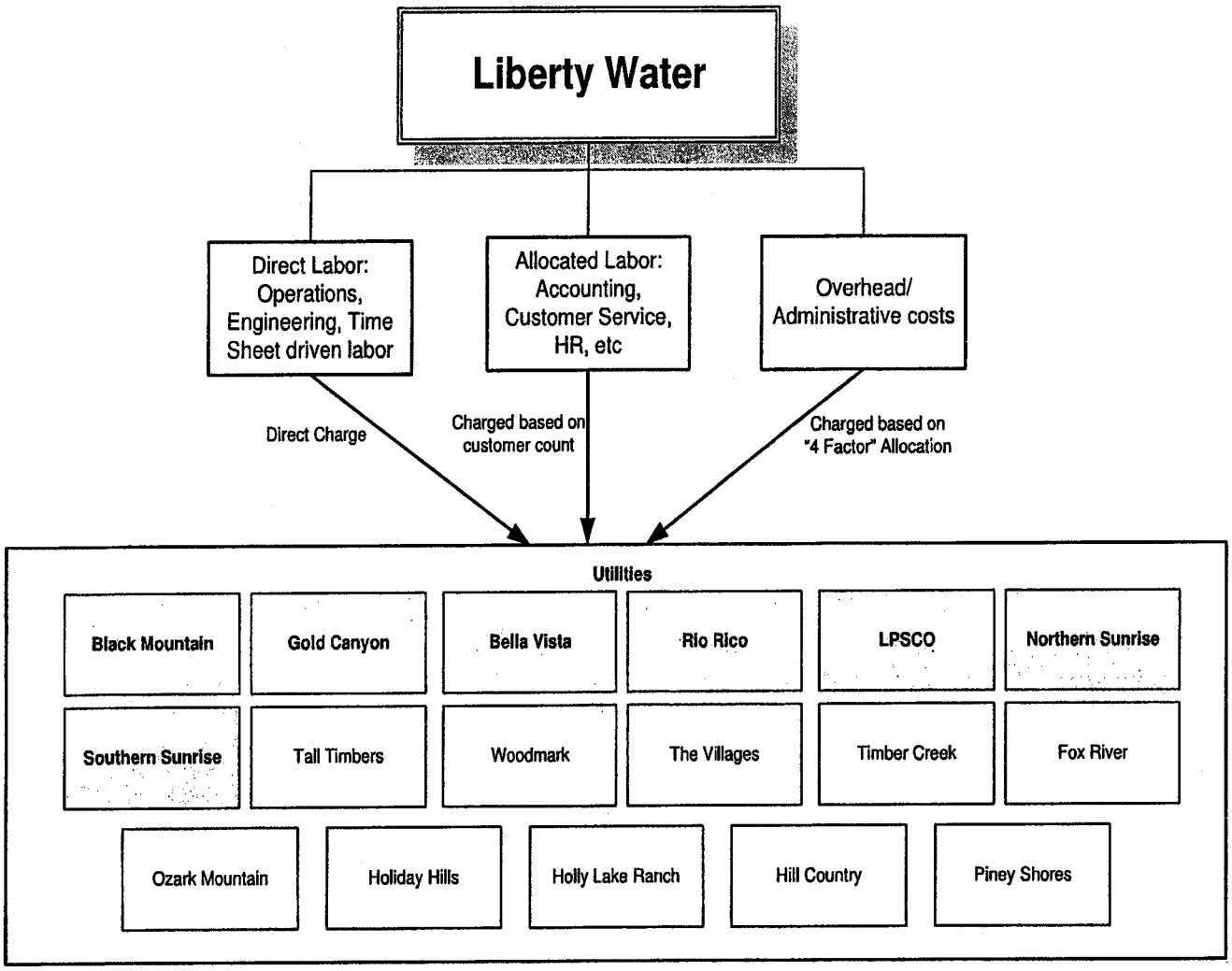
| | |
|---|---|
| Description | Trustee Fees are paid to the Board of Trustees, which meets on a quarterly basis. |
| Ratepayer Benefits | Trustees act in the same manner as Boards of Directors. They have a duty to shareholders to ensure that they will act in their best interests. This means that they must act in a way that optimizes the operations of the utilities. Trustees also approve the strategic direction of the company, provide corporate governance, and oversee the strategic direction and health of the Income Fund, and in turn the Regulated Utilities owned by APIF in order to ensure long term sustainability. In summary, the trustees help to ensure financial rigor, significant controls, and ultimately keeps rates low. |
| Need for Services | Trustees are required to oversee the operations of the utilities collectively. They also ensure on going access to capital and are a fundamental requirement for a publicly traded company and its affiliates. |

### *4. APT Administrative Costs.*

Finally, administrative costs incurred by APT such as rent, depreciation of office furniture, depreciation of computers, and general office costs are required to

house all the services mentioned above. Without these administrative costs, the employees of APT could not perform their work and provide the necessary services to the Regulated Utilities.

Appendix 1: Overview of Liberty Water Allocation Methodology




☐ Utilities located in Arizona

## Appendix 2: Sample Time Sheet of Liberty Water Employee

**ALGONQUIN WATER SERVICES - WEEKLY TIME SHEET**

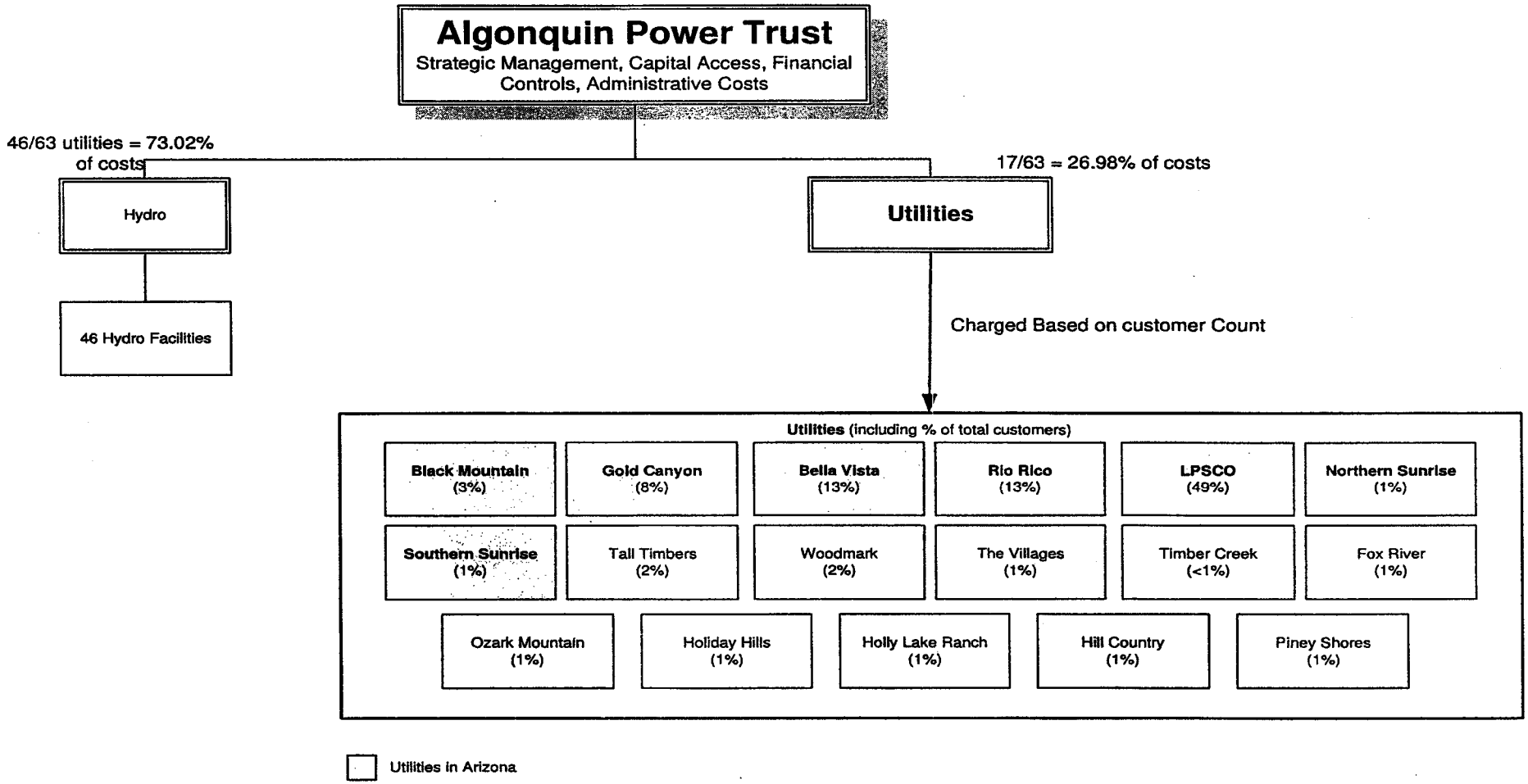
EMPLOYEE NAME: Martin Geriant | EMPLOYEE No: 1092 | Week Ending : November 7, 2009

| Day of Week | Date | Time from | Time to | Work Hours | Jury Duty Bereavement | Stat | Sick | Vac | Site Hours | Call Out Day | Call Out Hours | Site / Client # | OPS / FWO # | Labor Cost Code | Description |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Sunday | 11/1 | | | | | | | | | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |
| Monday | 11/2 | 7:00 AM | 12:00 PM | 5 | | | | | 2 | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | 1:00PM | 5:00PM | 4 | | | | | 1 | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | 1 | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 1 | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 4 | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |
| Tuesday | 11/3 | 7:00 AM | 12:00 PM | 5 | | | | | 2 | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | 1:00 PM | 5:00 PM | 4 | | | | | 2 | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | 1 | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 1 | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 3 | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |
| Wednesday | 11/4 | 7:00 AM | 12:00 PM | 5 | | | | | 2 | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | 1:00PM | 5:00 PM | 4 | | | | | 2 | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | 0.5 | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 0.5 | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 4 | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |
| Thursday | 11/5 | 7:00 AM | 12:00 PM | 5 | | | | | 5 | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | 1:00PM | 6:00 PM | 5 | | | | | 2 | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | 0.5 | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 0.5 | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 2 | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |
| Friday | 11/6 | 7:00 AM | 12:00 PM | 5 | | | | | 3 | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | 1:00 PM | 5:00 PM | 4 | | | | | 2 | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | 0.5 | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 0.5 | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 2 | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | 1 | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |
| Saturday | 11/7 | | | | | | | | | | | Rio Rico | 8134-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Rio Rico | 8134-0200-OPS1 | 1-5020-2000-0001 | |
| | | | | | | | | | | | | N. Sunrise | 8137-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | S. Sunrise | 8140-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Bella Vista | 8500-0100-OPS1 | 1-5020-1000-0001 | |
| | | | | | | | | | | | | Training | 9999-0000-TRAIN | 1-5020-0000-0001 | |

| | Regular Work Week Hours | | | | | | ON CALL | |
|---|---|---|---|---|---|---|---|---|
| | Work | Jury Duty Bereavement | Stat | Sick | Vac | Site | Days | Hours |
| TOTAL HOURS: | 46.00 | 0.00 | 0.00 | 0.00 | 0.00 | 46.00 | 0.00 | 0.00 |

SIGNATURE _____ SUPERVISOR _____

Appendix 3: Overview of APT Cost Allocations:

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**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REBUTTAL TESTIMONY**
**February 1, 2010**

# Exhibit PE-RB2

Rio Rico Utilities Inc.
Allocation Methodology Analysis
(all numbers in $ millions, except number of facilities)

Number of Facilities

| | | |
|---|---|---|
| Number of total utilities | 17 | |
| Number of total facilities | 63 | |
| Allocation based on number of facilities | 26.98% | |

Revenues

| | | |
|---|---|---|
| Year | 2008 | 2007 |
| Revenues from Utilities | 35.233 | 33.699 |
| Gross Revenues from 63 facilities | 206.99 | 161.889 |
| Allocation based on revenues | 17.02% | 20.82% |

Allocation based on Plant

| | |
|---|---|
| Total APIF Plant Value excluding CIAC and AIAC | 804.981 |
| Add: Liberty Water CIAC | 62.737 |
| Total APIF Plant | 867.718 |
| Total Liberty Water - Plant Value - excluding CIAC and AIAC & Intangible | 245.319 |
| Future Income Tax Adjustment | 12.770 |
| Total Liberty Water Plant | 258.088 |
| Allocation based on Plant | 29.74% |

Operating Costs

| | |
|---|---|
| Total APIF Operating costs | 44.413 |
| Utility operating costs | 12.82318 |
| Allocation based on Operating Costs | 28.87% |

Three Factor Calculation

| Factor | Allocation % | Weight | Total |
|---|---|---|---|
| Operating Costs | 28.87% | 33% | 9.53% |
| Revenue | 17.02% | 33% | 5.62% |
| Plant in Service | 29.74% | 33% | 9.82% |
| | | | 24.96% |
| | | | |
| Number of facilities | | | 26.98% |

**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REBUTTAL TESTIMONY**
**February 1, 2010**

# Exhibit PE-RB3

# COMPARISON OF RIO RICO'S OPERATING COSTS TO OTHER ARIZONA WATER UTILITIES

| | Az-Am (Paradise Valley) | Sunrise Water Co. | Arizona-American (Anthem Water) | Rio Verde Utilities, Inc. (Water) | Arizona Water Co. (Oracle) | Arizona Water Co. (San Manuel) | Chaparral City Water Co. | Arizona Water Co. (Sedona) | H20, Inc. | Global Water (Santa Cruz Water Co.) | Arizona Water Co. (Lakeside) | Arizona Water Co. (Coolidge) | Arizona Water Co. (Sierra Vista) | Willow Valley Water Co. | Rio Rico Water Division | Arizona Water Co. (Overgaard) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year | 12/31/2007 | 12/31/2007 | 12/31/2007 | 12/31/1999 | 12/31/2007 | 12/31/2007 | 12/31/2006 | 12/31/2007 | 12/31/2006 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2008 | 12/31/2007 |
| Customers[1] | 4,884 | 1,324 | 8,764 | 1,193 | 1,524 | 1,573 | 13,500 | 6,419 | 6,300 | 15,371 | 4,953 | 4,656 | 2,900 | 1,554 | 6,025 | 4,124 |
| Total Revenue | $7,848,732 | $1,304,363 | $9,357,346 | $953,199 | $1,115,109 | $812,359 | $7,446,700 | $3,521,124 | $3,383,145 | $9,110,720 | $2,588,943 | $2,214,952 | $1,461,897 | $473,327 | $1,847,256 | $1,686,342 |
| Total Expenses | $6,296,235 | $1,364,627 | $7,215,051 | $750,938 | $931,966 | $859,882 | $6,649,429 | $3,096,417 | $3,026,826 | $7,141,309 | $2,071,226 | $1,938,319 | $1,186,838 | $569,035 | $2,061,862 | $1,316,453 |
| Salary/Wages | $715,859 | $414,480 | $801,914 | $104,146 | | | $969,244 | | $790,693 | $781,051 | | | | $226,369 | | |
| Pension/Benefits | | | | $7,399 | | | | | | $189,983 | | | | $50,965 | | |
| Purchased Water | | | $444,337 | $67,382 | | $241,318 | $831,656 | $7,247 | $77,763 | | $1,233 | $10,262 | $2,096 | | | $58 |
| Purchased Power | $693,068 | $169,673 | $965,412 | $156,637 | $149,736 | $38,358 | $602,982 | $518,834 | $253,894 | $554,361 | $181,940 | $192,581 | $220,661 | $33,562 | $441,501 | $71,171 |
| Chemicals | $236,982 | $14,099 | $90,637 | $1,007 | $15,542 | $40,816 | $127,457 | $319,722 | $4,229 | $40,139 | $28,463 | $33,911 | $22,454 | $18,050 | $9,347 | $14,733 |
| Materials/Supp. | $87,860 | $53,733 | $64,824 | $15,399 | | | $19,800 | | $236,896 | $316,002 | | | | $60,189 | $23,150 | |
| Testing Serv. | | $2,635 | | $9,137 | | | $43,458 | | $12,289 | $36,113 | | | | $5,401 | | |
| Cust. Accounting | | | | | $100,428 | $104,642 | | $323,108 | | | $275,893 | $267,290 | $134,508 | | | $207,198 |
| Admin/General | | | | | $151,590 | $140,854 | | $641,077 | | | $506,659 | $378,361 | $152,251 | | | $279,673 |
| Contr. Serv. Other | | $45,163 | | $28,578 | | | $266,544 | | $72,107 | $67,911 | | | | $12,787 | $805,032 | |
| Management Fees | $923,778 | | $1,132,699 | | | | | | | | | | | | | |
| Rent | $21,467 | $37,664 | $14,739 | | | | | | $212,418 | $94,369 | | | | $9,185 | $26,954 | |
| Transportation | | $74,769 | | $593.00 | | | $70,430 | | $182,654 | $45,296 | | | | $13,076 | $79,315 | |
| Insurance-GL | $184,827 | $11,141 | $240,221 | $7,539 | | | ($1,294) | | $46,695 | $53,083 | | | | $5,119 | $37,699 | |
| Insurance Other | $45,435 | $50,775 | $61,231 | | | | | | $61,213 | $4,647 | | | | $1,072 | | |
| Misc. | $351,828 | ($21,980) | $279,744 | $139.00 | | | $1,259,948 | | $7,244 | $34,629 | | | | $10,257 | $14,822 | |
| Depreciation | $1,615,824 | $395,853 | $1,979,583 | $162,599 | $181,393 | $106,134 | $1,608,019 | $731,033 | $343,659 | $3,507,185 | $416,943 | $426,056 | $186,533 | $185,781 | $463,297 | $214,780 |
| Income Taxes | $228,400 | | $74,690 | $23,017 | $65,869 | ($77,597) | $270,020 | ($153,125) | $221,095 | $1,238,040 | $158,301 | $73,220 | $114,140 | ($72,987) | ($134,909) | $154,685 |
| Property Taxes | $268,996 | $64,714 | $414,503 | | $53,921 | $68,170 | $295,813 | $125,837 | $201,549 | | $116,684 | $151,656 | $80,115 | | $130,373 | $65,159 |
| Other Taxes | $67,972 | | $69,910 | $41,820 | $12,458 | $9,102 | $47,783 | $47,845 | $63,002 | $6,823 | $35,117 | $52,532 | $13,539 | $140 | | $22,756 |
| Cost/Customer[2] | $1,289.16 | $1,030.69 | $823.26 | $629.45 | $611.53 | $546.65 | $492.55 | $482.38 | $480.85 | $464.60 | $418.18 | $416.31 | $409.25 | $366.17 | $342.22 | $319.22 |
| Total Expenses Less Depr/Taxes | $4,115,043 | $904,060 | $4,676,365 | $523,502 | $618,325 | $754,073 | $4,427,794 | $2,344,827 | $2,197,521 | $2,389,261 | $1,344,181 | $1,234,855 | $792,511 | $456,101 | $1,603,101 | $859,073 |
| Cost/Customer Less Dep/Taxes[3] | $842.56 | $682.82 | $533.59 | $438.81 | $405.73 | $479.39 | $327.98 | $365.29 | $348.81 | $155.44 | $271.39 | $265.22 | $273.28 | $293.50 | $266.07 | $208.31 |
| Total Expenses - Tax/Dep/Pow/Chem | $3,184,993 | $720,288 | $3,175,979 | $298,476 | $453,047 | $433,581 | $2,865,699 | $1,499,024 | $1,861,635 | $1,794,761 | $1,132,545 | $998,101 | $547,300 | $404,489 | $1,152,253 | $773,111 |
| Cost/Cust.- Tax/ Dep/Power/Chem[4] | $652.13 | $544.02 | $362.39 | $250.19 | $297.27 | $276.64 | $212.27 | $233.53 | $295.50 | $116.76 | $228.66 | $214.37 | $188.72 | $260.29 | $191.25 | $187.47 |

[1] The customer numbers are based on each company's H-2 Schedule filed in each company's recent rate case.
[2] This row equals Total Operating Expenses divided by the total number of customers.
[3] This row equals Total Operating Expenses minus Taxes and Depreciation divided by the total number of customers.
[4] This row equals Total Operating Expenses minus Taxes, Depreciation, Purchased Power, Purchased Water and Chermicals divided by the total number of customers.

# COMPARISON OF RIO RICO'S OPERATING COSTS TO OTHER ARIZONA SEWER UTILITIES

| | Az-Am (Anthem-Agua Fria) | Rio Rico Wastewater | Az-Am (Anthem) | Az-Am (Mohave Wastewater) | Coronado Utilities | Global Water (Palo Verde) | Far West |
|---|---|---|---|---|---|---|---|
| Test Year | 12/31/2008 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2008 | 12/31/2007 |
| Customers[1] | 13,038 | 2,071 | 8,456 | 1,235 | 1,281 | 15,152 | 7,200 |
| Total Revenue | $8,637,123 | $1,829,976 | $6,395,183 | $796,161 | $883,530 | $6,521,201 | $2,139,964 |
| Total Expenses | $8,828,909 | $1,387,305 | $5,438,217 | $780,542 | $729,033 | $6,376,014 | $2,999,582 |
| Salary/Wages (601) | $1,335,278 | -- | $439,668 | $108,996 | $52,500 | $924,853 | $870,122 |
| Pension/Benefits (604) | -- | -- | -- | -- | -- | $215,792 | -- |
| Purchased Water (610) | $3,368 | -- | -- | -- | -- | -- | -- |
| Purchased Power (615) | $278,664 | $65,431 | $352,338 | $73,650 | $54,218 | $595,128 | $257,542 |
| Fuel for Power | -- | -- | | -- | -- | -- | -- |
| Chemicals (618) | $303,374 | $9,644 | $101,456 | $9,214 | $27,790 | $157,174 | $233,710 |
| Materials/Supplies (620/620.08) | $85,697 | $14,304 | $49,707 | $7,874 | $2,978 | $558,602 | $47,418 |
| Contract Services-Testing (635) | -- | -- | -- | -- | $3,676 | $99,923 | $158,510 |
| Contract Services Other (636) | -- | $473,571 | -- | -- | $182,727 | $183,263 | $107,425 |
| Rent (641) | $84,483 | -- | $18,363 | $1,613 | -- | $93,111 | $199,706 |
| Management Fees | $1,528,005 | -- | $890,005 | $123,665 | -- | -- | -- |
| Transportation (650) | -- | $26,817 | -- | -- | $209.00 | $35,559 | $63,570 |
| Insurance-GL (657) | $396,599 | $12,021 | $90,870 | $24,046 | $11,066 | $52,375 | $38,805 |
| Insurance Other (659) | $94,566 | -- | $49,453 | $7,294 | -- | $4,320 | -- |
| Misc. (675) | $534,489 | $155.00 | $259,385 | $16,726 | $37,081 | $65,212 | $34,270 |
| Depreciation (403) | $3,830,808 | $252,672 | $1,988,462 | $248,398 | $186,095 | $3,157,285 | $1,550,751 |
| Income Taxes | ($1,020,813) | $308,456 | $173,361 | ($76,894) | $49,987 | $89,555 | ($1,312,313) |
| Property Taxes | $296,804 | $91,705 | $512,237 | $37,922 | $57,733 | 0 | $179,467 |
| Other Taxes | $87,538 | 0 | $36,892 | $9,778 | $5,521 | $6,070 | $44,188 |
| Cost/Customer[2] | $677.17 | $669.89 | $643.12 | $632.02 | $569.11 | $420.80 | $416.61 |
| Total Expenses - Taxes/Deprec. | $5,634,572 | $734,472 | $2,727,265 | $561,338 | $429,697 | $3,123,104 | $2,537,489 |
| Cost/Cust. Less- Taxes/Deprec.[3] | $432.17 | $354.65 | $322.52 | $454.52 | $335.44 | $206.12 | $352.43 |
| Total Expenses-Tax/Dep./Power/Chem. | $5,052,534 | $659,397 | $2,273,471 | $478,474 | $347,689 | $2,370,802 | $2,046,237 |
| Cost/Cust. Less Tax/Dep./Power/Chem[4] | $387.52 | $318.40 | $268.86 | $387.43 | $271.42 | $156.47 | $284.20 |
| Cost/Cust Less Tax/Dep/Power/Chem per month | $32.29 | $26.53 | $22.40 | $32.29 | $22.62 | $13.04 | $23.68 |

[1] The customer numbers are based on each company's H-2 Schedule filed in each company's most recent rate case.
[2] This row equals Total Operating Expenses divided by the total number of customers.
[3] This row equals Total Operating Expenses minus Taxes and Depreciation divided by the total number of customers.
[4] This row equals Total Operating Expenses minus Taxes, Depreciation, Purchased Power, Purchased Water and Chemicals divided by the total number of customers.

**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REBUTTAL TESTIMONY**
**February 1, 2010**

# Exhibit PE-RB4

**2.9** Admit that Algonquin Power would not require audits if it did not own any facilities. If denied, please explain why.

**Response:** **Deny. It is conceivable that Algonquin Power's need to raise capital pre-dates the ownership of its first facility, and that this need to raise capital might have required audited financial statements.**

FENNEMORE CRAIG, P.C.
Jay L. Shapiro (No. 014650)
Todd C. Wiley (No. 015358)
3003 N. Central Ave.
Suite 2600
Phoenix, Arizona 85012
Attorneys for Rio Rico Utilities, Inc.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF RIO RICO UTILITIES, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER AND WASTEWATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON. | DOCKET NO: WS-02676A-09-0257 |

**REJOINDER TESTIMONY OF**

**PETER EICHLER**

**March 9, 2010**



EXHIBIT
A-11
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE OF TESTIMONY ..... 1
II. REJOINDER TO STAFF AND RUCO ADJUSTMENTS TO CENTRAL OFFICE COST ALLOCATIONS ..... 1
A. Rejoinder to Staff ..... 1
1. Directly Attributable Costs: ..... 6
2. Unsupported Costs: ..... 6
3. Out of Period Costs ..... 8
B. Rejoinder to RUCO ..... 11
III. OTHER ANALYSIS ..... 17

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FENNEMORE CRAIG
PROFESSIONAL CORPORATION
PHOENIX

## I. INTRODUCTION AND PURPOSE OF TESTIMONY

**Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Peter Eichler. My business address is 2485 Bristol Circle, Oakville, Ontario L6A 7H7.

**Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THE INSTANT CASE?**

A. Yes, my rebuttal testimony was submitted in support of the rebuttal filing in this docket by Rio Rico Utilities, Inc. ("RRUI" or "Company").

**Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?**

A. The purpose of my rejoinder testimony is to further support RRUI's application for rate relief by responding to testimony by the other parties regarding Liberty Water's affiliate cost allocation methodology. Neither Staff nor RUCO voice any objections to the cost allocations from Liberty Water to RRUI. Staff and RUCO both oppose the Central Office Cost allocations from Algonquin Power Trust ("APT") to RRUI. In this testimony, I respond to the surrebuttal testimony of Mr. Coley for RUCO and Mr. Becker for Staff relating to the Central Office Cost allocations from APT.

## II. REJOINDER TO STAFF AND RUCO ADJUSTMENTS TO CENTRAL OFFICE COST ALLOCATIONS.

### A. Rejoinder to Staff.

**Q. WHAT ARE YOUR OVERALL THOUGHTS ABOUT THE TESTIMONY OF MR. BECKER REGARDING YOUR CORPORATE COSTS?**

A. I have examined Mr. Becker's surrebuttal testimony and it is not persuasive. Unfortunately, Mr. Becker's testimony is premised on incorrect factual assumptions and unsupported conclusions. I recognize and understand Mr. Becker's concerns relating to the APT cost allocations. Even so, Mr. Becker



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has not supported his disallowance of the APT costs allocations with substantial evidence. Rather, he applies a presumption that the APT costs do not benefit RRUI's ratepayers. Liberty Water understands that Staff must scrutinize the APT cost allocations, but we do not believe it is fair to presume that the APT costs are improper. To the contrary, I assert that the costs and services related to the APT allocations provide substantial benefits to RRUI's ratepayers, and I attempt to address Mr. Becker's concerns in my testimony below. I also think it is important to emphasize that the Central Office Costs are necessary costs of doing business under the APIF business model as a publicly traded income fund, which makes those costs recoverable operating expenses under established rate making principles.

We appreciate Staff's concerns about unnecessary costs and potential subsidization by ratepayers, but the evidentiary record does not substantiate such concerns. Rather, the record shows that RRUI's operating costs, with the APT cost allocations, are reasonable and cost-effective and RRUI is providing high-quality utility service. The charts attached to my Rebuttal Testimony as Exhibit PE-RB3 demonstrate that RRUI's operating costs compare very favorably to the operating costs of numerous other Arizona water and wastewater companies. Those charts demonstrate that the Liberty Water shared services model allows RRUI to provide high quality service at a reasonable price. Neither Staff nor RUCO mention, let alone, refute those operating cost comparisons. I would hope that Staff's concerns will not override the underlying facts.

I also would like to take this opportunity to perhaps increase the level of communication with Staff and RUCO in general. I hope that increased communication regarding Liberty Water's operations on an ongoing basis can reduce disputes and rate case expenses for all parties going forward. We truly want



'ENNEMORE CRAIG
'ROFESSIONAL CORPORATION
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Staff and RUCO to understand and appreciate APIF's cost-effective and efficient business model for providing utility service. We believe Staff's and RUCO's recognition of this business model will serve the best interests of Arizona customers by allowing Liberty Water to provide high quality service at reasonable prices.

**Q. ON PAGE 10 OF HIS TESTIMONY, MR. BECKER STATES THAT "THE OVERALL OBJECTIVES OF THE PARENT COMPANY FUND SHOULD FIRST BE CONSIDERED IN APPRAISING THE NEED FOR THESE COSTS." HOW DO YOU RESPOND TO THAT ASSERTION?**

A. I agree with Mr. Becker to the extent that necessary business costs under the APIF business model should be considered in analyzing operating expenses. But Mr. Becker seems to imply that APIF's desire to obtain a profit means that APT costs are improper. I disagree with that notion completely. I also would note that the objectives of the parent company are not relevant to the question of whether the APT expenses are a necessary cost of doing business. Mr. Becker does not cite any rule, regulation or ratemaking principle for this statement. Finally, I would assert that the overall objectives of the parent company are to effectively run and operate the facilities it owns. The growth of the parent company has nothing to do with the Central Office Costs incurred. In fact, the growth of the parent, if anything, helps keep Central Office Costs low by taking advantage of larger scale and spreading the costs over more utilities and/or facilities. In short, it would be counterintuitive for the objectives of the parent to be incurring costs which do not derive a benefit for its facilities. I also would add that the fact that APIF is in the business of making a profit is very healthy and, in fact, provides additional incentive to tightly control these corporate costs considering that approximately 73% of the APT costs are allocated to the non regulated business. APT does not have any operating

business, except to provide services to the facilities owned, including the utilities. These are administration costs of the business model employed by APIF. If APIF did not own any facilities, APT would not incur these costs, so it is illogical to assume that the shareholders benefit from these costs. Simply put, if these costs were not incurred, there would be no investment capital available to APT to purchase and continue to own utilities. Mr. Becker's claim that APT would incur those costs even if APIF did not own RRUI or the other Arizona utilities is wrong.

Q. **ON PAGE 11 OF HIS TESTIMONY, MR. BECKER STATES "SINCE SHAREHOLDERS SEEK A PROFIT AND THE APIF INCURS EXPENSES (E.G. CENTRAL OFFICE COSTS) IN ORDER TO GENERATE THAT PROFIT, THEN A REASONABLE CONCLUSION IS THAT THE CENTRAL OFFICE COSTS ARE INCURRED PRIMARILY FOR THE BENEFIT OF THE SHAREHOLDERS RATHER THAN FOR RIO RICO AS THE COMPANY INDICATES. THE CENTRAL OFFICE COSTS WOULD HAVE BEEN INCURRED EVEN IF THE FUND DID NOT OWN RIO RICO BECAUSE THE CENTRAL OFFICE COSTS WERE INCURRED TO MAKE A PROFIT FOR THE SHAREHOLDERS AND NOT TO OPERATE RIO RICO. THE BENEFIT TO RIO RICO IS ONLY INCIDENTAL." CAN YOU RESPOND TO THAT TESTIMONY?**

A. Yes, that testimony is incorrect on several fronts. Staff's and RUCO's approach to the cost allocation issue is fundamentally flawed. Read closely, Mr. Becker's testimony does nothing more than state his beliefs or generic opinions that the APT costs do not benefit ratepayers. With respect to the APT costs, RRUI has shown that the contractual services expenses were actually incurred by APT/RRUI, that those costs are reasonable and that the APT costs are necessary expenses under the APIF business model, which allows RRUI to provide quality utility service at a low

cost. Mr. Becker does not really address these issues, but instead contends that the APT costs should be disallowed because they primarily benefit APIF, and not RRUI. I do not agree with that sentiment.

As noted above, APT exists solely for the benefit of the utilities and other facilities APIF owns. APT does not have any business operations, other than to provide administrative services to the facilities owned by APIF. If those utilities and other facilities did not exist, APT and all of these indirect corporate administrative costs would not exist. Put another way, the costs incurred by APT do not generate revenue or income for APIF because those costs are provided solely for the benefit of APIF's facilities, including RRUI. Allocation of those costs simply allows APIF to recover those necessary operating costs from the utilities, like RRUI, that use and benefit from the APT services. Mr. Becker's claims to the contrary are unfounded. To illustrate this point, let's say APT pays KPMG $100,000 for audit services relating to all 63 facilities owned by APIF. In turn, 26.98% of that cost is allocated to the 17 regulated utilities ($26,980) with 12% then allocated to RRUI or $3,237.60. Allocating that $3,237.60 to RRUI doesn't generate additional revenue for APIF; rather, such allocation pays for RRUI's portion of the audit costs paid by APT. Recovery of the costs of doing business under APIF's business model is not generation of shareholder revenue. Finally, I would note that Mr. Becker's disallowance of the APT costs because they "primarily" benefit APIF is contrary to the definition of "common costs" in the NARUC Guidelines,[1] which establishes that recoverable common costs can benefit both the regulated utility and unregulated affiliate.

[1] NARUC Guidelines at 2, ¶ 5.



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**Q. ON PAGE 12-13 OF HIS TESTIMONY, MR. BECKER DISCUSSES SOME OF THE COSTS INCLUDED IN THE APT COST POOL AND CLAIMS THAT THEY ARE UNSUPPORTED, OUT OF PERIOD, OR CAN BE DIRECTLY ATTRIBUTABLE TO NON-UTILITY OPERATIONS. HOW DO YOU RESPOND?**

A. I will respond to this question by independently addressing each of Mr. Becker's claims.

1. Directly Attributable Costs:

After further reviewing the responses to GWB 4.2., I agree with Mr. Becker that some costs that we allocated to RRUI are inappropriate. These costs include some payments to the Government of Quebec, donations, and some litigation costs that can be directly attributed to non-utility operations. RRUI has adjusted its central allocation pool in the amounts of $98,775 for licenses and fees, and $46,367 for legal costs. These adjustments are reflected in adjustments made by Mr. Bourassa in his Rejoinder Schedule C-2 (Water) at 9 and C-2 (Wastewater) at 7. As stated in my prior testimony, we have directly charged any and all costs to the extent practicable.

2. Unsupported Costs:

I disagree with Mr. Becker that a lot of costs are unsupported. As Mr. Becker points out, the Company provided every invoice over $5,000, and offered to provide those under $5,000 if requested by any party. Unfortunately, neither Staff nor Mr. Becker explain exactly what additional information they need in terms of invoicing. Staff's failure to define, let alone apply, a consistent standard is unfair to RRUI and other utilities. Staff's and RUCO's use of alleged lack of documentation as a means to deny the APT costs also places form over substance. Whether or not an invoice from APT or a vendor mentions RRUI does



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not change the nature of the service provided or the actual use of the APT services by RRUI. Even if RRUI could PE-write the invoices (which it can't) to mention RRUI, the services provided by APT would remain the same. While it is understood that some of the audit cost invoices do not meet that criteria (i.e. over $5,000), that does not make them inappropriate expenditures. For example, over $247,000 of the audit expenses relate to invoices from 2 companies, AccuSource and Contract Control Services. Both of these companies provided extensive services during the test year evaluating and testing internal financial controls related to financial reporting. The internal financial controls are regulatory requirements of Bill 198, which is very similar to the Sarbanes Oxley Act and compliance requirements in the United States. Some examples include:

1) Revenue Controls – These controls ensure items such as segregation of duties to ensure that those who collect cash do not record entries to the general ledger, that revenues are recorded correctly, and that management checks are in place.
2) Audit controls – These controls ensure that journal entries have evidence of approval and support, review of key account reconciliations, determining the adequacy of accruals, assignment of information access with segregation of duties in mind.
3) Information Technology Controls – These controls ensure that the server room is adequately protected, that electronic files are stored off site with restricted access,
4) Purchasing controls – These controls ensure that purchasing policies are in place, and include sampling wire transfers to ensure appropriate approvals have been received, ensuring a purchasing

policy is in place and up to date, sampling invoices for evidence of approval of variances from Purchase orders, etc.

To state that these types of costs don't benefit customers would be a very difficult argument to make.

The majority of the other audit costs relating to KPMG annual audit costs have been supported. I would like to further note that while RRUI does view producing every invoice as overly burdensome, if Mr. Becker would like to select a sample of invoices he is unsure about, I would be happy to provide them in a timely manner.

3. Out of Period Costs

In reviewing the billings from KPMG, some invoices that were received during 2008 relate to the 2007 annual audit; however, due to the lagging nature of audits, portions of the work related to a 2007 audit is usually not performed until 2008. Similarly, the Company would incur 2008 audit costs during 2009, etc. This is not out of period and is a consistently applied methodology throughout Liberty Water's rate cases. While in-period accruals are made for such costs, only the actual costs were reflected in this application.

**Q. WHAT ABOUT MR. BECKER'S ASSERTION THAT THE COST ALLOCATION METHODOLOGY DOES NOT COMPLY WITH THE NARUC GUIDELINES?**

A. The NARUC guidelines simply recommend that utilities directly allocate as much cost as possible where possible. RRUI conforms to this principle. While I understand Mr. Becker's concerns stated above, the Company does strive to allocate directly where at all possible and to the extent practicable. The removal of some of the legal costs and some of the Licenses and Fees costs is a recognition of Liberty Water's commitment to allocate appropriately and charge directly where

appropriate. We have complied with the NARUC Guidelines as set forth in my rebuttal testimony.

**Q. ON PAGE 11 OF HIS SURREBUTTAL, MR. BECKER STATES THAT HE DISAGREES THAT THE COST POOL WOULD BE LOWER IF ALGONQUIN POWER DID NOT OWN THE UTILITIES DIVISION. DO YOU AGREE WITH MR. BECKER?**

A. No. APIF would not exist and would not incur any costs if it did not own any facilities. APT has no other business than to operate the facilities APIF owns. Further, to contextualize the amount of effort required to run the utilities division, the power generation group, for the most part, has one customer per facility, meanwhile, the utilities group has over 60,000 customers to look after. Even with that disparity, it receives less than 27% of the overall costs. This is something that can only be done with a significant amount of scale. While the business structure of being a publicly traded company does drive a significant portion of the Central Office Costs, these costs are still incurred to the benefit of the utilities it owns. Again, most of these costs are associated with good corporate governance. These costs ensure that the entire corporate family remains viable for the long run. The APT costs and services are a necessary requirement for RRUI to receive equity capital funding from APIF, which absolutely benefits RRUI and its ratepayers.

In our view, this Commission should be encouraging larger companies to be acquiring smaller utilities and consolidating operations under shared services models like we have implemented in Arizona. In addition to access to capital, something increasingly critical in down economies where the need for critical infrastructure remains constant, larger companies provide good corporate governance, reducing the risk of smaller utility financial problems. There are no McLain or Far West messes under a corporate structure like ours. But, this has a

cost, as I have testified to above, and as Mr. Bourassa and Mr. Sorensen have tried to explain in their testimonies in this case and the recent BMSC rate case. However, under our model, there is a shared cost/benefit.

**Q. ON PAGE 12 OF HIS TESTIMONY, MR. BECKER POINTS TO THE GROWTH OF ALGONQUIN POWER IN RELATION TO THE GROWTH OF RRUI TO SUPPORT HIS CLAIMS THAT THE APT COSTS BENEFIT THE SHAREHOLDER. HOW DO YOU RESPOND TO THAT?**

A. I respond by stating that the costs incurred by APT are likely much lower due to the current size of the company. As the parent grows, it gains economies of scale and is able to procure services such as audits, tax management, and other costs for a lower incremental price on a consolidated basis. If the fund had not grown in the period from 2001 to 2007, it is conceivable that these costs would be higher today than they are. I also would hope that Staff agrees that larger companies can often run utilities more efficiently than standalone utilities.

**Q. CAN BEING A MEMBER OF A LARGE COMPANY PROVIDE BENEFIT FOR BOTH SHAREHOLDERS AND RATEPAYERS?**

A. Absolutely. A large company can provide many benefits to customers, such as access to capital and the ability to provide high quality service at the lowest possible cost leaving the utility with a fair and reasonable return on its investment after the recovery of the costs needed to provide that level of service. Everyone wins. Again, that general principle is reflected in the definition of "common costs" under the NARUC Guidelines.

**Q. WHAT ABOUT MR. BECKER'S ASSERTION THAT MANAGEMENT COSTS ARE DUPLICATIVE?**

A. The Management services received from APT are very different from the labor incurred at the Liberty Water level. The APT costs are Strategic Management

costs designed to provide benefit to the facilities owned by APUC, including the utilities.

Strategic management decisions are critical for any public utility. The need for strategic management is even more pronounced for RRUI as a regulated utility that depends on access to capital for ongoing operational and capital needs. Algonquin Power seeks to hire talented strategic managers that aid in running each facility owned by the fund, including RRUI, as efficiently and effectively as possible. This ensures the long term health of each utility and ensures that rates are kept as low as possible without compromising the level of service. It also facilitates each Regulated Utility's access to necessary capital funding at reduced costs.

**B. <u>Rejoinder to RUCO</u>**

**Q. LET'S SWITCH OVER TO RUCO'S TESTIMONY. PLEASE PROVIDE YOUR INITIAL THOUGHTS ON MR. COLEY'S SURREBUTTAL TESTIMONY REGARDING CENTRAL OFFICE COSTS**

A. My initial thoughts on Mr. Coley's testimony is that while I admire his attempt to compare Rio Rico with other utilities in Arizona, the analysis he has provided is flawed in several ways. Mr. Coley confuses the issue of corporate costs with that of wages and labor expense, and then he performs some severely flawed analyses to support his predetermined conclusion. Mr. Coley's testimony and analysis should be disregarded relating to the APT costs.

**Q. PLEASE EXPLAIN THE FLAWS IN MR. COLEY'S TESTIMONY AND ANALYSIS?**

A. Mr. Coley seeks to prove that non-labor costs, such as the APT costs, should be disallowed based on comparing wages per customer. Mr. Coley does not disallow any of the Liberty Water costs, which are where all the labor is contained. Instead,



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Mr. Coley seeks to disallow the Central Office Costs relating to access to capital and corporate governance (non-labor costs) by comparing them to other utilities' labor costs. Mr. Coley's analysis is flawed because he is comparing apples to oranges, so to speak. Mr. Coley's Surrebuttal Exhibit 1 is flawed because he does not analyze comparable numbers between the various utilities in his analysis. In his analysis, Mr. Coley sums only the labor and wages costs of various utilities, and then compares those numbers to the total contractual services costs of RRUI. Unfortunately, Mr. Coley does not recognize that the contractual services costs for RRUI include various non-labor/wages costs, including insurance, benefits and other items. In short, Mr. Coley has understated the costs for the other utilities and overstated the costs for RRUI in this analysis. To illustrate that point, the charts attached to my testimony as Exhibit PE-RJ1 correct the errors in Mr. Coley's analysis and demonstrate that RRUI's labor and wages costs compare very favorably to other utilities. Mr. Coley's claims to the contrary are not supported by actual data.

**Q. DO YOU AGREE WITH THE REST OF MR. COLEY'S ANALYSIS?**

A. No. I do not.

**Q. TAKE US THROUGH SOME OF THE FLAWS THAT YOU HAVE FOUND IN MR. COLEY'S ANALYSIS.**

A. As stated above, my biggest concern with Mr. Coley's analysis is that he is comparing non-labor costs to labor costs, in an effort to disallow costs that don't have labor in them. That does not make sense.

**Q. PLEASE PROVIDE SOME EXAMPLES OF WHAT YOU MEAN.**

A. The following are some examples of the errors in Mr. Coley's testimony.

- In the Wastewater division, payments to the City of Nogales for treatment of wastewater totaling over $130,000 are included in Contractual Services

accounts, and therefore Mr. Coley's calculation of labor costs. Clearly, these are non-labor costs.

- As previously mentioned, APT costs are non-labor but included anyway by Mr. Coley for both the Water and Wastewater divisions.
- Rio Rico's Contractual Services category includes labor for accounting staff and customer service staff as well as administrative costs. The Arizona Water Companies, for example, record these costs on separate line items. Mr. Coley did not include these costs for the Arizona Water Companies. To give an order of magnitude of these costs, Coolidge Water incurs $645,651 of these costs, or $137.28 per customer; Lakeside Water $782,552 or $157.96 per customer. Needless to say, these numbers would significantly impact Mr. Coley's analysis.
- Mr. Coley ignores that Liberty Water labor costs include 35% burdens for items such as medical insurance, 401k's, etc. These costs were included for Liberty Water companies, but not for some of the other companies in the analysis which record medical insurance costs on separate lines.
- Mr. Coley assumes that all costs labeled "Contractual Services" are Liberty Water labor costs. This is not true. In both divisions, there are costs included in Contractual Services that include ground maintenance, meter testing, janitorial services, alarm monitoring, office cleaning, armored car service, and other administrative costs. In the administrative cost allocation accounts, only approximately 35% of the total is labor related, including burdens such as medical insurance, etc. as described above.

**Q. ARE THERE ANY POSITIVES THAT YOU CAN POINT TO IN MR. COLEY'S ANALYSIS?**

A. Yes. Mr. Coley's attempted analysis actually supports the APT costs allocations on several fronts. I do not, however, necessarily agree with Mr. Coley's choice of comparable utilities. For example Mr. Coley compared RRUI's sewer division to three stand-alone sewer companies, including Ajo Improvement, Rio Verde and Far West. I believe that Ajo Improvement is subsidized by its parent company, which means that the numbers used by Mr. Coley don't reflect actual costs. Also, as established in a recent docket before the Commission, Far West is not providing adequate service and has substantial financial problems, which Mr. Coley did not address in his testimony. Even so, I have used these companies to develop my rejoinder schedules and charts attached as Exhibit PE-RJ1, in which I outlined the breakdown of RRUI's contractual services accounts and compared RRUI's labor/wages costs to the other Arizona sewer/water utilities cited by Mr. Coley.

**Q. PLEASE EXPLAIN YOUR REJOINDER SCHEDULES PE-RJ1.**

A. My rejoinder schedules attached as **Exhibit PE-RJ1** seek to correct the flaws in Mr. Coley's analysis and provide an apples to apples comparison of labor costs. As demonstrated, Rio Rico's labor costs per customer are not only well within the range of the other utilities, but in fact a lot lower than most of the utilities in the sample group. When accurately compared to 17 other water utilities, Rio Rico Utilities is the third lowest labor cost per customer. On the wastewater front, when compared to nine other wastewater companies, only three are lower in labor cost per customer than Rio Rico Utilities. This further proves the efficiency of the shared services model.

**Q. BUT MR. EICHLER, DIDN'T YOU SAY THAT THE LABOR COSTS SHOULDN'T BE USED TO DISCUSS APT COSTS?**

A. That is correct. I supplied the above analysis to only confirm the benefits of Liberty Water's shared services model.

**Q. SO HOW SHOULD WE COMPARE RIO RICO'S COSTS TO OTHER UTILITIES?**

A. During my rebuttal testimony, I provided a schedule which demonstrates that Rio Rico's overall controllable costs per customer were well within line of other utilities, in some cases being among the lowest. I have now expanded that analysis to include some of Mr. Coley's sample group. My analysis can be seen in the schedules attached as **Exhibit PE-RJ2**.

**Q. PLEASE DISCUSS YOUR EXHIBIT PE-RJ2 IN MORE DETAIL.**

A. As discussed above, the schedules attached as **Exhibit PE-RJ2** seek to compare various sample utilities, including those picked by Mr. Coley, to RRUI on an overall cost per customer basis. I have compared on a per customer basis both total costs, and total costs less taxes, depreciation, purchased power, and chemicals. The results speak for themselves.

**Q. PLEASE DISCUSS THE RESULTS OF YOUR ANALYSIS FURTHER.**

A. On an overall cost per customer basis, Rio Rico compares very favorably other Arizona utilities. For the water division, Rio Rico Utilities ranks sixth out of 23 companies compared. Further, on a controllable cost per customer (costs less taxes, depreciation, purchased power, and chemicals), Rio Rico ranks fourth out of 23. On the wastewater side, Rio Rico Utilities is in the middle of the pack, ranking fifth out of eleven utilities on a total cost basis and sixth out of eleven on a controllable cost per customer basis. I also would note that neither Staff nor RUCO objected or responded to the operating cost comparisons, Exhibit PE-RB3,



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in my rebuttal testimony. Those charts compared Rio Rico's total operating expenses to various other Arizona utilities.

**Q. WHY SHOULD THIS BE THE WAY TO MEASURE UTILITIES AGAINST EACH OTHER?**

A. As suggested in my testimony, different utilities have different ways of recording certain costs. Utilities may also choose to operate in different ways. For example, some will outsource certain work while others will choose to perform it in house. The only way to truly measure cost levels against each other is on an overall controllable cost per customer basis.

**Q. DO YOU HAVE ANY OTHER OBJECTIONS TO MR. COLEY'S TESTIMONY?**

A. Yes. On page 18-19 of his testimony, Mr. Coley describes the adjustment that the company made to transportation expense as the removal of costs related to evidence from the Litchfield Park hearing that the "corporate parent has a fleet of corporate executive jets and the costs were being allocated to the utilities".

**Q. WHAT IS YOUR OBJECTION TO THAT STATEMENT?**

A. That statement is factually incorrect. The parent company does not have a fleet, let alone a single corporate executive jet. Certain staff from APT/APIF occasionally use business travel service from a company called Algonquin Airlink, which is not owned by APIF. The suggestion that APIF owns a fleet of corporate jets is false. In LPSCO's rate case, after the Administrative Law Judge expressed concerns about those charges, we agreed to remove those costs in an effort settle an issue and avoid additional rate case expense and hearing time necessary to debate the merits of those charges. We also took it upon ourselves to remove those charges from RRUI's case to avoid increased hearing time.

## III. OTHER ANALYSIS

**Q. MR. EICHLER, DID YOU UNDERTAKE ANY OTHER ANALYSIS TO SHOW THE REASONABLENESS OF THE APT ALLOCATIONS?**

A. Yes. My rejoinder schedule **Exhibit PE-RJ3** is a comparison of some other large publicly traded corporations and their corporate costs.

**Q. WHAT DID YOU FIND?**

A. As my analysis shows, the cost per customer of some of the categories that I was able to find indicates that the services provided by APT are the second lowest in the peer group. This includes audit fees, tax services, board of director costs, and services received from CEO's (management services in the case of Rio Rico). This further demonstrates that not only is the overall cost per customer reasonable, but that the APT costs themselves are extremely reasonable.

**Q. PLEASE CONTINUE.**

A. The availability of comparable data for most of the categories also shows that the types of costs incurred are incurred by other publicly traded corporations as well and have benefit to rate payers of those companies.

**Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?**

A. Yes.



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**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REJOINDER TESTIMONY**
**March 9, 2010**

# Exhibit PE-RJ1

# COMPARISON OF RIO RICO'S LABOR/WAGES COSTS TO OTHER ARIZONA SEWER UTILITIES

| | Sun City Wastewater | Sun City West Wastewater | Global Water | Rio Rico Wastewater | Rio Verde | Ajo Improvement | Far West | Az-Am (Anthem) | Coronado Utilities | Az-Am (Mohave Wastewater) | Az-Am (Agua Fria) | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/1999 | 12/31/2002 | 12/31/2007 | | 12/31/2008 | 12/31/2007 | | |
| Customers | 47,260 | 31,209 | 15,152 | 2,071 | 1,193 | 1,089 | 7,166 | 8,456 | 1,281 | 1,235 | 13,038 | |
| Total Revenue | $5,940,381 | $5,654,504 | $6,521,201 | $1,829,976 | $611,278 | $95,505 | $2,139,964 | $6,395,183 | $883,530 | $796,161 | $8,637,123 | |
| Total Expenses | $5,991,974 | $5,040,379 | $6,376,014 | $1,387,305 | $427,853 | $164,038 | $2,999,582 | $5,438,217 | $729,033 | $780,542 | $8,828,909 | |
| Salary/Wages | $454,529 | $766,759 | $924,853 | | $113,551.00 | $29,012 | $870,122 | $439,668.00 | $52,500 | $108,996 | $1,335,278.00 | |
| Pension/Benefits | $75,595 | $150,285 | $215,792 | | $7,399.00 | $19,741 | | | | $18,447 | $221,650.00 | |
| Customer Accounting | $145,686 | $123,968 | | | | | | | | $16,497 | $242.170.00 | |
| Contractual Services-Testing | | | $99,923 | | | $103,637 | $158,510 | | $3,676.00 | | | |
| Contractual Services [1] | | | $183,263 | $204,603.35 | $35,142.00 | $4,343 | $77,754 | | $141,386.00 | | | |
| Contract Services-Other | | | | | $6,498 | | $29,671 | | $41,341.00 | | | |
| Management Fees | $933,155 | $789,604 | | | | $15,020 | | $890,005.00 | | $123,665 | $1,528,005 | |
| Group/Other Insurance | $198,849 | $315,850 | $4,320 | | | | | $49,453 | | $24,046 | $396,599 | |
| Total Labor/Wages Costs [2] | $2,146,466 | $2,146,466 | $1,428,151 | $204,603.35 | $162,590.00 | $171,753 | $1,136,057 | $1,379,126 | $238,903 | $291,651 | $3,481,532 | Average |
| Yearly Labor/Wages Cost Per Customer [3] | $45.42 | $68.78 | $94.25 | $98.79 | $136.29 | $157.72 | $158.53 | $163.09 | $186.50 | $236.15 | $267.03 | $146.60 |
| Rank Among All Listed Utilities | 1 | 2 | 3 | 4 | 5 | 5 | 6 | 7 | 8 | 9 | 10 | Rio Rico: $98.79 |
| Monthly Labor/Wage Cost Per Customer [4] | $3.78 | $5.73 | $7.85 | $8.23 | $11.36 | $13.14 | $13.21 | $13.59 | $15.54 | $19.68 | $22.25 | $12.22 |
| Rank Among All Listed Utilities | 1 | 2 | 3 | 4 | 5 | 5 | 6 | 7 | 8 | 9 | 10 | Rio Rico: $8.23 |

NOTES:

[1] Rio Rico's Contractual Services include only labor related costs and does not include rent, depreciation, computer equipment and any other non-labor related costs.The Contractual Services amount for Rio Rico includes $96,241 in operations labor (Liberty Water), $79,390 in administrative labor (Liberty Water) and $28,972.35 in administrative allocations from Liberty Water under a 4-Factor methodology.

[2] The total labor/wages costs is the sum of salary/wages, pension/benefits, customer accounting, contractual services, management fees and group/other insurance.

[3] The yearly labor/wages cost per customer is the total labor/wages costs divided by the total number of customers.

[4] The monthly labor/wage cost per customer is the yearly labor/wages cost per customers divided by twelve (12).This chart illustrates that Rio Rico's labor/wages costs compare very favorably to this comparable group of utilities and Rio Rico's yearly and monthly labor/wages costs per customer are well below the group average for all 10 utilities, which includes comparable utilities used by RUCO in Mr. Coley's Surrebuttal Exhibit 1.

SOURCE: The data on this chart originates from C-1 and H-2 schedules filed by the various companies in recent rate cases in the test years as noted.

# COMPARISON OF RIO RICO'S LABOR/WAGES COSTS TO OTHER ARIZONA WATER COMPANIES

| | Lago Del Oro | Global Water | Rio Rico Water | Arizona Water (Sierra Vista) | Arizona Water (Overgaard) | Bermuda Water | Arizona Water (Coolidge) | Sun City West | H2O, Inc. | Arizona Water (Sedona) | Arizona Water (San Manuel) | Arizona Water (Lakeside) | Sun City Water | Arizona Water (Oracle) | Willow Valley (Global) | AZ-AM (Anthem) | AZ-AM (Paradise Valley) | Sunrise Water | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/1997 | 12/31/2007 | 12/31/2008 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2007 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2007 | |
| Customers | 6,346 | 15,371 | 6,052 | 2,900 | 4,124 | 3,854 | 4,656 | 15,465 | 6,300 | 6,419 | 1,573 | 4,953 | 23,140 | 1,524 | 1,554 | 8,764 | 4,884 | 1,324 | |
| Total Revenue | $1,905,111 | $9,110,720 | $1,847,256 | $1,461,327 | $1,686,342 | $1,489,722 | $2,214,952 | $5,701,431 | $3,383,145 | $3,521,124 | $812,359 | $2,588,942 | $9,283,101 | $1,115,109 | $473,327 | $9,357,346 | $7,848,732 | $1,304,363 | |
| Total Expenses | $1,666,701 | $7,141,309 | $2,061,862 | $1,186,838 | $1,316,453 | $1,391,969 | $1,938,319 | $5,114,006 | $3,026,826 | $3,096,417 | $859,882 | $2,071,226 | $8,422,016 | $931,966 | $569,035 | $7,215,051 | $6,296,235 | $1,364,627 | |
| Salary/Wages | $186,384 | $781,051.00 | | | | $414,555 | | $703,217 | $790,693 | | | | $1,225,670 | | $226,369 | $801,914 | $715,859 | $414,480 | |
| Pension/Benefits | | $189,983.00 | | | | $62,750 | | $137,699 | | | | | $251,435 | | $50,965 | | | | |
| Customer Accounting | | | | $134,508 | $207,198.00 | | $267,290 | | | $323,108 | $104,642 | $275,893 | | $100,428 | | | | | |
| Contractual Services-Testing | $34,435 | $36,113 | | | | | | $133,476 | | | | | $235,438 | | | | | | |
| Contractual Services [1] | $56,007 | $67,911 | $570,723 | | | | | | | | | | | | | | | | |
| Contract Services-Other | | | $2,809 | | | 46,761 | | | $72,107 | | | | | | $12,787 | | | $45,163 | |
| Management Fees | | | | $152,251.00 | $279,673 | | $378,361 | $999,903 | | $641,077 | $140,854 | $506,659 | $1,509,322 | $151,590 | | $1,132,699 | $923,778 | | |
| Group/Other Insurance | | $4,647 | | | | $7,943 | | $249,742 | $61,213 | | | | $447,651 | | | | | $50,775 | |
| Total Labor/Wages Costs [2] | $276,826 | $1,079,705 | $573,532.43 | $286,759 | $486,871 | $532,009 | $645,651 | $2,224,037 | $924,013 | $964,185.00 | $245,496 | $782,552 | $3,669,516 | $252,018 | $290,121 | $1,934,613 | $1,639,637 | $510,418 | Average |
| Yearly Labor/Wages Cost Per Customer [3] | $43.62 | $70.24 | $94.77 | $98.88 | $118.06 | $138.04 | $138.67 | $143.81 | $146.67 | $150.21 | $156.07 | $158.00 | $158.58 | $165.37 | $186.69 | $220.75 | $335.72 | $385.51 | $161.65 |
| Rank Among All Listed Uti | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | Rico Rico: $94.77 |
| Monthly Labor/Wage Cost Per Customer [4] | $3.64 | $5.85 | $7.90 | $8.24 | $9.84 | $11.50 | $11.56 | $11.98 | $12.22 | $12.52 | $13.01 | $13.17 | $13.21 | $13.78 | $15.56 | $18.40 | $27.98 | $32.13 | $13.47 |
| Rank Among All Listed Utilities | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | Rico Rico: $7.90 |

NOTES:

[1] Rio Rico's Contractual Services includes only labor related costs and does not include rent, depreciation, computer equipment and any other non-labor related costs. The Contractual Services amount for Rio Rico 'S water division includes $264.195 in operations labor (Liberty Water), $242,221 in administrative labor (Liberty Water) and $63,307.43 in administrative allocations from Liberty Water under a 4-Factor methodology.

[2] The total labor/wages costs is the sum of salary/wages, pension/benefits, customer accounting, contractual services, management fees and group/other insurance.

[3] The yearly labor/wages cost per customer is the total labor/wages costs divided by the total number of customers.

[4] The monthly labor/wage cost per customer is the yearly labor/wages cost per customers divided by twelve (12). This chart illustrates that Rio Rico's labor/wages costs compare very favorably to this comparable group of utilities and Rio Rico's yearly and monthly labor/wages costs per customer are well below the group average for all 18 utilities, which includes comparable utilities used by RUCO in Mr. Coley's Surrebuttal Exhibit 1.

SOURCE: The data on this chart originates from C-1 and H-2 schedules filed by the various companies in recent rate case

## RICO RICO WATER DIVISION CONTRACTUAL SERVICES BREAKDOWN

| Contractual Services ($805,032) | | TOTAL | LABOR COSTS |
|---|---|---|---|
| 1. | Operations Labor (Liberty Water): | $264,195[1] | $264,195 |
| 2. | Administrative Labor (Liberty Water): | $242,221[2] | $242,221 |
| 3. | Administrative Allocation (Libery Water): | $194,871[3] | $64,307.43 |
| 4. | Central Office Costs (APT): | $103,745[4] | $0.00 |
| **Contractual Services Other ($76,859)** | | | |
| 1. | Technical Services Labor: | $2,809 | $2,809 |
| 2. | Contract Services Miscellaenous | $24,142[5] | $0.00 |
| 3. | Contract Services | $45,231[6] | $0.00 |
| 4. | Contract Services | $4,677[7] | $0.00 |

| | |
|---|---|
| **TOTAL COSTS FOR CONTRACTUAL SERVICES:** | **$805,032.00** |
| **TOTAL LABOR COSTS FOR CONTRACTUAL SERVICES:** | **$570,723.43** |
| **TOTAL NON-LABOR COSTS FOR CONTRACT SERVICES:** | **$234,308.57** |

| | |
|---|---|
| **RICO RICO 2008 CUSTOMER COUNT FOR WATER SERVICE:** | **6,025** |
| **RIO RICO ANNUAL LABOR/WAGE COST PER CUSTOMER:** | **$94.77** |
| **RIO RICO MONTHLY LABOR/WAGE COST PER CUSTOMER:** | **$7.89** |

2289391.1

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[1] These costs are direct charges from Liberty Water for operations and engineering. The labor rate charged by Liberty Water is the dollar hourly rate per employee as recorded in Liberty Water's payroll system, grossed up by roughly 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees. Engineering technical labor, which is capitalized, is charged on the same basis, plus a 10% allocation for corporate overheads incurred by Liberty Water, including rent, materials, supplies and other similar overhead costs.

[2] These costs are labor costs for accounting, billing, customer service and human resources. These labor costs incurred by Liberty Water are allocated to the Regulated Utilities based on customer count. The labor rate charged by Liberty Water is the dollar hourly rate per employee as recorded in Liberty Water's payroll system, grossed up by roughly 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees.

[3] These costs are incurred by Liberty Water for rent, administrative costs, depreciation of office furniture, depreciation of computers, and other labor that cannot be directly attributed to a specific Regulated Utility. Those administrative costs are allocated to RRUI by use of the "four factor" methodology. Other costs in this category include insurance, janitorial services and other general non-payroll costs. The methodology used by Liberty Water involves (1) Rate Base, (2) Total Customers, (3) Non-Labor Expenses and (3) Labor as allocating factors, with each factor assigned a specific weight. In total, the Administrative Allocation is 67% non-labor and 33% labor.

[4] The Central Office Costs from APT do not include any direct labor costs. Instead, these costs include professional services like third-party legal services, accounting services, tax planning and filings, and required auditing that are done for the benefit of all of the Liberty Water Regulated Utilities, including RRUI.

[5] These costs are non-labor costs for construction, alarm services, imaging, copiers and related services.

[6] These costs are non-labor costs for testing, ground maintenance, blue staking, septic services and other similar services.

[7] These costs relate to non-labor costs for painting and other relating services.

## RICO RICO SEWER DIVISION CONTRACTUAL SERVICES BREAKDOWN

| Contractual Services ($298,008) | | TOTAL | LABOR COSTS |
|---|---|---|---|
| 1. | Operations Labor (Liberty Water): | $96,241[1] | $96,241 |
| 2. | Administrative Labor (Liberty Water): | $79,390[2] | $79,390 |
| 3. | Administrative Allocation (Libery Water): | $87,795[3] | $28,972.35 |
| 4. | Central Office Costs (APT): | $34,582[4] | $0.00 |

| Contractual Services Other ($175,196) | | TOTAL | LABOR COSTS |
|---|---|---|---|
| 1. | Contract Services | $1,353 | $0.00 |
| 2. | Contract Services | $171,316[5] | $0.00 |
| 3. | Contract Services | $2,527[6] | $0.00 |

| | |
|---|---|
| **TOTAL COSTS FOR CONTRACTUAL SERVICES:** | **$473,204.00** |
| **TOTAL LABOR COSTS FOR CONTRACTUAL SERVICES:** | **$204,603.35** |
| **TOTAL NON-LABOR COSTS FOR CONTRACT SERVICES:** | **$268,600.65** |

| | |
|---|---|
| **RICO RICO 2008 CUSTOMER COUNT FOR WATER SERVICE:** | **2,071** |
| **RIO RICO ANNUAL LABOR/WAGE COST PER CUSTOMER:** | **$98.79** |
| **RIO RICO MONTHLY LABOR/WAGE COST PER CUSTOMER:** | **$8.1** |

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[1] These costs are direct charges from Liberty Water for operations and engineering. The labor rate charged by Liberty Water is the dollar hourly rate per employee as recorded in Liberty Water's payroll system, grossed up by roughly 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees. Engineering technical labor, which is capitalized, is charged on the same basis, plus a 10% allocation for corporate overheads incurred by Liberty Water, including rent, materials, supplies and other similar overhead costs.

[2] These costs are labor costs for accounting, billing, customer service and human resources. These labor costs incurred by Liberty Water are allocated to the Regulated Utilities based on customer count. The labor rate charged by Liberty Water is the dollar hourly rate per employee as recorded in Liberty Water's payroll system, grossed up by roughly 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees.

[3] These costs are incurred by Liberty Water for rent, administrative costs, depreciation of office furniture, depreciation of computers, and other labor that cannot be directly attributed to a specific Regulated Utility. Those administrative costs are allocated to RRUI by use of the "four factor" methodology. Other costs in this category include insurance, janitorial services and other general non-payroll costs. The methodology used by Liberty Water involves (1) Rate Base, (2) Total Customers, (3) Non-Labor Expenses and (3) Labor as allocating factors, with each factor assigned a specific weight. In total, the Administrative Allocation is 67% non-labor and 33% labor.

[4] The Central Office Costs from APT do not include any direct labor costs. Instead, these costs include professional services like third-party legal services, accounting services, tax planning and filings, and required auditing that are done for the benefit of all of the Liberty Water Regulated Utilities, including RRUI.

[5] These costs are non-labor costs for construction work and related services.

[6] These costs are non-labor costs for construction work and payments to the City of Nogales for wastewater disposal. The City of Nogales payment was $156,975.

**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REJOINDER TESTIMONY**
**March 9, 2010**

# Exhibit PE-RJ2

## COMPARISON OF RIO RICO'S OPERATING COSTS TO OTHER ARIZONA WATER UTILITIES

| | Lago Del Oro Water Co. [1] | Az-Am Water Co. (Mohave) | Bermuda Water Co. | Arizona Water Co. (Oracle) (Overgaard) | Az-Am Water Co. (Sun City West) | Rio Rico Utilities, Inc. | Az-Am Water Co. (Sun City) | Willow Valley Water | Arizona Water Co. (Coolidge) | Arizona Water Co. (Lakeside) | Az-Am Water Co. (Havasu) | Arizona Water Co. (Casa Grande) | Global Water Co. (Santa Cruz) | Az-Am Water Co. (Agua Fria) | Arizona Water Co. (Sedona) | Chaparral City Water Co. | Arizona Water Co. (Winkleman) | Arizona Water Co. (San Manuel) | Arizona Water Co. (Oracle) (Oracle) | H20, Inc. | Rio Verde Utilities, Inc. | Az-Am Water Co. (Anthem) | Az-Am Water Co. (Paradise Valley) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year | 12/31/2008 | 12/31/2007 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2007 | 12/31/2008 | 12/31/2008 | 12/31/2007 | 12/31/2007 |
| Customers[2] | 6,346 | 16,635 | 7,672 | 4,124 | 15,465 | 6,605 | 23,140 | 1,554 | 4,656 | 4,953 | 2,565 | 22,455 | 15,371 | 34,402 | 6,419 | 13,423 | 171 | 1,573 | 1,524 | 6,300 | 1,688 | 8,764 | 4,884 |
| Total Revenue | $1,905,111 | $5,113,631 | $3,103,252 | $1,686,342 | $5,701,431 | $182,050 | $9,283,101 | $482,166 | $2,214,952 | $2,588,943 | $1,026,587 | $10,934,895 | $9,453,438 | $18,818,613 | $3,521,124 | $7,471,697 | $98,722 | $812,539 | $1,115,109 | $3,934,320.46 | $1,402,646 | $9,357,346 | $7,848,732 |
| Total Expenses | $1,666,701 | $5,076,491 | $2,410,387 | $1,316,453 | $5,114,006 | $2,291,663 | $8,422,016 | $586,481 | $1,938,319 | $2,071,226 | $1,158,005 | $10,277,900 | $7,196,180 | $16,217,325 | $3,096,417 | $6,856,065 | $88,524 | $859,882 | $931,996 | $4,263,281.58 | $1,176,153 | $7,215,051 | $6,296,235 |
| Salary/Wages | $186,384 | $899,973 | $752,628 | | $703,217 | | $1,225,670 | $248,567 | | | $204,471 | | $857,540 | $1,440,677 | | $982,169 | | | | $1,146,370.93 | $145,812 | $801,914 | $715,859 |
| Pension/Benefits | | | | | | | | $55,580 | | | | | $205,327 | | | | | | | | | | |
| Purchased Water | | $44,384 | | $58 | ($2,690) | | | | | $1,233 | | $374,207 | | $901,467 | | $802,368 | | $241,318 | | $138,403.02 | $68,561 | $444,337 | |
| Purchased Power | $376,962 | $501,877 | $359,090 | $71,171 | $830,074 | $435,559 | $1,722,582 | $33,979 | $192,581 | $181,940 | $111,139 | $1,387,878 | $588,793 | $1,954,815 | $518,834 | $609,412 | $7,310 | $38,358 | $149,736 | $354,337.27 | $217,417 | $965,412 | $693,068 |
| Chemicals | $12,570 | $7,846 | $61,759 | $14,733 | $227,889 | $9,387 | $37,037 | | $33,911 | $28,463 | $88,249 | $531,617 | $3,505 | $1,121,555 | $319,722 | $116,571 | $1,372 | $40,816 | $15,542 | $5,633.36 | $11,430 | $90,637 | $236,982 |
| Materials/Supp. | | $103,944 | $56,770 | | $57,226 | $34,542 | $78,546 | $18,274 | | | $13,616 | | $41,783 | $161,107 | | $21,358 | | | | | $11,129 | $64,824 | $87,860 |
| Testing Serv. | $34,435 | | 706 | | | $27,451 | | $5,401 | | | | | $36,113 | | | $47,072 | | | | $20,926.77 | $11,443 | | |
| Cust. Accounting | | $132,002 | | | $133,476 | | $235,348 | | $267,290 | $275,893 | $22,062 | $909,384 | | $370,806 | $323,108 | | $11,332 | $104,428 | $100,428.00 | | | | |
| Admin/General | | | | | | | | $12,770 | $378,361 | $506,659 | | $1,761,682 | | | $641,077 | | $16,116 | $151,590 | $151,590.00 | | | | |
| Contr. Serv. Other | $56,007 | | $57,743 | | | $907,246 | | | | | | | $67,741 | | | $268,977 | | | | $455,818.27 | $93,990 | $14,739 | $21,467 |
| Management Fees | | $940,899 | | $486,871 | $999,903 | | $1,509,322 | | | | $166,461 | | | $2,775,604 | | | | | | | | $1,132,699 | $923,778 |
| Rent | | $15,559 | $8,229 | | $14,331 | $26,954 | $60,016 | $9,185 | | | $5,059 | | $94,639 | $63,217 | | | | | | $350,895.47 | | | |
| Transportation | | | $58,567 | | | $79,315 | | $12,699 | | | | | $43,326 | | | $74,600 | | | | $185,890.68 | $13,868.00 | | |
| Insurance-GL | $18,339 | $209,312 | $69,678 | | $191,120 | $37,699 | $354,396 | $5,119 | | | $63,729 | | $53,083 | $396,645 | | $29,241 | | | | $39,453.09 | $9,475 | $240,221 | $184,827 |
| Insurance Other | | $51,991 | | | $58,622 | | $93,255 | $1,058 | | | $8,974 | | | $158,153 | | $102,877 | | | | $78,822.54 | $17,952 | $45,435 | $45,435 |
| Misc. | $74,039 | $354,017 | ($79,663) | | $232,408 | $9,328 | $300,084 | $9,936 | | | $42,644 | | $34,089 | $591,329 | | $850,715 | | | | $156,563.92 | $21,875.00 | $351,828 | $351,828 |
| Depreciation | $605,880 | $883,235 | $666,306 | $214,780 | $1,323,541 | $202,752 | $1,565,706 | $126,911 | $426,056 | $416,943 | $291,351 | $2,329,760 | $3,431,687.00 | $4,397,190 | $731,033 | $2,051,748 | $19,928 | $106,134 | $181,393 | $958,802.67 | $177,320 | $1,979,583 | $1,615,824 |
| Income Taxes | $109,419 | ($196,927) | $185,211 | $154,685 | ($324,059) | $322,818 | $9,746 | ($41,507) | $73,220 | $158,301 | ($159,839) | ($549,326) | $924,207 | ($138,756) | ($153,125) | $111,401 | ($1,170) | ($77,597) | $65,869 | | $88,268 | $228,400 | $228,400 |
| Property Taxes | $107,326 | $221,795 | $48,114 | $65,159 | $179,896 | $148,295 | $156,074 | | $151,656 | $116,684 | $44,112 | $806,467 | $423,523 | $803,071 | $125,837 | $187,217 | $10,675 | $68,170 | $53,921 | $158,746.98 | 26059 | $268,996 | $268,996 |
| Other Taxes | | $75,809 | $50,154 | $22,756 | $65,832 | | $94,912 | $21,944 | $52,532 | $35,117 | $17,638 | $219,346 | $6,823 | $128,923 | $47,845 | $48,353 | $1,235 | $9,102.00 | $12,458 | $91,543.43 | $19,206 | $67,972 | $67,972 |
| Cost/Customer[3] | $262.64 | $305.17 | $314.18 | $319.22 | $330.68 | $346.96 | $363.96 | $377.40 | $416.31 | $418.18 | $451.46 | $457.71 | $468.17 | $471.41 | $482.38 | $510.77 | $517.68 | $546.65 | $611.55 | $676.71 | $696.77 | $823.26 | $1,289.16 |
| Rank Out of 23 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 | 21 | 22 | 23 |
| Total Expenses Less Depr/Taxes | $844,076 | $4,092,579 | $1,460,602 | $859,073.00 | $3,868,796 | $1,617,798 | $6,595,578 | $479,133 | $1,234,855 | $1,344,181 | $964,743 | $7,471,653 | $2,409,940 | $11,026,897 | $2,344,827 | $4,457,346 | $57,856 | $754,073 | $618,355 | $3,054,188.50 | $865,300 | $4,670,100 | $4,115,043 |
| Cost/Customer Less Dep/Taxes[4] | $133.01 | $246.02 | $190.38 | $208.31 | $250.16 | $244.94 | $285.03 | $308.32 | $265.22 | $271.39 | $376.12 | $332.74 | $156.78 | $320.53 | $365.29 | $332.07 | $338.34 | $479.39 | $405.74 | $484.79 | $512.62 | $532.87 | $842.56 |
| Total Expenses - Tax/Dep/Pow/Chem | $454,544 | $3,538,472 | $1,039,753 | $773,111.00 | $2,813,523 | $1,172,852 | $4,835,959 | $445,154.00 | $1,008,363 | $1,132,545 | $765,355 | $5,177,951 | $1,775,859 | $7,049,060 | $1,506,271 | $2,928,995 | $49,174 | $433,581.00 | $453,077.00 | $2,555,814.85 | $567,892 | $3,169,714.00 | $3,097,133.00 |
| Cost/Cust.- Tax/ Dep/Power/Chem[5] | $71.63 | $212.71 | $135.53 | $187.47 | $181.93 | $177.57 | $208.99 | $286.46 | $216.57 | $228.66 | $298.38 | $230.59 | $115.53 | $204.90 | $234.66 | $218.21 | $287.57 | $275.64 | $297.29 | $405.68 | $336.43 | $361.67 | $634.14 |

[1] Data is based on each company's 2008 utility annual report on file with the Arizona Corporation Commission, with the exception of the Arizona-American Water Company systems and Arizona Water Company systems included on this chart, which data is based on the C-1 and H-2 schedules attached to the applications filed in the recent rate cases

[2] The customer numbers are as of December 2008 as reported in the 2008 utility annual report, or come from Arizona-American Water Company's and Arizona Water Company's H-2 schedules attached to the applications filed in the recent rate cases.

[3] This row equals Total Operating Expenses divided by the total number of customers.

[4] This row equals Total Operating Expenses minus Taxes and Depreciation divided by the total number of customers.

[5] This row equals Total Operating Expenses minus Taxes, Depreciation, Purchased Power, Purchased Water and Chermicals divided by the total number of customers.

## COMPARISON OF RIO RICO'S OPERATING COSTS TO OTHER ARIZONA SEWER UTILITIES

| | Az-Am Water Co. (Sun City) [1] | Ajo Improvement[6] | Az-Am Water Co. (Sun City West) | Rio Rico Utilities, Inc. | Global Water (Palo Verde) | Rio Verde Utilities, Inc. | Far West Water & Sewer, Inc. | Coronado Utilities | Az-Am Water Co. (Mohave) | Az-Am (Anthem) | Az-Am Anthem-Agua Fria |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Test Year | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2008 | 12/31/2007 | 12/31/2007 | 12/31/2007 |
| Customers[2] | 47,260 | 1,053 | 31,209 | 2,183 | 15,152 | 1,622 | 7,166 | 1,281 | 1,235 | 8,456 | 13,038 |
| Total Revenue | $5,940,381 | $223,879 | $5,654,504 | $1,834,481 | $6,605,305 | $961,414 | $2,098,426 | $899,226 | $796,161 | $6,395,183 | $8,637,123 |
| Total Expenses | $5,991,974 | $257,588 | $5,040,379 | $825,158 | $6,412,203 | $760,668 | $3,377,272 | $685,635 | $780,542 | $5,438,217 | $8,828,909 |
| Salary/Wages (601) | $454,529 | $87,645 | $766,759 | | $991,267 | $121,639 | $584,440 | $22,570 | $108,996 | $439,668 | $1,335,278 |
| Pension/Benefits (604) | | | | | $229,670 | | | | | | |
| Purchased Water (610) | | $931 | | | | | | | | | $3,368 |
| Purchased Power (615) | $15,804 | $410 | $315,512 | $17,482 | $534,930 | $81,237 | $245,610 | $53,814 | $73,650 | $352,338 | $278,664 |
| Fuel for Power | | | | | $7,004 | | | | | | |
| Chemicals (618) | $4,885 | | $401,862 | $9,856 | $160,523 | $40,168 | $272,924 | $28,079 | $9,214 | $101,456 | $303,374 |
| Materials/Supplies (620/620.08) | $44,944 | $47,593 | $49,950 | $14,304 | $263,090 | $9,718 | $49,574 | $2,978 | $7,874 | $49,707 | $85,697 |
| Contract Services-Testing (635) | | | | | $99,923 | $2,129 | $133,233 | $3,676 | | | |
| Contract Services Other (636) | | | | $452,687 | $477,939 | $93,991 | $24,241 | $291,374 | | | |
| Rent (641) | $40,868 | $16,568 | $38,079 | 25781 | $93,111 | | $192,693 | | $1,613 | $18,363 | $84,483 |
| Management Fees | $933,155 | | $789,604 | | | | | | $123,665 | $890,005 | $1,528,005 |
| Transportation (650) | | | | $26,817 | $31,222 | $12,037 | $68,279 | $209 | | | |
| Insurance-GL (657) | $141,193 | | $267,064 | $12,021 | | $9,475 | $29,734 | | $24,046 | $90,870 | $396,599 |
| Insurance Other (659) | $57,656 | | $48,786 | | $56,553 | | | $11,066 | $7,294 | $49,453 | $94,566 |
| Misc. (675) | $104,503 | $172,701 | $243,174 | $83,226.00 | $55,422.00 | $192,220.00 | $753,136 | | $16,726 | $259,385 | $534,489 |
| Depreciation (403) | $679,999 | ($7,612) | $1,238,799 | ($14,104) | $2,883,976 | $76,977 | $598,772 | $175,111 | $248,398 | $1,988,462 | $3,830,808 |
| Income Taxes | ($310,869) | | $49,967 | $138,350 | $89,215 | $44,443 | | ($3,335) | ($76,894) | $173,361 | ($1,020,813) |
| Property Taxes | $157,456 | $6,111 | $135,000 | $49,415 | $280,937 | $24,241 | $78,255 | $13,194 | $37,922 | $512,237 | $296,804 |
| Other Taxes | $34,880 | $709 | $58,909 | | $4,814 | $20,289 | $3,303 | | $9,778 | $36,982 | $87,538 |
| Cost/Customer[3] | $126.79 | $244.62 | $161.50 | $377.99 | $423.19 | $468.97 | $471.29 | $535.23 | $632.02 | $643.12 | $677.17 |
| Rank Out of 11 | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 | 11 |
| Total Expenses - Taxes/Deprec. | $5,430,508 | $258,380 | $3,557,704 | $651,497 | $3,153,261 | $594,718 | $2,696,942 | $500,665 | $561,338 | $2,727,175 | $5,634,572 |
| Cost/Cust. Less- Taxes/I | $114.91 | $245.38 | $114.00 | $298.44 | $208.11 | $366.66 | $376.35 | $390.84 | $454.52 | $322.51 | $432.17 |
| Total Expenses-Tax/Dep./Power/Chem. | $5,409,819 | $257,970 | $2,840,330 | $624,159 | $2,611,327 | $473,313 | $2,178,408 | $472,586 | $478,474 | $2,273,381 | $5,052,534 |
| Cost/Cust. Less Tax/Dep./Power/Chem[ | $114.47 | $244.99 | $91.01 | $285.92 | $172.34 | $291.81 | $303.99 | $368.92 | $387.43 | $268.85 | $387.52 |
| Cost/Cust Less Tax/Dep/Power/Chem per month | $9.54 | $20.42 | $7.58 | $23.83 | $14.36 | $24.32 | $25.33 | $30.74 | $32.29 | $22.40 | $32.29 |

[1] Data is based on each company's 2008 utility annual report on file with the Arizona Corporation Commission, with the exception of the Arizona-American Water Company systems and Arizona Water Company systems included on this chart, which data is based on the C-1 and H-2 schedules attached to the applications file
[2] The customer numbers are as of December 2008 as reported in the 2008 utility annual report, or come from Arizona-American Water Company's and Arizona Water Company's H-2 schedules attached to the applications filed in the recent rate cases.
[3] This row equals Total Operating Expenses divided by the total number of customers.
[4] This row equals Total Operating Expenses minus Taxes and Depreciation divided by the total number of customers.
[5] This row equals Total Operating Expenses minus Taxes, Depreciation, Purchased Power, Purchased Water and Chemicals divided by the total number of customers.
[6] Ajo Improvement Company is not comparable to Rio Rico because it is heavily subsidized by its parent company Phelps Dodge.

**Rio Rico Utilities, Inc.**
**Docket No. WS-02676A-09-0257**

**PETER EICHLER**
**REJOINDER TESTIMONY**
**March 9, 2010**

# Exhibit PE-RJ3

**Corporate Cost Allocation**
**Comparative Cost per Customer Analysis**

| | 2008 Connecticut Water | 2008 San Jose Water | 2008 American States | 2008 Aqua America | 2008 California Water | 2008 Middlesex water | 2008 Liberty Water | 2008 Rio Rico |
|---|---|---|---|---|---|---|---|---|
| Revenue | 61,270,000 | 220,347,000 | 318,718,000 | 626,972,000 | 410,312,000 | 91,038,000 | 35,233,000 | 5,367,969 |
| % of revenue from Regulated Water/Sewer | 100% | 97% | 78% | 100% | 92% | 89% | 100% | 100% |
| Service Connections | 87,361 | 234,300 | 291,077 | 945,540 | 490,493 | 104,200 | 69,190 | 8,788 |
| Number of Board of Directors | 9 | 7 | 7 | 8 | 8 | 8 | - | - |
| Director Fees Paid | 188,000 | 710,250 | 718,457 | 483,975 | 911,379 | 266,150 | 60,728 | 4,496 |
| Audit Fees | 367,000 | 652,500 | 1,141,536 | 1,218,134 | 842,350 | 330,200 | 266,462 | 35,608 |
| Tax Services | 70,000 | 15,279 | 146,471 | 28,500 | - | 14,350 | 103,603 | 11,239 |
| CEO Base Salary | 344,992 | 455,000 | 592,192 | 486,808 | 791,523 | 352,574 | 171,688 | 22,404 |
| CEO Total Compensation | 644,597 | 1,166,082 | 1,445,371 | 2,401,514 | 3,307,304 | 430,147 | 171,688 | 22,404 |
| Source | 2009 Proxy Statem | 2009 Proxy Statemen | 2009 Proxy Statem | 2009 Proxy Statem | 2009 Proxy Statem | 2009 Proxy Statem | 2008 annual report Per Schedule | |
| **Cost per customer** | | | | | | | | |
| Director Fees Paid | 0.18 | 0.25 | 0.21 | 0.04 | 0.15 | 0.21 | 0.07 | 0.04 |
| Audit Fees | 0.35 | 0.23 | 0.33 | 0.11 | 0.14 | 0.26 | 0.32 | 0.34 |
| Tax Fees | 0.07 | 0.01 | 0.04 | 0.00 | - | 0.01 | 0.12 | 0.11 |
| CEO Total Compensation | 0.61 | 0.41 | 0.41 | 0.21 | 0.56 | 0.34 | 0.21 | 0.21 |
| **Total** | **1.21** | **0.90** | **0.99** | **0.36** | **0.86** | **0.83** | **0.73** | **0.70** |

## RIO RICO MONTHLY APT COSTS PER CUSTOMER

| | |
|---|---|
| APT Central Office Cost Allocation (Water) | $124,102.00[1] |
| APT Central Office Cost Allocation (Wastewater) | $40,934.00[2] |
| Total APT Central Office Cost Allocation | $165,036.00 |
| Total APT Cost/Month | $13,753.00 |
| APT Monthly Cost Per Customer | **$1.56[3]** |
| | |
| APT Cost/Month for Water | $10,341.83 |
| APT Monthly Cost Per Water Customer | $1.57[4] |
| | |
| APT Cost/Month for Wastewater | $3,411.67 |
| APT Monthly Cost Per Wastewater Customer | $1.56[5] |

2293234.1

---

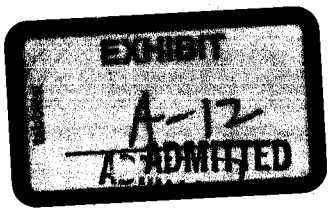
[1] Rejoinder Schedule (Water Division), C-2 at 9 (Revised), Adj. 8.

[2] Rejoinder Schedule (Wastewater Division), C-2 at 7, Adj. 6.

[3] $13,753/8,788 customers = $1.56 per customer. RRUI has 6,605 water customers and 2,183 wastewater customers, for a total of 8,788 customers.

[4] $10,341.83/6,605 customers = $1.57/customer

[5] $3,411.67/2,183 customer = $1.59/customer



## COMPARISON OF SHARED SERVICES TO STAND-ALONES

## TOTAL OPERATING COST PER CUSTOMER (WATER)[1]

| Stand Alone Water Utilities | |
|---|---|
| Lago Del Oro[2] | $262.64/Customer |
| Bermuda Water[3] | $314.18/Customer |
| H2O, Inc. | $676.71/Customer |
| Rio Verde | $696.77/Customer |
| Average: | $487.58/Customer |
| Rio Rico: | $346.96/Customer |

| Shared Services Water Utilities | |
|---|---|
| Az-Am Mohave | $305.17/Customer |
| Az-Am Sun City West | $330.68/Customer |
| Rio Rico | $346.96/Customer |
| Az-Am Sun City | $363.96/Customer |
| Willow Valley | $377.40/Customer |
| Az-Am Havasu | $457.46/Customer |
| Global/Santa Cruz | $468.17/Customer |
| Az-Am Agua Fria | $471.41/Customer |
| Chaparral City | $510.77/Customer |
| Az-Am Anthem | $823.26/Customer |
| Az-Am Paradise Valley | $1,289.16/Customer |
| Average: | $470.05/Customer |
| Rio Rico: | $346.96/Customer |

| Arizona Water Co. (Shared Services) | |
|---|---|
| Overgaard | $319.32 |
| Coolidge | $416.31 |
| Lakeside | $418.18 |
| Casa Grande | $457.71 |
| Sedona | $482.38 |
| Winkelman | $517.68 |
| San Manuel | $546.65 |
| Oracle | $611.55 |
| Average: | $471.22 |
| Rio Rico: | $346.96 |

EXHIBIT
A-13
ADMITTED

[1] Data from Exhibit PE-RJ2, Page 1.

[2] RUCO (Mr. Coley) asserts that Lago Del Oro is a stand alone utility. In reality, however, Lago Del Oro is owned by Robson Communities. Robson owns six utilities, including Lago Del Oro, Mountain Pass Utility Company, Picacho Sewer Company, Pima Utility Company, Saddlebrooke Utility Company, and Santa Rosa Utility Company. RRUI does not believe Lago Del Oro is a stand alone utility, but includes that company on this chart for illustration purposes.

[3] RUCO (Mr. Coley) also claims that Bermuda Water Company is a stand alone utility. Bermuda Water Company, however, is owned by Utilities, Inc. Utilities, Inc. owns utilities in 17 states with over 300,000 customers. Utilities, Inc. also is owned by American International Group (AIG). *See* www.citizen.org/cmep/Water/general/majorwater/aig/index.cfm.

## COMPARISON OF SHARED SERVICES TO STAND ALONES

## (TOTAL WASTEWATER OPERATING COSTS PER CUSTOMER[4]

| Stand Alone | | Shared Services | |
|---|---|---|---|
| Ajo Improvement[5] | $244.62/Customer | Az-Am Sun City | $126.79/Customer |
| Rio Verde | $468.97/Customer | Az-Am Sun City West | $161.50/Customer |
| Far West | $471.29/Customer | Rio Rico | $377.49/Customer |
| | | Global Palo Verde | $423.19/Customer |
| Average: | $394.96/Customer | Coronado Utilities | $535.23/Customer |
| Rio Rico: | $377.49/Customer | Az-Am Mohave | $632.02/Customer |
| | | Az-Am Anthem | $643.12/Customer |
| | | Average: | $414.19/Customer |
| | | Rio Rico | $377.49/Customer |

EXHIBIT
A-14
ADMITTED

[4] Data from Exhibit PE-RJ2, Page 2

[5] RUCO (Mr. Coley) claims that Ajo Improvement Company is a stand alone utility. Ajo Improvement Company, however, is owned and operated by Freeport McMoran, one of the largest mining companies in the world. Again, RRUI has included Ajo Improvement Company on this exhibit as a stand alone utility solely for illustrative purposes.

**Corporate Cost Build Up**

| | Corpoarte Costs | | | | Rio Rico | |
|---|---|---|---|---|---|---|
| | Total Budget 2008 | Pool per RB 2008 | Total Actual 2008 | Variance* | Total Budget 2008 | Total Actual 2008 |
| Audit | 507,000 | 1,021,609 | $994,309 | $27,300 | 17,672 | 34,657 |
| Tax Services | 265,000 | 322,446 | $322,446 | $0 | 9,237 | 11,239 |
| Legal | 300,000 | 767,451 | $651,363 | $116,088 | 10,457 | 22,703 |
| Other Professional Services | 455,000 | 565,649 | $425,552 | $140,097 | 15,859 | 14,833 |
| Management Fee - Total | 636,619 | 642,771 | $642,771 | $0 | 22,190 | 22,404 |
| Unit Holder Communications | 314,100 | 289,796 | $209,617 | $80,179 | 10,948 | 7,306 |
| Trustee Fees | 204,000 | 129,000 | $129,000 | $0 | 7,110 | 4,496 |
| Escrow & Transfer Agent Fees | 75,000 | 71,366 | $71,366 | $0 | 2,614 | 2,487 |
| Rent | 430,739 | 299,586 | $299,586 | $0 | 15,014 | 10,442 |
| Licenses/Fees & Permits | 305,000 | 140,852 | $27,169 | $113,683 | 10,631 | 947 |
| Office Expenses | 254,000 | 808,101 | $746,979 | $61,122 | 8,853 | 26,036 |
| Depreciation | 204,242 | 211,253 | $211,253 | $0 | 7,119 | 7,363 |
| **Total Admin Costs** | **3,950,700** | **$5,269,880** | **$4,731,412** | **$538,469** | **137,703** | **$164,915** |

* includes removal of Kendall Printing Invoice

EXHIBIT
A-15
ADMITTED

Rio Rico Utilities Inc.
Removed costs from Corporate Pool

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7/31/2008 | Legal | 7360 | Legal Expenses - APIF | 162466 | $40,239.00 | BST Valuation & Litigation Advisors, LLC | TPI LITIGATION |
| 7/31/2008 | Legal | 7360 | Legal Expenses - APIF | 161813 | $17,546.78 | BST Valuation & Litigation Advisors, LLC | TPI LITIGATION |
| 7/31/2008 | Legal | 7360 | Legal Expenses - APIF | 152745 | $4.030.33 | Rackemann, Sawyer & Brewster | TPI LITIGATION |
| 10/6/2008 | Legal | 7360 | Legal Expenses - APIF | 154010 | $7,905.47 | Rackemann, Sawyer & Brewster | TRAFALGAR POWER V.AETNA LIFE I |
| 2/27/2008 | Legal | 7360 | Legal - APFA | 114785 JAD | $62.00 | Menter, Rudin Trivelpiece P.C. | BEAVER FALLS HYDRO |
| 3/12/2008 | Legal | 7360 | Legal - APFA | 2116754 | $18,700.00 | DLA Piper US LLP | CROSSRAODS -LEGAL JAN31,08 |
| 7/16/2008 | Legal | 7360 | Legal Expenses - APIF | 118069 MJK | $17,640.26 | Menter, Rudin Trivlpiece | TPI LITIGATION |
| 10/28/2008 | Legal | 7360 | Legal - AP Trust | 014225003 SEP08 | $2,444.00 | Davis Webb LLP Barristers and Solicitors | GAS TURBINE SEP29'08 |
| 10/28/2008 | Legal | 7360 | Legal - AP Trust | 014225002 SEP08 | $2,840.75 | Davis Webb LLP Barristers and Solicitors | PDEEL-EFW |
| 10/28/2008 | Legal | 7360 | Legal - AP Trust | 13049 | $4.679.75 | Glen Schnarr & Associates Inc. | PEEL POWER SITE EXTENSION 616- |
| | | | **Total Legal** | | **$116,088.34** | | |
| 7/31/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees | JC37171 | $14,354.01 | Algonquin Power Systems Inc | WIND DEVELOPMENT |
| 2/4/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees - APFC | TAXES PROVIN 2001 | $381.51 | Minister of Finance | 2001 TAXES PROVINCES APFC |
| 4/15/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees - Belleterre | PENALTY APR08 | $171.98 | Minister of Revenue Quebec QST | PENALTY/INTEREST |
| 5/23/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees - APFA | MAY23,08.1 | $175.00 | Vermont Secretary of State | ANNUAL FILING FEE |
| 5/23/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees - APFA | MAY23,08 | $175.00 | Vermont Secretary of State | ANNUAL FILING FEE |
| 6/12/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees - Ste Alban | LSB023352-LSB | $199.00 | Ministry of Environment, Quebec | BARRAGES-DROITS ANNUELS CLASSE |
| 6/12/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees - Arthurville | LSB023751-LSB | $199.00 | Ministry of Environment, Quebec | BARRAGES-DROITS ANNUELS CLASS |
| 6/12/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees | 3363725816 | $32.00 | Registraire des entreprises Quebec | REGISTRAIRE FEE |
| 6/20/2008 | Licenses/Fees & Permits | 7430 | Licenses, Fees and Permits | INCOME TAX 2007 | $79.00 | Minister of Revenue Quebec | QUEBEC INCOME TAX 2007 |
| 6/27/2008 | Licenses/Fees & Permits | 7430 | Licenses, Fees and Permits | QE INCOME TAX 2007 | $79.00 | Minister of Revenue Quebec | QUEBEC INCOME TAX 2007 |
| 8/13/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees | 9345491 APR08 | $3,136.48 | Minister of Revenue Quebec | QST 9345491 APR09'08 |
| 8/21/2008 | Licenses/Fees & Permits | 7430 | Licenses, Fees and Permits | LATE FEE'06 QE ANNUA | $39.50 | Minister of Revenue Quebec QST | ANNUAL QE DECLARATION06 LATE F |
| 8/21/2008 | Licenses/Fees & Permits | 7430 | Licenses, Fees and Permits | LATE FEE'07 QE ANNUA | $39.50 | Minister of Revenue Quebec QST | ANNUAL QE DECLARATION'07 LATE |
| 8/31/2008 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees | JC37473 | $1.375.46 | Algonquin Power Systems Inc | WIND DEVELOPMENT |
| 39728 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees | PENALTY SEP08 | 2515.27 | Minister of Revenue Quebec | NOTICE ASSESSMENT #7050771 |
| 39782 | Licenses/Fees & Permits | 7430 | Licenses, Permits & Fees | | 181.25 | | NB Movable Hypothec |
| 11/27/2007 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION NOV07 | $13,350.00 | Canadian Cancer Society | DONATION-STEP-BY-STEP |
| 11/28/2007 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | NOV. 22, 2007 | $25,000.00 | Bearpaw Corporation Inc. | CONTRIBUTION |
| 11/28/2007 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION NOV07 | $5,000.00 | Princess Margaret Hospital | MULTI MYELOMA 5K WALK-DONATION |
| 11/30/2007 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION NOV07 | $200.00 | The Toronto Rehab Foundation | DONATION- SEAN'S FATHER |
| 12/19/2007 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DAIGA DEC07 | $25,000.00 | World Vision Canada | WTER PROJECT CONTRI IN KENYA A |
| 4/17/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION 2008 | $200.00 | Region of Peel | DONATION-GOLF |
| 5/22/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | MAY22/08-GOLF | $2,000.00 | Golf Tournament for the Arts | DONATION-GOLF TOURNAMENT |
| 5/22/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | MAY22/08-CLARKSON | $1,000.00 | Clarkson 1808 | DONATION-GOLF TOURNAMENT |
| 6/25/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | JUN08 EXP | $150.00 | JANET YEUNG | JUN08 EXPENSE REPORT |
| 7/11/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | GOLF ENTRY FEE JUL08 | $700.00 | Birdies For Babies 2008 | GOLF TOURNAMENT ENTRY FEE-CHAR |
| 7/15/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION JUL14, 2008 | $5,000.00 | Region of Peel | DONATION |
| 7/15/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION JUL14, 2008 | $7,800.00 | EMIL KOLB HOOTENANNY | DONATION |
| 7/25/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | SPONSORSHIP JUL08 | $5,000.00 | Town of Caledon | PLATINUM SPOSORSHIP |
| 7/31/2008 | Licenses/Fees & Permits | 7450 | Donations / Contributions - AP Trust | DONATION AUG2008 | $150.00 | Community Living Grimsby | IN MEMORY OF BRADLEY ANDERSON |
| | | | **Total Licenses Fees & Permits** | | **$113,682.96** | | |
| 6/30/2008 | Office Costs | 7142 | Office Supplies / Rentals / Repairs | JC36861 | $15,055.96 | Algonquin Power Systems Inc | APT- WINDPRO SOFTWARE+TRAINING |
| 7/31/2008 | Office Costs | 7142 | Office Supplies / Rentals / Repairs | JC37177 | $1,750.28 | Algonquin Power Systems Inc | APT-ST.LEON EXP PRE-CON.ACTIV |
| 10/31/2008 | Office Costs | 7142 | Office Supplies / Rentals / Repairs | JC38135 | $244.06 | Algonquin Power Systems Inc | APT-PROJ DEVPMT/AMHERST WIND |
| 2/29/2008 | Office Costs | 7150 | Postage/Courier | JC35530 | $35.56 | Algonquin Power Systems Inc | WIND DEVELOPMENT |
| 7/31/2008 | Office Costs | 7150 | Postage/Courier | JC37174 | $37.46 | Algonquin Power Systems Inc | APT-WINDY SUNSHINE DEVELOPEMEN |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 2/29/2008 | Office Costs | 7200 | Communications - AP Trust | JC35530 | $119.53 | Algonquin Power Systems Inc | WIND DEVELOPMENT |
| 7/31/2008 | Office Costs | 7200 | Communications - AP Trust | JC37171 | $119.53 | Algonquin Power Systems Inc | WIND DEVELOPMENT |
| 8/31/2008 | Office Costs | 7200 | Communications - AP Trust | JC37473 | $119.53 | Algonquin Power Systems Inc | WIND DEVELOPMENT |
| 8/31/2008 | Office Costs | 7215 | Cellular - APT | JC37481 | $5.02 | Algonquin Power Systems Inc | APT-PROJ DEVLPMT/AMHERST WIND |
| 10/31/2008 | Office Costs | 7215 | Cellular - APT | JC38135 | $4.55 | Algonquin Power Systems Inc | APT-PROJ DEVPMT/AMHERST WIND |
| 5/31/2008 | Office Costs | 7100 | Other Administration Expenses - AP Tru | JC36556 | $20,000.00 | Algonquin Power Systems Inc | 002-99908-3777 |
| 5/31/2008 | Office Costs | 7100 | Other Administration Expenses - AP Tru | JC36545 | $7,188.62 | Algonquin Power Systems Inc | 002-999907-3686 APT-CIEL POT.A |
| 5/31/2008 | Office Costs | 7100 | Other Administration Expenses - AP Tru | JC36549 | $438.94 | Algonquin Power Systems Inc | 002-999907-3714 APT-PRO.DEV |
| 6/30/2008 | Office Costs | 7100 | Other Administration Expenses - AP Tru | JC36862 | $5,675.00 | Algonquin Power Systems Inc | APT-BUSINESS DEVEL.OPPORTUNIT |
| 6/30/2008 | Office Costs | 7100 | Other Administration Expenses - AP Tru | JC36854 | $261.25 | Algonquin Power Systems Inc | APT-RED LILY PRE-CONSTR.ACTIV |
| 5/31/2008 | Office Costs | 7142 | Office Supplies / Rentals / Repairs | JC36545 | $6,172.95 | Algonquin Power Systems Inc | 002-999907-3686 APT-CIEL POT.A |
| 12/31/2008 | Office Costs | 7150 | Postage/Courier | JC38606 | $11.06 | Algonquin Power Systems Inc | APT-HALTON SKYWAY WWTP COGEN |
| 8/31/2008 | Office Costs | 7200 | Communications - AP Trust | JC37475 | $53.94 | Algonquin Power Systems Inc | APT-CIEL POT.ACQ 110098400061 |
| 10/31/2008 | Office Costs | 7200 | Communications - AP Trust | JC38131 | $53.94 | Algonquin Power Systems Inc | APT-CIEL POT ACQ |
| 11/28/2008 | Office Costs | 7200 | Communications - AP Trust | JC38405 | $53.94 | Algonquin Power Systems Inc | APT-CIEL POT ACQ |
| 11/28/2008 | Office Costs | 7200 | Communications - AP Trust | JC38408 | $66.97 | Algonquin Power Systems Inc | OPA CHP 2 RFP |
| 12/31/2008 | Office Costs | 7200 | Communications - AP Trust | JC38601 | $53.94 | Algonquin Power Systems Inc | APT CIEL POT ACQ |
| 5/31/2008 | Office Costs | 7142 | Office Supplies / Rentals / Repairs | JC36550 | $99.95 | Algonquin Power Systems Inc | 002-999907-3722 APT-WINDY SUNS |
| 3/25/2008 | Office Costs | 7420 | Dues & Membership Fees - APT | 577069COR | $3,500.00 | Canadian Wind Energy Association 2 | CANWEA 2008 CORPORATE |
| | | | **Total Office Costs** | | **$61,121.98** | | |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| 7/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37181 | $821.25 | Algonquin Power Systems Inc | APT-PROJ-DEVLPMT/AMHERST WIND |
| 7/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37174 | $315.00 | Algonquin Power Systems Inc | APT-WINDY SUNSHINE DEVELOPEMEN |
| 7/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37176 | $1,562.50 | Algonquin Power Systems Inc | APT-RED LILY PRE-CONSTR.ACTIV |
| 7/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37177 | $3,845.00 | Algonquin Power Systems Inc | APT-ST.LEON EXP PRE-CON.ACTIV |
| 7/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37183 | $19,347.50 | Algonquin Power Systems Inc | APT-STE FELIITE PRE-CONSTRUCT |
| 7/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37182 | $10,428.00 | Algonquin Power Systems Inc | APT-ST.DAMASE PRE-CONSTR.ACTIV |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37481 | $2,655.00 | Algonquin Power Systems Inc | APT-PROJ DEVLPMT/AMHERST WIND |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37479 | $971.25 | Algonquin Power Systems Inc | APT-OPA CHP2 RFP |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37478 | $2,047.50 | Algonquin Power Systems Inc | APT-ST.LEON EXP PRE-CON.ACTIV |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37477 | $5,045.00 | Algonquin Power Systems Inc | APT-RED LILY PRE-CONSTR.ACTIV |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37475 | $285.00 | Algonquin Power Systems Inc | APT-CIEL POT.ACQ 110098400061 |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37482 | $105.00 | Algonquin Power Systems Inc | APT-ST.DAMASE PRE-CONSTR.ACTIV |
| 8/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37483 | $1,072.50 | Algonquin Power Systems Inc | APT-WINDPRO SOFTWARE+TRAINING |
| 9/30/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37847 | $247.50 | Algonquin Power Systems Inc | APT-WINDPRO SOFTWARE+TRAINING |
| 9/30/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37846 | $3,930.00 | Algonquin Power Systems Inc | APT-PROJ DEVLPMT/AMHERST WIND |
| 9/30/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37844 | $862.50 | Algonquin Power Systems Inc | APT-ST.LEON EXP PRE-CON ACTIV |
| 9/30/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37845 | $127.50 | Algonquin Power Systems Inc | APT-OPA CHP 2 RFP |
| 9/30/2008 | Other Professional Services | 7370 | Other - AP Trust | JC37843 | $9,600.00 | Algonquin Power Systems Inc | APT-RED LILY PRE-CONSTR.ACTIV |
| 10/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38137 | $55.00 | Algonquin Power Systems Inc | APT-STE FELICITE PRE-CONSTUCT |
| 10/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38133 | $467.50 | Algonquin Power Systems Inc | APS-ST.LEON EXP PRE.CON.ACTIV |
| 10/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38134 | $513.75 | Algonquin Power Systems Inc | APT-OPA CHP2 RFP |
| 10/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38132 | $788.75 | Algonquin Power Systems Inc | APT-RED LILY PRE-CONSTR ACTIV |
| 10/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38136 | $935.00 | Algonquin Power Systems Inc | APT-WINDPRO SOFTWARE+TRAINING |
| 10/31/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38135 | $7,851.25 | Algonquin Power Systems Inc | APT-PROJ DEVPMT/AMHERST WIND |
| 11/28/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38410 | $18.75 | Algonquin Power Systems Inc | ST.DAMASE PRE CONSTR ACTIV |
| 11/28/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38407 | $3,025.00 | Algonquin Power Systems Inc | RED LILY PRE CONSTR ACTIV |
| 11/28/2008 | Other Professional Services | 7370 | Other - AP Trust | JC38409 | $4,285.00 | Algonquin Power Systems Inc | PROJ DEVLPMT AMHERST WIND |
| 7/17/2008 | Other Professional Services | 7370 | Other - AP Trust | 052 | $20,000.00 | 2034101 Ontario Ltd | CONSULTING FEE MAY-JUN 2008 |
| 8/25/2008 | Other Professional Services | 7370 | Other Professional - APIF | 118560 MJK | $38,888.95 | Menter, Rudin Trivlpiece | LEGAL SERVICE JUL08 |
| | | | **Other Professional Services** | | **$140,096.95** | | |

| | | | | | | |
|---|---|---|---|---|---|---|
| 5/29/2008 | Accrued Liabilities- CDN | $0.00 | $22,050.00 | $22,050.00 | KPMG | Audit |
| 9/22/2008 | Accrued Liabilities- APIF | $0.00 | $5,250.00 | $5,250.00 | KPMG LLP | Audit |

| | | | | | |
|---|---|---|---|---|---|
| | | **Total Audit** | | **$27,300.00** | |
| 7/30/2008 Accrued Liabilities- APIF | $0.00 | $80,179.20 | $80,179.20 | Kendall Printing Co Unit Holder Communications | |
| | | **Total Unitholder Communications** | | **$80,179.20** | |

List of Facilities

| | Plants | Location | Division | Owner |
|---|---|---|---|---|
| 1 | Burgess | Ontario | Hydro | APFC |
| 2 | Hurdman | Ontario | Hydro | APFC |
| 3 | Long Sault | Ontario | Hydro | APFC |
| 4 | Snemo | Quebec | Hydro | APFC |
| 5 | St Raphael | Quebec | Hydro | APFC |
| 6 | St Alban | Quebec | Hydro | APFC |
| 7 | Hydraska | Quebec | Hydro | APFC |
| 8 | Chuteford | Quebec | Hydro | APFC |
| 9 | Rattlebrook | Newfoundland | Hydro | APFC |
| | **Total** | | | |
| 1 | Burt Dam | New York | Hydro | APFA |
| 2 | Hollow Dam | New York | Hydro | APFA |
| 3 | Otter | New York | Hydro | APFA |
| 4 | Kings Falls | New York | Hydro | APFA |
| 5 | Phoenix | New York | Hydro | APFA |
| 6 | Clement | New Hampshire | Hydro | APFA |
| 7 | Gregg | New Hampshire | Hydro | APFA |
| 8 | Pembroke | New Hampshire | Hydro | APFA |
| 9 | Mine Falls | New Hampshire | Hydro | APFA |
| 10 | Franklin | New Hampshire | Hydro | APFA |
| 11 | Lochmere | New Hampshire | Hydro | APFA |
| 12 | Lakeport | New Hampshire | Hydro | APFA |
| 13 | Milton | New Hampshire | Hydro | APFA |
| 14 | Great Falls | New Jersey | Hydro | APFA |
| 15 | Moretown | Vermont | Hydro | APFA |
| 16 | Sanger | California | Co-gen | APFA |
| 17 | Windsor Locks | Connecticut | Co-gen | APFA |
| 18 | Crossroads | New Jersey | Co-gen | APFA |
| 19 | Beaver Falls | New York | Hydro | APFA |
| 20 | Balesfill Landfill | New Jersey | Alternative | APFA |
| 21 | Kingsland Landfill | New Jersey | Alternative | APFA |

EXHIBIT
A-16
ADMITTED

| | | | | |
|---|---|---|---|---|
| | **Total** | | | |
| 1 | Black Mountain | Arizona | Infrastructure | AWRA |
| 2 | Gold Canyon | Arizona | Infrastructure | AWRA |
| 3 | Bella Vista | Arizona | Infrastructure | AWRA |
| 4 | Tall Timbers | Texas | Infrastructure | AWRA |
| 5 | Woodmark | Texas | Infrastructure | AWRA |
| 6 | LSPCo | Arizona | Infrastructure | AWRA |
| 7 | Fox River | Illinois | Infrastructure | AWRA |
| 8 | Hill Country | Texas | Infrastructure | AWRA |
| 9 | Holiday Hills | Missouri | Infrastructure | AWRA |
| 10 | Holly Lake Ranch | Texas | Infrastructure | AWRA |
| 11 | Ozark Mountain | Missouri | Infrastructure | AWRA |
| 12 | Piney Shores | Texas | Infrastructure | AWRA |
| 13 | Timber Creek | Missouri | Infrastructure | AWRA |
| 14 | The Villages | Texas | Infrastructure | AWRA |
| 15 | Rio Rico | Arizona | Infrastructure | AWRA |
| 16 | Southern Sunrise | Arizona | Infrastructure | AWRA |
| 17 | Northern Sunrise | Arizona | Infrastructure | AWRA |
| | **Total** | | | |
| 1 | Belleterre | Quebec | Hydro | APIF |
| 2 | Brigitte | Quebec | Hydro | APIF |
| 3 | Rawdon | Quebec | Hydro | APIF |
| 4 | Donnacona | Quebec | Hydro | APIF |
| | **Total** | | | |
| 1 | Campbellford | Ontario | Hydro | APT |
| 2 | Arthurville | Quebec | Hydro | APT |
| 3 | Cochrane | Ontario | Co-gen | APT |
| 4 | Kirkland | Ontario | Co-gen | APT |
| 5 | Chapais | Quebec | Alternative Fuel | APT |
| 6 | Brooklyn | Nova Scotia | Alternative Fuel | APT |
| | **Total** | | | |
| 1 | Peel | Ontario | Alternative Fuel | APEFW |
| | **Total** | | | |

| | | | | |
|---|---|---|---|---|
| 1 | Dickson Dam | Alberta | Hydro | DVPIF |
| 2 | Drayton Valley | Alberta | Alternative Fuel | DVPIF |
| | **Total** | | | |
| 1 | St Leon Wind Energy | Manitoba | Alternative Fuel | St Leon Wind |
| | **Total** | | | |
| 1 | Mont Laurier | Quebec | Hydro | Mont Laurier |
| 2 | Cote St Catherine | Quebec | Hydro | Mont Laurier |
| | **Total** | | | |

63 **Total Plants**

17 **Number of Infrastructure Facilities**

26.98% Utility facilities as a % of Total APIF facilities

BEFORE THE ARIZONA CORPORATION C

Arizona Corporation Commission
DOCKETED
DEC 23 2009
DOCKETED BY nR

COMMISSIONERS

KRISTIN K. MAYES - Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF FAR WEST WATER & SEWER COMPANY, AN ARIZONA CORPORATION, FOR APPROVAL OF INTERIM RATES AND CHARGES.

DOCKET NO. WS-03478A-08-0608

DECISION NO. 71447

**OPINION AND ORDER**

| | |
|---|---|
| DATES OF HEARING: | April 6, and 7, 2009, and May 12, 13, 14, and 21, 2009 |
| PLACE OF HEARING: | Tucson, Arizona |
| DATE OF PUBLIC COMMENT: | March 5, 2009 |
| PLACE OF PUBLIC COMMENT: | Yuma, Arizona |
| ADMINISTRATIVE LAW JUDGE: | Jane L. Rodda |
| APPEARANCES: | Mr. Jay Shapiro, FENNEMORE CRAIG, on behalf of Applicant; |
| | Ms. Michelle Wood, Staff Attorney, on behalf of the Residential Utility Consumer Office; and |
| | Mr. Kevin Torrey and Ms. Robin Mitchell, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission. |

**BY THE COMMISSION:**

On December 19, 2008, Far West Water & Sewer Company ("Far West" or "Company") filed with the Arizona Corporation Commission ("Commission") an emergency application for the immediate implementation of interim rates for sewer service, which rates would be effective until a decision has been issued on the Company's application for permanent rate increase.

The Company had filed an application for permanent rates on August 29, 2008, in Docket No. WS-03478A-08-0454. By Procedural Order dated December 10, 2008, the permanent rate case was

EXHIBIT
ADMITTED

set for hearing to commence on July 29, 2009. Following the filing of the emergency rate application, by Procedural Order dated January 23, 2009, the proceedings in the permanent rate case were suspended pending the conclusion of the emergency case.

Summary of Request

The Company is seeking an emergency rate increase designed to produce additional revenue of $2,161,788 on an annual basis. The Company claims its request would result in a zero Operating Income.[1] The requested increase would be a 101.95 percent increase over current sewer division revenues.[2] The Company argues that all three of the conditions identified in Arizona Attorney General Opinion 71-17, which establishes the guidelines to determine when an "emergency" exists for the purpose of approving interim rates, are present, or threatened, in this case.

Far West asserts that it cannot pay its debts as they come due. Far West projects that in 2009, the Company will have a cash flow deficit of over $6.4 million. It states that it has invested more than $18 million in improvements in the last three years, which are not yet included in rate base, and is paying debt service on more than $20 million in new debt used to pay for these improvements. Far West states it is unable to complete the sewer system improvements necessary to comply with its October 2006 Consent Order with the Arizona Department of Environmental Quality ("ADEQ"). The Company claims it has been unable to raise the additional capital needed to pay for the cost overruns related to its sewer system renovation project. Thus, the Company asserts that it is insolvent, as it cannot complete the plant to comply with the Consent Order and cannot obtain permanent rate relief to address its severe cash flow shortage. Far West states that because it cannot make the necessary improvements to its water and wastewater utility systems, its ability to maintain safe and reliable water and sewer service in doubt.

RUCO argues that the Commission should deny the request for interim rates because, on a total company basis, the Company has sufficient funds to meet its operating expenses and debt service. RUCO argues that shortfalls in the Company's capital budget for construction work in progress are not appropriately charged to ratepayers.[3] According to RUCO, the Company is not

[1] Far West Closing Brief at 1.
[2] Ex A-3 Bourassa Rebuttal at 2.
[3] RUCO Reply Brief at 1.

insolvent and there is no emergency. RUCO's analysis of the Company's relevant financial ratios indicates that the Company actually has a better cash flow now than it did in 2007.

Staff believes that when Far West is viewed as a whole, the Company's existing rates are sufficient to allow it to remain financially solvent and to provide reasonable funds for unexpected events or contingencies until the conclusion of the permanent rate case.[4] Staff argues the Company's request for interim rates is unfair to ratepayers and would only aggravate the Company's financial situation. Staff advocates that the only viable solution to the Company's need to complete its sewer renovation project is an infusion of equity. In the event the Commission determines that there is an emergency, Staff offers an alternative recommendation that would provide the Company with interim relief in the amount of $972,150, a 46.3 percent revenue increase, to be spread evenly among all customer classes.

Background Events

Far West is located in Yuma County and provides water utility service to approximately 15,000 customers and sewer utility service to approximately 7,300 of those customers. In the past ten years, the Company's service area experienced a period of tremendous growth. In 1998, Far West provided service to 8,400 water customers and 260 sewer customers. By 2005, Far West served 5,500 sewer customers. The shareholders of Far West are sisters Paula Capestro and Sandy Braden. Mr. Andrew Capestro is married to Paula Capestro and has been overseeing the Company during its sewer renovation project. Mr. Capestro does not receive compensation for operating the Company but does receive compensation when he performs services as a lawyer for the Company.

By its own admission, the Company was not able to keep up with the growth in its service area.[5] The Company came to have seven independently operating "package-type" treatment plants across its service territory. The Company's plants are known as Palm Shadows, which has a current average flow of 263,000 gallons per day ("gpd"); Section 14, with a current average flow of 102,000 gpd; Marwood, with a current average flow of 306,000 gpd; Del Oro, with a current average flow of 180,000 gpd; Del Rey, with a current average flow of 14,000 gpd; Villa Royale, with a current

[4] Staff Closing Brief at 2.
[5] Far West Closing Brief at 4.

average flow of 10,000 gpd; and Seasons, with a current average flow of 73,000 gpd.[6]

Following customer complaints about odors and effluent quality, ADEQ investigated Far West's sewer operations.[7] On March 10, 2006, ADEQ entered into a Consent Order with Far West with respect to the Del Oro treatment facility. In that Consent Order, Far West was required to make short, medium and long-term measures to address operational, maintenance, capacity and permitting deficiencies associated with the Del Oro plant.[8]

In April 2006, after the Del Oro Consent Order, Far West states that it hired Coriolis, an engineering firm, to perform a "comprehensive review of the entire utility, water and sewer" including addressing the issues of the wastewater plants.[9] Far West claims, however, that before Coriolis could prepare a comprehensive engineering study, the Company had to address the issues surrounding the Del Oro treatment plant.[10] Far West claims it had to find a way to treat approximately 300,000 gpd at the Del Oro Plant, and with the assistance of Coriolis, was able to locate a temporary treatment facility. Far West was able to install the temporary plant at the Del Oro location and have it in operation prior to the deadline in the ADEQ Consent Order.[11] Far West states its next priority was solving a system wide odor problem, which resulted in the Company injecting bioxide chemicals throughout the system and installing carbon filters.[12]

According to the Company, Coriolis found that Far West had many more issues besides the Del Oro Treatment Plant, including issues facing the water division.[13] After addressing the deficiencies at the Del Oro Plant and the odor problems, the Company states it then proceeded to address longer-term goals of designing a water and water system, which would allow the Company to "get ahead of the curve and get this in a more management position."[14] Because the Company did not have proper plant inventories or maps of its systems, and had a hard time locating facilities for repair and maintenance and keeping track of customers, Coriolis recommended that Far West engage

[6] Ex A-17, Wastewater flows at 2.
[7] Ex RCUO -1, Finance Application Docket No. WS-03478A-07-0442, Ex 3, ADEQ Consent Order.
[8] Ex R-1, attachment 3.
[9] Far West Closing Brief at 5 and 6.
[10] Far West Closing Brief at 6; Tr. at 660-670.
[11] Tr. at 355-56; 670.
[12] Far West Closing Brief at 6; Tr. at 660-670.
[13] Far West Closing Brief at 6; Tr. at 660-61.
[14] Tr. at 688.

in a mapping project and purchase new billing software.[15]

According to Far West, Coriolis determined that all of Far West's wastewater plants, except the Marwood plant, required major modifications. The engineers opined that Far West had too many treatment plants for the size of its service area. Far West claims that the hodgepodge of treatment plants was the result of the rapid development, with individual developers building the plant capacity that they needed for their individual developments and then contributing the plant to Far West.[16] In addition, the treatment systems were not working properly and could not easily be made to work properly.[17] Problems with the wastewater treatment plants included inadequate aeration in the tanks, and inadequate mechanisms for handling sludge and removing effluent. As a result, Far West's treatment plants were not meeting the applicable nitrogen requirements and were sometimes exceeding turbidity and fecal coliform limits.[18]

Coriolis designed a sewer renovation project which involves expanding the Section 14 plant, from a capacity of 150,000 gpd to 1.3 million gpd,[19] closing the Palm Shadows plant and diverting the flows that had been going to Palm Shadows to Section 14 for treatment. [20] The Palm Shadows plant would be decommissioned and converted to a lift station.[21] The Del Oro plant would be expanded from a capacity of 300,000 gpd[22] to 495,000 gpd, and the Villa Del Rey and Villa Royale flows would be diverted to the new Del Oro plant, and the Villa Del Rey and Villa Royale plants would be closed.[23] The temporary plant currently installed at Del Oro would be moved to the Seasons plant, which would expand that capacity from 70,000 gpd to 150,000 gpd.[24] In addition, some of the flows currently treated at the Marwood plant would also be diverted to the Section 14 Plant.[25]

In July 2006, the Company obtained the first of two bridge anticipation notes ("BANs"). The

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[15] Tr. at 683-84.
[16] Tr. at 673.
[17] Tr. at 664.
[18] Tr. at 665.
[19] Phase I expands Section 14 to 681,000 gpd, and Phase II increases the capacity to 1.3 mgpd.
[20] Tr. at 729-730.
[21] Tr. at 776.
[22] Del Oro is currently operating as a temporary plant with a capacity of 300,000 gpd.
[23] Ex A-19 at 2.
[24] Ex A-20.
[25] Tr. at 730

first BAN, was in the amount of $11.1 million, and was secured by the pledge of the shareholders' stock in Far West. The purpose of the first BAN was to allow Far West to begin funding the costs of the system-wide improvements, including design and engineering costs.

On October 25, 2006, Far West entered into a second Consent Order with ADEQ, which order superseded the first. The new Consent Order required Far West to apply for new or amended aquifer protection permits ("APPs") for the Del Oro, Seasons and Section 14 plants, as well as closure permits for the Villa Royale, Villa Del Rey and Palm Shadows plants. The Company was required to submit APP applications relating to these projects within 30 to 90 days. The Company met the deadlines for these submissions.[26]

On December 31, 2006, Far West closed on a second BAN for $17.7 million, which was secured by a pledge of the shareholders' stock. The purpose of the second BAN was to pay off the first BAN and provide additional funds to cover the costs of the ongoing water and sewer system renovation. Far West states that Coriolis' goal was to complete its work for Far West by February 2007.[27] Far West's shareholders used the BANs to continue the procurement process and begin construction. Far West determined that it would order plant prior to receiving ADEQ approval of the APPs.[28] The Company believed that they could start ordering equipment as long as it did not hook it up until after it received the APP approvals from ADEQ.[29]

In the Second Consent Order, ADEQ directed Far West to cease all construction-related activities, including procuring equipment until the APPs were issued.[30] Far West states that it tried to convince ADEQ to allow it to proceed at its own risk with construction activities, but ADEQ would not agree.[31] All construction and most procurement activities stopped until ADEQ issued the APPs. Far West states that it took ADEQ 18 months to issue all of the permits.[32]

During the period ADEQ had the APPs under review, Far West states that it undertook activities that did not require ADEQ permits, such as preparing sites for the renovation projects and

[26] Tr. at 799-821.
[27] Tr. at 734-35.
[28] Tr. at 478.
[29] Tr. at 478.
[30] Tr. at 477-78, 735-738.
[31] Tr. 477-78, 735-738.
[32] Tr. at 736.

preparing the long-range engineering study. Far West states that it also sought permanent financing for the system improvements. The Company obtained a commitment for the issuance of Industrial Development Authority ("IDA") bonds through the Yuma County IDA in the amount of $32.5 million.[33] The projects included in the request included "the acquisition, construction and installation of improvements to Far West's wastewater treatment plants and drinking water treatment system."[34]

The IDA financing required Commission approval and on July 26, 2007, Far West filed a Financing Application with the Commission.[35] Far West concluded that under its existing rates it might not be able to support a Financing Application with the Commission for the entire $32.5 million,[36] and thus, reduced its IDA funding request to a little more than $25 million.[37] The $25 million was intended to allow Far West to pay off an existing WIFA loan in the amount of $4.45 million (as required by the IDA bondholders), pay off the second BAN and construct the sewer system upgrades once ADEQ approved the APPs. Far West's Financing Application sought authority to "(1) issue evidence of indebtedness in an amount not to exceed $25,215,000 . . . for the purpose of constructing sewer system infrastructure improvement needed to ensure safe and reliable utility service and comply with the two Consent Orders between the Company and the Arizona Department of Environmental Quality ("ADEQ") and for the repayment and consolidation of certain existing debt, which was incurred by the Company on a short-term basis for similar purposes."[38] On October 30, 2007, in Decision No. 69950, the Commission authorized Far West to obtain the IDA financing.

The Company notes that in making its Financing Application with the Commission it stated that a portion of the IDA funds would be used to repay and consolidate the outstanding debt, which debt had been used in part for water system improvements. The Company states that by the time the IDA funds were taken down, the Company had already spent nearly $1 million to improve its water system, and had committed to spend roughly $1.8 million on water system related improvements.

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[33] Ex A-24; Tr. at 1040.
[34] Ex A-24; Tr. at 1037 and 1040.
[35] Docket No. WS-03478A-07-0442.
[36] Tr. at 1040-1045.
[37] Ex A-8 and Ex A-12.
[38] Ex R-1 at 1.

Far West states that it inadvertently omitted requesting authority to finance improvements to the water system as well as the sewer projects falling outside those improvements strictly necessary to comply with the Consent Order, when it requested financing authority from the Commission. It claims that the omission was its oversight, and that it never intended to act in a manner that was contrary to Decision No. 69950.[39]

Far West closed on the IDA bonds on or about December 13, 2007.[40] The Company incurred approximately $1.3 million in costs and fees to obtain the IDA bonds, which were paid from the bond proceeds. After paying off the $4.45 million WIFA loan, and the second BAN in the amount of $17.7 million, $8.5 million remained from the IDA bond proceeds to fund the construction project.

By mid-2007, the effluent ponds at the Palm Shadows plant had ceased to percolate, and the Company began to incur the costs of hauling effluent from the Palm Shadows treatment plant to the City of Yuma facilities. Far West utilized its affiliate, H&S Developers, a real estate development company, owned by the principals of Far West, to deliver the effluent from the Palm Shadows plant to the City of Yuma for disposal at a monthly cost of approximately $45,000, including the costs paid to the City. Far West states that by using H&S Developers, it was able to reduce its costs of hauling this effluent.[41]

In August 2008, ADEQ issued the last of the APPs and other approvals necessary for Far West to proceed with its wastewater treatment plant renovation project.[42] At this time, Far West began seeking bids for the project. Far West states that from the time it obtained the bonds and the time when it was able to bid the project, prices had increased dramatically, including prices for plastic and plastic piping, metals, electronics, and mechanical equipment, and the dollar had also lost significant strength against the Canadian dollar, which increased the cost of the membranes.[43] Far West asserts that additional costs resulted from requirements imposed in the ADEQ permits, including the construction of vadose wells.[44] Far West has identified total "cost overruns" over its

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[39] Tr. at 1035-38, 1041; Far West Closing Brief at 12, fn 66.
[40] Ex. A-12.
[41] Tr. at 984-85.
[42] Far West Closing Brief at 13; Tr. at 92, 97, 736.
[43] Tr. at 738-39.
[44] Tr. at 526-27. Vadose wells are used to recharge effluent into the aquifer. See Tr. at 725-26.

original estimates of approximately $4.5 million.[45]

Far West states that when it became aware of the amount of increased costs associated with the sewer improvement project, it tried to find additional funds to complete the project.[46] Mr. Capestro testified that by September 2008, the Company had a loan commitment from Wells Fargo Bank for an additional $5 million.[47] In late September 2008, however, ADEQ announced that it was filing a lawsuit against Far West for past violations and in October 2008, it was generally apparent that the national banking system was in trouble. Mr. Capestro testified that as a result of these two events, Wells Fargo withdrew its loan commitment.[48] Mr. Capestro claims Far West continued to seek additional funding by means of loans to the Company or its shareholder, but these efforts were unsuccessful.[49] In the meantime, the Company states it was incurring costs for equipment and construction and was rapidly depleting the remaining funds available from the IDA financing.

Far West estimates that it requires additional funds for the materials and labor necessary to complete the various plant projects as set forth below:[50]

| | Open Invoices | Required to Complete | Total |
|---|---|---|---|
| Section 14 Phase 1 to 681,000 gpd | $2,416,002 | $224,416 | $2,540,418 |
| *Del Oro Phase 1 to 300,000 gpd* | 786,213 | | 786,213 |
| Seasons (not including electrical and mechanical – no contract at this time) | 16,724 | 79,735 | 96,459 |
| Palm Shadows | 131,994 | 145,348 | 277,342 |
| Del Rey and Royale | | 74,236 | 74,236 |
| Total | $3,350,933 | $523,735 | $3,874,668 |
| | | | |
| Section 14 Phase II to 1,300,000 gpd | | $330,000 | $330,000 |
| Del Oro Phase II to 495,000 gpd | | 418,928 | 418,928 |

[45] Tr. at 616, Ex R-28.
[46] Far West Closing Brief at 14.
[47] Tr. at 313, 489, 528.
[48] Tr. at 489.
[49] Tr. at 311-13, 567-69, 618.
[50] Ex A-11.

| | | | |
|---|---|---|---|
| Total | _____ | $748,928 | $748,928 |
| Grand Total | $3,350,933 | $1,272,663 | $4,623,596 |

Far West's Position

The Company requests a $2,161,788 revenue increase, which is a 101.95 percent increase over adjusted sewer division Test Year 2007 revenues. The Company states that its requested increase is premised on generating sufficient operating revenue to service the IDA debt and allow Far West to achieve zero Operating Income for its sewer division.[51]

Far West provided schedules which indicated that as of April 2009, it owed more than $3.3 million to vendors for equipment and construction of plant associated with the wastewater treatment renovations it states are necessary to comply with the Consent Order.[52] In addition, the Company claims it will need an additional $1.27 million to complete the renovation project.[53]

Far West provided evidence that by December 2008, when it filed its emergency request, it owed vendors nearly $2 million, and claimed that it was struggling to keep up with its operating expenses. At the hearing, Mr. Capestro testified it owes the Yuma Mesa Irrigation District ("YMID") $100,000 for purchased water, and $318,281 to Yuma County for property taxes.[54] The Company states that it has a projected cash flow shortage in excess of $6.4 million for 2009.[55] The Company argues that because it can no longer pay its debts as they come due in the ordinary course of business, Far West is insolvent.[56]

Far West asserts that it cannot complete the sewer renovations necessary to comply with the Consent Order. The Company claims that project vendors, who are owned significant sums for equipment already delivered, will not finish installation and start-up of the plant until they are paid.[57] Mr. Capestro testified that the shareholders infused $400,000 in capital to pay critical expenses, but claims to have depleted the shareholders' personal resources; and although they are willing to pledge

[51] Ex A-2, Bourassa Direct at 4.
[52] Ex. A-9.
[53] Ex A-11.
[54] Ex. A-1, Capestro Rebuttal at 3-7, Ex. A-5.
[55] Ex. S-3.
[56] Tr. at 122, 983, 898, 1132-33, 1231-33.
[57] Ex A-1 at 4; Tr. at 99.

stock or make personal guaranties, they have not been able to raise either equity or debt in sufficient sums to complete the project.[58]

Currently, Far West states that its wastewater system does not meet regulatory requirements and as a result its ability to maintain safe and reliable sewer service is in doubt.[59] Far West feels in limbo, unable to complete the project, while continuing to spend $45,000 to transport the effluent from the Palm Shadows plant to the City of Yuma for disposal. The Company also asserts that its inability to address needed water system improvements is problematic, and it is unknown how long water system improvements can be deferred without service problems.[60] The Company believes that if creditors force it into bankruptcy, the situation will worsen precipitously. The Company argues the constant threat of service interruptions is sufficient to warrant emergency relief.

Far West's proposal would have the interim rates effective until the Commission issues a decision in the Company's permanent rate case, and in the event the permanent rate case established rates that are less than the interim rates, the difference would be subject to refund with appropriate interest.[61] Far West claims its requested interim rate increase is intended to provide funds to pay the monthly debt service on the IDA bonds and achieve a 0.0 percent operating margin. The Company states that monthly debt service plus reserve payments on the IDA loans is $201,096.61, and at this time, the debt service amounts are not included in the Company's sewer rates. Far West argues that an interim rate increase equivalent to the debt service requirement would immediately free up that amount of funds which would be used to complete the treatment plant renovations.[62] In addition, the Company believes that the additional revenue stream would allow Far West to work out payment plans with vendors that want their bills paid before they will start-up the new plant.[63] The Company believes also that the additional revenue stream will give lenders comfort that Far West can make payments on a loan for the amount needed to finish the treatment plant renovations and comply with the Consent Order. Once the plant is in service, the Company states it will be able to obtain

[58] Tr. at 570; 641-42.
[59] Far West Closing Brief at 18.
[60] Far West Closing Brief at 18.
[61] Far West Closing Brief at 18.
[62] Tr. at 566, 635, 983.
[63] Tr. at 540-541, 569, 887, 934.

permanent rate relief and earn a return on its investment.

Far West argues that its requested relief is authorized under Arizona law and within the scope of the Commission's regulatory authority. The Company argues that pursuant to Attorney General Opinion 71-17, interim rates may be authorized "as an emergency measure when sudden change brings hardship to a company, when the company is insolvent, or when the condition of the company is such that its ability to maintain service pending a formal rate determination is in serious doubt."[64] Far West asserts that while Attorney General Opinions are not binding, the Arizona Court of Appeals has cited with approval and followed this opinion.[65] Far West also argues the Commission may grant interim rates, when the Commission is unable to grant permanent rate relief within a reasonable time.[66]

Far West argues that RUCO's argument that capital investments are a shareholder responsibility is an over-simplification. Far West asserts that Far West cannot pay its day-to-day operating expenses due in large part to the debt service on the IDA bonds, on which it has been making monthly payments in excess of $200,000 for more than 18 months. Far West argues there is nothing wrong with the Commission issuing interim rate relief to help a utility complete a major construction project, citing Decision No. 61833 in which the Commission granted interim relief to Far West to secure financing for a water treatment plant, and Decision No. 53909 (January 30, 1984) that granted APS emergency rates "because severe cash flow restraints associated with extensive construction projects."

Far West claims that it agrees that the Company-wide cash flow should be considered, and that on a company-wide basis, its cash flow analysis shows that the Company will have a $6 million shortfall in 2009.[67] The Company states it has presented evidence that due to the problems of its sewer division, it cannot make critical improvements to its water infrastructure nor pay the full amount due for purchased water, or pay its company-wide property taxes.[68] Far West thinks that

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[64] Op. Att'y Gen. 71-17, at 50.
[65] *RUCO v. Ariz Corp. Comm'n*, 199 Ariz. 588, 591, 20 P.3d 1169, 1172 (App. 2001); *Scates v. Ariz Corp. Comm'n*, 118 Ariz. 531, 535, 578 P.2d 612, 616 (App. 1978).
[66] Op. Att'y Gen. 71-17 at 50.
[67] Ex S-3, Tr. at 1115.
[68] Far West Reply Brief at 6.

Staff and RUCO are distorting the severity of the company-wide crisis by focusing on the success of the water division. The Company states that on a stand-alone basis, the water division lowered the 2009 operating losses from nearly $3 million in the sewer division to under $1 million on a company-wide basis. Without the water division, Far West states it could not operate, nor could it have borrowed the money to make the improvements to the sewer division.[69]

The Company does not disagree that using a TIER or DSC analysis was appropriate to evaluate the financing application.[70] Far West argues, however, that it is also appropriate to consider other ways to evaluate the financial condition of the business in the context of its application for emergency relief. The Company argues that it cannot pay its bills as they come due and for the purposes of determining its solvency, whether the expenses are "above the line" or "below the line" is irrelevant because either way, Far West must pay these expenses.[71] Far West believes that Staff and RUCO place too heavy a reliance on the 2006 financial data used in the financing application and are ignoring current financial data that show a severe financial crisis. The Company refutes RUCO's claim that the ratios indicate that the Company's financial position has improved according to the financial ratios. Far West asserts that RUCO ignores the rate increase granted in 2007, and that since 2006, the Company has cut back on top management and other expenses in its control in an attempt to conserve cash.[72] Far West asserts that these cut-backs are not sustainable over time as its ability to maintain safe and reliable service will suffer. Far West argues the mere improvement in the TIER and DSC does not mean the Company is in better financial condition as the Company has provided evidence that the financial metrics mask the real cash flow problems that currently exist. Far West notes that in 2007, when the financing was approved, the Company was not late in paying its property taxes, or its water provider for Colorado River water or in paying refunds under its main extension agreements, and was not paying over $40,000 a month to dispose of effluent from its Palm Shadows facility, nor did it owe vendors more than $3 million.

In response to RUCO's claims of mismanagement and miss-spent funds, the Company argues

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[69] Ex A-3, Bourassa Rebuttal at 11-12; Tr. at 894, 972.
[70] Far West Reply Brief at 7.
[71] Far West Reply Brief at 8.
[72] Tr. at 537; Far West Reply Brief at 8-9.

that RUCO can criticize the Company's decisions only with the benefit of hindsight, and that such claims do not provide a basis to deny the interim relief.[73] Far West argues that the time to determine fault for the current financial crisis is during the prudency review in the Company's general rate case, but that the focus in the current proceeding is to determine if there is an emergency and whether emergency rates are warranted.

Far West claims Staff's remedy of obtaining an equity infusion is unrealistic, as the current shareholders do not have any more capital to invest and securing a private equity placement is highly unlikely given the Company's financial condition, that it has never paid dividends to shareholders, and reaching a positive return on investment is likely several years away.[74]

Finally, Far West argues the interim relief is not inequitable to ratepayers. It claims that it is simply asking that ratepayers start providing revenue to pay debt service on plant that the Company had to build in order to provide service to its customers.[75] The Company claims it will not earn a return as a result of the relief sought.[76]Absent the emergency relief, the Company argues the ratepayers are in the same sinking boat as the shareholders. Moreover, the Company states the interim rates are subject to refund so that ratepayers are fully protected when permanent rates become effective, which it argues makes the emergency rate relief far more equitable than the alternatives, including bankruptcy relief.

The Company seeks interim revenue of $2,161,788, an increase of 101.95 percent over 2007 adjusted test year revenues. The Company's current and proposed interim rates are set forth below:

| | Current | Proposed | Increase | % Increase |
|---|---|---|---|---|
| Residential | $21.75 | $45.54 | $23.78 | 109.3 |
| RV Park, per space | 5.44 | 11.40 | 5.96 | 109.5 |
| Commercial | 43.50 | 91.18 | 47.68 | 109.6 |
| Effluent (per acre foot) | 325.85 | 325.85 | 0 | 0 |

[73] Far West Reply Brief at 12-14.
[74] Far West Reply Brief at 16.
[75] Tr. at 535.
[76] Tr. at 535-36, 612; Emergency App at 2; Bourassa Direct at 1-4.

Under these proposed rates, residential customers would see a monthly increase of $23.84, or 109.6 percent over current rates.[77]

RUCO's Position

First, RUCO argued that Far West's Application for Interim Rates is legally deficient on its face because the Company did not assert in its application that it was insolvent. RUCO noted that in the Emergency Application the Company asserted that an immediate increase in revenue was necessary to ensure that the Company did not become insolvent and unable to continue providing utility services to its customers. RUCO argued that the Company is entitled to receive interim rate relief when it can demonstrate that 1) an emergency exists; 2) a bond is posted guaranteeing refund if interim rates are higher than final rates determined by the Commission; and 3) the Commission undertakes to determine final rates after making a finding of fair value. However, RUCO argued that because the Company did not argue that it was currently insolvent, unable to provide service, or suffered from a sudden change resulting in hardship, its application was insufficient to grant relief and interim rates should be denied.[78]

Furthermore, RUCO argues the evidence presented in this proceeding shows that the Company is not insolvent. RUCO believes that the Company's ability to meet debt service and operating expenses should be evaluated on a company-wide basis, and not determined based on the operating results of the sewer division alone. RUCO argues that because the Company applied for the IDA bonds on a total company basis, the cash flows of both the water and sewer divisions should be available to satisfy the debt service. RUCO notes that the Company used $6.3 million of the IDA bonds to pay off a WIFA loan in the amount of $4.4 million and for water infrastructure projects unrelated to the ADEQ Consent Orders in the amount of $1.9 million.[79] RUCO asserts that because the water division received $6.3 million from the proceeds of the IDA bonds, its cash flows should be included in the determination of the Company's ability to meet debt service.

In addition, RUCO argues that the Company has sufficient cash flow to meet its operational expenses and its debt service and is not insolvent. RUCO calculated that Far West had free cash flow

[77] Ex A-2 at 7-8.
[78] RUCO Initial Closing Brief at 2.
[79] Ex R-31; Tr. at 1074-1076.

of $674,756 in 2007 and $939,066 in 2008, after annual interest and principal payments.[80] RUCO asserts that when its witness, Mr. Rigsby, calculated the Company's cash flow, he included the payment of $326,702 in property taxes and $1,925,000 for principal and interest payments.[81] The Company claims that it is unable to pay $100,000 to the YMID for 2,500 acre feet of water. [82] RUCO states the Company has acknowledged that the additional 2,500 acre feet are not used.[83] RUCO asserts that this additional water is not used and useful and thus, the unpaid bill should not be considered in determining the Company's cash flow needs. RUCO claims that if the Company had prioritized operational expenses and debt service, it would not be facing shortfalls. According to RUCO, "poor planning on the part of Far West's management team does not constitute an emergency necessitating approval of the Company's request for a 101 percent increase in rates from ratepayers."[84]

Furthermore, RUCO questions why if cash flow is so tight, the Company's affiliates are not paying for amounts owing to Far West. According to RUCO, Far West's affiliate, H&S Developers, owns three golf courses, which as of February 2009, owed $253,172 for water.[85] Although Mr. Capestro testified that the unpaid golf course bills are setoff by work H & S Developers does for Far West, RUCO believes the financial statements refute that claim. According to RUCO, if Far West had applied a set off as suggested, H&S Developer's unpaid golf course bills would not be recorded as a Far West account receivable.[86]

RUCO claims that the DSC and TIER are the appropriate means to evaluate the Company's ability to meet operating expenses and debt service. RUCO states that when it approved Far West's application to borrow $25 million in IDA bonds, the Commission relied on TIER and DSC ratios to determine if the Company could meet its debt service requirements. RUCO asserts the DSC and TIER ratios from 2007 and 2008 indicate that Far West has the ability to cover its IDA bonds debt obligations. RUCO's witness testified that when Far West submitted its financing application, its pro

[80] RUCO Initial Closing Brief at 6.
[81] Ex R-2; WAR-1.
[82] Tr. At 486.
[83] Id.
[84] RUCO Reply Brief at 7.
[85] Tr. At 164-171.
[86] RUCO Reply Brief at 8.

forma DSC was 1.15 and its TIER was 0.50. RUCO calculated that on a consolidated basis, the Company had a DSC of 1.35 and TIER of 0.77 in 2007 and DSC of 1.49 and TEIR of 0.89 in 2008.[87]

RUCO argues that using liquidity ratios, as contained in the Company's testimony, to analyze the Company's cash flows are not appropriate because they are based on the balance sheet which includes non-utility related liabilities and assets such as fines, restitutions and penalties. RUCO argues that regardless of which ratios are used, however, the ratios indicate that the Company has an improved financial condition since the finance application in 2007.[88]

RUCO argues that the Company's cash flow analysis is flawed. First, RUCO argues that the Commission should not consider extraordinary expenses resulting from the Company's mismanagement. RUCO notes that Mr. Bourassa, the Company's witness, testified that on a total Company basis in 2008, Far West lost $972,000 and had a positive cash flow of only $13,058.[89] RUCO's witness, Mr. Rigsby, testified that the Company had free cash flow of $674,756 in 2007 and $939,066 in 2008, after annual interest and principal payments.[90] RUCO states that the major difference between Mr. Bourassa and Mr. Rigsby is the treatment of extraordinary expenses. RUCO notes that typically, these expenses are "below the line" expenses and not collected from ratepayers. The bulk of the extraordinary expenses are attributable to hauling effluent from the Palm Shadows plant to the City of Yuma facilities. In 2007 and 2008, the Company spent $347,446 and $501,363, respectively, to collect and haul the effluent.[91] The Company spent $130,398 and $132,107 for legal fees in 2007 and 2008, respectively, associated with the defense of the Company's former president who was prosecuted in connection with the death of Company employees who were overcome by gasses in a confined space due to inadequate training and supervision.[92] RUCO asserts that the construction of percolation ponds on non-percolating soils which has led to the expense of hauling effluent from the Palm Shadows plant or the poor management that led to the death of an employee should not become the burden of ratepayers. RUCO believes these expenses result from the

[87] Ex R-3 at 15. Schedule WAR-1.
[88] Tr. at 1059. RUCO Initial Closing Brief at 6-7.
[89] Ex A-3.
[90] Ex R-3 at 15, WAR-1; RUCO notes that Staff witness, Gerald Becker, estimated the Company's free cash flow for 2009 as $781,792.
[91] Ex R-18 and Ex R-19.
[92] Ex A-3, Exhibit 1.

mismanagement and negligence of Far West management. RUCO presented evidence that Far West hired the engineer that designed the Palm Shadows plant and that Far West applied for the permits for that plant, and furthermore, that the developer of the area, Palm Shadows Partnership, was related to Far West, in that Mr. Brent Wiedman, who was president of Far West at the time, was a director of H & S Developers and also a partner in Palm Shadows Partnership.[93] RUCO argues that the shareholders' inability or unwillingness to cover extraordinary expenses does not render the Company insolvent.[94]

Even though RUCO believes the extraordinary expenses should not be considered to determine if Far Wet has sufficient cash flow, Mr. Rigsby calculated the 2008 cash flow including the effluent disposal expense of $501,363 and excluding the below the line interest income. RUCO determined that after factoring in these expenses, the 2008 financial statements produce a DSC of 1.23 and TIER of 0.58. RUCO states these ratios are higher than those the Commission relied on in Decision No. 69950 when it approved the IDA financing. Thus, RUCO asserts, regardless of whether the extraordinary expenses are considered or not, the Company has more cash flow available now than it did in 2007.

RUCO also argues that complying with the ADEQ Consent Order does not constitute an emergency. RUCO asserts that capital investment is the responsibility of shareholders and should not be used as a basis for determining interim rates.[95] RUCO notes the Company spent $3.7 million on non-ADEQ required sewer and water projects,[96] and that this amount is roughly equal to the amount the Company owes in accounts payable. RUCO believes that the Company misspent the funds, and had it not, it would have sufficient funds available to complete the remaining work. RUCO notes that when the Commission approved the IDA financing, it authorized the indebtedness for three specific purposes: 1) sewer system improvements necessary to comply with ADEQ Consent Orders; 2) to retire a 1999 WIFA loan; and 3) to retire other short term debt incurred in December 2006 to undertake emergency sewer plant upgrades and improvements necessary to comply with the

[93] RUCO Reply Brief at 5.
[94] RUCO Initial Closing Brief at 7.
[95] RUCO Initial Closing Brief at 10.
[96] RUCO Initial Closing Brief at 11.

requirements imposed by ADEQ.[97] RUCO believes the Commission should deny the request and is adamant that ratepayers should not be required to pay a 101 percent increase in interim rates to subsidize the shareholders' poor decision-making.

RUCO disputes an implication in the Company's testimony that the capital budget shortfalls were due to increased construction costs, when in RUCO's view, the Company's problems result primarily from its failure to abide by Decision No. 69950. RUCO notes that the Company used $1,883,593 of the IDA bond proceeds to fund water-related projects (including Design and Construction of the 4th Street Water Main Project) which were not priorities authorized by the Commission's order.[98] RUCO notes as well that the Company spent $357,059 on software programs for asset management and mapping, billing and fuel dispensing, and $379,487 on a Fortuna Road improvement project which was not an ADEQ mandated project.[99] By using these funds on "non-priority" projects, RUCO states the Company did not have these funds for the ADEQ sewer projects.

RUCO also believes that shareholder greed contributed to the Company's difficulties. RUCO argues that the Company designed the Section 14 plant to a capacity of 2.0 million gallons per day ("mgpd"), and built it to a capacity of 1.3 mgpd. RUCO asserts the Company spent $420,000 to engineer the expansion of the Section 14 plant from 1.3 mgpd to 2.0 mgpd.[100] RUCO notes that ADEQ did not mandate that the Section 14 plant be built at a 1.3 mgpd capacity, but accepted the Company's offer to build at that capacity.[101] RUCO believes that under ADEQ rules, the design flow of the plant only needs to cover current flows and any previously granted "capacity assurances."[102] According to RUCO, the evidence shows that the combined flows of the Palm Shadows and Section 14 plants are 274,000 gpd, which begs the question why the Company would design the new plant to 1.3 mgpd. RUCO asserts that the Company designed the new Section 14 plant to accommodate future development, and that Far West affiliates own many of the future real estate developments in the area.[103] RUCO also questions why Far West drew on IDA loan funds between August 19, 2008

[97] Decision No. 69950 at 2; Ex R-1 (Financing Application in Docket No. WS-03478A-07-0442).
[98] Ex A-8 at 7.
[99] Tr. at 773-74.
[100] Tr. at 513-14.
[101] Tr. at 446-447.
[102] RUCO Reply Brief at 13-14.
[103] RUCO Reply Brief at 14.

and September 8, 2008, after the Company learned that there would be a capital budget short-fall, to expand the Section 14 plant from 671,000 gpd to 2.0 million gpd, The Company spent $200,000 to purchase land from an affiliate to construct vadose recharge wells. RUCO notes they also drew on IDA loan funds for this purpose in October 2008, after the Company supposedly learned of the capital budget shortfalls.

RUCO alleges that although the ADEQ Consent Order mandated little change to the Marwood plant, the Company made significant expenditures to redirect Marwood flows to Section 14 in order to free capacity at Marwood to accommodate new development by the shareholders in the Marwood service area.[104] RUCO notes the Company used $607,381 of the IDA funds to develop the Paula Street Lift Station to redirect flows from Marwood to Section 14.[105]

RUCO notes further that prior to the ADEQ Consent Order, the Del Oro plant had a design flow of 300,000 gpd. Pursuant to the Consent Order, the Del Oro plant had to absorb 40,000 gpd redirected flows from the Del Rey and Villa Royale plants. According to the Company, the total average monthly flow at Del Oro under its new permit is 127,500 gpd, and yet, RUCO argues the Company redesigned Del Oro for a flow of 495,00 gpd.[106] The additional flow capacity will allow the addition of 1,780 new residences.[107] RUCO argues the costs for future expansion should fall on the subdivision developers, and not on current ratepayers.

RUCO asserts that the Far West shareholders have put their own interests above that of ratepayers. RUCO states that at the same time it encountered capital budget overruns and owes $3.4 million on accounts payable to project vendors, it made large payments to H & S Developers and its shareholders. According to RUCO, in 2007 Far West paid affiliates $1,462,684, and $920,651 in 2008 for accounts payable and a long-term loan owed to shareholders.[108]

Finally, RUCO argues there is no precedent established by Decision No. 61833, in which the Commission authorized interim rates to allow the Company to borrow funds to build a water treatment plant, or Decision No. 70667, in which the Commission granted APS interim rates to

[104] RUCO Reply Brief at 16.
[105] Ex A-8.
[106] Ex R-21 at 16.
[107] Ex R-12.
[108] RUCO Reply Brief at 18; Ex A-18; Tr. at 1189.

ensure its access to capital funds to develop renewable resources, that would compel approving interim rates in this case. RUCO argues the Commission decides each case on the record before it.

Staff's Position

Staff argues that although the Company provided financial statements that indicate the Company's sewer division had a loss of $2,161,788 in 2007, the Commission should look at the combined water and sewer results to determine whether there is an emergency. Staff asserts that a negative net income does not necessarily represent an emergency because non-cash expenses are considered in calculating net income.

Staff does not believe that the circumstances of this case "demonstrate the existence of an emergency, either current or pending, which would justify the requested relief."[109] Staff states that in 2007 when the Company sought authority to borrow the $25 million, Staff's analysis indicated that with the additional debt, the Company would have a TIER of 0.50 and a DSC of 1.15. Staff asserts that based on its analysis in the 2007 financing docket, Far West has the ability to remain financially viable until the Commission is able to conclude a permanent rate case. Staff believes it is inappropriate to view the financial health of only a single division of the company when determining the Company's overall financial health. Staff notes that whether Staff agrees or not that it was proper to use part of the $25 million in borrowed funds for water system improvements, there is little doubt that the funds were used for the benefit of both systems.

Staff argues that the only solution to the Company's current dilemma is for Far West to obtain a capital infusion to finance the remaining projects.[110] Staff notes that Far West currently only has approximately 7 percent equity in its capital structure. Staff believes that it is the Company's inadequate capitalization that has contributed to its current financial difficulties. Staff notes the Company has testified that it has been unable to find another lender because potential new lenders are unwilling to accept a second position in the Company's assets. In Staff's view, given the value of the Company's assets and the amount of debt they already secure, there is no equity remaining to provide security to a new lender,[111] and that even if the Commission were to authorize added revenue

[109] Staff Closing Brief at 5.
[110] Staff Closing Brief at 9.
[111] Staff Closing Brief at 8.

streams, it is highly unlikely that any bank will lend more money to the Company based on the financial statements presented at the hearing. Staff believes that if the Company's assertions are accurate, it cannot afford more debt. Staff argues that granting the requested relief would only increase the financial risk, and the Commission should act now to stop the Company from incurring additional debt. Staff believes it is patently unfair to ratepayers to treat them as guarantors of the Company, by bailing out the shareholders from the financial mess they have created.

Moreover, Staff argues that the Company should not come to the Commission seeking assistance to complete the wastewater improvement projects, at the expense of ratepayers, when it admitted that it used funds from the IDA funding on projects not related to the ADEQ Consent Order. Staff alleges that the Company has placed its own needs above those of the ratepayers. Staff notes that while it has funding needs of $4,623,566 (for past due invoices and necessary to complete the project), it paid H&S Developers $330,000, to pay back an advance so that Far West could hire Coriolis, and that in 2008, Far West paid off $920,000 in accounts payable and $571,244 for loan re-payment to affiliated companies.[112] In 2008, Staff notes that accounts receivable from H&S Developers increased by approximately $200,000, that is, it did not collected these funds from H&S. Thus, Staff calculates that of approximately $1.7 million of cash, that could have been used to comply with the Consent Order, paid to H & S Developers.[113]

Staff argues that Far West could accumulate the sums necessary to make the initial $400,000 down payment to the GE/Zenon that the Company believes would be sufficient to complete the project, from operational savings.[114] Staff believes that the Company would not have had its cash flow difficulties if it had not had to expend approximately $500,000 a year in sludge removal from the Palm Shadows plant. Staff believes it ironic that had GE/Zenon been paid and the Palm Shadow's plant been completed, Far West would have avoided the costs of hauling the effluent.

Staff states that the Company's current financial stress is the direct result of mismanagement of the IDA bond funds, and that had the Company limited its projects to those associated with the

[112] Tr. at 561.
[113] Staff Reply Brief at 3.
[114] Staff Reply Brief at 4.

ADEQ Consent Order, then the current situation would not have arisen.[115]

Although Staff does not believe the Far West situation is an emergency warranting interim rate relief, in the event the Commission found an emergency, Staff's analysis shows that instead of the Company's proposed increase of $2,161,788, an increase of $972,150, or 46.3 percent, would provide the Company with a projected net income of zero.[116] Staff states that with a net income of zero and non-cash expenses of $1,423,338, Far West would have adequate funds available for unexpected events/contingencies.[117]

Staff's alternative rates are set for below:

| | Current | Proposed | Increase | % Increase |
|---|---|---|---|---|
| Residential | $21.75 | $31.23 | $9.48 | 43.6 |
| RV Park, per space | 5.44 | 7.81 | 2.37 | 43.6 |
| Commercial | 43.50 | 62.47 | 18.97 | 43.6 |
| Effluent (per acre foot) | 325.85 | 467.92 | 142.07 | 43.6 |

If the Commission finds interim rates to be warranted, Staff further recommends that: the Company maintain records that show the revenue generated each month by the interim rates authorized herein be segregated from all other revenue; that the rates be subject to refund plus interest; that the interim rate be subject to refund pending the Decision resulting from the 2008 Rate Case that has been filed but is presently suspended; that the Company post a bond or letter of credit with the Commission in the amount of $300,000, prior to implementing the emergency rate increase authorized in this proceeding;[118] the Company be directed to file, within 30 days of the Decision, a revised rate schedule reflecting the interim rate increase with Docket Control, as a compliance item in this docket; and that the Company notify its customers of the revised rates, and their effective date, in a form acceptable to Staff, by means of an insertion in the Company's next regularly scheduled billing.[119]

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[115] Staff Reply Brief at 4.
[116] Ex S-1 at 4.
[117] *Id.*
[118] Staff states that this amount is approximately 30 percent of the annual rate increase being approved, and Staff estimates that if approved, the interim rates would be in effect for approximately 12 months.
[119] Ex S-1 at 5.

Analysis and Resolution

The Company operates seven wastewater plants, all of which had deficiencies.[120] ADEQ entered into two Consent Orders with the Company in 2006, and directed Far West to bring all seven of its wastewater treatment plants into full compliance with ADEQ regulations. To achieve compliance, Far West determined to undertake extensive improvements to its wastewater system. Because the Company did not have sufficient funds to make the improvements without additional capital, the Company applied for authority to borrow $25,215,000. The Commission authorized the Company to borrow the funds for the purpose of completing the sewer system improvements necessary to comply with the ADEQ Consent Orders; to retire an existing WIFA loan in the amount of $4,686,466; to retire short-term debt incurred in December 2006 which was used to undertake emergency sewer plant upgrades and improvements necessary to comply with the ADEQ Consent Orders; to establish a $0.9 million debt service reserve fund; and pay $1.3 million in issuance costs.[121]

In December 2008, when it filed this emergency application, the Company asserted that it had essentially depleted the proceeds of the IDA loans, but that none of the projects had been completed. The Company estimates that an additional $4.6 million is needed to complete the improvements.[122] Although aspects of the project are close to completion, to date, Far West has not been able to negotiate with vendors to complete the work necessary to bring the project on-line. Far West believes it can complete the project if it can make a down payment on the amounts owed and show vendors an improved cash flow.

As part of its ratemaking authority, the Commission has the power to authorize interim rates when (1) there is an emergency; (2) a bond is posted by the utility to guaranty a refund to customers if the interim rates paid are higher than the final rates determined by the Commission; and (3) the Commission sets final rates based on the fair value of the utility's property."[123] An emergency exists "when sudden charge brings hardship to a company, when the company is insolvent, or when the

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[120] See Engineering Report, Docket No. WS-03478A-05-0801 (Financing Application).
[121] Decision No. 69950 at 2-3 and 5.
[122] Ex A-11.
[123] *RUCO v. ACC*, 20 P.3d 1169, 1173 (App. 2001).

condition of the company is such that its ability to maintain service pending a formal rate determination is in serious doubt."[124]

The Company offers evidence that it is insolvent as it cannot pay its bills as they come due and cannot complete the wastewater improvement plant that is necessary to comply with the ADEQ Consent Order. The Company presented evidence that it owes $3,350,933 to vendors on the sewer project and $318,281 to Yuma County and $100,000 to the YMID. Based on paying past due payables of $3,400,000, it projects a deficit cash flow of $6.4 million in 2009.

Despite the sums owed by the Company, neither Staff nor RUCO believe that Far West's circumstances constitute an emergency warranting interim relief. They assert that the Company's financial statements and financial metrics indicate that the Company has sufficient cash flow to continue operating until a permanent rate case can be completed. Both Staff and RUCO argue that neither the extraordinary expenses associated with hauling the effluent from the Palm Shadows plant, nor the costs of completing the sewer renovation project should be factored into the cash flow analysis. Staff and RUCO believe that the Company mismanaged the IDA bond funds by using them on projects not required to comply with the Consent Order and has put the interests of shareholders and affiliates over those of ratepayers and contractors. In addition, RUCO's investigation has raised serious questions about how much of the sewer renovation project was engaged in to serve existing customer and commitments, and how much was to serve future growth.

In 2008, on a Company-wide basis, Far West experienced operating income of $1,441,403, and a net loss of $809,863 on total income of $7,857,117.[125] The water division had net income of $1,766,803 and the sewer division had a net loss of $2,576,667.[126] With non-cash expenses of $1,423,338, the Company had a positive cash flow of $613,475 in 2008. The Company's inability to pay its obligations is traceable to its large capital improvement project and past due payables are overwhelmingly related to construction invoices. If not for the demands of the construction project, the Company would have had sufficient funds to pay its Property Taxes and the YMID. Far West's cash flow from operations is adequate to meet its on-going operating expenses, including its debt

[124] Att'y Gen Op. 71-17 at 13.
[125] Ex-A-3, Exhibit 1.
[126] *Id.*

service.

Based on its current revenues and operating expenses, we agree with Staff and RUCO that there does not appear to be an emergency as the Company has the financial ability to continue providing service. However, the Company cannot complete the sewer renovation project and come into compliance with the ADEQ Consent Orders without an infusion of capital. Attempts to find new sources of debt or equity have been unsuccessful. Given the Company's high leverage and ongoing disputes with ADEQ, it would appear to be an unlikely candidate to receive additional debt or equity capital. Having depleted its options for additional debt and its ability to obtain additional capital from the shareholders, Far West turns to its ratepayers for a bailout.

The Company claims that if ratepayers can provide an additional revenue stream of $2.1 million, it will be able to complete the sewer projects necessary to comply with the ADEQ Consent Order. The additional requested revenue is not sufficient, however, to complete the projects in the near term, as the Company estimates the project will cost $4.6 million to complete. The Company suggests that the additional cash flow will allow it to obtain another loan, or at least convince its contractors to complete the project in return for partial payments on the amounts already owed. The Company has not submitted a loan commitment or agreement from its creditors, but merely the hope that if it approaches its vendors with a better cash flow that the vendors will agree to perform additional work for the Company. It is far from certain that the Company's plan would succeed. Based on the Company's performance to date in managing this project, we find little in the record that would allow a conclusion that it is even more likely than not to succeed. We are concerned that if the Commission approves the Company's request, ratepayers would end up paying more and still not receive the benefit of a complete and working wastewater treatment plant or a viable company.

Looking at the Company as a whole, and based on all of its activities, including its construction project, the Company has not paid its obligations as they come due. Thus, expanding the analysis beyond normal operations, the Company is insolvent, which is one of the conditions that can support an application for interim rate relief. For the reasons set forth below, however, we do not find it in the public interest to grant the requested interim relief at this time. Although the Company may be insolvent, the unpaid bills are overwhelmingly attributable to the construction project. The

Company has a positive cash flow from operations. This is not a case of operating expenses having increased so much that the Company cannot continue to provide service pending a traditional rate case. Neither is it a case of a sudden change that results in hardship. The Company's compliance deficiencies have been an issue for years, and the fact that the final construction budget increased in August 2008 after ADEQ approved the APPs was a foreseeable occurrence resulting from the delay.

We are concerned, however, about the public safety implication of this Company continuing to operate wastewater treatment plants with operational deficiencies. It is extraordinary to consider a request to have ratepayers to pay up front to construct utility plant. In was extraordinary in 1999 when we authorized interim rates in Decision No. 61833 for Far West to construct its water treatment plant. The circumstances of that 1999 case are distinguishable from those here, as at that time, we found a clear ratepayer benefit from allowing the Company to borrow the funds from WIFA to complete the plant. That ratepayer benefit is not obvious in the current case.

Current management has given us little comfort that with the funds they have requested, they would be able to complete the project or use ratepayer funds to the benefit of the ratepayers. Company projections assume continued pay down of affiliate payables. The shareholders claim to have exhausted their personal ability to contribute equity to Far West, but have not explained or demonstrated whether the Company's affiliates, including H & S Developers, could not and should not act as a source of capital. Before we can authorize the implementation of the interim rates, we would need the Company to provide proof, by means of audited financial statements, that neither the shareholders nor affiliate companies are able to provide the additional capital that they are requesting from ratepayers. In addition, we would need a plan that specifies the terms under which the Company's contractors would agree to complete the project. That being said, the additional $2.1 million requested by the Company, which results in a greater than 100 percent increase for ratepayers, is not reasonable. Although we reserve judgment on what, <u>if any</u> interim rate increase could ultimately be found in the public interest, we believe that Staff's recommended alternative position, which results in an increase of approximately $972,000, is more reasonable and in-line with prior Commission practice in analyzing interim requests.

Although the Company was reluctant to prioritize the projects, we believe that certain projects

are more critical than others and could be completed first. By prioritizing the project, the Company may be able to complete the plant improvements without needing the entire $4.5 million at once. For instance, the Phase I of Section 14 plant is critical because it will take the flows from the malfunctioning Palm Shadows plant. Phase II of the Section 14 and Del Oro upgrades account for $1.2 million of the remaining $4.6 million, but it is not clear that these upgrades must be made immediately. The Company must devise a more detailed plan for how it can bring these plants on-line with realistic and reasonable assumptions.

Without additional information, we cannot find that interim relief is in the public interest.

This proceeding has raised the issue of whether the current management is able to manage the completion of the project. Consequently, we direct Staff to conduct an investigation and formulate a recommendation to the Commission whether it is in the public interest to have an interim operator appointed for the Company. One of the witnesses for the Company testified that he believed ADEQ had lost trust in the Company and was consequently unwilling to allow the Company latitude in commencing construction prior to the final approval of the APPs. Based upon the testimony and evidence presented in this case, this Commission has lost confidence in the Company's current management's ability to complete the sewer construction project and operate the company to the benefit of the ratepayers. The Company has engaged in many transactions with affiliates and there has not been adequate investigation whether the sums paid were fair and arms length. An interim manager, if one can be found, may be able to do much to restore the confidence of vendors and the Company's regulators.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

## FINDINGS OF FACT

1. On December 19, 2008, Far West filed with the Commission an emergency application for the immediate implementation of interim rates for sewer service, which rates would be effective until a Decision has been issued on the Company's application for permanent rate increase.

2. The Company filed an application for permanent rates on August 29, 2008, in Docket

No. WS-03478A-08-0454. By Procedural Order dated December 10, 2008, the permanent rate case was set for hearing to commence on July 29, 2009.

3. On January 13, 2009, Staff filed a Response to the emergency rate application. Staff also filed a Motion to Suspend Time Clock in the permanent rate case.

4. On January 20, 2009, Far West filed a "Motion to Consolidate; Combined Response to Staff's Motion to Suspend Time and Request for Scheduling Order." Far West filed its Request in both the emergency and permanent rate case dockets.

5. On January 21, 2009, RUCO filed in both dockets its "Response to Staff's Request to Suspend the Time Clock and the Company's Response."

6. On January 22, 2009, a Procedural Conference convened for the purpose of scheduling the interim rate case. Far West, Staff and RUCO appeared through counsel. RUCO, already an intervener in the permanent rate case, moved to intervene in the interim matter. Neither Far West nor Staff objected, and RUCO was granted intervention in the interim case.

7. By Procedural Order dated January 26, 2009, issued in Docket No. WS-03478A-08-0454, the proceedings in the permanent rate case were suspended pending the conclusion of the emergency case.

8. By Procedural Orders dated January 26, 2009, and January 28, 2009, in the interim rate docket, the hearing for the interim request was set to commence on April 6, 2009, at the Commission's Tucson offices, a schedule for pre-filed testimony was established, the March 5, 2009 public comment meeting in the permanent rate case in Yuma was expanded to include the interim rate request, and Far West was directed to provide public notice of the interim proceeding.

9. On March 11, 2009, Far West filed a Notice of Filing Certification of Publication and Proof of Mailing, indicating that notice was mailed to customers on February 17, 2009, and published it the *The Sun*, a newspaper of general circulation in Yuma, Arizona, on February 19, 2009.

10. On March 19, 2009, intervention was granted to Seth and Barbara Davis, residential customers of the Company.

11. The Commission received a great number of customer responses in opposition to both the interim and permanent rate requests. In addition, on March 5, 2009, the Commission convened a

Public Comment meeting in Yuma, at which many hundreds of people attended. In general, customers were shocked and angered about the size of the requested increase, expressed service-related concerns and were very suspicious, and sought investigation of the Company's transactions with its shareholders and companies affiliated with its shareholders.

12. On March 19, 2009, RUCO filed the Direct Testimony of William Rigsby, and on March 24, 2009, Staff filed the Staff Report of Gerald Becker.

13. On March 31, 2009, Far West filed the Rebuttal Testimony of Andrew Capestro and Thomas Bourassa.

14. The hearing commenced on April 6, 2009, and continued on April 7, 2009, May 12 - 14, 2009, and May 21, 2009.

15. On June 22, 2009, Far West, Staff and RUCO filed their Initial Briefs. Staff filed its Reply Brief on July 2, 2009, and RUCO and Far West filed their Reply Briefs on July 9, 2009.

16. Far West is located in Yuma County and provides water utility service to approximately 15,000 customers and sewer utility service to approximately 7,300 of those customers.

17. The Company is seeking an emergency rate increase designed to produce additional revenue of $2,161,788 on an annual basis. The Company claims its request would result in a zero Operating Income. The requested increase would be a 101.95 percent increase over current sewer division revenues.

18. On March 10, 2006, ADEQ entered into a Consent Order with Far West with respect to the Del Oro treatment facility. In that Consent Order, Far West was required to make short, medium and long-term measures to address operational, maintenance, capacity and permitting deficiencies associated with the Del Oro plant.

19. In April 2006, after the Del Oro Consent Order, Far West hired Coriolis, an engineering firm, to perform a "comprehensive review of the entire utility, water and sewer" including addressing the issues of the wastewater plants. With the assistance of Coriolis, Far West found a temporary solution to the operational deficiencies of the Del Oro plant and addressed odor issues plaguing the Company, and later developed a comprehensive sewer renovation project as discussed herein.

20. In July 2006, the Company obtained the first of two BANs. The first BAN was in the amount of $11.1 million, and was secured by the pledge of the shareholders' stock in Far West. The purpose of the first BAN was to allow Far West to begin funding the costs of the system-wide improvements, including design and engineering costs.

21. On October 25, 2006, Far West entered into a second Consent Order with ADEQ, which order superseded the first. The new Consent Order required Far West to apply for new or amended APPs for the Del Oro, Seasons and Section 14 plants, as well as closure permits for the Villa Royale, Villa Del Rey and Palm Shadows plants.

22. In the Second Consent Order, ADEQ directed Far West to cease all construction-related activities, including procuring equipment, until the APPs were issued. Far West could not convince ADEQ to allow it to proceed at its own risk with construction activities. Far West states that all construction on the Consent Order projects and most procurement activities stopped until ADEQ issued the APPs.

23. On December 31, 2006, Far West closed on a second BAN for $17.7 million, which was secured by a pledge of the shareholders' stock. The purpose of the second BAN was to pay off the first BAN and provide additional funds to cover the costs of the ongoing water and sewer system renovation. Far West's shareholders used the BANs to continue the procurement process and begin construction. Far West determined that it would order plant prior to receiving ADEQ approval of the APPs. The Company believed that it could start ordering equipment as long as it did not hook it up until after it received the APP approvals from ADEQ.

24. During the period ADEQ had the APPs under review, Far West sought permanent financing for the system improvements. The Company obtained a commitment for the issuance of IDA bonds through the Yuma County IDA.

25. On July 26, 2007, Far West filed a Financing Application with the Commission for authority to issue evidence of indebtedness in an amount not to exceed $25,215,000 for the purpose of constructing sewer system infrastructure improvements needed to ensure safe and reliable utility service and comply with the two Consent Orders and for the repayment and consolidation of the BANs. On October 30, 2007, in Decision No. 69950, the Commission authorized Far West to obtain

the IDA financing.

26. The Company used the IDA bond funds to pay off the BANs and an existing WIFA loan and to construct portions of the sewer renovation project that did not require ADEQ approval.

27. ADEQ issued the final permits in August, 2008.

28. After ADEQ approved the final APPs, Far West began seeking bids for the project, and discovered that from the time it first obtained the bonds and the time when it was able to bid the project, prices had increased dramatically due to price increases for materials and the devaluation of the U.S. dollar against the Canadian dollar.

29. The Company discovered that the IDA loan proceeds would not be sufficient to complete the project and tried to secure additional financing. The Company claims that despite its efforts, neither the Company, nor its shareholders have been unable to secure additional equity or debt capital that would allow it to complete the projects required under the second ADEQ Consent Order.

30. Far West provided evidence that it owes contractors on the project $3,350,933 and that an additional $1,272,663 is required to complete the project.

31. Far West states that its contractors will not agree to complete their work on the project without a substantial down payment on past due invoices.

32. In addition, the Company owes Yuma County $318,281 and the YMID $100,000 for Colorado River water.

33. In 2008, on a Company-wide basis, Far West experienced operating income of $1,441,403, and a net loss of $809,863 on total income of $7,857,117. The water division had net income of $1,766,803 and the sewer division had a net loss of $2,576,667. With non-cash expenses of $1,423,338, the Company had a positive cash flow of $613,475 in 2008.

34. Based on the Company-wide financial statements for 2007 and 2008, which indicate a positive cash flow, neither Staff nor RUCO believe that Far West is facing an emergency that casts doubt on its ability to continue providing service pending a permanent rate case.

35. The Company's revenues from operations are sufficient to meet its operating expenses and its debt service.

36. The Company has depleted its IDA loan proceeds prior to completing the sewer renovation project and cash from operations is not sufficient to complete the project.

37. While cash flow from operations is sufficient for this Company to continue operations, the continued operation of wastewater treatment plants that do not comply with ADEQ regulations creates a serious issue of public health and safety.

38. As discussed herein, the Company has not demonstrated that it cannot raise additional capital from its shareholders or affiliated companies, and has not offered a reasonable plan for how the sewer renovation project will be completed even with the assistance of an interim rate increase.

39. Without additional information, we cannot find that interim relief is in the public interest.

40. This proceeding has raised issues concerning the ability of the current management to manage the completion of the project, and it is reasonable to direct Staff to conduct an investigation and formulate a recommendation to the Commission, in the permanent rate case or sooner, whether it is in the public interest to have an interim operator appointed for the Company.

## CONCLUSIONS OF LAW

1. Far West is a public service corporation pursuant to Article XV of the Arizona Constitution and A.R.S. §§ 40-250 and 40-251.

2. The Commission has jurisdiction over Far West and the subject matter of the application.

3. Notice of the proceeding was provided in conformance with law.

4. The interim rates proposed by the Company are not just and reasonable and are not in the public interest.

## ORDER

IT IS THEREFORE ORDERED that the application of Far West Water and Sewer Company for an interim rate increase of $2,161,788 is denied.

IT IS FURTHER ORDERED that within 30 days of the Effective Date of this Decision, Far West Water and Sewer Company shall supplement the record with additional evidence of the ability of its shareholders and/or affiliates to provide capital to Far West Water and Sewer Company and a

more detailed and comprehensive plan on how the sewer improvements will be completed.

IT IS FURTHER ORDERED that Staff shall investigate and formulate a recommendation to the Commission, in the permanent rate case or sooner, about whether it is in the public interest to appoint an interim manager for this Company, and any other appropriate recommendations.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 23rd day of December, 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: FAR WEST WATER AND SEWER COMPANY

DOCKET NO.: WS-03478A-08-0608

Norman D. James
Jay L. Shapiro
FENNEMORE CRAIG
3003 North Central Avenue, Suite 2600
Phoenix, AZ 85012-2913

Michelle Wood
RESIDENTIAL UTILITY CONSUMER OFFICE
1110 West Washington Street, Suite 220
Phoenix, AZ 85007-2958

Seth and Barbara Davis
2006 S. Arboleda Dr.
Merced, CA 95341

Janice Alward, Chief Counsel
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

Steve Olea, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

KPMG

March 25, 2008

Invoice No. : **43032725**
Reference : CA001-11592866
Client : 60110711

KPMG LLP
Suite 3300 Commerce Court West
199 Bay Street
Toronto ON M5L 1B2

Telephone : (416) 777-8500
Telefax : (416) 777-8818

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact : Gord Mount
Telephone : (416) 777-8125

Algonquin Power Income Fund
Attention: Mr. David Bronicheski
2845 Bristol Circle
Oakville ON L6H 7H7

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| | |
|---|---|
| Final billing with respect to 2007 annual audit. | $ 340,000.00 |
| Less: interim billings | (200,000.00) |
| | 140,000.00 |
| Disbursements | 7,000.00 |
| Out-of-pocket | 4,387.00 |
| CPAB participation fee surcharge at 1.6% of fees for audit and related services rendered on this invoice. | 2,240.00 |
| | 153,627.00 |
| GST | 7,681.35 |
| **INVOICE AMOUNT** | **$ 161,308.35** |

POSTED
APR 17 2008
OAKVILLE

| RECEIVED | VENDOR ID |
|---|---|
| | 1000 KPMG |
| COMPANY | G/L CODE |
| APIF | 1000-1-0000-20-2110-0000 |
| APPROVED | JOB # |
| | |
| PAID | COST CODE |
| | |

OK

RECEIVED
APR 04 2008

Payment is due upon receipt

EXHIBIT
A-18
ADMITTED

KPMG

February 8, 2008

Invoice No. : 42987658
Reference : CA001-11592866
Client : 60110711

KPMG LLP
Suite 3300 Commerce Court West
199 Bay Street
Toronto ON M5L 1B2

Telephone : (416) 777-8500
Telefax : (416) 777-8818

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact : Gordon R. Mount
Telephone : (416) 777-8125

Algonquin Power Income Fund
Attention: Mr. David Bronicheski
2845 Bristol Circle
Oakville, Ontario L6H 7H7

| | |
|---|---|
| Second interim bill with respect to 2007 annual audit. | $ 100,000.00 |
| Disbursements | 5,000.00 |
| CPAB participation fee surcharge at 1.6% of audit and related services rendered on this invoice. | 1,600.00 |
| | 106,600.00 |
| Goods and Services Tax | 5,330.00 |
| **INVOICE AMOUNT** | **$ 111,930.00** |

-02- 20 2008

Charyback

| RECEIVED | VENDOR ID |
|---|---|
| | 1000KPMG |
| COMPANY | G/L CODE |
| API F | 1000-1-0000-20-2110-0000 |
| APPROVED | JOB # |
| | |
| PAID | COST CODE |
| | |

OK

RECEIVED
FEB 19 2008

Payment is due upon receipt

KPMG

May 30, 2008

Mr. David Bronicheski
Algonquin Power Fund (America) Inc.
2845 Bristol Circle
Oakville, ON L6H 7H7

**Invoice No.** : **C 43112799**
Reference : CA001-11627640
Client : 60117994

KPMG LLP
Suite 200 Yonge Corporate Centre
4100 Yonge Street
North York ON M2P 2H3

Telephone : (416) 228-7000
Telefax : (416) 228-7123

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact : Steve Southard
Telephone : (416) 228-7105

---

Progress billing for U.S. tax compliance services rendered through May 15, 2008.

| | |
|---|---|
| OUR FEE | $ 78,330.00 |
| GST (zero rated: U.S. Corporation) | 0.00 |
| **INVOICE AMOUNT** | **$ 78,330.00** |

POSTED

| RECEIVED | VENDOR # |
|---|---|
| | 1000 KPMG |
| COMPANY | G/L CODE |
| APIF | 1000-1-0000-20-2110-0000 |
| APPROVED | JOB # |
| PAID | COST CODE |

OK

JUN 13 2008

Payment is due upon receipt

**Algonquin Power Fund (America) Inc. & Subsidiaries**
***Billing detail for U.S. tax services rendered***
***from September 16, 2007 through May 15, 2008***

| | Billing | |
|---|---|---|
| **Tax Compliance Services** | | |
| ▸ Progress billing for preparation of 2007 federal and state tax returns for APFA and its subsidiaries / affiliates. | $ 30,000 | ✓ |
| ▸ Final billing for preparation of 2006 federal and state tax returns for APFA and its subsidiaries / affiliates, including combined state returns. | 5,500 | ✓ |
| ▸ Preparation of amended 2006 federal and state tax returns for APFA & Subsidiaries to claim tax refund resulting from revised calculation of earnings stripping [163(j)] limitation on interest deductibility, including research, analysis, and consideration of application of proposed regulations to APFA's ownership structure. | 9,500 | ✓ |
| ▸ Calculation of 2007 4th quarter estimated tax payments and preparation of payment vouchers. | 1,200 | ✓ |
| ▸ Follow up on various state tax notices for New Hampshire, Vermont, New York, including preparation of response letters to state tax departments. | 1,200 | ✓ |
| **Tax Advisory Services** | | |
| ▸ Various discussions with IRS associate chief counsel office regarding KMS America Inc. private letter ruling request, including adverse conference with IRS, preparation/gathering of additional information requested (affidavits, etc), and various discussions/correspondence between KPMG personnel and Algonquin personnel and legal counsel. | 7,400 | ✓ |
| ▸ Meetings with 1) David Bronicheski and Luisa Paniconi to discuss overall U.S. tax matters, including U.S. group's tax structure, potential financing structures, planning opportunities, etc., and 2) Algonquin trustees to discuss overall tax issues (CDN and US), risk areas and opportunities, including preparation for meeting and summary slide package. | 8,200 | ✓ |
| ▸ Research and analysis with respect to California sales tax issue on Sanger repowering project, including various discussions with Dan Tobias regarding potential availability of California income tax credit, and research and technical assistance with respect to accounting treatment of sales tax credit. | 4,800 | ✓ |
| ▸ Tax assistance with respect to sale of landfill gas facilities, including review of purchase and sale agreements, consideration of federal and California state tax implications upon transfer, and various discussions and emails with Algonquin's legal counsel. | 4,000 | ✓ |
| ▸ Miscellaneous other items including: 1) discussions and summary emails regarding potential use of centralized payroll/purchasing company and utilization of SRLY losses, 2) discussions regarding US entity classification of APIF, and 3) discussions regarding cash repatriation alternatives, and including use of short term loan up to Canada. | 2,800 | ✓ |
| **Disbursements and Administrative Charges** | | |
| ▸ Out of pocket expenses including travel, meals, telephone, word-processing, graphics, courier, and administrative support (which should not exceed 10% of total estimated fees) | 3,730 | ✓ |
| Total (CDN$) | $ 78,330 | |

EXHIBIT
A-19
ADMITTED

# HOOK UP FEES

Applies to all **WATER** service areas

## WATER HUF

## I. Purpose and Applicability.

The purpose of the hook-up fees payable to **Rio Rico Utilities, Inc. – Water Division** ("the Company") pursuant to this tariff is to equitably apportion the costs of constructing additional shared Off-Site Facilities necessary to provide water production, delivery, storage and pressure among all new service connections. These charges are applicable to all new service connections undertaken via Main Extension Agreements or requests for service not requiring a Main Extension Agreement entered into after the effective date of this tariff. The charges are one-time charges and are payable as a condition to Company's establishment of service, as more particularly provided below.

## II. Definitions.

Unless the context otherwise requires, the definitions set forth in A.C.C. R14-2-401 of the Arizona Corporation Commission's ("Commission") rules and regulations governing water utilities shall apply in interpreting this tariff schedule.

"Applicant" means any party entering into an agreement with Company for the installation of water facilities to serve new service connections, and may include Developers and/or Builders of new residential subdivisions and/or commercial and industrial properties.

"Company" means Rio Rico Utilities, Inc. – Water Division.

"Main Extension Agreement" means an agreement whereby an Applicant, Developer and/or Builder agrees to advance the costs of the installation of water facilities necessary or desirable to serve new service connections within a development, or; installs such water facilities necessary or desirable to serve new service connections and transfers ownership of such water facilities to the Company, which agreement shall require the approval of the Commission pursuant to A.A.C. R14-2-406, and shall have the same meaning as "Water Facilities Agreement" or "Line Extension Agreement."

"Off-Site Facilities" means wells and other water supply facilities, storage tanks and related appurtenances necessary for proper operation, including engineering and design costs. Off-Site Facilities also may include booster pumps, pressure tanks, transmission mains and related appurtenances necessary for proper operation, if these facilities are not for the exclusive use of the applicant and will benefit the entire water system or provide regional or division wide benefits.

"Service Connection" means and includes all service connections for single-family residential, commercial, industrial or other uses, regardless of meter size.

## III. Off-Site Hook-Up Fee.

For each new service connection, the Company shall collect a Hook-Up Fee derived as follows:

| OFF-SITE HOOK-UP FEE TABLE | | |
|---|---|---|
| Meter Size | Size Factor | Total Fee |
| 5/8" x 3/4 " | 1 | $1,800 |
| 3/4" | 1.5 | $2,700 |
| 1" | 2.5 | $4,500 |
| 1-1/2 " | 5 | $9,000 |
| 2" | 8 | $14,400 |
| 3" | 16 | $28,800 |
| 4" | 25 | $45,000 |
| 6" or larger | 50 | $90,000 |

## IV. Terms and Conditions.

(A) Assessment of One Time Hook-Up Fee: The Hook-Up Fee may be assessed only once per parcel, service connection, or lot within a subdivision or commercial/industrial property although a supplemental assessment may apply to conform to the above table if the intended use of a parcel is subsequently altered from that originally intended when the first assessment was paid.

(B) Use of Hook-Up Fee: Hook-Up Fees only may be used to pay for capital items of Off-Site Facilities, or for repayment of loans obtained to fund the cost of installation of Off-Site Facilities. Hook-Up Fees shall not be used to cover repairs, maintenance, or other operating costs. All funds collected by the Company as Hook-Up Fees shall be deposited into a separate account and bear interest and shall be used solely for the purposes of paying for the costs of the installation of Off-Site Facilities, including repayment of loans previously obtained for the installation of Off-Site Facilities that will benefit the water system. The Company shall not record amounts collected under this tariff as CIAC until such amounts have been expended for plant.

(C) Time of Payment:

1. For those requiring a Main Extension Agreement: In the event that the person or entity that will be constructing improvements ("Applicant", "Developer" or "Builder") is otherwise required to enter into a Main Extension Agreement, whereby the Applicant, Developer or Builder agrees to advance the costs of installing mains, valves, fittings, hydrants and other on-site improvements in order to extend service in accordance with R-

14-2-406(B), payment of the Hook-Up Fee required hereunder shall be made by the Applicant, Developer or Builder concurrent with execution of the Main Extension Agreement.

2. For those connecting to an existing main that was installed pursuant to a Main Extension Agreement that was approved by the Arizona Corporation Commission: In the event that the Applicant, Developer or Builder for service is not required to enter into a Main Extension Agreement, the Hook-Up Fee charges hereunder shall be due and payable at the time the meter and service line installation fee is due and payable.

(D) Off-Site Facilities Construction By Developer: Company and Applicant, Developer or Builder may agree to construction of Off-Site Facilities necessary to serve a particular development by Applicant, Developer or Builder, which facilities are then conveyed to Company. In that event, Company shall credit the total cost of such Off-Site Facilities as an offset to Hook-Up Fees due under this Tariff or against additional facilities required by the Company for the provision of service. If the total cost of the Off-Site Facilities constructed by Applicant, Developer or Builder and conveyed to Company is less than the applicable Hook-Up Fees under this Tariff, plus any additional requirements imposed by the Company then Applicant, Developer or Builder shall pay the remaining amount owed hereunder. If the total cost of the Off-Site Facilities constructed by Applicant, Developer or Builder and conveyed to Company is more than the applicable Hook-Up Fees under this Tariff plus the additional requirements then Applicant, Developer or Builder shall not be entitled to any refunds.

(E) Failure to Pay Charges; Delinquent Payments: The Company will not be obligated to make an advance commitment to provide or actually provide water service to any Developer, Builder or other Applicant for service in the event that the Developer, Builder or other Applicant for service has not paid in full all charges hereunder. Under no circumstances will the Company set a meter or otherwise allow service to be established if the entire amount of any payment due hereunder has not been paid.

(F) Large Subdivision Projects: In the event that the Applicant, Developer or Builder is engaged in the development of a residential subdivision containing more than 150 lots, the Company may, in its discretion, agree to payment of Hook-Up Fees in installments. Such installments may be based on the residential subdivision development's phasing, and should attempt to equitably apportion the payment of charges hereunder based on the Applicant's, Developer's or Builder's construction schedule and water service requirements.

(G) Hook-Up Fees Non-refundable: The amounts collected by the Company as Hook-Up Fees pursuant to this Hook-Up Fee Tariff shall be non-refundable contributions in aid of construction.

(H) Hook-Up Fee in Addition to On-Site Facilities: The Hook-Up Fee shall be in addition to any costs associated with the construction of on-site facilities under a Main Extension Agreement. The applicable Hook-Up Fee under this Tariff may not cover the total costs to be

borne by Applicant for necessary Off-Site Facilities necessary to provide service to Applicant's property or development.

(I) Disposition of Excess Funds: After all necessary and desirable Off-Site Facilities are constructed utilizing funds collected pursuant to the Hook-Up Fees, or if the Hook-Up Fee has been terminated by order of the Arizona Corporation Commission, any funds remaining in the account shall be refunded. The manner of the refund shall be determined by the Commission at the time a refund becomes necessary.

(J) Fire Flow Requirements: In the event the Applicant for service has fire flow requirements that require additional facilities beyond those facilities whose costs were included in the Hook-Up Fee, and which are contemplated to be constructed using the proceeds of the Hook-Up Fees, the Company may require the Applicant to install such additional facilities as are required to meet those additional fire flow requirements, as a non-refundable contribution, in addition to the Hook-Up Fee.

(K) Status Reporting Requirements to the Commission: The Company shall submit a calendar year Hook-Up Fee status report each January 31st to Docket Control for the prior twelve (12) month period, beginning January 31, 2010, until the hook-up fee tariff is no longer in effect. This status report shall contain a list of all customers that have paid the hook-up fee tariff, the amount each has paid, the physical property in respect of which such fee was paid, the amount of money spent from the account, the amount of interest earned on the funds within the tariff account, and an itemization of all facilities that have been installed using the tariff funds during the 12 month period.

# RIO RICO WATER SYSTEM

## MASTER PLAN
## (REVISION NO. 1)

*Prepared for:*


**RIO RICO UTILITIES, INC.**
1060 Yavapai Drive, Suite No. 9
Rio Rico, Arizona 85648
(520) 281-7000


*Prepared by:*


**WESTLAND RESOURCES, INC.**
4001 E. Paradise Falls Drive
Tucson, Arizona 85712
(520) 206-9585


Registered Professional Engineer (Civil)
CERTIFICATE NO. 22989
MARK F. TAYLOR
Date signed 10/1/08
ARIZONA, U.S.A.
EXPIRES 9/30/2010

**OCTOBER 2008**
Project No. 231.29

EXHIBIT
A-26
ADMITTED

## TABLE OF CONTENTS

CHAPTER 1 – WATER SYSTEM OVERVIEW ..... 1
1.1. Introduction ..... 1
1.2. Define Key Issues ..... 2
1.3. Water System Planning Horizon ..... 2
1.4. Limits of Water Service Area ..... 2
1.5. Water Resources and Development ..... 2
1.6. Water Quality Regulations ..... 2
1.7. System Improvements for Existing Customers ..... 3
1.8. System Improvements for Growth ..... 3

CHAPTER 2 – REGULATORY REQUIREMENTS ..... 4
2.1. Federal Requirements ..... 4
2.1.1. Safe Drinking Water Act ..... 4
2.1.2. Public Health Security and Bioterrorism Preparedness and Response Act ..... 4
2.2. State Requirements ..... 4
2.2.1. Arizona Department of Environmental Quality ..... 5
2.2.1.1. Pressure Requirements ..... 5
2.2.1.2. Regulatory Storage Requirements ..... 5
2.2.1.3. Backflow Requirements ..... 6
2.2.1.4. Emergency Operations Plan ..... 6
2.2.1.5. Clean Water Act – National Pollutant Discharge Elimination System – Arizona Pollutant Discharge Elimination System ..... 7
2.2.2. Arizona Department of Water Resources ..... 7
2.2.2.1. Groundwater Management Code ..... 7
2.2.2.2. Active Management Areas ..... 8
2.2.2.3. Conservation Requirements ..... 8
2.2.2.4. Assured Water Supply ..... 9
2.2.2.5. Groundwater Rights in AMAs ..... 10
2.3. Arizona Corporation Commission ..... 10
2.4. Local Requirements ..... 11
2.4.1. Water Rates and Other Fees ..... 11

CHAPTER 3 – EXISTING SYSTEM ANALYSIS ..... 12
3.1. Existing Water System ..... 12
3.1.1. Existing Groundwater Well Capacity Summary ..... 17
3.1.2. Existing Reservoir and Booster Station Capacity Summary ..... 19
3.1.3. Existing Distribution System Summary ..... 21
3.2. Existing System Design Criteria ..... 21
3.2.1. Demand Criteria ..... 21
3.2.2. Supply Criteria ..... 22
3.2.3. Storage Criteria ..... 22
3.2.4. Distribution System Criteria ..... 22
3.3. System Demands ..... 22
3.4. Existing System Requirements ..... 24
3.4.1. Existing Well Capacity ..... 24
3.4.2. Existing Storage ..... 24
3.4.3. Existing Distribution System ..... 24

CHAPTER 4 – FUTURE SYSTEM ANALYSIS ..... 25

4.1. Future Analysis Introduction ..... 25
4.2. Future Demand Projections ..... 25
4.3. Future System Requirements ..... 27
4.3.1. Future Well Capacity ..... 28
4.3.2. Storage Capacity ..... 29
4.3.3. 3650-Zone Well and Reservoir Control ..... 32
4.3.4. Distribution System ..... 32

CHAPTER 5 – CAPITAL IMPROVEMENT PLAN ..... 34
5.1. Introduction ..... 34
5.2. Cost Projection Assumptions ..... 34
5.2.1. Installation of Water Mains ..... 34
5.2.2. Installation of Reservoirs ..... 35
5.2.3. Well Installations ..... 35
5.2.4. Booster Stations ..... 35
5.2.5. Engineering and Contingencies ..... 36

## LIST OF TABLES

Table 3.1. Service Connections (2003-2007) ..... 12
Table 3.2. Five-Year Usage Summary (2003-2007) ..... 12
Table 3.3. Equivalent Dwelling Unit Meter Factors ..... 13
Table 3.4. 2008 Meter Summary (May 2008) ..... 13
Table 3.5. Pressure Zone Boundaries ..... 14
Table 3.6. Number of Customers for Each Water Plant by Zone as of May 2008 ..... 15
Table 3.7. Equivalent Dwelling Units and Per Capita Use Summary (2003-2007) ..... 16
Table 3.8. South Industrial Park Water Use Data ..... 17
Table 3.9. Existing Well Summary ..... 17
Table 3.10. Well System Pumpage (2006) ..... 18
Table 3.11. Existing Reservoir Summary ..... 19
Table 3.12. Existing Booster Station Summary ..... 20
Table 3.13. Existing Water Usage Summary (May 2008) ..... 23
Table 4.1. Water Demands East of I-19 ..... 26
Table 4.2. Water Demands West of I-19 ..... 27
Table 4.3. Existing Well Capacity Summary East of I-19 ..... 28
Table 4.4. Existing Well Capacity Summary West of I-19 ..... 28
Table 4.5. Existing Reservoir Storage Summary East of I-19 ..... 29
Table 4.6. Existing Reservoir Storage Summary West of I-19 ..... 29
Table 4.7. Reservoir Service Area Summary East of I-19 ..... 30
Table 4.8. Reservoir Service Area Summary West of I-19 ..... 30
Table 4.9. Future Reservoir Storage Summary East of I-19 ..... 31
Table 4.10. Future Reservoir Storage Summary West of I-19 ..... 31
Table 4.11. Future Booster Station Summary East of I-19 ..... 32
Table 4.12. Future Booster Station Summary West of I-19 ..... 33
Table 5.1. Five-Year Capital Improvement Plan Cost Projections ..... 36

## LIST OF EXHIBITS

Exhibit 1. Rio Rico Utilities Water System Master Plan
Exhibit 2. Rio Rico Utilities Water Storage Figure
Exhibit 3. Rio Rico Utilities CTC/CC&N Boundaries

## LIST OF APPENDICES

Appendix A. Rio Rico Demands East and West of I-19 Calculation Spreadsheets
Appendix B. Rio Rico Storage Area East and West of I-19 Calculation Spreadsheets

# LIST OF ACRONYMS

| | |
|---|---|
| AAC | Arizona Administrative Code |
| ACC | Arizona Corporation Commission |
| ADD | Average Daily Demand |
| ADEQ | Arizona Department of Environmental Quality |
| ADWR | Arizona Department of Water Resources |
| AMA | Active Management Area |
| ARS | Arizona Revised Statutes |
| AWS | Assured Water Supply |
| AWWA | American Water Works Associated |
| AZPDES | Arizona Pollutant Discharge Elimination System |
| CIP | Capital Improvement Plan |
| CWA | Clean Water Act |
| DIP | ductile iron pipe |
| EDU | equivalent dwelling units |
| EPA | Environmental Protection Agency |
| gpad | Gallons Per Acre Per Day |
| GPCD | Gallons Per Capital Per Day |
| gpm | gallons per minute |
| I-19 | Interstate Highway 19 |
| lf | lineal feet |
| MCL | Maximum Contaminant Level |
| MG | million gallons |
| mgd | million gallons per day |
| NPDES | National Pollutant Discharge Elimination System |
| NPDWR | National Primary Drinking Water Regulations |
| NIWTP | Nogales International Wastewater Treatment Plant |
| PDD | Peak Day Demand |
| PHD | Peak Hour Demand |
| PHSBPRA | Public Health Security and Bioterrorism Preparedness and Response Act |
| PRV | Pressure Reducing Valve |
| psi | pounds per square inch |
| pphu | persons per housing unit |
| RAC | residents per acre |
| RRU | Rio Rico Utilities |
| SDWA | Safe Drinking Water Act |
| SMCL | Secondary Maximum Contaminant Level |
| UPC | Uniform Plumbing Code |
| VFD | variable frequency drive |
| WHP | Wellhead Protection Program |

# CHAPTER 1 – WATER SYSTEM OVERVIEW

## 1.1. INTRODUCTION

The Rio Rico Utilities (RRU) Water System is a private water utility, which serves residential, commercial, and industrial customers within the unincorporated community of Rio Rico in Santa Cruz County, Arizona. The community is located approximately 50 miles south of Tucson and approximately 15 miles north of Nogales in the Santa Cruz River Valley.

This Water Master Plan is the key guidance document for the Utility to identify the capital components required for both existing and future customers. It is essential to make a distinction between these two elements in order to properly allocate monies and resources for the continued reliable operation, maintenance, and expansion of the water system.

The goal of this Master Plan is to identify and define policy issues and present a plan to effectively manage these issues. This goal will be accomplished by defining the key water system planning elements that are most important to RRU, evaluating the existing system for service and upgrade requirements, and planning the infrastructure to provide appropriate service to the expanding community.

The approach to the Master Plan is first to examine the current regulatory environment and identify the regulatory constraints to which the utility must adhere. After the regulatory requirements are identified, the water system policies are presented. These policies include the definition of water service area, the planning horizon expected for this report, the criteria used for infrastructure development, and the growth projections used to develop this planning document. RRU has generally implemented policies which exceed the minimum standard of service for potable water as required by law. A coordination effort with the Rio Rico Properties allowed for the updating of existing land uses and population projections throughout the RRU service area. The information has been compiled to evaluate existing system infrastructure. Using the system infrastructure capacity requirements, a comprehensive water system plan has been provided which defines capital improvements required to improve the existing potable water system.

As with all planning documents, this document is intended to be a tool that is flexible and fluid and is subject to change as growth patterns and infrastructure requirements change. Updates to the Potable Water Master Plan should be every two to three years or as needed based upon the new planning constraints that RRU will face in the future. This Master Plan should be considered an update of the *Long Range Plan and Four Year Plan* prepared by Cella, Barr, Evans and Associates, dated April 1, 1972. This update excludes a significant portion of Rio Rico's original planning area, most of which are large Ranchettes that will be served by individual wells or are otherwise not planned to be served by RRU.

## 1.2. Define Key Issues

The development of a Master Plan requires defining key issues and policies early in the planning process. These key issues and policies, and their initial assumptions, ultimately define the water system facility projections. Said policies dictate the required water system layout, facility sizing, reliability, and costs of the required infrastructure.

## 1.3. Water System Planning Horizon

The planning horizon for this document is ultimate buildout. The Master Plan will identify current conditions and population projections for the projected buildout. Population projections and demands will be projected on a community-wide service area basis. These projections allow for the development of a capital improvement program and the sizing of required infrastructure.

## 1.4. Limits of Water Service Area

Rio Rico Utilities is the sole provider of potable water service to the Rio Rico Planned Community. The service area of RRU is shown on Exhibit 1 in the Appendix (Rio Rico Water System Master Plan). The southern border of Rio Rico's service area is Ruby Road which is the northern limit of the Valle Verde Water Company.

## 1.5. Water Resources and Development

The RRU Water System currently relies solely on groundwater supplies for its production water source. The existing well fields lie within the upper Santa Cruz Valley River Basin. The development of groundwater wells as a source of water has historically provided a high-quality and reliable source of water.

The RRU Water System is within the Santa Cruz Active Management Area (AMA). The primary goal of the Santa Cruz AMA Conservation Program is to gradually reduce water consumption by encouraging the use of the best available water conservation practices and maximizing the efficient use of all water supplies. A goal of the water system Master Plan is to provide a water system that has the flexibility to accommodate future rule changes as they are adopted and mandated by regulatory agencies.

## 1.6. Water Quality Regulations

Both Federal and State standards regulate water quality for the RRU Water System. The Safe Drinking Water Act (SDWA) establishes minimum water quality standards for health and aesthetic water quality considerations. The SDWA identifies enforceable maximum contaminant levels (MCLs) for health-

related constituents and non-enforceable secondary maximum contaminant levels (SMCLs) for aesthetic-related constituents. The SMCLs are not federally enforceable; they are intended as guidance to the states.

At the state level, the Arizona Environmental Quality Act establishes water quality criteria for water treatment, storage, and distribution. The Arizona Department of Environmental Quality (ADEQ) was set up to administer the act and has adopted the federal regulations for drinking water quality. It is the policy of RRU to meet or exceed the requirements of ADEQ for potable water. RRU regularly monitors MCLs and SMCLs based upon the ADEQ requirements. A summary of regulatory agencies and their respective requirements affecting the RRU Water System is identified in Chapter 2, Regulatory Requirements.

## 1.7. System Improvements for Existing Customers

This Master Plan will identify improvements necessary to bring the RRU Water System to the levels of service defined by the system-related policies. These improvements are related to providing for capacity-related needs as well as operational issues. Improvements to the existing system that are considered operational and replacement-based are generally funded by the existing rate base.

## 1.8. System Improvements for Growth

The goal of RRU is to plan for the future development and construction of adequately sized, integrated infrastructure for future customers. Currently, RRU receives frequent requests from land developers throughout its planning area for water service. It is the goal of the Master Plan to provide a roadmap for system integration and reliability and to capture the appropriate fees to accommodate the long-term infrastructure development requirements of RRU. Improvements supporting growth are generally funded by the development community.

# CHAPTER 2 – REGULATORY REQUIREMENTS

## 2.1. FEDERAL REQUIREMENTS

### 2.1.1. Safe Drinking Water Act

The Safe Drinking Water Act (SDWA) was presented to Congress by the Environmental Protection Agency (EPA) as an act to protect public health by regulating national public drinking water supplies. Congress originally passed the SDWA in December 1974 and the law was amended in 1986, 1996, and 2002. The original SDWA authorizes the EPA to set health-based standards for naturally occurring and man-made drinking water contaminants. The 1996 amendment to the SWDA created regulatory standards for source water protection, operator training, funding for system improvements, and public information. National Primary Drinking Water Regulations (NPDWRs or primary standards) are legally enforceable standards that apply to public water systems. The drinking water regulations set forth in the SDWA establish legally enforceable MCLs for a number of contaminants, and require the EPA to continuously identify and set MCLs for newly identified contaminants. The EPA also established non-enforceable SMCLs, relating to contaminants that may adversely affect the aesthetic quality of drinking water. The authority to enforce the MCL and SMCL standards has been delegated to the State of Arizona. Water quality programs are overseen by ADEQ.

### 2.1.2. Public Health Security and Bioterrorism Preparedness and Response Act

The Public Health Security and Bioterrorism Preparedness and Response Act (PHSBPRA) of 2002 amended the SDWA to add new requirements for public drinking water systems created to prevent, prepare for, and respond to bioterrorism acts or other public health emergencies. Title IV of the PHSBPRA requires community water systems that serve over 3,300 persons to conduct a vulnerability assessment to determine the susceptibility of the system to terrorist attack or other intentional acts intended to substantially disrupt the ability of the system to provide a safe and reliable supply of drinking water. The vulnerability assessment helps the water utility to evaluate susceptibility of the water supply, storage, distribution system, and electronic or computer systems to possible threats, and determine risks to the community based on potential threat scenarios. The vulnerability assessment was submitted by RRU.

## 2.2. STATE REQUIREMENTS

The Arizona Revised Statutes (ARS) Titles 45 and 49 are those statutes developed by the State of Arizona that deal with subjects most relevant to the operation of a municipal water system. ARS Title 45 describes the duties and programs of the Arizona Department of Water Resources (ADWR). ARS Title 49 describes water quality control and is the primary regulation for potable water supplies. Title 49 designates the ADEQ as the agency responsible for ensuring the health and safety of public water supplies. The Arizona Administrative Code (AAC) consists of those rules and regulations used to expand

and define the provisions of the ARS. AAC Title 18 relates to environmental quality, and covers the subjects of safe drinking water, water quality standards, and operator certification.

### 2.2.1. Arizona Department of Environmental Quality

The Environmental Quality Act was established in 1986 for the purpose of describing the responsibilities of ADEQ. Authorities were established for the management, control, and regulation of sources which may impact water quality. The ADEQ was required to adopt numerous standards for surface waters and aquifer water quality, define aquifer boundaries, and establish aquifer classification procedures. The ADEQ has provided a number of guidelines for water system design to assist water suppliers in constructing a water system to provide safe, reliable water service. ADEQ administers local authority over the RRU Water System for new construction and sanitary surveys and for testing and compliance with EPA water quality standards. The following information has been summarized from the AAC, Engineering Bulletin No. 10, Title 18 and various ADEQ guidance publications.

#### *2.2.1.1. Pressure Requirements*

Pressure extremes in water systems result in a potential for contamination to enter the system. Low pressures may allow polluted fluids to be forced into the system. High pressures may cause ruptures or breaks. Normal working pressure in the distribution system should not be less than 35 pounds per square inch (psi). The system shall be designed to maintain a minimum pressure of 20 psi at ground level at all points in the distribution system under all conditions of flow. This requirement is generally interpreted to mean that the minimum residual pressure must be 20 psi during a fire flow event or instantaneous demand.

Maximum pressures of as much as 120 psi can be allowed at the meter in small, low-lying areas not subject to high flow rates and surge pressure. Pipeline restraints, service saddles, corporation stops, air release valves, drain valve assemblies and other appurtenances shall be constructed according to their anticipated pressure ranges with tolerances for surge pressures. The Uniform Plumbing Code (UPC) limits the water pressure within the individual property owner's plumbing to 15 to 80 psi.

For cases where it is not practical to meet the maximum pressure limit, in the past ADEQ has allowed the use of individual pressure reducing valves (PRVs) at service connections as a means of lowering pressures to acceptable levels. Increasing or regulating the pressure from the meter to the customer shall be the responsibility of the customer.

#### *2.2.1.2. Regulatory Storage Requirements*

The minimum storage capacity for a community water system serving residential or school customers shall be equal to the average daily demand (ADD) during the peak month of the year plus fire flow storage. This requirement may be reduced by aquifer storage components. Storage capacity may be

based on existing consumption and phased as the water system expands. Storage should be provided in the zone where the usage is required or in a location where it may be readily transferred to the zone of use.

#### 2.2.1.3. Backflow Requirements

The AAC requires that water suppliers protect the public water system from contamination caused by backflow through unprotected cross-connections by requiring the installation and periodic testing of backflow prevention assemblies. The law requires that a backflow preventer be installed whenever there is a possibility that cross-connections may occur, or any foreign substance may enter the water system. Such substances include chemicals, chemical or biological process waters, and water from public water supplies, which has deteriorated in sanitary quality. Backflow prevention assemblies must be tested annually, and the test records must be kept for a period of at least three years.

#### 2.2.1.4. Emergency Operations Plan

It is the requirement of ADEQ that each community water system develop an Emergency Operations Plan. A water supply Emergency Operations Plan is also required as part of the EPA Wellhead Protection Program (WHP) established under the 1986 amendments to the SDWA. The recently enacted PHSBPRA also requires that each community water system incorporate the results of the required vulnerability assessments. The AAC requires that each community water system shall develop an Emergency Operations Plan and keep it in an easily accessible location. The ADEQ has prepared a Drinking Water Emergency Operations Plan Checklist to provide specific guidance regarding information to be included in the emergency plan. This checklist has a specific requirement for utilities to identify how they will maintain the system without their largest supply source.

The plan shall detail steps that a water system will take to assure continuation of service in the following emergency situations:

- Loss of a water supply source
- Loss of supply due to major component failure
- Damage to power supply equipment or loss of power
- Contamination of water in the distribution system as a result of backflow
- Collapse of reservoirs or reservoir roofs or pump-house structures
- Breaks in transmission or distribution lines
- Chemical or microbiological contamination of the water supply

The emergency plan should address procedures to be implemented in response to an emergency situation which could result in the loss or contamination of drinking water supplies and to continue providing drinking water that meets compliance requirements during potential emergency situations involving the water system. The document should provide an overview of the water system, including system mapping,

establish personnel duties, identify emergency contacts and notification procedures, and delineate emergency operating procedures. The emergency plan should also provide for alternate sources of water, and identify critical system components and spare parts.

#### *2.2.1.5. Clean Water Act – National Pollutant Discharge Elimination System – Arizona Pollutant Discharge Elimination System*

The Clean Water Act (CWA) regulates discharges of pollutants residing in "process" water to waters of the United States (waters) through the National Pollutant Discharge Elimination System (NPDES) permit program. The ADEQ gained primacy for the NDPES permit program. Although ADEQ has been involved in the NPDES program for a number of years, this delegation of authority means that the state government now administers the program and issues permits instead of the EPA.

Water systems may be granted a 90-day permit waiver for activities associated with line, well, and hydrant flushing and similar system operation activities.

ADEQ will provide a General Permit for De Minimis discharges, including those associated with potable water delivery systems. RRU may apply for area wide coverage under the general permit. Activities proposed to be included in the General Permit include: operations and maintenance flushing, well flushing, post-repair flushing, and discharges related to system pressure releases and overflows. Monitoring and reporting requirements for potable water systems is proposed to be limited to flow rate and duration of flow per discharge. It is strongly recommended that RRU obtain a General Permit for De Minimis discharges.

### 2.2.2. Arizona Department of Water Resources

The ADWR was created in 1980 to administer state water laws, except those relating to water quality. They also explore methods of augmenting water supplies to meet future demands, and work to develop public policies that promote conservation and the equitable distribution of water. The ADWR oversees the use of surface and groundwater resources under state jurisdiction and negotiates with external political entities to protect and augment Arizona's water supply.

#### *2.2.2.1. Groundwater Management Code*

To address groundwater depletion in the State's most populous areas, the State Legislature created the Groundwater Management Code in 1980 and directed the ADWR to implement it. The objectives of the Code are to control severe groundwater overdraft, provide the means for effectively allocating Arizona's groundwater resources, and augment Arizona's groundwater supply through water supply development.

The Code contains six main provisions:

1. The establishment of a program of groundwater rights and permits.
2. A provision prohibiting new agricultural irrigation within AMAs.
3. The preparation of five water management plans for each AMA.
4. The development of a program that requires demonstration of an Assured Water Supply (AWS) for new growth.
5. A requirement to meter/measure water pumped from all large wells that pump in excess of 35 gallons per minute (gpm).
6. A program for annual water withdrawal and use reporting.

#### *2.2.2.2. Active Management Areas*

Areas where groundwater depletion is most severe are designated as AMAs and are subject to regulation. There are five designated AMAs, including the Santa Cruz AMA which includes the RRU Water System. The future anticipated limits of the water service area are fully within the Santa Cruz AMA. The Santa Cruz AMA has the statutory goals of maintaining safe-yield conditions and preventing long-term declines in local water table levels. Safe-yield means that the amount of groundwater pumped from the aquifer on an average annual basis must not exceed the amount that is naturally or artificially recharged. The safe-yield goal is a basin-wide balance. This means that water level declines in one portion of the AMA can be offset by recharging water in another part of the AMA.

The Groundwater Code directs ADWR to develop and implement water conservation requirements for agricultural, municipal, and industrial water users. Management plans reflect evolution of the Groundwater Code, moving Arizona toward its long-term water management goals. The management plans establish conservation requirements for municipal, agricultural, and industrial water users. In each successive management plan, water conservation and management plan requirements will become increasingly stringent as new management plans are developed. The Santa Cruz AMA is operating under the Third Management Plan, but it is the First Management Plan that is specific to the Santa Cruz AMA since its separation from the southeastern portion of the Tucson AMA in 1994.

#### *2.2.2.3. Conservation Requirements*

The ADWR develops conservation requirements with assistance from water users in the AMAs. Municipal water conservation requirements apply to water providers, cities, towns, private water companies, and irrigation districts that provide water for non-irrigation uses. The goal of the municipal conservation program in all AMAs is to promote efficient water use.

The principal method of regulating water consumption is through the establishment of conservation requirements. The primary conservation program focuses on reducing per capita water use, which is measured in gallons per capita per day (GPCD). Rio Rico Utilities has elected to move forward using the Non-Per-Capita Conservation Program.

Along new publicly owned medians or roadside areas served by municipal providers, groundwater may only be used for watering specific low-water-use plants. The ADWR maintains a list of approved low-water-use plants.

The management plans restrict water use at turf facilities larger than 10 acres in size, such as golf courses, schools, parks, cemeteries, and common areas of homeowners' associations. The amount of water that turf facilities can use on an annual basis is specified by a formula in the plans. The municipal restrictions for turf facilities are the same as those that apply to industrial facilities.

The First Management Plan contains restrictions on the use of groundwater in artificial lakes. A 1987 State Law (The "Lakes" bill) restricts the use of groundwater in lakes, ponds, and swimming pools within AMAs. In general, new lakes in AMAs cannot be larger than 12,320 square feet unless certain exemptions apply. For example, the lakes may be filled with effluent. However, special permits are available from the ADWR that allow new lakes to be filled with poor quality groundwater or other water sources on an interim or emergency basis. Lakes built before January 1, 1987 and lakes located in certain public facilities, such as parks, can continue to use groundwater. Golf course lakes are also exempt from the law because they are regulated by the management plans.

Private residential swimming pools cannot be larger than Olympic size (12,320 square feet). Resorts, motels, and country clubs can have several pools, but only one pool can be larger than Olympic size, and not larger than one acre in size.

While local plumbing and landscape ordinances may apply within the RRU service area, RRU itself lacks the authority to enact or enforce ordinances regulating water use by its customers. During the development of the Third Management Plan, ADWR explored the possibility of establishing a municipal conservation program specifically designed for private water companies. In order to meet the goals of ADWR and obtain the support of the Arizona Corporation Commission (ACC), ADWR considered a program which would mandate specific conservation measures and reduce reliance on groundwater supplies. It was determined that additional statutory authority would be needed to implement such a program and ADWR decided not to pursue the action at this time. However, ADWR will continue to explore options aimed at achieving the most economically efficient reduction in groundwater reliance by private water companies.

Each large municipal water provider must maintain its distribution system, and properly meter and account for all deliveries. Water losses may not exceed 10 percent. Small providers must maintain their systems such that losses do not exceed 15 percent.

#### *2.2.2.4. Assured Water Supply*

The Groundwater Code established requirements to ensure that water supplies are adequate to meet the long-term needs of new development. The AWS Program requires the demonstration that sufficient water

supplies of adequate quality are physically, continuously, and legally available for 100 years. In an AMA, anyone who offers subdivided land for sale must demonstrate an assured supply of water to ADWR before the land may be marketed to the public. To receive an AWS certificate from ADWR, a developer must demonstrate that: 1) water of sufficient quantity and quality is available to sustain the proposed development for 100 years, 2) the proposed use is consistent with the management plan and achievement of the AMA management goal, and 3) the water provider has the financial capability to construct water delivery and treatment systems to serve the proposed development. Alternatively, the developer can locate the proposed development within the service area of a city, town, or private water company that has already received a Designation of Assured Water Supply from ADWR. If a "Designated" provider will serve the subdivision, the developer need only obtain a written commitment of service from the water provider.

There are significant committed water demands associated with previously platted lots that remain undeveloped within the Santa Cruz AMA. A large portion of these undeveloped lots are within the Rio Rico Planned Community. As previously stated, RRU will comply with the Non-Per-Capita Conservation Program.

#### *2.2.2.5. Groundwater Rights in AMAs*

A vital part of groundwater management involves identifying existing water rights and providing ways for water users to initiate new withdrawals. Within an AMA, an entity must have a groundwater right or permit to pump groundwater legally, unless the entity is withdrawing groundwater from an exempt well (maximum pump capacity of 35 gpm). Exempt wells may be used to withdraw groundwater only for non-irrigation purposes and are generally used for domestic purposes, including watering less than two acres of grass or garden. Exempt wells must be registered with ADWR, but they are subject to fewer requirements than non-exempt wells within AMAs. In order to withdraw water from non-exempt wells in AMAs, either grandfathered rights, service area rights, or a withdrawal permit must exist for the well.

Users who pump groundwater from non-exempt wells in AMAs must also report annual pumpage to ADWR. This provision helps ADWR determine how much water is being used and where it is being used. The Code also requires payment of an annual groundwater withdrawal fee. Revenues from the fee pay for half of the cost of administering the Code; the other half goes to Arizona's General Fund. Withdrawal fees may also be used for conservation assistance and augmentation projects, and retirement of irrigated land.

## 2.3. ARIZONA CORPORATION COMMISSION

The ACC is an elected body whose mission includes exercising exclusive state regulatory authority over public service corporations (public utilities) in the public interest. The ACC monitors the operation of private water utility companies throughout the State by reviewing financial records, evaluating revenue

requirements, and approving rate and fee increases. The regulatory powers and responsibilities of the ACC are delineated in Article XV of the Arizona Constitution and ARS Title 40.

## 2.4. Local Requirements

Under regulation of the ACC, RRU has responsibility for water system operation and for rate setting and other water management issues. RRU evaluates water system development, long-term water source requirements, capital needs, rate adjustments, capital budget and allocations, state and federal legislation regarding water-related issues, and expansion of utility service area. Based on the present and future water system requirements, RRU develops capital improvement programs and formulates rate structure modifications. RRU also provides the public information and education on water utility issues.

### 2.4.1. Water Rates and Other Fees

Customers served by RRU are charged a monthly service fee according to meter size, independent of the number of gallons used. The base rate is $6.45 for the typical 5/8 x 3/4-inch residential water meter. In addition to the base rate, there is a three-tier commodity charge structured as follows:

- $1.44/1,000 gallons for zero through 4,000 gallons
- $1.70/1,000 gallons for 5,000 through 10,000 gallons
- $1.90/1,000 gallons for consumption greater than 10,000 gallons

An installation charge is required for all new water service connections. This charge includes the cost of the water meter, valves, boxes, and installation. Charges for installation vary with the size of the meter. Other service fees apply, such as the new service establishment fee, service reconnection fee, after 5:00 p.m. service reconnection fee, meter re-read fee, insufficient funds/returned check fee, customer requested meter test, customer service deposit, vacation service fee, and delinquent payment fee.

# CHAPTER 3 – EXISTING SYSTEM ANALYSIS

## 3.1. EXISTING WATER SYSTEM

A summary of connections within the service areas of the RRU for years 2003 through 2007 is shown in Table 3.1. The increase in service connections has averaged approximately 10 percent/year.

**Table 3.1. Service Connections (2003-2007)**

| Year | Residential | Commercial | Total |
|---|---|---|---|
| 2007 | 6,024 | 215 | 6,239 |
| 2006 | 5,727 | 212 | 5,939 |
| 2005 | 5,313 | 206 | 5,519 |
| 2004 | 4,814 | 85 | 4,899 |
| 2003 | 4,486 | 82 | 4,568 |

Table 3.2 provides a detailed breakdown of annual water use for the same five-year period. During this time period, unaccounted for water has ranged from a low of about 3.6 percent to a high of 7.68 percent with an annual average of approximately six percent.

**Table 3.2. Five-Year Usage Summary (2003-2007)**

| Year | Total Pumped (MG) | Total Sold (MG) | Commercial Sold (MG) | Residential Sold (MG) | Company Use (MG) | Accounted For (MG) | Unaccounted For (MG) | Unaccounted For (Percent) |
|---|---|---|---|---|---|---|---|---|
| 2007 | 842.698 | 759.490 | 127.226 | 631.164 | 42.135 | 801.625 | 41.073 | 4.87 |
| 2006 | 801.252 | 733.107 | 151.801 | 577.123 | 13.593 | 746.700 | 54.552 | 6.81 |
| 2005 | 774.460 | 716.952 | 163.281 | 553.671 | 9.426 | 726.378 | 48.082 | 6.21 |
| 2004 | 776.595 | 706.276 | 176.304 | 529.972 | 10.700 | 716.976 | 59.619 | 7.68 |
| 2003 | 681.739 | 641.163 | 147.379 | 493.784 | 16.082 | 657.245 | 24.494 | 3.59 |

Equivalent dwelling units (EDUs) are an industry method used to estimate and convert water consumption rates to a standard 5/8-inch x 3/4-inch water meter. The ratios shown are taken from the American Water Works Association (AWWA) M-26 Manual for meter sizes up to 3-inch. The 4- and 6-inch ratios are representative of similar meter factors used by other local municipalities and have been accepted by the ACC for private water providers. Table 3.3 provides the EDU ratios and their associated meter factors.

**Table 3.3. Equivalent Dwelling Unit Meter Factors**

| Meter Size (inches) | EDU Ratio |
|---|---|
| 5/8 x 3/4 | 1.0 |
| 3/4 | 1.2 |
| 1 | 2.5 |
| 1-1/2 | 5.0 |
| 2 | 8.0 |
| 3 | 15.0 |
| 4 | 25.0 |
| 6 | 50.0 |

Table 3.4 provides the number and meter types within the existing system by rate, class, and size. As of May 2008, there were 6,494 active water meters within the RRU Water System. The meters range in size from 5/8-inch x 3/4-inch to 6-inch.

**Table 3.4. 2008 Meter Summary (May 2008)**

| Rate Class | Meter Size (inches) | Number | EDUs |
|---|---|---|---|
| Residential | 5/8 x 3/4 | 6,194 | 6,194 |
| | 3/4 | 8 | 9.6 |
| | 1 | 41 | 102.5 |
| | 1-1/2 | 6 | 30 |
| | 2 | 4 | 32 |
| **Subtotal** | - | **6,253** | **6,368** |
| Multi-Family | 5/8 x 3/4 | 7 | 9 |
| | 1-1/2 | 1 | 5 |
| **Subtotal** | - | **8** | **12** |
| Commercial | 5/8 x 3/4 | 108 | 108 |
| | 1 | 45 | 112.5 |
| | 1-1/2 | 11 | 55 |
| | 2 | 45 | 360 |
| | 3 | 18 | 270 |
| | 4 | 5 | 125 |
| | 6 | 1 | 50 |
| **Subtotal** | - | **233** | **1080.5** |
| **TOTAL** | - | **6,494** | **7,463** |

The existing meter connection to EDU ratio as of May 2008 is calculated to be approximately **1.15** (7,463 EDUs ÷ 6,494 total meters). This calculation is used to estimate the historical EDU's later in this report (See Table 3.8).

The RRU Water System is divided into seven pressure zones at 150-foot intervals. Table 3.5 identifies the high water elevations, elevation boundaries, and static pressure ranges for each pressure zone. The 150-foot intervals were established in the original approved water system master plan prepared by Cella, Barr, Evans and Associates in 1972.

**Table 3.5. Pressure Zone Boundaries**

| Zone | High Water Elevation | Elevation Boundaries | Static Pressure (psi) |
|---|---|---|---|
| 3500*[1] | 3500 | 3250-3400 | 43 – 108 |
| 3650 | 3650 | 3400 – 3550 | 43 – 108 |
| 3800 | 3800 | 3550 – 3700 | 43 – 108 |
| 3950 | 3950 | 3700 – 3850 | 43 – 108 |
| 4100 | 4100 | 3850 – 4000 | 43 – 108 |
| 4250 | 4250 | 4000 – 4150 | 43 – 108 |
| 4400 | 4400 | 4150 – 4300 | 43 – 108 |

*[1]The 3500-Zone is served by the upper 3650 Zone using pressure reducing valves (PRVs).

The pressure zones are divided into service areas that are identified by the water plant that serves the area and by the pressure zone in which the service area operates. In general, the service areas in a particular pressure zone operate independently of each other.

Table 3.6 is a listing of current meter connections by service area. The table identifies each service area by its pressure zone and the water plant that serves the area. The 3650 pressure zone is served directly from the existing wells.

**Table 3.6. Number of Customers for Each Water Plant by Zone as of May 2008**

| Water Plant | Pressure Zone Served | Meter Connections | Calculated Equivalent Dwelling Units |
|---|---|---|---|
| Wells | 3650[*1] | 3,218[*1*2] | 4,187[*1*2] |
| WP1 | 3800 | 173 | 173 |
| WP1 | 3950 | 166 | 166 |
| WP7 | 4100 | 19 | 19 |
| WP10 | 4100 | 10 | 10 |
| WP13 | 4250 | 7 | 7 |
| WP28 | 4100 | 31 | 31 |
| WP29 | 3950 | 148 | 148 |
| WP30 | 3800 | 971 | 971 |
| WP31 | 4100 | 19 | 19 |
| WP34 | 3950 | 23 | 23 |
| WP35 | 3800 | 99 | 99 |
| WP38 | 3800 | 123 | 123 |
| WP41 | 4100 | 57 | 57 |
| WP42 | 3950 | 37 | 37 |
| WP44 | 3800 | 60 | 60 |
| WP44 | 3950 | 23 | 23 |
| WP44 | 4100 | 44 | 44 |
| WP56 | 3800 | 153 | 153 |
| WP56 | 3950 | 117 | 117 |
| WP58 | 3950 | 159 | 159 |
| WP58 | 4100 | 91 | 91 |
| WP59 | 3800 | 237 | 237 |
| WP60 | 3800 | 305 | 305 |
| WP81 | 3800 | 83 | 83 |
| WP81 | 3950 | 32 | 32 |
| WP99 | 4100 | 7 | 7 |
| WP101 | 4400 | 24 | 24 |
| WP102 | 4100 | 11 | 11 |
| WP103 | 3800 | 19 | 19 |
| WP103A | 3950 | 14 | 14 |
| WP104 | 3800 | 12 | 12 |
| WP104 | 3950 | 2 | 2 |
| **TOTALS** | - | **6,494** | **7,463** |

[*1]The 3500-Zone is served by the upper 3650 Zone using pressure reducing valves (PRVs).
[*2]115 units could not be definitively linked by the utility to a specific water plant and those connections are added to the known 3650-Zone connections.

Approximately 50 percent of the meters and 56 percent of the EDUs in the RRU Water System are in the 3650-Zone. Virtually all of the 3/4-inch through 6-inch meters are also located within the 3650-Zone.

Table 3.7 provides estimates of the EDUs and per capita water use for the previous five years. As previously stated, existing meter connection to EDU ratio as of May 2008 is calculated to be 1.15. This assumption was used to estimate the historical EDUs for 2003-2007 where historical data could be recovered. The average usage is based on total water pumped for each year (See Table 3.2) and 2.8 persons per dwelling unit.

**Table 3.7. Equivalent Dwelling Units and Per Capita Use Summary (2003-2007)**

| Year | EDUs | Average GPCD*1 |
|---|---|---|
| 2007 | 7,170 | 115 |
| 2006 | 6,958 | 113 |
| 2005 | 6,343 | 119 |
| 2004 | 5,630 | 135 |
| 2003 | 5,250 | 127 |
| **AVERAGE** | | **122** |

*1 Based on total water pumped (see table 3.2) and 2.8 persons per dwelling unit.

The average gallons per capita day for the last five years is calculated to be **122 gpcd**. Water system usage demand calculation examples are based on the previous design criteria and are as follows:

*EDU Usage*

ADD = EDUs x 2.8 persons/unit x 122 GPCD/1,440 = 0.237 gpm/EDU
PDD = ADD x 2.0 = 0.474 gpm/EDU
PHD = ADD x 3.5 = 0.830 gpm/EDU

Water usage data from the South Industrial Park was used to obtain an equivalent use conversion for the non-residential portions of Rio Rico. Table 3.8 provides a summary of the water use data.

**Table 3.8. South Industrial Park Water Use Data**

| Month | Usage (gallons\ month) | Total Area | Avg. gal/acre/month | Avg. gal/acre/day |
|---|---|---|---|---|
| November (2006) | 2,373,000 | 256 | 9,270 | 309 |
| December (2006) | 2,401,000 | 256 | 9,379 | 313 |
| January (2007) | 2,353,000 | 256 | 9,191 | 306 |
| February(2007) | 2,363,000 | 256 | 9,230 | 308 |
| March (2007) | 3,453,000 | 256 | 13,488 | 450 |
| April (2007) | 2,524,000 | 256 | 9,859 | 329 |
| May (2007) | 2,685,000 | 256 | 10,488 | 350 |
| June (2007) | 2,785,000 | 256 | 10,879 | 363 |
| July (2007) | 1,754,000 | 256 | 6,852 | 228 |
| August (2007) | 1,757,000 | 256 | 6,863 | 229 |
| September (2007) | 1,542,000 | 256 | 6,023 | 201 |
| October (2007) | 1,801,000 | 256 | 7,035 | 235 |

The highest water use was calculated to be 450 gallons per acre per day (gpad). This converts to approximately 1.32 residents per acre (RAC) [450 gpad / (122 gpcd x 2.8 persons per unit)]. A more conservative estimate of **two RAC** is assumed to convert commercial and industrial areas to equivalent residential dwelling units.

### 3.1.1. Existing Groundwater Well Capacity Summary

The RRU Water System currently delivers groundwater from six production wells. There are a total of eight wells within the system; however, two of the wells have been taken out of service. Table 3.9 provides a summary of the well capacity, the pressure zone served by the well, and the approximate elevation of the well site. All of the wells pump directly into the 3650 pressure zones water mains and are level controlled by the existing reservoirs. Water is delivered to the rest of the water system through a system of booster stations and reservoirs that take water from the 3650 pressure zone.

**Table 3.9. Existing Well Summary**

| Well Number | Capacity (gpm) | Water Service Area Pressure Zone Served | Approximate Well Site Elevation (feet) |
|---|---|---|---|
| 5 | 500 | 3650 | 3,422 |
| 6 | 1,500 | 3650 | 3,410 |
| 8 | 550 | 3650 | 3,433 |
| 9 | capped | - | - |
| 15 | 900 | 3650 | 3,436 |
| 21 | capped | - | - |
| 52 | 550 | 3650 | 3,414 |
| 86 | 1,200 | 3650 | 3,312 |
| **TOTAL** | **5,200** | - | - |

Table 3.10 provides a summary of the average and peak monthly pumpage from each well for the year 2006. The peak monthly pumpage for the individual wells did not occur during the same month. However, peak pumpage for the entire system occurred during the month of May with an average rate of 2.876 million gallons per day (mgd), which is 57 percent of the total well system pumping capacity.

**Table 3.10. Well System Pumpage (2006)**

| Well Number | Capacity as of 12/06 (gpm) | Capacity as of 12/06 (mgd) | 2006 Daily Average Pumpage (mgd) | 2006 Daily Average for Peak Month Pumpage (mgd) | Percent Peak Month Capacity |
|---|---|---|---|---|---|
| 5 | 500 | 0.720 | 0.491 | 0.501 | 70 |
| 6[*1] | 1,500 | 2.16 | - | - | - |
| 8[*2] | 550 | 0.792 | 0.015 | 0.003 | 0.4[*2] |
| 9 | capped | - | - | - | - |
| 15 | 900 | 1.296 | 0.445 | 0.912 | 70 |
| 21 | capped | - | - | - | - |
| 52 | 550 | 0.792 | 0.298 | 0.550 | 69 |
| 86 | 1,200 | 1.440 | 0.946 | 0.910 | 63 |
| **TOTAL/AVERAGE** | **5,200** | **7.200** | **2.195** | **2.876** | **68[*2]** |

[*1]Well No. 6 was brought on-line after 12/06.
[*2]Well No. 8 pumps air which causes white water complaints and is maintained as an back-up well and is excluded from the total/average percent month peak capacity calculation.

### 3.1.2. Existing Reservoir and Booster Station Capacity Summary

The capacities and elevations of reservoirs within the RRU Water System are summarized in Table 3.11.

**Table 3.11. Existing Reservoir Summary**

| Plant Number | Storage (gallons) | Reservoir High Water Elevation (feet) | Site Elevation (feet) | Water Serve Area Pressure Zone Served |
|---|---|---|---|---|
| 1 | 640,000 | 3654 | 3622 | 3800 (f) |
| 1 | - | - | - | 3950 (f) |
| 1 | - | - | - | 3650 (g) |
| 29 | 150,000 | 3800 | 3776 | 3950 (f) |
| 29 | - | - | - | 3800 (g) |
| 38 | 200,000 | 3650 | 3626 | 3800 (f) |
| 38 | - | - | - | 3650 (g) |
| 56 | 100,000 | 3650 | 3626 | 3800 (f) |
| 56 | - | - | - | 3950 (f) |
| 56 | - | - | - | 3650 (g) |
| 7 | 10,000 | 3947 | 3935 | 4100 (f) |
| 10 | 10,000 | 3977 | 3965 | 4100 (f) |
| 44 | 10,000 | 3812 | 3800 | 3800 (f) |
| 60 | 10,000 | 3637 | 3625 | 3800 (f) |
| 81 | 1,000,000 | 3650 | 3620 | 3650 (g) |
| **TOTAL** | 2,130,000 | --- | --- | --- |

(g) gravity (f) forebay

The installed pump capacities given in Table 3.12 were calculated based on discharge pressures and motor horsepower provided by RRU. The wire to water horsepower is assumed to be 0.6. In general, for pumps that draw water from a reservoir, the suction pressure was assumed to be 5 psi. Similarly, it was generally assumed that the suction pressure was 40 psi for pumps that draw water directly from the distribution system.

**Table 3.12. Existing Booster Station Summary**

| Water Plant | Approximate Site Elevation | Calculated Capacity (gpm) | Average Suction Pressure (psi) | Average Discharge Pressure (psi) | Boost to Water Service Area Pressure Zone | Pump Motors (number @ horsepower) |
|---|---|---|---|---|---|---|
| 1 | 3622 | 900 | 5 | 91 | 3800 | 3 @ 25 |
| 1 | 3622 | 660 | 5 | 145 | 3950 | 3 @ 30 |
| 7 | 3935 | 125 | 5 | 130 | 4100 | 1 @ 15 |
| 10 | 3965 | 145 | 5 | 110 | 4100 | 1 @ 15 |
| 13 | 4150 | 250 | 40 | 101 | 4250 | 2 @ 7 ½ |
| 28 | 4000 | 315 | 40 | 89 | 4100 | 2 @ 7 ½ |
| 29 | 3776 | 685 | 5 | 95 | 3950 | 3 @ 20 |
| 30 | 3540 | 1,100 | 40 | 110 | 3800 | 3 @ 25 |
| 31 | 3850 | 375 | 40 | 108 | 4100 | 1 @ 25 |
| 34 | 3700 | 300 | 40 | 90 | 3950 | 1 @ 15 |
| 35 | 3550 | 1,500 | 40 | 115 | 3800 | 2 @ 15 and 2 @ 40 |
| 38 | 3626 | 340 | 5 | 126 | 3800 | 1 @ 15 and 1 @ 25 |
| 41 | 3850 | 595 | 40 | 109 | 4100 | 2 @ 20 |
| 42 | 3600 | 170 | 40 | 130 | 3950 | 2 @ 7 ½ |
| 44 | 3690 | 295 | 5 | 109 | 3800 | 2 @ 15 |
| 44B | 3400 | 100 | 100 | 125 | WP 44 | 1 @ 3 |
| 56 | 3626 | 180 | 5 | 90 | 3800 | 2 @ 7 ½ |
| 56 | 3626 | 375 | 5 | 141 | 3950 | 2 @ 25 |
| 58 | 3850 | 330 | 40 | 86 | 4100 | 2 @ 7 ½ |
| 58 | 3850 | 490 | 40 | 144 | 3950 | 2 @ 25 |
| 59 | 3650 | 600 | 40 | 126 | 3800 | 2 @ 25 |
| 60 | 3625 | 900 | 5 | 73 | 3800 | 2 @ 30 |
| 81 | 3620 | 350 | 13 | 78 | 3800 | 2 @ 25 (VFD) |
| 81 | 3620 | 350 | 13 | 143 | 3950 | 2 @ 50 (VFD) |
| 99 | 4025 | 250 | 40 | 143 | 4100 | 1 @ 25 |
| 101 | 4150 | 250 | 40 | 140 | 4100 | 1 @ 25 |
| 102 | 4000 | 195 | 40 | 145 | 4100 | 1 @ 20 |
| 103 | 3600 | 195 | 20 | 150 | 3950 | 1 @ 25 |
| 103A | 3470 | 235 | 80 | 145 | 3800 | 1 @ 15 |
| 104 | 3575 | 150 | 32 | 97 | 3800 | 2 @ 5 (VFD) |
| 104 | 3575 | 150 | 32 | 162 | 3950 | 2 @ 10 (VFD) |

The service area with the greatest water demand is within the 3650 pressure zone which is served directly from the existing wells. It is estimated that approximately **55 percent** of the total system water use occurs within the 3650 pressure zone. The 3650 pressure zone is the lowest zone within the system and tends to follow the Santa Cruz River alignment. Water storage for the 3650 pressure zone is provided by existing reservoirs at Water Plant Nos. 1, 29, 38, 56, and 81 which float directly on the 3650 pressure zone. In addition, these reservoirs, along with the existing 10,000 tanks at Water Plant Nos. 7, 10, 44, and 60 serve as forebays for booster pumps that lift water to other service areas throughout the water distribution system.

### 3.1.3. Existing Distribution System Summary

It is estimated that the existing RRU water system includes over 320 miles of water mains. These pipes range in size from 4-inches through 16-inches in diameter. The distribution system has been continuously expanded with growth over the past 35-plus years of the systems existence.

## 3.2. Existing System Design Criteria

Current system design criteria for the RRU Water System are described below, in terms of demand, supply, storage, and distribution system assumptions.

RRU has not historically been required to provide fire flow for the water system. New developments will most likely be regulated by the fire jurisdiction under more current requirements which may require upsizing of some facilities.

### 3.2.1. Demand Criteria

Demand flow and population estimates are based on RRU Water System estimated water use data and existing parcel connection information.

- Average daily per capita water usage for equivalent dwelling units ..... **122 gpcd**
- Average number of persons per equivalent housing unit..... **2.8 pphu**
- Ratio of peak day to average day ..... **2.0**
- Ratio of peak hour to average day ..... **3.5**
- Equivalent RAC for Industrial and Commercial Areas ..... **2 RAC**

### 3.2.2. Supply Criteria

The criteria for the evaluation of supply projections to each individual service area are listed as follows:

- Well capacity to meet Peak Day Demand (PDD) with the largest well out of service
- Minimum supply from well and boosters pumping to elevated storage shall meet PDD
- Minimum booster capacity to service areas without elevated storage shall meet peak hour demand (PHD) or instantaneous demand (ADEQ Bulletin No. 10, Chapter 5, Table 3), whichever is greater

### 3.2.3. Storage Criteria

The criteria for storage capacity requirements for the water system are based upon the following:

- Provide storage volume equal to a minimum of the ADD

As previously stated, ADEQ may allow for a reduction in aboveground storage by accounting for aquifer storage.

### 3.2.4. Distribution System Criteria

The design criteria for the distribution system are generally used to size and arrange the distribution lines to provide the required flows while meeting the ADEQ requirement to maintain 20 psi under all conditions of flow. The standard water main-sizing criteria limit velocities to a maximum of 5 feet per second under peak-day conditions. Velocities should not exceed 10 feet per second under any condition. The maximum friction head loss for lines up to and including 8 inches in size should be 8 feet or less per 1,000 feet. Head loss for lines over 8 inches in size is 5 feet or less per 1,000 feet, according to pipe size. For main transmission lines, a friction loss of 2 feet per 1,000 feet is recommended.

## 3.3. System Demands

The existing water system, as shown in Exhibit 1 is divided into seven pressure zones. Table 3.13 estimates the ADD, PDD, and PHD for each service sub-area within the RRU Water System.

**Table 3.13. Existing Water Usage Summary (May 2008)**

| Water Plant | Pressure Zone Served | Existing Equivalent Dwelling Units | Average Daily Demand (gpm) | Peak Day Demand (gpm) | Peak Hour Demand (gpm) |
|---|---|---|---|---|---|
| Wells | 3650 | 4,187 | 993 | 1,986 | 3,476 |
| WP1 | 3800 | 173 | 41 | 82 | 144 |
| WP1 | 3950 | 166 | 39 | 79 | 138 |
| WP7 | 4100 | 19 | 5 | 9 | 16 |
| WP10 | 4100 | 10 | 2 | 5 | 8 |
| WP13 | 4250 | 7 | 2 | 3 | 6 |
| WP28 | 4100 | 31 | 7 | 15 | 26 |
| WP29 | 3950 | 148 | 35 | 70 | 123 |
| WP30 | 3800 | 971 | 230 | 461 | 806 |
| WP31 | 4100 | 19 | 5 | 9 | 16 |
| WP34 | 3950 | 23 | 5 | 11 | 19 |
| WP35 | 3800 | 99 | 23 | 47 | 82 |
| WP38 | 3800 | 123 | 29 | 58 | 102 |
| WP41 | 4100 | 57 | 14 | 27 | 47 |
| WP42 | 3950 | 37 | 9 | 18 | 31 |
| WP44 | 3800 | 60 | 14 | 28 | 50 |
| WP44 | 3950 | 23 | 5 | 11 | 19 |
| WP44 | 4100 | 44 | 10 | 21 | 37 |
| WP56 | 3800 | 153 | 36 | 73 | 127 |
| WP56 | 3950 | 117 | 28 | 56 | 97 |
| WP58 | 3950 | 159 | 38 | 75 | 132 |
| WP58 | 4100 | 91 | 22 | 43 | 76 |
| WP59 | 3800 | 237 | 56 | 112 | 197 |
| WP60 | 3800 | 305 | 72 | 145 | 253 |
| WP81 | 3800 | 83 | 20 | 39 | 69 |
| WP81 | 3950 | 32 | 8 | 15 | 27 |
| WP99 | 4100 | 7 | 2 | 3 | 6 |
| WP101 | 4400 | 24 | 6 | 11 | 20 |
| WP102 | 4100 | 11 | 3 | 5 | 9 |
| WP103 | 3800 | 19 | 5 | 9 | 16 |
| WP103A | 3950 | 14 | 3 | 7 | 12 |
| WP104 | 3800 | 12 | 3 | 6 | 10 |
| WP104 | 3950 | 2 | 0 | 1 | 2 |
| **TOTAL** | - | **7,463** | **1,770** | **3,541** | **6,196** |

## 3.4. Existing System Requirements

The water system design criteria, as previously provided was used to develop the existing capacity upgrade requirements for the RRU Water System. Existing system requirements include the capacity upgrades needed for wells and storage to serve all existing connected parcels.

### 3.4.1. Existing Well Capacity

Well production requirements are based on meeting PDD with the largest well out of service. The entire RRU Water System is supplied by six active wells that feed directly into the 3650 pressure zone. The wells are interconnected by a network of 12 and 16 inch diameter pipes that run parallel to and across the Santa Cruz River. Water for the remaining pressure zones is boosted from the 3650 pressure zone to the various service areas throughout the water system by a series of booster pumps at existing water plants.

Since all of the wells pump directly into the 3650 pressure zone which supplies the rest of the system, it is necessary to evaluate current well capacity on a global basis rather than on the basis of individual pressure zones.

The total well capacity for the water system is, from Table 3.9, 5,200 gpm. Well No. 6 has the greatest pumping capacity at 1,500 gpm. With Well No. 6 out of the service, the remaining well capacity would be 3,700 gpm. The PDD from Table 3.13 is 3,541 gpm, which indicates a well capacity surplus of approximately 150 gpm for the existing water system.

### 3.4.2. Existing Storage

Storage sizing requirements are based on meeting the ADD. The total existing water system storage volume is 2,130,000 gallons (See Table 3.11). The calculated ADD for the system based on Table 3.13 is approximately 2,548,800 million gallons (MG) (1,770 gpm x 1,440 minutes/day). The existing aboveground storage deficit is approximately 418,000 gallons.

### 3.4.3. Existing Distribution System

The distribution system, including booster capacity, appears to be meeting current system needs. However, portions of the distribution system are in excess of 30 years old, which may impact system capacity.

# CHAPTER 4 – FUTURE SYSTEM ANALYSIS

## 4.1. FUTURE ANALYSIS INTRODUCTION

The water system design criteria established in the Existing System Design Criteria (Chapter 3) are used to develop the future water system capacity requirements. Future system requirements include well capacity, storage capacity, and booster capacity to serve buildout system demands. Future infrastructure requirements will be determined on a service area by service area basis and are described in more detail in the following sections.

## 4.2. FUTURE DEMAND PROJECTIONS

Some of the Ranchettes, Villas, and Units originally platted within Rio Rico are excluded from water master planning due to the uncertain nature of whether they will be constructed in the foreseeable future, if at all. Some of the excluded developments were originally platted with very large parcels which would most likely be served by individual wells. The developments excluded from the water master plan are Ranchettes Unit 8, Ranchettes Unit 13 (Sonoita Creek Ranch), Ranchettes Unit 15, Ranchettes Unit 16, Ranchettes Unit 19 (Sonoita Creek Ranch), Villas Unit 9, and Estates Unit 12. Those excluded developments will require their own water master plans defining their individual infrastructure requirements if and when they are developed in the future. The locations of the excluded units can be seen in Exhibit 3 in the Appendix.

Rio Rico Properties has also sold 2,842 units scattered throughout Rio Rico to a private developer which are known as the Vatari Lots. These units have been sold with the restriction that they cannot be built on and are dedicated as open space. These units account for approximately 9 percent of the total equivalent units included in this master plan.

In addition to the Vatari Lots, it is probable that the rugged terrain of Rio Rico will impose significant limitations on the contractibility of some parcels. Past assessments performed by Rio Rico Properties have assumed that 10 percent of the lots are non-buildable. This report assumes a slightly more conservative estimate from a water master planning perspective of 8 percent non-buildable parcels.

The following tables provide a summary of the total units that will be served water by RRU. The units are separated by whether they are east or west of Interstate 19 (I-19) for purposes of planning future infrastructure. The numbers of buildable units are derived by subtracting out the Vitari Lots and 8 percent non-buildable units. A detailed spreadsheet showing how the projected number of total buildable units was derived is included in Appendix A. Table 4.1 provides a summary of the buildout water demands east of the I-19.

**Table 4.1. Water Demands East of I-19**

| Development | Total Equivalent Buildable Units | ADD (gallons) | PDD (gpm) |
|---|---|---|---|
| Estates 16 | 893 | 304,985 | 424 |
| Estates 14 | 927 | 316,682 | 440 |
| Estates 3 | 402 | 137,229 | 191 |
| Estates 10 | 844 | 288,152 | 400 |
| Estates 11 | 374 | 127,814 | 178 |
| Villas 11 | 763 | 260,478 | 362 |
| Villas 12 | 757 | 258,481 | 359 |
| Villas 10 | 623 | 212,833 | 296 |
| Villas14 | 250 | 85,304 | 118 |
| Villas 5 | 915 | 312,688 | 434 |
| Villas 16 | 281 | 96,146 | 134 |
| Ranchettes 18 | 1,696 | 579,443 | 805 |
| Ranchettes 17 | 1,437 | 490,715 | 682 |
| Ranchettes 4 | 867 | 296,141 | 411 |
| Ranchettes 3 | 697 | 237,940 | 330 |
| Ranchettes 11 | 600 | 205,130 | 285 |
| Ranchettes 14 | 851 | 290,720 | 404 |
| Ranchettes 12 | 945 | 322,959 | 449 |
| Unit 3 | 580 | 197,998 | 275 |
| Unit 15 | 716 | 244,501 | 340 |
| North Industrial Park | 1,538 | 525,521 | 730 |
| **TOTAL** | **16,955** | **5,791,860** | **8,044** |

Table 4.2 provides a summary of the buildout water demands west of I-19.

**Table 4.2. Water Demands West of I-19**

| Development | Total Equivalent Buildable Units | ADD (gallons) | PDD (gpm) |
|---|---|---|---|
| Estates 9 | 701 | 239,366 | 332 |
| Estates 4 | 633 | 216,257 | 300 |
| Estates 6 | 204 | 69,613 | 97 |
| Estates 7 | 342 | 116,973 | 162 |
| Estates 13 | 760 | 259,622 | 361 |
| Estates 8 | 704 | 240,507 | 334 |
| Villas 13 | 738 | 252,205 | 350 |
| Villas 18 | 289 | 98,714 | 137 |
| Ranchettes 10 | 593 | 202,562 | 281 |
| Ranchettes 9 | 441 | 150,638 | 209 |
| Ranchettes 7 | 241 | 82,451 | 115 |
| Ranchettes 5 | 395 | 134,947 | 187 |
| Unit 6 | 501 | 171,180 | 238 |
| Unit 7 | 681 | 232,519 | 323 |
| Unit 4 | 308 | 105,275 | 146 |
| South Industrial Park | 428 | 146,073 | 203 |
| **TOTAL** | **7,959** | **2,718,902** | **3,776** |

## 4.3. Future System Requirements

As new development occurs throughout the water service area, it is critical that wells, reservoirs, and booster stations are installed within the appropriate water system pressure zones. In addition, it is necessary that pipelines be strategically located to provide service to new developments as they occur but also in a way that provides for additional downstream development where applicable. Judicious selection of facility capacities and locations will provide for flexible and reliable operation of the water system during all stages of development.

### 4.3.1. Future Well Capacity

All of the existing wells serving the RRU water system are located within a corridor that follows the Santa Cruz River. The *Long Range Plan and Four Year Plan* proposed close to 50 wells to ultimately be drilled along the Santa Cruz River.

Table 4.3 provides a summary of the existing wells east of I-19.

**Table 4.3. Existing Well Capacity Summary East of I-19**

| Wells East of I-19 | Capacity (gpm) |
|---|---|
| Well No. 5 | 500 |
| Well No. 15 | 900 |
| Well No. 86 | 1,200 |
| **Subtotal** | **2,600** |

Table 4.4 provides a summary of the existing wells west of I-19.

**Table 4.4. Existing Well Capacity Summary West of I-19**

| Wells West of I-19 | Capacity (gpm) |
|---|---|
| Well No. 6 | 1,500 |
| Well No. 8 | 550 |
| Well No. 52 | 550 |
| **Subtotal** | **2,600** |

The average well capacity for the existing wells is approximately 900 gpm and it is assumed that future wells will have similar capacities. As previously specified in Chapter 3 of this report, well capacity is based on meeting PDD with the largest well out of service.

The calculated PDD of the portion of Rio Rico east of I-19 is calculated in Table 4.1 to be 8,044 gpm which provides a well capacity deficit of 5,444 gpm (8,044 gpm – 2,600 gpm). Approximately six new wells will be required to meet the PDD plus a redundant well for **seven** future wells.

A similar calculation is provided to determine the number of new wells to serve the west portion of I-19. The PDD for the west portion of Rio Rico is calculated to be 3,776 gpm (See Table 4.2). Subtracting out the existing wells leaves a capacity deficit of 1,176 gpm (3,776 – 2,600). Approximately two new wells will be required on the west side of I-19 plus one redundant well for **three** future wells.

The new wells should be sized and located to efficiently provide source capacity without over pressurizing the lower 3650-Zone. It is anticipated that the wells will continue to be level controlled by the 3650-Zone reservoirs. Operational guidelines for multiple wells pumping to several reservoirs floating the same zone are discussed in more detail below in this chapter.

Well siting analysis and design shall also consider what impacts if any exist from effluent discharges from the existing Nogales International Wastewater Treatment Plant (NIWTP) or future Rio Rico wastewater treatment system.

### 4.3.2. Storage Capacity

The storage requirement has been previously described in Chapter 3 which is to provide a storage volume equal to the ADD. Tables 4.5 and 4.6 provide a summary of the existing aboveground storage reservoirs and their respective locations west and east of I-19.

**Table 4.5. Existing Reservoir Storage Summary East of I-19**

| Reservoirs East of I-19 | Floating Zone | Capacity (gallons) |
|---|---|---|
| Water Plant 1 | 3650 | 640,000 |
| Water Plant 56 | 3650 | 100,000 |
| Water Plant 81 | 3650 | 1,000,000 |
| **Subtotal** | | **1,740,000** |

The calculated ADD of the portion of Rio Rico east of I-19 is calculated above as approximately 5.79 MG (see Table 4.1) which provides a storage capacity deficit of approximately **4.05 MG** (5.79 MG – 1.74 MG).

**Table 4.6. Existing Reservoir Storage Summary West of I-19**

| Reservoirs West of I-19 | Floating Zone | Capacity (gallons) |
|---|---|---|
| Water Plant 38 | 3650 | 200,000 |
| Water Plant 29 | 3800 | 150,000 |
| **Subtotal** | | **350,000** |

A similar calculation is provided to determine the storage requirement that serves the west portion of I-19. The ADD for the west portion of Rio Rico is calculated to be 2.72 MG (See Table 4.2). Subtracting out the existing storage reservoirs leaves a capacity deficit of **2.37 MG** (2.72 MG– 0.35 MG).

The Rio Rico service area was separated into several smaller areas to locate and size the future storage reservoirs. The limits of the smaller service areas were developed based on their potential to share regional facilities, pressure zone, and topographical boundaries including major washes. The separations are shown in Exhibit 2. A detailed spreadsheet showing how the numbers of buildable units and demand by service were calculated is included in Appendix B.

The Table 4.7 provides a summary of the approximate number of customers in each area east of I-19.

**Table 4.7. Reservoir Service Area Summary East of I-19**

| Reservoir Service Area | Total Equivalent Buildable Units | ADD (gallons) |
|---|---|---|
| 1 | 2,085 | 712,392 |
| 2 | 1,055 | 360,333 |
| 3 | 10,368 | 3,541,705 |
| 4 | 642 | 219,395 |
| 5 | 984 | 336,083 |
| 6 | 1,821 | 621,952 |
| **TOTAL** | **16,955** | **5,791,860** |

The Table 4.8 provides a summary of the approximate number of customers in each area west of I-19.

**Table 4.8. Reservoir Service Area Summary West of I-19**

| Reservoir Service Area | Total Equivalent Buildable Units | ADD (gallons) |
|---|---|---|
| 7 | 5,844 | 1,996,239 |
| 8 | 1,483 | 506,691 |
| 9 | 632 | 215,972 |
| **TOTAL** | **7,959** | **2,718,902** |

Table 4.9 provides a summary of the future storage reservoirs and sizes east of I-19. The storage capacity is calculated by subtracting the existing storage capacity in Table 4.5 from the total storage requirement by service area in Table 4.7 (5.79 MG – 1.74 MG = **4.05 MG**).

**Table 4.9. Future Reservoir Storage Summary East of I-19**

| Reservoirs East of I-19 | Floating Zone | Capacity (gallons) | Reservoir Service Area |
|---|---|---|---|
| Water Plant 7 | 3950 | 250,000 | 3 (Portion) |
| Water Plant 55 | 3650 | 250,000 | 3 (Portion) |
| Water Plant 103 | 3650 | 600,000 | 3 (Portion) |
| Water Plant 116 | 3650 | 575,000 | 3 (Portion) |
| Water Plant 58 | 3800 | 650,000 | 6 (Portion) |
| Water Plant 79 | 3800 | 750,000 | 1 |
| Water Plant 105 | 3800 | 375,000 | 2 |
| Water Plant 114 | 3950 | 350,000 | 5 |
| Water Plant 122 | 3950 | 250,000 | 4 |
| **TOTAL** | | **4,050,000** | |

Table 4.10 provides a summary of the future storage reservoirs west of I-19. The storage capacity is calculated by subtracting the existing storage capacity in Table 4.6 from the total storage requirement by service area in Table 4.8 (2.718 MG – 0.350 MG = **2.375 MG**).

**Table 4.10. Future Reservoir Storage Summary West of I-19**

| Reservoirs West of I-19 | Floating Zone | Capacity (gallons) | Reservoir Service Area |
|---|---|---|---|
| Water Plant 26 | 3650 | 750,000 | 9<br>7<br>(Portion) |
| Water Plant 30 | 3650 | 500,000 | 7<br>(Portion) |
| Water Plant 38 | 3650 | 400,000 | 7<br>(Portion) |
| Water Plant 44 | 3650 | 50,000 | 7<br>(Portion) |
| Water Plant 27 | 3800 | 375,000 | 8 |
| Water Plant 43 | 3950 | 300,000 | 7<br>(Portion) |
| **TOTAL** | | **2,375,000** | |

The schematic reservoir sites have been selected based on coordination with RRU and sites described in the *Long Range Plan and Four Year Plan* and are shown in Exhibit 1 and in Appendix B. The final reservoirs sizes and locations will require a more detailed review of constructability of terrain, property acquisition, pipeline sizes, and development projections.

### 4.3.3. 3650-Zone Well and Reservoir Control

The 3650-Zone will continue to be provided floating storage by multiple reservoirs filled by the same wells. This method of operation will require consistency in design to prevent reservoir overflows and tanks from completely draining out. The existing 3650-Zone reservoirs are approximately 30 feet tall which sets the height standard for all future 3650-Zone reservoirs. Reservoirs with similar heights have less potential to overflow one another than those with variations in overflow/weir elevations.

Potential for overflowing tanks will also be mitigated by installing motor operated valves on the reservoir fills/inlets which will slowly close when the tanks are full. This process allows other tanks in the 3650-Zone to continue filling off the same wells. Slow control valve operation is critical to control water hammer/surge.

Some 3650-Zone transmission mains may also require upsizing to efficiently transfer water to the future reservoir locations. In some cases, additional telemetry control measures may be required so that only certain wells will be level controlled by particular reservoirs and not be allowed to pump from one end of the system to the other, potentially over pressurizing some areas.

### 4.3.4. Distribution System

The *Long Range Plan and Four Year Plan* proposed approximately 125 total booster stations of various capacities to serve Rio Rico. The future booster facilities described in this report are based on a review of the constructed system and recommendations of RRU operations staff.

Table 4.11 provides a summary of the future booster stations east of I-19.

**Table 4.11. Future Booster Station Summary East of I-19**

| Boosters East of I-19 | Discharge Zone | Pressure System Control or Tank Level Controlled |
|---|---|---|
| Water Plant 103[*1] | 3800 | Level Control @ Future WP 105 |
| | 3950 | Pressure Control |
| Water Plant 55 | 3800 | Pressure Control |
| | 3950 | Level Control @ Future WP 114) |
| Water Plant 116 | 3800 | Pressure Control |
| | 3950 | Level Control @ Future WP 122 |
| Water Plant 78 | 4100 | Pressure Control |
| Water Plant 79 | 4100 | Pressure Control |
| Water Plant 105 | 4100 | Pressure Control |

[*1]The existing 3950-Zone booster at WP 103 will be replaced by a new 3950-Zone booster station during the site upgrades which will include a new reservoir.

Table 4.12 provides a summary of the future booster stations west of I-19.

**Table 4.12. Future Booster Station Summary West of I-19**

| Boosters West of I-19 | Discharge Zone | Pressure System or Tank Level Controlled |
|---|---|---|
| Water Plant 26 | 3800 | Pressure Control |
| Water Plant 30 | 3800 | Level Control @ WP 29 |
| Water Plant 27 | 3950 | Pressure Control |

As previously stated, booster stations pumping to elevated storage shall be sized to meet PDD. Booster facilities pumping to portions of the distribution system without elevated storage shall be sized to meet PHD or Instantaneous Demand, whichever is greater. Final booster station capacity may require upsizing to meet future fire flow requirements as required by the authority having jurisdiction.

# CHAPTER 5 – CAPITAL IMPROVEMENT PLAN

## 5.1. INTRODUCTION

Chapter 5 presents the infrastructure cost estimates and a capital improvement plan (CIP) for the upgrades to the existing system and future facility expansions previously discussed in Chapters 3 and 4 for the next five years. The water utility currently has adequate source and transmission facilities, as defined in Chapter 3, to provide service to the existing customers. The existing system is deficient in aboveground storage capacity. A list of the proposed infrastructure projects and associated cost projections are provided in Table 5.1, near the end of this chapter. The following sections provide the assumptions made in projecting the infrastructure costs.

## 5.2. COST PROJECTION ASSUMPTIONS

Due to the fact that the Master Plan planning document shows conceptual layouts for proposed facilities, assumptions were made to predict probable construction costs. Standard assumptions were made for several categories of improvements based on recent bids of similar projects and discussions with local contractors. All costs provided in this report and appendices exclude property and easement acquisition. Costs also exclude three-phase power to the sites. Costs are based on July 2008 costs.

### 5.2.1. Installation of Water Mains

Based on recent bids in other water utilities and standard assumption of soil conditions, the following costs were used for water main installation. RRU requires that all new water mains be constructed ductile iron pipe (DIP).

- $45 per lineal feet (lf) of 6-inch DIP water main
- $60 per lf of 8-inch DIP water main
- $95 per lf of 12-inch DIP water main
- $140 per lf of 16-inch DIP water main
- $10 per lf additional for pavement replacement, where specifically identified
- $15,000 additional for pressure reducing valve station in below ground concrete vault

The cost excluded rock excavation. This cost assumption includes valves, fittings, and appurtenances required for the installation of the future water mains. The cost assumption does not include easement acquisition or abandonment and removal of existing water mains which may be required for upsizing or replacement of facilities. Waterline extensions to new customers in Rio Rico have historically been funded by Rio Rico Properties.

### 5.2.2. Installation of Reservoirs

The two most commonly used types of storage facilities are welded steel reservoirs and belowground concrete reservoirs. Welded steel reservoirs are generally less expensive to install than concrete reservoirs. All of Rio Rico's storage tanks have been constructed using aboveground steel tanks. It is assumed that the majority of storage required for the Rio Rico water system can be accomplished with welded steel reservoirs. A construction cost of $0.80 to $2.00 per gallon for welded steel storage reservoirs is utilized in the CIP. This range is provided to accommodate the large variation in sizes and site work required for the reservoirs throughout Rio Rico. This cost assumption includes a steel reservoir, foundation preparation, site piping, telemetry, motor control valve, and chain link fencing. This cost assumption does not include site acquisition.

The rugged terrain of Rio Rico will likely be the most significant factor in determining the final cost and phasing of future storage. All of Rio Rico's large reservoir sites have required some site grading and varying degrees of slope projection. It is assumed that future storage sites will also require significant amounts of grading and slope stabilization. Due to the limited number of suitable storage sites, it is recommended that the water utility develop the full storage potential of each site when available.

### 5.2.3. Well Installations

Using recent bids and applying standard assumptions for drilling rig requirements for access, a cost of $650,000 was assumed to drill and equip each new well. This cost projection includes standard drilling operations, well casing, sanitary seal, well column tube and shaft, motor, and pump bowl assembly, assuming the wells are to be drilled using an reverse-circulation, air-rotary drilling rig. The cost assumption also includes components for site piping and equipment, hydropneumatic tank, site grading, chain link fence, and telemetry. The cost excludes site acquisition, bringing three-phase power to the site, or water treatment facilities.

### 5.2.4. Booster Stations

The more recently constructed booster stations at Water Plant Nos. 104 and 81 have utilized skid mounted, pre-packaged variable frequency drive (VFD) stations with small bladder tanks. A construction cost of $250,000 to $450,000 per booster station is utilized in this CIP. This cost range is provided to account for varying degrees of pump capacities, electrical upgrades, demolition, and provisions for temporary service or keeping existing booster stations online as may be required for replacements of existing facilities. Back-up generator costs are not included, however, additional cost have been added to account for a manual transfer switch and generator receptacle. This cost assumption includes minimal site piping and equipment, site grading, chain link fences, and telemetry. The cost excludes site acquisition or bringing three-phase power to the site.

### 5.2.5. Engineering and Contingencies

Due to the planning nature of the locations of the facilities proposed in the Master Plan, contingencies are added to reflect unforeseen conditions that may affect the individual projects. Unforeseen conditions can range from environmental issues that may need to be addressed on individual projects, to easements that may need to be acquired for pipeline construction. This cost component also includes engineering fees, permits, inspection, and project management. Engineering and contingencies of 25 percent have been included in the cost as shown in Table 5.1.

**Table 5.1. Five-Year Capital Improvement Plan Cost Projections**

| Water Plant | Facility Description | Project Sub-Total | 25% Engineering and Contingencies | Total | Timeframes (Years) |
|---|---|---|---|---|---|
| 59 | Demolish and replace existing 3800-Zone booster with a new packaged VFD pump station. | $350,000 | $87,500 | $437,500 | 1 |
| 7 | Demolish and replace existing 3950-Zone booster with a new packaged VFD pump station. | $400,000 | $100,000 | $500,000 | 1-2 |
| 7 | Replace existing 10,000 gallon forebay reservoir with new 250,000 gallon 3800-Zone floating reservoir. | $425,000 | $106,250 | $531,250 | 1-2 |
| 7 | Extend existing 3800-Zone 12-inch water main up to new tank for fill/float line and provide additional access road. | $100,000 | $25,000 | $125,000 | 1-2 |
| 44 | Demolish and replace existing 3800-Zone booster with a new packaged VFD pump station. | $300,000 | $75,000 | $375,000 | 2-3 |
| 44 | Replace existing 10,000 gallon forebay reservoir with new 50,000 gallon forebay reservoir. | $85,000 | $21,250 | $106,250 | 2-3 |
| 58 | Demolish and replace existing 3950 and 4150-Zone booster stations with a new two-zone packaged VFD pump station. | $350,000 | $87,500 | $437,500 | 2-3 |
| 58 | Construct new 250,000 (Phase I Minimum Size) gallon reservoir. Buildout storage at this site is projected to be 650,000 gallons. | $375,000 | $93,750 | $468,750 | 2-3 |
| 30 | Demolish and replace existing 3800-Zone booster with a new packaged VFD pump station. | $300,000 | $75,000 | $375,000 | 3-5 |

# EXHIBIT 1

## RIO RICO UTILITIES
## WATER SYSTEM
## MASTER
## PLAN

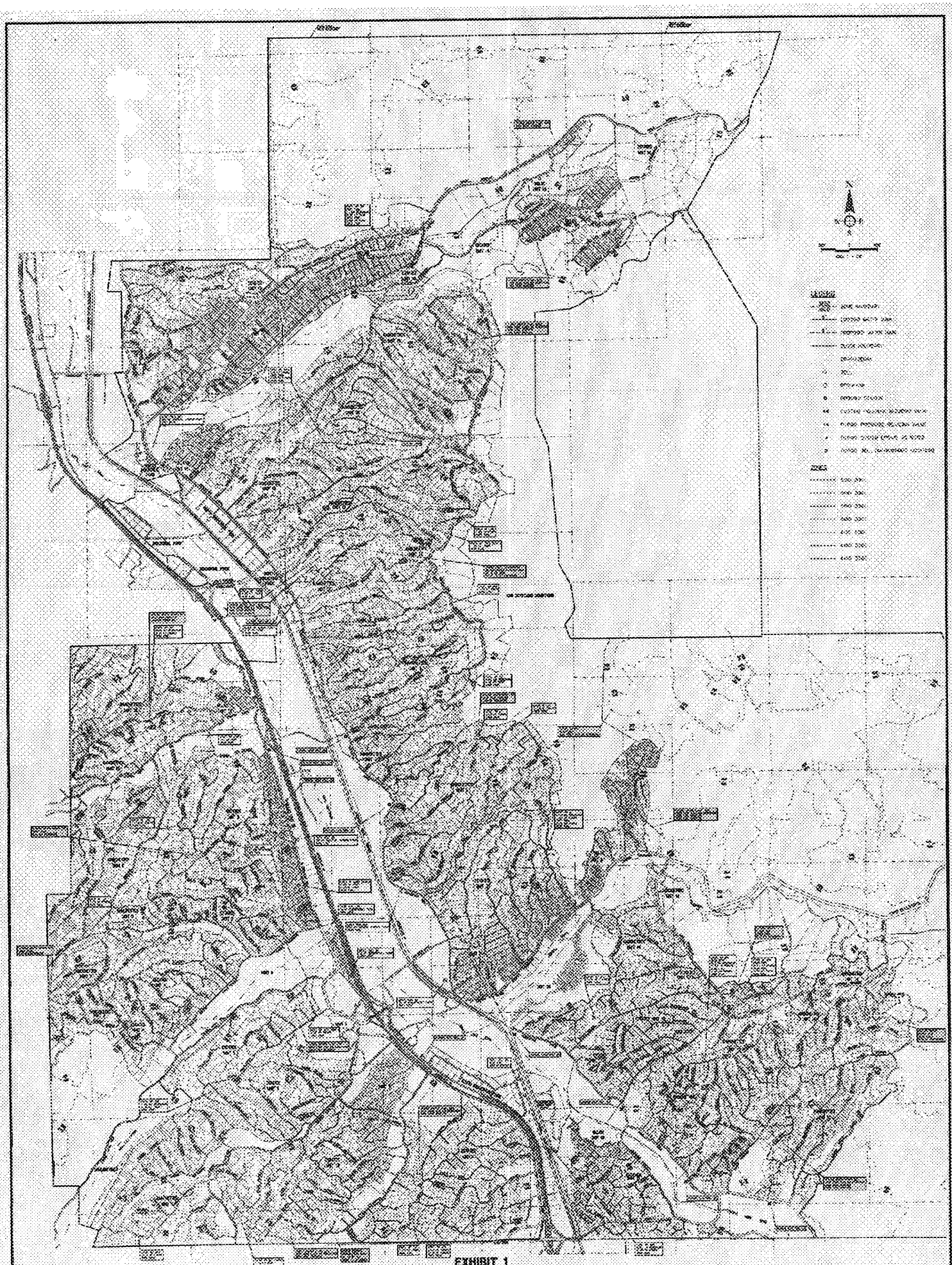


EXHIBIT 1

**RIO RICO UTILITIES**

**WATER SYSTEM MASTER PLAN**

# EXHIBIT 2

## RIO RICO UTILITIES
## WATER STORAGE
## FIGURE

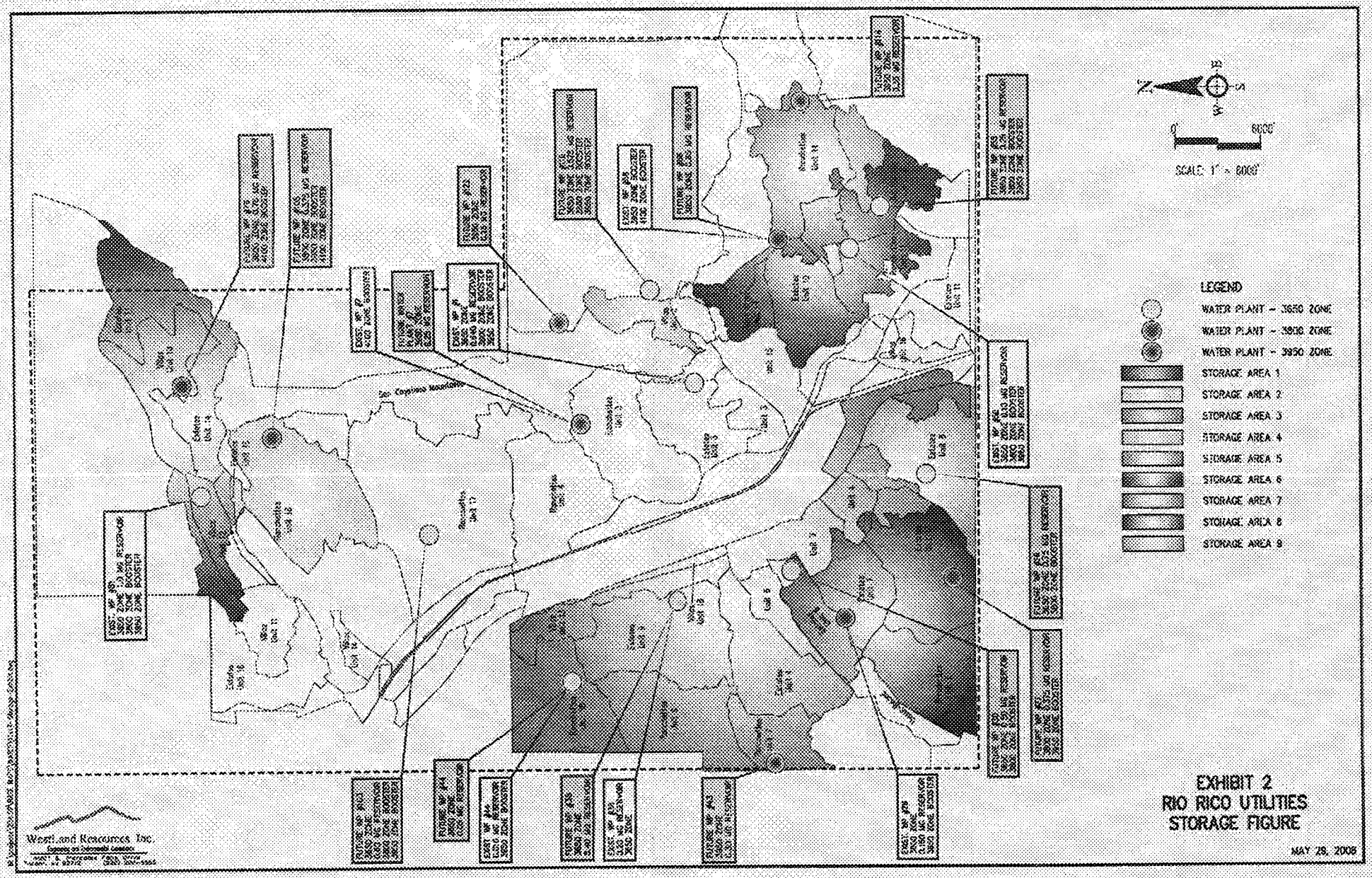



EXHIBIT 2
RIO RICO UTILITIES
STORAGE FIGURE

MAY 28, 2008

# EXHIBIT 3

## RIO RICO UTILITIES
## CTC/CC&N
## BOUNDARIES

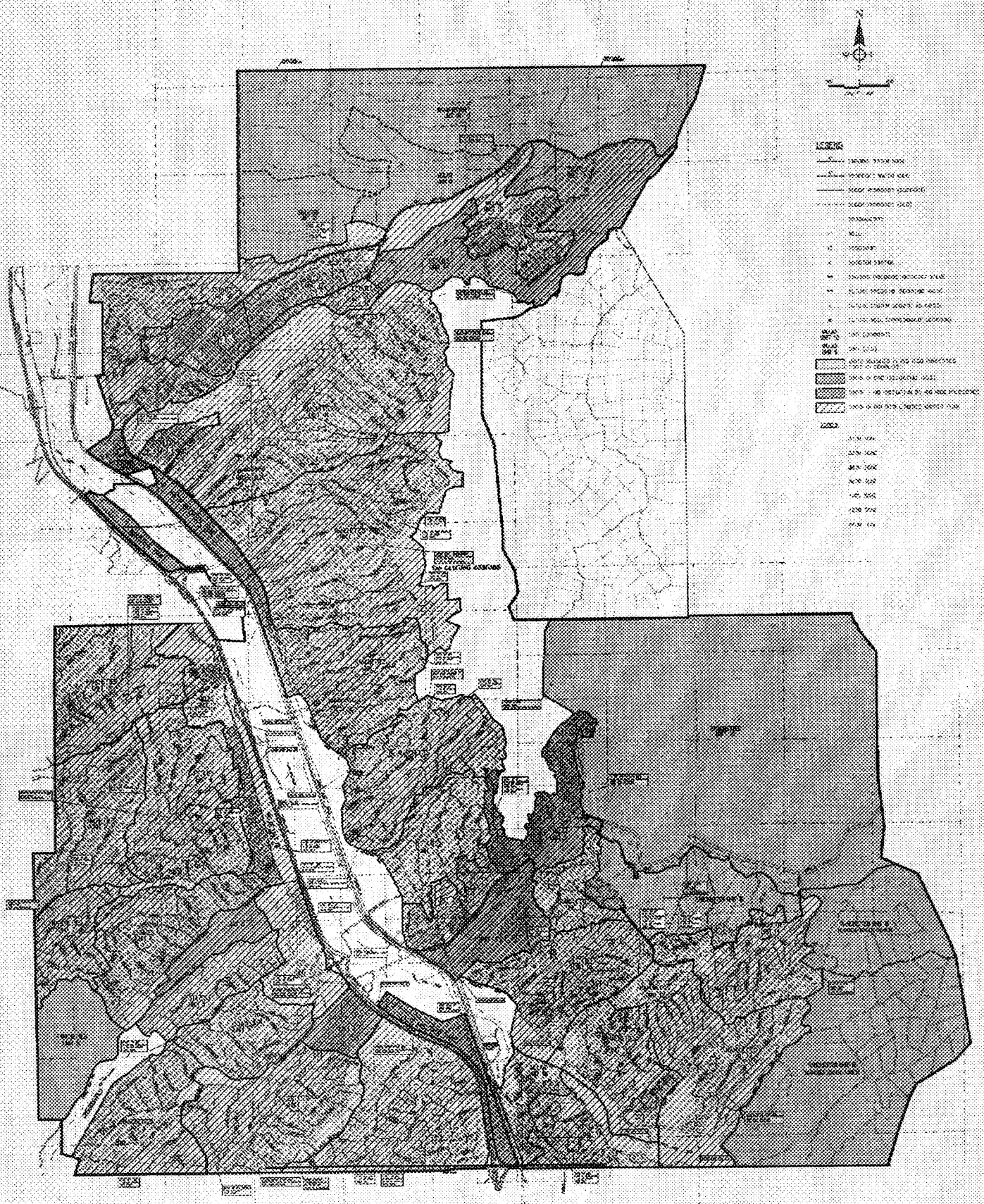


EXHIBIT 3
**RIO RICO UTILITIES**
CTC/CCN BOUNDARIES

# APPENDIX A

## RIO RICO DEMANDS EAST AND WEST OF I-19 CALCULATION SPREADSHEETS

## Rio Rico Calculated Water Demand East of I-19

| Column 1 | Column 2 | Column 3 | Column 4 | Column 5 | Column 6 | Column 7 | Column 8 | Column 9 | Column 10 | Column 11 | Column 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Column 3 (x 2 RAC) | | Column 5 (x 2 RAC) | Column 2 + Column 4 + Column 6 | Column 7 (x 0.092) | (Column 7 - Column 8) (x 0.08) | Column 7 - Column 8 - Column 9 | Column 10 x 2.8 ppu x 122 gpcd | Column 11 x 2.0 P.F. / 1440 min/day |
| **Development** | **Original Planned Units** | **Comm. Acres** | **Equivalent Comm. Units (2 RAC)** | **Indust. Acres** | **Equivalent Indust. Units (2 RAC)** | **Total Equivalent Units** | **Deduct 9% Vitari Lots** | **Deduct 8% Non-Buildable Lots** | **Total Equivalent Buildable Units** | **ADD (gallons)** | **PDD (gpm)** |
| Estates 16 | 1,069 | 0 | 0 | 0 | 0 | 1,069 | 99 | 78 | 893 | 304,985 | 424 |
| Estates 14 | 1,110 | 0 | 0 | 0 | 0 | 1,110 | 102 | 81 | 927 | 316,682 | 440 |
| Estates 3 | 481 | 0 | 0 | 0 | 0 | 481 | 44 | 35 | 402 | 137,229 | 191 |
| Estates 10 | 1,010 | 0 | 0 | 0 | 0 | 1,010 | 93 | 73 | 844 | 288,152 | 400 |
| Estates 11 | 448 | 0 | 0 | 0 | 0 | 448 | 41 | 33 | 374 | 127,814 | 178 |
| Villas 11 | 913 | 0 | 0 | 0 | 0 | 913 | 84 | 66 | 763 | 260,478 | 362 |
| Villas 12 | 906 | 0 | 0 | 0 | 0 | 906 | 84 | 66 | 757 | 258,481 | 359 |
| Villas 10 | 746 | 0 | 0 | 0 | 0 | 746 | 69 | 54 | 623 | 212,833 | 296 |
| Villas14 | 299 | 0 | 0 | 0 | 0 | 299 | 28 | 22 | 250 | 85,304 | 118 |
| Villas 5 | 1,096 | 0 | 0 | 0 | 0 | 1,096 | 101 | 80 | 915 | 312,688 | 434 |
| Villas 16 | 337 | 0 | 0 | 0 | 0 | 337 | 31 | 24 | 281 | 96,146 | 134 |
| Ranchettes 18 | 2,031 | 0 | 0 | 0 | 0 | 2,031 | 187 | 148 | 1,696 | 579,443 | 805 |
| Ranchettes 17 | 1,720 | 0 | 0 | 0 | 0 | 1,720 | 159 | 125 | 1,437 | 490,715 | 682 |
| Ranchettes 4 | 1,038 | 0 | 0 | 0 | 0 | 1,038 | 96 | 75 | 867 | 296,141 | 411 |
| Ranchettes 3 | 834 | 0 | 0 | 0 | 0 | 834 | 77 | 61 | 697 | 237,940 | 330 |
| Ranchettes 11 | 719 | 0 | 0 | 0 | 0 | 719 | 66 | 52 | 600 | 205,130 | 285 |
| Ranchettes 14 | 1,019 | 0 | 0 | 0 | 0 | 1,019 | 94 | 74 | 851 | 290,720 | 404 |
| Ranchettes 12 | 1,132 | 0 | 0 | 0 | 0 | 1,132 | 104 | 82 | 945 | 322,959 | 449 |
| Unit 3 | 694 | 0 | 0 | 0 | 0 | 694 | 64 | 50 | 580 | 197,998 | 275 |
| Unit 15 | 707 | 75 | 150 | 0 | 0 | 857 | 79 | 62 | 716 | 244,501 | 340 |
| North Industrial Park | 0 | 0 | 0 | 921 | 1842 | 1,842 | 170 | 134 | 1,538 | 525,521 | 730 |
| **Totals** | **18,309** | **75** | **150** | **921** | **1,842** | **20,301** | **1,872** | **1,474** | **16,955** | **5,791,860** | **8,044** |

## Rio Rico Calculated Water Demand West of I-19

| Column 1 | Column 2 | Column 3 | Column 4 | Column 5 | Column 6 | Column 7 | Column 8 | Column 9 | Column 10 | Column 11 | Column 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | | Column 3 (x 2 RAC) | | Column 5 (x 2 RAC) | Column 2 + Column 4 + Column 6 | Column 7 (x 0.092) | (Column 7 - Column 8) (x 0.08) | Column 7 - Column 8 - Column 9 | Column 10 x 2.8 ppu x 122 gpcd | Column 11 x 2.0 P.F. / 1440 min/day |
| **Development** | **Original Planned Units** | **Comm. Acres** | **Equivalent Comm. Units (2 RAC)** | **Indust. Acres** | **Equivalent Indust. Units (2 RAC)** | **Total Equivalent Units** | **Deduct 9% Vitari Lots** | **Deduct 8% Non-Buildable Lots** | **Total Equivalent Buildable Units** | **ADD (gallons)** | **PDD (gpm)** |
| Estates 9 | 839 | 0 | 0 | 0 | 0 | 839 | 77 | 61 | 701 | 239,366 | 332 |
| Estates 4 | 758 | 0 | 0 | 0 | 0 | 758 | 70 | 55 | 633 | 216,257 | 300 |
| Estates 6 | 244 | 0 | 0 | 0 | 0 | 244 | 22 | 18 | 204 | 69,613 | 97 |
| Estates 7 | 410 | 0 | 0 | 0 | 0 | 410 | 38 | 30 | 342 | 116,973 | 162 |
| Estates 13 | 910 | 0 | 0 | 0 | 0 | 910 | 84 | 66 | 760 | 259,622 | 361 |
| Estates 8 | 843 | 0 | 0 | 0 | 0 | 843 | 78 | 61 | 704 | 240,507 | 334 |
| Villas 13 | 844 | 20 | 40 | 0 | 0 | 884 | 81 | 64 | 738 | 252,205 | 350 |
| Villas 18 | 0 | 173 | 346 | 0 | 0 | 346 | 32 | 25 | 289 | 98,714 | 137 |
| Ranchettes 10 | 710 | 0 | 0 | 0 | 0 | 710 | 65 | 52 | 593 | 202,562 | 281 |
| Ranchettes 9 | 528 | 0 | 0 | 0 | 0 | 528 | 49 | 38 | 441 | 150,638 | 209 |
| Ranchettes 7 | 289 | 0 | 0 | 0 | 0 | 289 | 27 | 21 | 241 | 82,451 | 115 |
| Ranchettes 5 | 473 | 0 | 0 | 0 | 0 | 473 | 44 | 34 | 395 | 134,947 | 187 |
| Unit 6 | 600 | 0 | 0 | 0 | 0 | 600 | 55 | 44 | 501 | 171,180 | 238 |
| Unit 7 | 175 | 320 | 640 | 0 | 0 | 815 | 75 | 59 | 681 | 232,519 | 323 |
| Unit 4 | 369 | 0 | 0 | 0 | 0 | 369 | 34 | 27 | 308 | 105,275 | 146 |
| South Industrial Park | 0 | 0 | 0 | 256 | 512 | 512 | 47 | 37 | 428 | 146,073 | 203 |
| **Totals** | **7,992** | **513** | **1,026** | **256** | **512** | **9,530** | **879** | **692** | **7,959** | **2,718,902** | **3,776** |

# APPENDIX B

## RIO RICO STORAGE SERVICE AREA EAST AND WEST OF I-19 CALCULATION SPREADSHEETS

# Rio Rico Storage Service Area West of I-19 Spreadshheet Summary

| Column 1 | Column 2 | Column 3 | Column 4 | Column 5 | Column 6 | Column 7 | Column 8 | Column 9 | Column 10 | Column 11 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Column 3 (x 2 RAC) | | Column 5 (x 2 RAC) | Column 2 + Column 4 + Column 6 | Column 7 (x 0.092) | (Column 7 - Column 8) (x 0.08) | Column 7 - Column 8 - Column 9 | Column 10 x 2.8 ppu x 122 gpcd |
| **Reservoir Service Area** | **Original Planned Units** | **Comm. Acres** | **Equivalent Comm. Units (2 RAC)** | **Indust. Acres** | **Equivalent Indust. Units (2 RAC)** | **Total Equivalent Units** | **Deduct 9% Vitari Lots** | **Deduct 8% Non-Buildable Lots** | **Total Equivalent Buildable Units** | **ADD (gallons)** |
| 1 | 2,497 | 0 | 0 | 0 | 0 | 2,497 | 230 | 181 | 2,085 | 712,392 |
| 2 | 1,263 | 0 | 0 | 0 | 0 | 1,263 | 116 | 92 | 1,055 | 360,333 |
| 3 | 10,422 | 75 | 150 | 921 | 1,842 | 12,414 | 1,144 | 902 | 10,368 | 3,541,705 |
| 4 | 769 | 0 | 0 | 0 | 0 | 769 | 71 | 56 | 642 | 219,395 |
| 5 | 1,178 | 0 | 0 | 0 | 0 | 1,178 | 109 | 86 | 984 | 336,083 |
| 6 | 2,180 | 0 | 0 | 0 | 0 | 2,180 | 201 | 158 | 1,821 | 621,952 |
| **Totals** | **18,309** | **75** | **150** | **921** | **1,842** | **20,301** | **1,872** | **1,474** | **16,955** | **5,791,860** |

# Rio Rico Storage Service Area East of I-19 Spreadshheet Summary

| Column 1 | Column 2 | Column 3 | Column 4 | Column 5 | Column 6 | Column 7 | Column 8 | Column 9 | Column 10 | Column 11 |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | Column 3 (x 2 RAC) | | Column 5 (x 2 RAC) | Column 2 + Column 4 + Column 6 | Column 7 (x 0.092) | (Column 7 - Column 8) (x 0.08) | Column 7 - Column 8 - Column 9 | Column 10 x 2.8 ppu x 122 gpcd |
| **Reservoir Service Area** | **Original Planned Units** | **Comm. Acres** | **Equivalent Comm. Units (2 RAC)** | **Indust. Acres** | **Equivalent Indust. Units (2 RAC)** | **Total Equivalent Units** | **Deduct 9% Vitari Lots** | **Deduct 8% Non-Buildable Lots** | **Total Equivalent Buildable Units** | **ADD (gallons)** |
| 7 | 5,459 | 513 | 1,026 | 256 | 512 | 6,997 | 645 | 508 | 5,844 | 1,996,239 |
| 8 | 1,776 | 0 | 0 | 0 | 0 | 1,776 | 164 | 129 | 1,483 | 506,691 |
| 9 | 757 | 0 | 0 | 0 | 0 | 757 | 70 | 55 | 632 | 215,972 |
| **Totals** | **7,992** | **513** | **1,026** | **256** | **512** | **9,530** | **879** | **692** | **7,959** | **2,718,902** |

# RIO RICO UTILITIES

# WASTEWATER MASTER PLAN
# (REVISION NO. 1)

*Prepared for:*

**RIO RICO UTILITIES INC.**
1060 Yavapai Drive, Suite No. 9
Rio Rico, Arizona 85648
(520) 281-7000

*Prepared by:*

**WESTLAND RESOURCES, INC.**
4001 E. Paradise Falls Drive
Tucson, Arizona 85712
(520) 206-9585

Registered Professional Engineer (Civil)
CERTIFICATE NO.
22999
MARK F.
TAYLOR
Date signed 10/7/08
ARIZONA U.S.A.
EXPIRES 9/30/2010

**OCTOBER 2008**
Project No. 23129

EXHIBIT
A-21
ADMITTED

## TABLE OF CONTENTS

1. INTRODUCTION ..... 1

2. EXISTING WASTEWATER CONVEYANCE AND TREATMENT SYSTEM ..... 2

3. SOUTH SEWER BASIN ..... 3
   3.1. Rio Rico South Sewer Sub-Basins ..... 3
      3.1.1. South Sewer Sub-Basin A ..... 3
      3.1.2. South Sewer Sub-Basin B ..... 3
      3.1.3. South Sewer Sub-Basin C ..... 3
      3.1.4. South Sewer Sub-Basin D ..... 3

4. EXISTING POPULATION AND FLOW DATA ..... 4

5. POPULATION AND WASTEWATER FLOW PROJECTIONS ..... 6
   5.1. Rio Rico Growth Projections and Historical Data ..... 7
   5.2. Rio Rico South Sewer Basin Flow Projections at Five-Year Intervals ..... 7
   5.3. South Sewer Basin Existing Infrastructure Analysis ..... 9
      5.3.1. Gravity Sewer Interceptors (South Sewer Basin Existing Capacity Analysis) ..... 9
      5.3.2. Sewer Lift Stations (South Sewer Basin Existing Capacity Analysis) ..... 10
      5.3.3. Pressure Sewer Force Mains (South Sewer Basin Existing Capacity Analysis) ..... 10
      5.3.4. Wastewater Treatment Facilities (South Sewer Basin Existing Capacity Analysis) ..... 11
   5.4. South Sewer Basin Future Infrastructure Analysis ..... 12
      5.4.1. Gravity Sewer Interceptors (South Sewer Basin Future Capacity Analysis) ..... 12
      5.4.2. Sewer Lift Stations (South Sewer Basin Future Capacity Analysis) ..... 12
      5.4.3. Pressure Sewer Force Mains (South Sewer Basin Future Capacity Analysis) ..... 13
      5.4.4. Wastewater Treatment Facilities (South Sewer Basin Future Capacity Analysis) ..... 13

6. NORTH SEWER BASIN ..... 18
   6.1. Rio Rico North Sewer Sub-Basins ..... 18
      6.1.1. North Sewer Sub-Basin A ..... 18
      6.1.2. North Sewer Sub-Basin B ..... 18
   6.2. Rio Rico North Sewer Basin Flow Projections at Five-Year Intervals ..... 18
   6.3. North Sewer Basin Existing Infrastructure Analysis ..... 20
      6.3.1. Gravity Sewer Interceptors (North Sewer Basin Existing Capacity Analysis) ..... 20
      6.3.2. Sewer Lift Stations (North Sewer Basin Existing Capacity Analysis) ..... 21
      6.3.3. Pressure Sewer Force Main (North Sewer Basin Existing Capacity Analysis) ..... 21
      6.3.4. Wastewater Treatment Facilities (North Sewer Basin Existing Capacity Analysis) ..... 22
   6.4. North Sewer Basin Future Infrastructure Analysis ..... 22
      6.4.1. Gravity Sewer Interceptors (North Sewer Basin Future Capacity Analysis) ..... 22
      6.4.2. Sewer Lift Stations (North Sewer Basin Future Capacity Analysis) ..... 23
      6.4.3. Pressure Sewer Force Main (North Sewer Basin Future Capacity Analysis) ..... 23
      6.4.4. Wastewater Treatment Facilities (North Sewer Basin Future Capacity Analysis) ..... 24

7. CAPITAL IMPROVEMENT PLAN ..... 26
   7.1. Introduction ..... 26
   7.2. Cost Projection Assumptions ..... 26
      7.2.1. Engineering, Inspection, and Contingencies ..... 26
   7.3. Wastewater Treatment Facility Permitting Cost ..... 27
      7.3.1. Effluent Disposal Cost ..... 28
   7.4. South Sewer Basin Capital Improvement Plan ..... 28
      7.4.1. Alternative 1 (Pump All Existing and Future Flows to NIWTP for Treatment) ..... 28

7.4.2. Alternative 2 (Construct New WWTF to Treat All of the South Sewer Basin Flows) ..... 29
7.4.3. Alternative 3 (Pump 0.55 MGD to NIWTP and Construct new WWTF) ..... 29
7.5. North Sewer Basin Capital Improvement Plan ..... 30

## LIST OF FIGURES

Figure 1. Rio Rico Golf Course Irrigation Summary ..... 15

## LIST OF TABLES

Table 4-1. Rio Rico South Sewer Basin Historical Metered Flows (2003-2007) ..... 4
Table 4-2. South Industrial Park Water Use Data ..... 4
Table 4-3. Existing School Wastewater Flows in Villas 13 ..... 5

Table 5-1. Water Service Connections (2003-2007) ..... 7
Table 5-2. Rio Rico South Sewer Basin Flows (2008) ..... 7
Table 5-3. Rio Rico South Sewer Basin Flows (2013) ..... 8
Table 5-4. Rio Rico South Sewer Basin Flows (2018) ..... 8
Table 5-5. Rio Rico South Sewer Basin Flows (2023) ..... 8
Table 5-6. Rio Rico South Sewer Basin Flows (Buildout) ..... 9
Table 5-7. Rio Rico South Sewer Basin Gravity Sewer Capacity Summary ..... 10
Table 5-8. Rio Rico South Sewer Basin Lift Station Capacity Summary ..... 10
Table 5-9. Rio Rico South Sewer Basin Force Main Capacity Summary ..... 11
Table 5-10. Rio Rico South Sewer Basin Buildout Gravity Sewer Capacity Summary ..... 12
Table 5-11. Rio Rico South Sewer Basin Buildout Lift Station Capacity Summary ..... 12
Table 5-12. Rio Rico South Sewer Basin Buildout Force Main Capacity Summary ..... 13
Table 5-13. Arizona Administrative Code Setback Requirements ..... 14

Table 6-1. Rio Rico North Sewer Basin Flows (2008) ..... 19
Table 6-2. Rio Rico North Sewer Basin Flows (2013) ..... 19
Table 6-3. Rio Rico North Sewer Basin Flows (2018) ..... 19
Table 6-4. Rio Rico North Sewer Basin Flows (2023) ..... 20
Table 6-5. Rio Rico North Sewer Basin Flows (Buildout) ..... 20
Table 6-6. Rio Rico North Sewer Basin Gravity Sewer Capacity Summary ..... 21
Table 6-7. Rio Rico North Sewer Basin Lift Station Capacity Summary ..... 21
Table 6-8. Rio Rico North Sewer Basin Force Main Capacity Summary ..... 21
Table 6-9. Rio Rico North Sewer Basin Buildout Gravity Main Capacity Summary ..... 22
Table 6-10. Rio Rico North Sewer Basin Buildout Lift Station Capacity Summary ..... 23
Table 6-11. Rio Rico South Sewer Basin Buildout Force Main Capacity Summary ..... 23

Table 7-1. Five-Year Capital Improvement Plan Cost Projections (South Sewer Basin) ..... 31
Table 7-2. Five-Year Capital Improvement Plan Cost Projections (North Sewer Basin) ..... 31

## LIST OF APPENDICES

Appendix A. Rio Rico Utilities Service Area and Sewer Infrastructure Layout
Appendix B. Wastewater Facility Buildout Capacity Sizing Spreadsheets

# LIST OF ACRONYMS

| | |
|---|---|
| AAC | Arizona Administrative Code |
| ACC | Arizona Corporate Commission |
| ADEQ | Arizona Department of Environmental Quality |
| ADWF | average dry weather flow |
| AOC | Approval of Construction |
| APP | Aquifer Protection Permit |
| AZPDES | Arizona Pollution Discharge Elimination System Permit |
| BADCT | Best Available Demonstrated Control Technologies |
| CIP | Capital Improvement Plan |
| EPA | Environmental Protection Agency |
| ft/s | feet per second |
| gpacd | gallons per commercial acre per day |
| gpad | gallons per acre per day |
| gpcd | gallons per capita per day |
| gpd | gallons per day |
| gpiad | gallons per industrial acre per day |
| gpm | gallons per minute |
| I-19 | Interstate 19 |
| IBWC | International Boundary and Water Commission |
| IOI | International Outfall Interceptor |
| mgd | million gallons per day |
| NIWTP | Nogales International Wastewater Treatment Plant |
| pphu | person per housing unit |
| PDWF | Peak Dry Weather Flow |
| PVC | polyvinyl chloride |
| PWWF | Peak Wet Weather Flow |
| RRU | Rio Rico Utilities |
| SEAGO | Southeastern Arizona Association of Governments Organization |
| WWTF | wastewater treatment facilities |

# 1. INTRODUCTION

The purpose of this document is to provide a master plan for the Rio Rico Utilities (RRU) wastewater collection and treatment systems and to address current and future infrastructure requirements. This wastewater master plan will provide a planning basis for present and future operation of the RRU wastewater collection and treatment systems in a manner consistent with the existing facilities, physical constraints, and resources of RRU. The infrastructure evaluation and requirements are developed based on the Arizona Department of Environmental Quality (ADEQ) regulations and standard engineering practices.

Rio Rico encompasses approximately 55,000 acres located 15 miles north of Nogales, Arizona in Santa Cruz County. The project is platted into individual developments or subdivisions consisting of Urban Units, Villas, Estates, Ranchettes, and Industrial Parks. The vast majority of Rio Rico wastewater treatment will continue to be served by individual septic systems. Rio Rico Utilities currently provides sewer service to specific portions of Rio Rico including some Urban Units, several Villas communities, and the South Industrial Park.

This master plan provides population and wastewater flow projections at five-year intervals up to the projected buildout. Residential and commercial wastewater flow contributions are derived based on current metered data which has been compared to the numbers and types of existing connections. This document includes a description and analysis of the existing infrastructure. The system infrastructure is also analyzed for capacity to serve future growth and provides recommendations for future facility expansion. Growth rates are projected at five-year intervals with buildout projections.

## 2. EXISTING WASTEWATER CONVEYANCE AND TREATMENT SYSTEM

Rio Rico is separated into two major service areas generally referred to as the North and South sewer basins. Both basins operate independently of one another. The South sewer basin includes the majority of the existing and projected customers. The layouts of the sewer service areas are depicted on the color figure provided in Appendix A.

The South sewer basin consists of the South Industrial Park, Unit 3, Unit 4, Unit 7, Unit 15, a portion of Estates Unit 8, Villas 5, Villas 13, and Villas 18. This sewer basin includes four lift stations and a collection of gravity mains that convey this basin's flow to Lift Station No. 1. This lift station pumps through approximately 11,500 feet of 8-inch Class 160 polyvinyl chloride (PVC) force main to the International Outfall Interceptor's (IOI) Manhole No. 86 located upstream of the Nogales International Wastewater Treatment Plant (NIWTP).

The North sewer basin includes the undeveloped North Industrial Park, Villas 12, and a portion of Estates Unit 16. Rio Rico Villas 12 and a portion of Estates 16 compose Sub-Basin A which either currently, or have potential to treat their wastewater flows at the existing Villas 12 Evaporation Ponds. Sub-Basin B includes the undeveloped North Industrial Park located along the Santa Cruz River.

The following sections provide an analysis of the existing and projected customers in each major sewer basin and include more detailed descriptions of the customers and facilities within the sub-basins.

# 3. SOUTH SEWER BASIN

## 3.1. Rio Rico South Sewer Sub-Basins

The South sewer basin is the larger of the two sewer basins and is projected to include the most growth. All of the South sewer basins flows are currently conveyed to the existing Lift Station No. 1 where they are pumped to the NIWTP. The following sections provide a more detailed description of each South sewer sub-basin.

### 3.1.1. South Sewer Sub-Basin A

Sewer Sub-Basin A consists of commercial facilities within the South Industrial Park and a small portion of Estates Unit 8. The South Industrial Park consists primarily of large warehouses and truck drop-off and loading facilities. South Industrial Park wastewater flows are conveyed north by gravity to Lift Station No. 1, where they are pumped to the NIWTP. There is an existing 10-inch sewer which provides the majority of the South Industrial Parks wastewater flows which increases to 12-inch before flowing into the Lift Station No. 1 site piping. There is an 8-inch sewer main near the south of this sewer basin that extends toward the southern boundary of the service area.

### 3.1.2. South Sewer Sub-Basin B

Existing sewer Sub-Basin B contains residential homes within Unit 3. This sub-basin will also provide future service to residential units in Villas Unit 5 and residential units and commercial facilities within Unit 15. There are plans to construct a future school near the southern boundary of Villas Unit 5. The wastewater flows are conveyed southwest by a 12-inch gravity main which connects to a 16-inch gravity main constructed under the Santa Cruz River. The 16-inch main connects to Lift Station No. 1, where flows are then pumped to the NIWTP.

### 3.1.3. South Sewer Sub-Basin C

Sub-Basin C consists of residential units and commercial facilities within Unit 7. This sub-basin will also provide service for residential customers in Unit 4. Flows from these units are conveyed by a network of 8-inch gravity sewer mains. A 12-inch spine sewer conveys these flows east and across Interstate 19 (I-19) to Lift Station No. 1.

### 3.1.4. South Sewer Sub-Basin D

This sewer sub-basin consists of residential homes within Villas 13 and commercial facilities within Villas 13 and Villas 18. The Villas 13 evaporation ponds are located near the northern boundary of this sub-basin and are permitted and maintained for emergency use only. This basin's flows are conveyed north by 10, 12, and 16-inch gravity mains into Lift Station No. 3 where they are pumped south to Lift Station No. 2. Lift Station No. 2 pumps into the Unit 7 gravity mains where they are conveyed east to Lift Station No. 1.

# 4. EXISTING POPULATION AND FLOW DATA

The four existing South sewer sub-basins have an average metered flow at Lift Station No. 1 of approximately 0.43 million gallons per day (mgd). Table 4-1 shows the historic metered flows.

**Table 4-1. Rio Rico South Sewer Basin Historical Metered Flows (2003-2007)**

| Year | Maximum Flow (MGD) | Minimum Flow (MGD) | Average Flow (MGD) |
|---|---|---|---|
| 2003 | 0.42 | 0.22 | 0.35 |
| 2004 | 0.44 | 0.30 | 0.39 |
| 2005 | 0.46 | 0.32 | 0.40 |
| 2006 | 0.47 | 0.36 | 0.43 |
| 2007 | 0.55 | 0.31 | 0.43 |

The overwhelming majority of the existing wastewater customers are residential units. There is very little commercial development. The South Industrial Park is built out and contributes wastewater flows to Lift Station No. 1. Table 4-2 provides a summary of the water use within the South Industrial Park.

**Table 4-2. South Industrial Park Water Use Data**

| Month | Usage (gallons\ month) | Total Area | Avg. gal/acre/month | Avg. gal/acre/day |
|---|---|---|---|---|
| November (2006) | 2,373,000 | 256 | 9,270 | 309 |
| December (2006) | 2,401,000 | 256 | 9,379 | 313 |
| January (2007) | 2,353,000 | 256 | 9,191 | 306 |
| February(2007) | 2,363,000 | 256 | 9,230 | 308 |
| March (2007) | 3,453,000 | 256 | 13,488 | 450 |
| April (2007) | 2,524,000 | 256 | 9,859 | 329 |
| May (2007) | 2,685,000 | 256 | 10,488 | 350 |
| June (2007) | 2,785,000 | 256 | 10,879 | 363 |
| July (2007) | 1,754,000 | 256 | 6,852 | 228 |
| August (2007) | 1,757,000 | 256 | 6,863 | 229 |
| September (2007) | 1,542,000 | 256 | 6,023 | 201 |
| October (2007) | 1,801,000 | 256 | 7,035 | 235 |

The low, average, and high water uses are calculated to be 201, 302, and 450 gallons per industrial acre per day (gpiad). This master plan assumes that the existing average daily wastewater flow is **242 gpiad** which is 80 percent of the average water use. The projected wastewater flows from the South Industrial Park are calculated to be approximately 61,952 gallons (242 gpiad x 256 acres).

The South Industrial Park consists primarily of large warehouses and storage facilities which may not be representative of future industrial developments including the North Industrial Park. This master plan assumes that future industrial developments will have average wastewater flows of **500 gpiad**.

Another non-residential customer that contributes significant wastewater flows includes the three existing schools in Villas 13. Table 4-3 provides a summary of the calculated wastewater contributions from each school based on the standard engineering criteria provided by ADEQ.

**Table 4-3. Existing School Wastewater Flows in Villas 13**

| School Name | Number of Students*1 | Number of Staff*2 | gpd / student*3 | gpd / staff*3 | Total (gpd) |
|---|---|---|---|---|---|
| Rio Rico High School | 1,013 | 51 | 28 | 20 | 29,377 |
| San Cayetano Elementary School | 721 | 36 | 18 | 20 | 13,699 |
| Mountain View Elementary School | 574 | 29 | 18 | 20 | 10,906 |
| **TOTAL** | **2,308** | **115** | | | **53,982** |

*1Number of students derived from Arizona School Report Cards for Academic Years 2006-2007
*2Number of staff assumes one staff member per 20 students or 5 percent student populations
*3Student and staff wastewater flows per AAC, Title 18, Ch. 9 Unit Design Flow Tables

The existing schools are calculated to have an average dry weather flow (ADWF) of 53,982 gallons. The flow calculations for the schools are based on standard calculations provided by and accepted by ADEQ and may be greater than the actual flows.

The following calculation is used to estimate the gallons per capita day (gpcd) flow assuming a residency rate of 2.8 persons per housing unit (pphu).

- (430,000 gallons per day (gpd) @ Lift Station 1) – (61,952 gpd @ South Industrial Park) – (53,982 gpd @ Schools) = 314,066 gpd remaining
- 314,066 gpd = [(2.8 pphu) x (1,928 existing residential connections) x (X gcpd)]
- Solving for X yields 58 gpcd wastewater flow

The calculations used to derive the average gpcd may not be appropriate for design of future wastewater conveyance and treatment facilities. This master plan assumes a more conservative **70 gpcd** be used for planning purposes.

Storm events have historically shown an increase in wastewater flows of approximately 60,000 gpd at Lift Station No. 1. Wet weather infiltration is most significant in the South Industrial Park. The existing South sewer basin service area encompasses approximately 1,700 acres. The wet weather infiltration is calculated to be **35 gallons per acre (gpad)** (60,000 gpd / 1,700 acres).

## 5. POPULATION AND WASTEWATER FLOW PROJECTIONS

The wastewater flows generated by the sewer basins described in this document are developed based on the existing metered flows at Lift Station No. 1 and water meter data of commercial customers provided by the utility. The flow projection criteria should be re-examined during phase designs so future upgrades are sufficiently sized to account for the latest available data. The design criteria for planning purposes are as follows:

- Maintain force main velocities between 3.5 to 6 feet per second (ft/s). In no case shall the velocity be less than 2 ft/s per ADEQ Bulletin No. 11, Chapter V B.5.a.
- Lift Station capacity to meet 1.15 x Peak Wet Weather Flow (PWWF).
- Ratio of flow depth in the pipe to the diameter of the pipe (gravity sewers) shall not exceed 0.75 for Peak Dry Weather Flow (PDWF) per R18-9-E301 (D) (2) (e). This document assumes a Manning's "n" pipe roughness of 0.13.

- Average number of persons per residential unit ..... 2.8
- Future planning average daily per capita contributions ..... 70 gpcd
- Residential peaking factors based on population per R18-9-E301 (D)(1)(b)

- South Industrial Park Average Daily Flow ..... 242 gpaid
- North Industrial Park Average Daily Flow ..... 500 gpaid
- Commercial Average Daily Flow ..... 1,000 gallons per commercial acre per day (gpacd)
- Industrial / Commercial Peaking Factor ..... 3.0

- Wet Weather Infiltration ..... 35 gpad

The equations used to calculate ADWF, PDWF, and PWWF are listed as follows:

**Average Dry Weather Flow (ADWF)** (gallons per day) = (No. of residential connections x persons per connection x average residential daily flow) + (No. of commercial connections x commercial average daily flow)

**Peak Dry Weather Flow (PDWF)** (gallons per day) = (No. of residential connections x persons per connection x average residential daily flow x residential peaking factor) + (No. of commercial connections x commercial average daily flow x commercial peaking factor)

**Peak Wet Weather Flow (PWWF)** (gallons per day) = PDWF + Wet weather infiltration x No. of sewered acres

## 5.1. Rio Rico Growth Projections and Historical Data

A summary of water connections within the service areas of the RRU for 2003 through 2007 is shown in Table 5-1.

**Table 5-1. Water Service Connections (2003-2007)**

| Year | Residential | Commercial | Total |
|---|---|---|---|
| 2007 | 6,024 | 215 | 6,239 |
| 2006 | 5,727 | 212 | 5,939 |
| 2005 | 5,313 | 206 | 5,519 |
| 2004 | 4,814 | 85 | 4,899 |
| 2003 | 4,486 | 82 | 4,568 |

The increase in water service connections within all of Rio Rico has averaged approximately 10 percent per year. The growth projections provided below in this report assume that growth within Rio Rico's sewered service area will follow a similar trend. It is noted that current growth in Rio Rico is significantly less than recent growth in the last five years and has averaged about 4 percent in 2008.

## 5.2. Rio Rico South Sewer Basin Flow Projections at Five-Year Intervals

Table 5-2 provides a summary of the existing South sewer basin contributing flows based on the numbers and types of connections and design criteria presented earlier in this master plan. Future flow projections are provided at five year increments in Tables 5-2 through 5-5 and a buildout projection in Table 5-6.

**Table 5-2. Rio Rico South Sewer Basin Flows (2008)**

| South Sewer Sub-Basin | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | South Industrial Park | 0 | 256 | 0 | 256 | 0 | 61,952 | 0.00 | 185,856 | 8,960 | 194,816 |
| | Estates 8 | 38 | 0 | 0 | 55 | 106 | 6,171 | 3.53 | 21,771 | 1,925 | 23,696 |
| B | Unit 3 | 685 | 0 | 0 | 377 | 1,918 | 111,244 | 2.09 | 232,390 | 13,195 | 245,585 |
| | Villas 5 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 | 0 | 0 | 0 |
| | Unit 15 | 0 | 0 | 5 | 10 | 0 | 5,000 | 0.00 | 15,000 | 350 | 15,350 |
| C | Unit 4 | 0 | 0 | 0 | 0 | 0 | 0 | 0.00 | 0 | 0 | 0 |
| | Unit 7 | 258 | 0 | 26 | 400 | 722 | 67,899 | 2.49 | 182,469 | 14,000 | 196,469 |
| D | Villas 13 | 947 | 0 | 50 | 400 | 2,652 | 203,793 | 1.97 | 452,963 | 14,000 | 466,963 |
| | Villas 18 | 0 | 0 | 5 | 173 | 0 | 5,000 | 0.00 | 15,000 | 6,055 | 21,055 |
| **TOTAL** | - | **1,928** | **256** | **86** | **1,671** | **5,398** | **461,059** | **1.73** | **986,106** | **58,485** | **1,044,591** |

**Table 5-3. Rio Rico South Sewer Basin Flows (2013)**

| South Sewer Sub-Basin | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | South Industrial Park | 0 | 256 | 0 | 256 | 0 | 61,952 | 0.00 | 185,856 | 8,960 | 194,816 |
| | Estates 8 | 38 | 0 | 0 | 55 | 106 | 7,448 | 3.53 | 26,275 | 1,925 | 28,200 |
| B | Unit 3 | 687 | 0 | 0 | 377 | 1,924 | 134,701 | 2.09 | 281,224 | 13,195 | 294,419 |
| | Villas 5 | 274 | 0 | 0 | 125 | 767 | 53,704 | 0.00 | 0 | 4,375 | 4,375 |
| | Unit 15 | 177 | 0 | 23 | 101 | 495 | 57,143 | 0.00 | 67,500 | 3,544 | 71,044 |
| C | Unit 4 | 93 | 0 | 0 | 65 | 259 | 18,130 | 0.00 | 0 | 2,275 | 2,275 |
| | Unit 7 | 264 | 0 | 100 | 400 | 738 | 151,146 | 2.48 | 426,780 | 14,000 | 440,780 |
| D | Villas 13 | 1,132 | 0 | 50 | 400 | 3,170 | 271,921 | 1.91 | 573,245 | 14,000 | 587,245 |
| | Villas 18 | 0 | 0 | 47 | 173 | 0 | 47,000 | 0.00 | 141,000 | 6,055 | 147,055 |
| **TOTAL** | - | **2,664** | **256** | **219** | **1,952** | **7,460** | **803,145** | **1.63** | **1,695,729** | **68,329** | **1,764,058** |

**Table 5-4. Rio Rico South Sewer Basin Flows (2018)**

| South Sewer Sub-Basin | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | South Industrial Park | 0 | 256 | 0 | 256 | 0 | 61,952 | 0.00 | 185,856 | 8,960 | 194,816 |
| | Estates 8 | 38 | 0 | 0 | 55 | 106 | 7,448 | 3.53 | 26,275 | 1,925 | 28,200 |
| B | Unit 3 | 690 | 0 | 0 | 377 | 1,931 | 135,142 | 2.09 | 281,978 | 13,195 | 295,173 |
| | Villas 5 | 548 | 0 | 0 | 250 | 1,534 | 107,408 | 0.00 | 0 | 8,750 | 8,750 |
| | Unit 15 | 354 | 0 | 40 | 193 | 990 | 109,286 | 0.00 | 120,000 | 6,738 | 126,738 |
| C | Unit 4 | 185 | 0 | 0 | 130 | 518 | 36,260 | 0.00 | 0 | 4,550 | 4,550 |
| | Unit 7 | 269 | 0 | 173 | 400 | 753 | 225,724 | 2.47 | 649,468 | 14,000 | 663,468 |
| D | Villas 13 | 1,318 | 0 | 50 | 400 | 3,689 | 308,230 | 1.86 | 629,154 | 14,000 | 643,154 |
| | Villas 18 | 0 | 0 | 89 | 173 | 0 | 89,000 | 0.00 | 267,000 | 6,055 | 273,055 |
| **TOTAL** | - | **3,401** | **256** | **352** | **2,234** | **9,521** | **1,080,450** | **1.56** | **2,283,336** | **78,173** | **2,361,508** |

**Table 5-5. Rio Rico South Sewer Basin Flows (2023)**

| South Sewer Sub-Basin | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | South Industrial Park | 0 | 256 | 0 | 256 | 0 | 61,952 | 0.00 | 185,856 | 8,960 | 194,816 |
| | Estates 8 | 38 | 0 | 0 | 55 | 106 | 7,448 | 3.53 | 26,275 | 1,925 | 28,200 |
| B | Unit 3 | 692 | 0 | 0 | 377 | 1,937 | 135,583 | 2.09 | 282,731 | 13,195 | 295,926 |
| | Villas 5 | 822 | 0 | 0 | 375 | 2,302 | 161,112 | 0.00 | 0 | 13,125 | 13,125 |
| | Unit 15 | 530 | 0 | 58 | 284 | 1,485 | 161,429 | 0.00 | 172,500 | 9,931 | 182,431 |
| C | Unit 4 | 278 | 0 | 0 | 195 | 777 | 54,390 | 0.00 | 0 | 6,825 | 6,825 |
| | Unit 7 | 275 | 0 | 247 | 400 | 769 | 300,302 | 2.47 | 872,148 | 14,000 | 886,148 |
| D | Villas 13 | 1,503 | 0 | 50 | 400 | 4,208 | 344,539 | 1.81 | 683,652 | 14,000 | 697,652 |
| | Villas 18 | 0 | 0 | 131 | 173 | 0 | 131,000 | 0.00 | 393,000 | 6,055 | 399,055 |
| **TOTAL** | - | **4,137** | **256** | **485** | **2,515** | **11,583** | **1,357,755** | **1.51** | **2,863,624** | **88,016** | **2,951,641** |

**Table 5-6. Rio Rico South Sewer Basin Flows (Buildout)**

| South Sewer Sub-Basin | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | South Industrial Park | 0 | 256 | 0 | 256 | 0 | 61,952 | 0.00 | 185,856 | 64,000 | 249,856 |
| | Estates 8 | 38 | 0 | 0 | 55 | 106 | 7,448 | 3.53 | 26,275 | 13,750 | 40,025 |
| B | Unit 3 | 694 | 0 | 0 | 377 | 1,943 | 136,024 | 2.08 | 283,484 | 94,250 | 377,734 |
| | Villas 5 | 1,096 | 0 | 0 | 500 | 3,069 | 214,816 | 0.00 | 0 | 125,000 | 125,000 |
| | Unit 15 | 707 | 0 | 75 | 375 | 1,980 | 213,572 | 0.00 | 225,000 | 93,750 | 318,750 |
| C | Unit 4 | 370 | 0 | 0 | 260 | 1,036 | 72,520 | 0.00 | 0 | 65,000 | 65,000 |
| | Unit 7 | 280 | 0 | 320 | 400 | 784 | 374,880 | 2.46 | 1,094,821 | 100,000 | 1,194,821 |
| D | Villas 13 | 1,688 | 0 | 50 | 400 | 4,726 | 380,848 | 1.77 | 736,943 | 100,000 | 836,943 |
| | Villas 18 | 0 | 0 | 173 | 173 | 0 | 173,000 | 0.00 | 519,000 | 43,250 | 562,250 |
| **TOTAL** | - | **4,873** | **256** | **618** | **2,796** | **13,644** | **1,635,060** | **1.46** | **3,438,127** | **699,000** | **4,137,127** |

At buildout, the South sewer basin is projected to produce an ADWF of approximately 1.6 mgd.

## 5.3. South Sewer Basin Existing Infrastructure Analysis

The existing infrastructure has been analyzed to determine the system capacity. Recommendations for future upgrades are provided in the future system analysis later in this report.

### 5.3.1. Gravity Sewer Interceptors (South Sewer Basin Existing Capacity Analysis)

The locations of the spine sewer mains and lift stations are shown in the Rio Rico Utilities Service Area and Sewer Infrastructure Layout in Appendix A. Internal subdivision gravity sewer mains are typically 8-inches with sufficient capacity to sewer those units. Only spine interceptor gravity mains are evaluated for capacity at the projected flows.

The gravity spine interceptor sewers consist of 8- through 16-inch mains. The sewer mains were evaluated by their respective reaches according to sewer size and minimum slope at each reach. The gravity sewer capacity analysis includes data derived from the Rio Rico Sewer Basin and Wastewater Treatment Feasibility Study (WLB 1996) and has not been field verified. The slope and calculated capacity of Reach 7 is based on as-built plans titled Sewer Augmentation Plan for Rio Rico Unit 7 (WestLand Resources, Inc. (WestLand) 1998).

A summary of each sewer reach in the South Sewer Basin is provided in Table 5-7.

**Table 5-7. Rio Rico South Sewer Basin Gravity Sewer Capacity Summary**

| South Sewer Sub-basin | Sewer Reach No. | Diameter (inches) | Minimum Slope (%) | Sewer Capacity (gpm) @ 0.75 d/D |
|---|---|---|---|---|
| A | 1 | 10 | 0.40 | 569 |
| | 2 | 12 | 0.37 | 890 |
| B | 3 | 12 | 0.25 | 731 |
| | 4 | 12 | 0.40 | 925 |
| | 5 | 16 | 0.50 | 2,227 |
| C | 6 | 12 | 0.44 | 970 |
| D | 7 | 10 | 0.32 | 509 |
| | 8 | 12 | 0.24 | 716 |
| | 9 | 14 | 0.24 | 1,080 |

The existing spine gravity mains are adequate to convey the existing wastewater flows. Augmentations and upsizing of facilities are provided in the future system analysis later in this report.

### 5.3.2. Sewer Lift Stations (South Sewer Basin Existing Capacity Analysis)

There are four existing lift stations that provide capacity to portions of the South sewer basin. The lift stations consist of submersible pumps in concrete wet wells. The pumps typically operate in simplex operation and take turns being the lead and lag pumps to distribute wear evenly. Table 5-8 provides a summary of the South sewer basin lift stations.

**Table 5-8. Rio Rico South Sewer Basin Lift Station Capacity Summary**

| Lift Station Number | Existing Pumps (HP) | Existing Capacity Simplex (gpm) | Pumping Head Simplex (feet) |
|---|---|---|---|
| 1 | 2-88 | 750 | 140 |
| 2 | 2-47 | 400 | 136 |
| 3 | 2-47 | 400 | 135 |
| 5 | 2-7.5 | 27 | 97 |

The operations staff indicated that all the lift stations are operating adequately to support the existing wastewater flows.

### 5.3.3. Pressure Sewer Force Mains (South Sewer Basin Existing Capacity Analysis)

Each lift station discharges wastewater through belowground sewer force mains. In general, the force mains do not experience significant changes in elevation and the majority of the pipeline pressures are

created by dynamic pumping heads. Table 5-9 provides a summary of the South sewer basin lift station force mains.

**Table 5-9. Rio Rico South Sewer Basin Force Main Capacity Summary**

| Lift Station Number/ Capacity (gpm) | Lift Station Pumps to | Force Main Diameter (inches) | Min. Capacity at 3.5 ft/s (gpm) | Max. Capacity at 6.0 ft/s (gpm) |
|---|---|---|---|---|
| 1 (750 gpm) | IOI Manhole 86 | 8 | 550 | 940 |
| 2 (400 gpm) | Unit 7 Gravity Main | 8 | 550 | 940 |
| 3 (400 gpm) | Lift Station No. 2 or Villas 13 Evaporation Ponds | 8 | 550 | 940 |
| 5 (27 gpm) | Unit 13 Gravity Main | 2 | 35 | 60 |

Lift Station Nos. 2 and 3 have 8-inch force mains which typically operate at approximately 2.5 ft/s while pumping 400 gallons per minute (gpm). This meets the minimum allowable velocity per ADEQ Bulletin No. 11, Chapter V B.5.a. but is less than the recommended minimum of 3.5 ft/s.

### 5.3.4. Wastewater Treatment Facilities (South Sewer Basin Existing Capacity Analysis)

Rio Rico has purchased 0.55 mgd (annual wastewater flow) from the City of Nogales which is being treated at the existing 17.2 mgd treatment plant. The NIWTP is currently being upgraded to increase effluent quality. Rio Rico is in the process of negotiating with the City of Nogales to upsize the upgraded plant by 0.740 mgd (total Rio Rico treatment capacity). The current NIWTP plant is permitted for 17.2 mgd with 9.9 mgd allocated to Nogales, Sonora, and the remainder going to Nogales, Arizona. The new NIWTP plant's capacity is currently planned for 14.74 mgd. Under the current plan, Nogales, Sonora would remain at 9.9 mgd, and Nogales, Arizona's share would drop to 4.1 mgd. Rio Rico Utilities would account for the other 0.740 mgd. The current construction schedule anticipates the treatment plant upgrades will be complete in August of 2009.

The Villas 13 evaporation ponds are maintained and permitted for emergency use and may be filled from a 6-inch bypass force main connecting from Lift Station No. 3 to the ponds. The bypass force main was originally constructed to pump wastewater from a decommissioned lift station near Lift Station No. 3 to the ponds. The plant consists of 8.5 acres (pond surface area) with Cells 1, 2, and 3 of 3.8, 2.9, and 1.8 acres, respectively. The aquifer protection permit (APP) File No. 101731 states that the facility is designed to operate with a daily influent not to exceed 150,000 gpd.

## 5.4. South Sewer Basin Future Infrastructure Analysis

### 5.4.1. Gravity Sewer Interceptors (South Sewer Basin Future Capacity Analysis)

A summary of the projected PDWF for each sewer reach is compared to the calculated sewer capacity in Table 5-10. Detailed calculations for each reach are included in Appendix B.

**Table 5-10. Rio Rico South Sewer Basin Buildout Gravity Sewer Capacity Summary**

| South Sewer Sub-basin | Sewer Reach No. | Diameter (inches) | Minimum Slope (%) | Sewer Capacity (gpm) @ 0.75 d/D | Buildout PDWF (gpm) |
|---|---|---|---|---|---|
| A | 1 | 10 | 0.40 | 569 | 147 |
| | 2 | 12 | 0.37 | 890 | 147 |
| B | 3 | 12 | 0.25 | 731 | 286 |
| | 4 | 12 | 0.40 | 925 | 428 |
| | 5 | 16 | 0.50 | 2,227 | 718 |
| C | 6 | 12 | 0.44 | 970 | 1,626 |
| D | 7 | 10 | 0.32 | 509 | 168 |
| | 8 | 12 | 0.24 | 716 | 741 |
| | 9 | 14 | 0.24 | 1,080 | 408 |

Sewer Reach 6 in Sub-Basin C will likely require upsizing to convey the future buildout flows. The requirement to upsize Lift Station No. 3 and consequently Lift Station No. 2 will be the triggering event for augmentations at Reach 6. Lift station requirements are discussed in more detail later in this report. Note that the capacities of each sewer are based on the minimum slope of the whole reach which may not be representative of the entire sewer alignment. It may be possible that only a portion of Reach 6 will actually require an augmentation.

The conservative assumptions used in this planning document indicate that Reach 8 may also require an upsizing which should be re-evaluated in the future based on actual observed flows.

### 5.4.2. Sewer Lift Stations (South Sewer Basin Future Capacity Analysis)

A summary of the projected 1.15 PWWF for each sewer lift station is compared to the calculated capacity in Table 5-11. Detailed calculations for each lift station and their contributing customers are included in Appendix B.

**Table 5-11. Rio Rico South Sewer Basin Buildout Lift Station Capacity Summary**

| Lift Station Number | Existing Capacity Simplex (gpm) | Buildout 1.15 PWWF (gpm) |
|---|---|---|
| 1 | 750 | 2,695 |
| 2 | 400 | 926 |
| 3 | 400 | 926 |
| 5 | 27 | 24 |

Lift Station No. 1 will require significant upsizing to meet the future flows from Lift Station Nos. 2 and 3 [926 gpm (buildout capacity) each] and the undeveloped Units 4 (370 total units), Unit 5 (1,096 total units), and Unit 15 (707 total units and 75 commercial acres).

Lift Station No. 3 will require a minimum upgrade to 926 gpm for buildout of Villas 18 (173 total commercial acres which is mostly undeveloped) and the majority of Villas 13 (1,688 total residential units which is slightly more than half built out). Lift Station No. 2 will be required to match the pumping rate of Lift Station No. 3 since Lift Station No. 2 is effectively an inline transfer station for all of Lift Station No. 3 flows.

### 5.4.3. Pressure Sewer Force Mains (South Sewer Basin Future Capacity Analysis)

The existing force main capacities are compared with the projected buildout 1.15 PWWF in Table 5-12. Detailed calculations are provided in Appendix B (Lift Station Capacity Tables).

**Table 5-12. Rio Rico South Sewer Basin Buildout Force Main Capacity Summary**

| Lift Station Number/ Capacity (gpm) | Force Main Diameter (inches) | Existing Simplex Capacity (gpm) | Future Buildout 1.15 PWWF (gpm) | Max. Capacity at 6.0 ft/s (gpm) |
|---|---|---|---|---|
| 1 | 8 | 750 | **2,695** | **940** |
| 2 | 8 | 400 | 926 | 940 |
| 3 | 8 | 400 | 926 | 940 |
| 5 | 2 | 27 | 24 | 60 |

The new Lift Station No. 1 force main will be designed to provide adequate scour velocities from the upgraded Lift Station No. 1 pumping regime which will be affected by the ultimate sizing of a future wastewater treatment plant. Alternatives for retrofitting Lift Station No. 1 are provided later in this master plan.

A more detailed analysis will be required at the time of detailed pump upgrade design at Lift Station Nos. 2 and 3 to determine whether it is more energy efficient to upsize those 8-inch force mains to larger diameter. Upsizing the force mains would reduce the dynamic pumping heads on the upgraded pumps which may result in more long-term energy savings.

### 5.4.4. Wastewater Treatment Facilities (South Sewer Basin Future Capacity Analysis)

As previously stated, RRU is in the process of negotiating with the City of Nogales to oversize the upgraded plant by 0.740 mgd to include capacity for Rio Rico. Either additional NIWTP plant capacity will need to be acquired or a new treatment facility constructed once this capacity is exceeded.

Previous planning efforts have recommended that the future South sewer basin wastewater treatment facility be constructed at the Lift Station No. 1 site. Although the entire infrastructure system within the

South sewer basin has been constructed to convey flows to this site, it should be noted that a future treatment plant may be located anywhere the utility is willing and able to acquire a new site for the treatment plant and easements / right-of-way for a new force main from Lift Station No. 1. As previously stated, all the current flows are being pumped approximately two miles south of Lift Station No. 1 to the Nogales IOI gravity sewer.

Some other advantages for using the Lift Station No. 1 site are that it has all major utilities including three phase power, phone, and water, and meets the setback requirements.

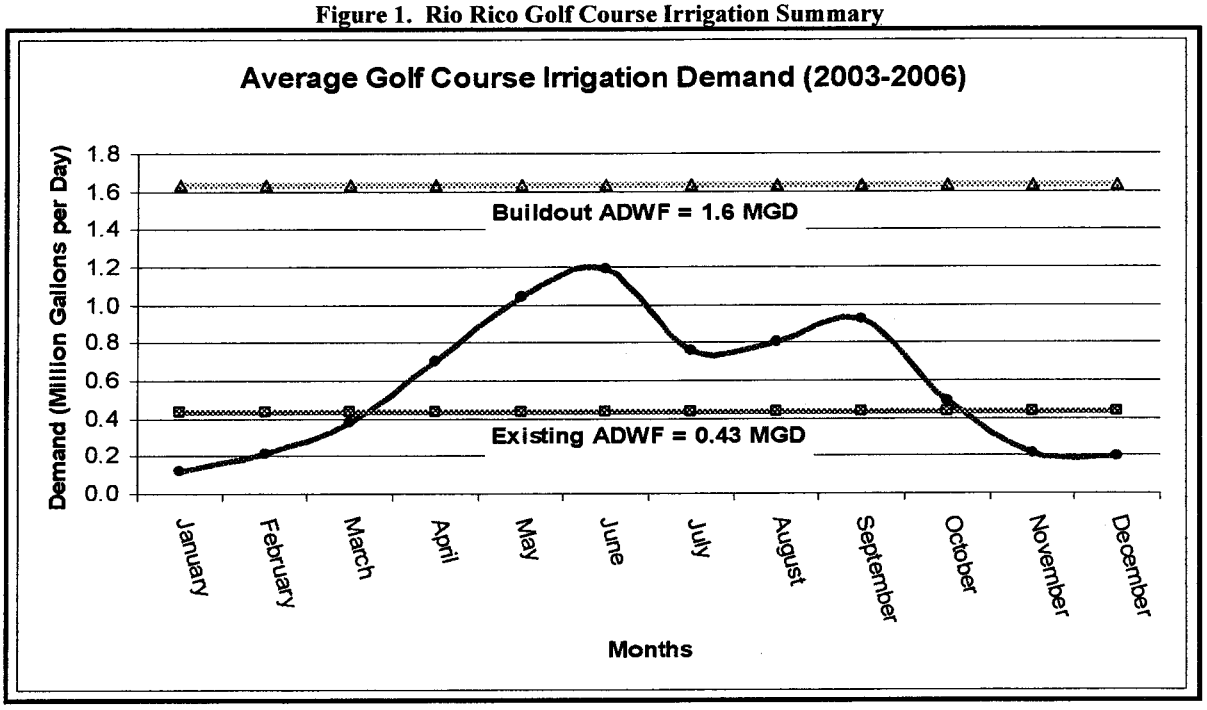
The setback requirements for wastewater treatment facilities (WWTF) are based on the ultimate system flows and treatment capacity per Arizona Administrative Code R-18-9-B201(I). Table 5-13 is adapted from R-18-9-B201(I).

**Table 5-13. Arizona Administrative Code Setback Requirements**

| Sewage Treatment Facility Design Flow (gallons per day) | No Noise, Odor, or Aesthetic Controls (feet) | Full Noise, Odor, and Aesthetic Controls (feet) |
|---|---|---|
| 100,000 to less than 500,000 | 500 | 100 |
| 500,000 to less than 1,000,000 | 750 | 250 |
| 1,000,000 or greater | 1000 | 350 |

Another advantage is that the Lift Station No. 1 site is adjacent to the Santa Cruz River so little effluent conveyance infrastructure would be required for disposal into the river. The Lift Station No. 1 site is across the Santa Cruz River from the golf course making re-use of effluent for irrigation possible with the construction of additional conveyance facilities including a new reclaimed water pump station and effluent force main. Figure 1 provides a summary of Rio Rico Golf Course Irrigation usage provided by the golf course maintenance department.

**Figure 1. Rio Rico Golf Course Irrigation Summary**




The data indicates that the golf course irrigation demand varies between 115,000 gpd in January up to almost 1,200,000 gpd in June.

A disadvantage of the Lift Station No. 1 site is that a large portion of the site is within the 100-year floodplain and erosion hazard setback of the Santa Cruz River which is protected to an unknown degree by a rock riprap berm along the south and east portions of the site. Santa Cruz County will likely require that a future treatment facility be constructed outside or above the 500-year floodplain. The appropriate floodplain limits, future site elevation, and flood protection measures would need to be further evaluated by a qualified hydrologist.

The groundwater depth at this site has historically been near the ground surface which may make installation and maintenance of buried structures less favorable than other locations not impacted by high groundwater levels. Portions of a future wastewater treatment facility at this site could be constructed of aboveground sections to keep some larger structures at grade.

The existing Lift Station No. 1 is equipped to pump approximately two miles south to the IOI at a head of 140 feet. A new treatment plant at Lift Station No. 1 site would still require a pump station to lift flows up to the headworks of the plant but that pumping head would be much lower than provided by the existing pumps at the Lift Station No. 1. Modifications would be required to the existing lift station to more efficiently pump wastewater flows at a lower head to the headworks of a new treatment facility. Three alternatives for treatment facilities are discussed in the following sections.

#### 5.4.4.1. Alternative 1 (Pump All Existing and Future Flows to NIWTP for Treatment)

This alternative assumes that RRU will acquire additional plant capacity and pump all of the South sewer basins flow, both existing and future, to the NIWTP for treatment. The main advantage to this alternative is that RRU would not be required to build, permit, and operate a new WWTF.

A disadvantage to this alternative is that RRU would not be in control of the day-to-day operation of the plant or the conveyance and monitoring of flows coming into it. It should be noted that a significant portion of the wastewater flows into the NIWTP currently come from Nogales, Sonora. Flows from Nogales, Sonora include both sanitary waste and storm flows which have historically contributed to surcharging of the IOI gravity sewer and overwhelmed the NIWTP.

The existing NIWTP may require a significant expansion to meet Rio Rico's South sewer basins flows in excess of 0.740 mgd. Such a facility expansion would require coordination with the other agencies overseeing the NIWTP including both the City of Nogales and U.S. International Boundary and Water Commission (IBWC). The required coordination and timing of events may not be practical or even possible at the time Rio Rico needs additional plant capacity.

Another disadvantage to this alternative is that RRU will not have any physical control of the effluent produced by the NIWTP which may be used to augment some of Rio Rico's water demands.

#### 5.4.4.2. Alternative 2 (Construct New WWTF to Treat All of the South Sewer Basin Flows)

Rio Rico Utilities could construct a new WWTF to treat the entire South sewer basins wastewater flows; both existing and buildout, which is calculated to be an ADWF of 1.6 mgd (See Table 5-6). The advantage of constructing a new WWTF is that Rio Rico would be in control over the monitoring and future planning of influent flows while gaining physical control over the effluent produced. The utility would also be able to more precisely plan future upgrades and expansions since the only wastewater contributions will be from within Rio Rico and any outside projects the utility chooses to accept into the sewer service area. The existing Lift Station No. 1 could be retrofit to lift flows up to the treatment plant's headworks rather than pumping to the IOI.

One disadvantage to this alternative is that Rio Rico has already paid for 0.55 mgd and possibly up to 0.740 mgd of treatment capacity at the NIWTP. Under this alternative, a new treatment plant would need to include the 0.740 mgd plus the additional buildout flows. This would likely result in a significant capital expenditure which would be passed onto the rate base. There may be a possibility that Rio Rico could sell the 0.740 mgd capacity back to Nogales, Sonora or the Nogales, Arizona which would need to be negotiated in the future. The utility would have to justify the increased rates for approval by the Arizona Corporation Commission (ACC) before those costs could be recovered from the customer rate base.

#### *5.4.4.3. Alternative 3 (Pump 0.55 MGD to NIWTP and Construct new WWTF)*

This alternative considers continued pumping up to 0.55 mgd (existing purchased capacity) to the NIWTP and building a new WWTF to treat the excess wastewater flows up to the buildout of Rio Rico's South sewer basin. The advantage of this option is that Rio Rico will be able to make use of the pre-purchased NIWTP treatment capacity while gaining control over the timing and decision making of any future treatment capacity requirement.

The disadvantages of this alternative are similar to but less in scale to those previously discussed in Alternative 2 for building and operating a new treatment plant. The rate base would not be impacted to the extent of Alternative 2 because this alternative fully utilizes the 0.55 mgd of existing purchased capacity at the NIWTP. A treatment plant designed under this alternative would require 1.1 mgd (1.64 mgd – 0.55 mgd) of buildout treatment capacity which could be constructed in phases as required by future growth. This alternative will also provide Rio Rico with physical control of the effluent produced by the new plant.

##### 5.4.4.3.1. Alternative 3 Implementation

Rio Rico Utilities' purchased plant capacity agreement may allow some flexibility in the design and operation of a future South sewer basin treatment plant. The utility affirmed that the 0.55 mgd of existing purchased capacity is calculated as an annual average daily flow. The pumped flow rates may fluctuate throughout the day provided that the annual average daily flow does not to exceed 0.55 mgd. This flexibility in operation may allow a reduction in the size of equalization facilities within the treatment system typically essential to attenuate peak flow rates since peak flows could be bypassed and pumped to the NIWTP.

Rio Rico may consider a treatment plant design that excludes equalization facilities by varying the pump discharge at Lift Station No. 1 to send peak flows (up to 0.55 mgd) to the NIWTP. Under this alternative, a new Rio Rico South sewer basin treatment plant would be designed to treat only those flows in excess of the 0.55 mgd. The 0.55 mgd could be pumped at varying flow rates as required to the WWTF. Lift Station No. 1 pumps and force main may need significant upgrades depending on how much greater the peak flows become relative to the average flows delivered to a new Rio Rico treatment facility.

# 6. NORTH SEWER BASIN

## 6.1. Rio Rico North Sewer Sub-Basins

The North sewer basin is significantly smaller than the previously described South sewer basin. The North sewer basins flows are currently conveyed to the Villas 12 evaporation ponds. The following sections provide a more detailed description of customers and facilities that make-up the two North sewer sub-basins.

### 6.1.1. North Sewer Sub-Basin A

North Sewer Sub-Basin A currently includes residential units in Rio Rico Villas Unit 12 and a portion of Rio Rico Estates Unit 16. Rio Rico Villas 12 and portions of Estates 16 encompass approximately 400 acres of residential development. Wastewater is conveyed by a gravity sewer system to Lift Station No. 4. Wastewater is pumped from Lift Station No. 4 into the Villas 12 evaporation ponds located in Josephine Canyon. All of the gravity sewers have already been installed in Villas Unit 12 and portions of Estates 16.

### 6.1.2. North Sewer Sub-Basin B

Sub-Basin B includes the undeveloped North Industrial Park. The industrial park was originally platted along the east and west banks of the Santa Cruz River. Most of the original North Industrial Park located east of the Santa Cruz River has been re-platted for residential development and will be served by individual septic systems. The terrain gradually slopes toward the northwest with the river. It is anticipated that a future WWTF will be located near the low point of this sewer sub-basin so that gravity sewers could convey flows to the head of any future wastewater treatment plant.

## 6.2. Rio Rico North Sewer Basin Flow Projections at Five-Year Intervals

Tables 6.1 through 6.5 provide a summary of the existing North sewer basin flows based on the numbers and types of connections and design criteria presented earlier in this report. Future flow projections are provided at five year increments with buildout projections. The 15-year projection assumes approximately 10 percent annual growth which is consistent with the calculations and discussion provided in Section 5.1 although it is noted that current growth in Rio Rico is significantly less than historical averages. A buildout projection is also provided in Table 6-5.

**Table 6-1. Rio Rico North Sewer Basin Flows (2008)**

| North Sewer Sub-Basins | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Villas 12 | 108 | 0 | 0 | 369 | 302 | 21,168 | 2.92 | 61,800 | 12,915 | 74,715 |
| | Estates Unit 16 (Portion) | 24 | 0 | 0 | 15 | 67 | 4,704 | 3.83 | 18,036 | 525 | 18,561 |
| | **Sub-Total** | **132** | **0** | **0** | **384** | **370** | **25,872** | **2.82** | **72,837** | **13,440** | **86,277** |
| B | North Industrial Park West | **0** | **0** | **0** | **0** | **0** | **0** | **0.00** | **0** | **0** | **0** |
| **TOTAL** | - | **132** | **0** | **0** | **384** | **370** | **25,872** | **2.82** | **72,837** | **13,440** | **86,277** |

**Table 6-2. Rio Rico North Sewer Basin Flows (2013)**

| North Sewer Sub-Basins | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Villas 12 | 174 | 0 | 0 | 369 | 487 | 34,091 | 2.68 | 91,296 | 12,915 | 104,211 |
| | Estates Unit 16 (Portion) | 39 | 0 | 0 | 20 | 108 | 7,576 | 3.52 | 26,644 | 700 | 27,344 |
| | **Sub-Total** | **213** | **0** | **0** | **389** | **595** | **41,667** | **2.58** | **107,600** | **13,615** | **121,215** |
| B | North Industrial Park West | **0** | **0** | **0** | **0** | **0** | **0** | **0.00** | **0** | **0** | **0** |
| **TOTAL** | - | **213** | **0** | **0** | **389** | **595** | **41,667** | **2.58** | **107,600** | **13,615** | **121,215** |

**Table 6-3. Rio Rico North Sewer Basin Flows (2018)**

| North Sewer Sub-Basins | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Villas 12 | 280 | 0 | 0 | 369 | 784 | 54,904 | 2.46 | 134,870 | 12,915 | 147,785 |
| | Estates Unit 16 (Portion) | 62 | 0 | 0 | 25 | 174 | 12,201 | 3.23 | 39,361 | 875 | 40,236 |
| | **Sub-Total** | **342** | **0** | **0** | **394** | **959** | **67,105** | **2.37** | **158,955** | **13,790** | **172,745** |
| B | North Industrial Park West | **0** | **0** | **0** | **0** | **0** | **0** | **0.00** | **0** | **0** | **0** |
| **TOTAL** | - | **342** | **0** | **0** | **394** | **959** | **67,105** | **2.37** | **158,955** | **13,790** | **172,745** |

**Table 6-4. Rio Rico North Sewer Basin Flows (2023)**

| North Sewer Sub-Basins | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Villas 12 | 451 | 0 | 0 | 369 | 1,263 | 88,424 | 2.25 | 199,240 | 12,915 | 212,155 |
| | Estates Unit 16 (Portion) | 100 | 0 | 0 | 30 | 281 | 19,650 | 2.96 | 58,147 | 1,050 | 59,197 |
| | **Sub-Total** | **551** | **0** | **0** | **399** | **1,544** | **108,074** | **2.17** | **234,820** | **13,965** | **248,785** |
| B | North Industrial Park West | **0** | **100** | **0** | **100** | **0** | **40,000** | **0.00** | **120,000** | **3,500** | **123,500** |
| **TOTAL** | - | **551** | **100** | **0** | **499** | **1,544** | **148,074** | **2.17** | **354,820** | **17,465** | **372,285** |

**Table 6-5. Rio Rico North Sewer Basin Flows (Buildout)**

| North Sewer Sub-Basins | Subdivision Tract | Residential Connections | Indust. Area | Comm. Area | Sewered Area (Acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) |
|---|---|---|---|---|---|---|---|---|---|---|---|
| A | Villas 12 | 790 | 0 | 0 | 369 | 2,212 | 154,840 | 2.04 | 315,210 | 12,915 | 328,125 |
| | Estates Unit 16 (Portion) | 160 | 0 | 0 | 40 | 448 | 31,360 | 2.72 | 85,262 | 1,400 | 86,662 |
| | **Sub-Total** | **950** | **0** | **0** | **409** | **2,660** | **186,200** | **1.97** | **366,593** | **14,315** | **380,908** |
| B | North Industrial Park West | **0** | **279** | **0** | **279** | **0** | **111,600** | **0.00** | **334,800** | **9,765** | **344,565** |
| **TOTAL** | - | **950** | **279** | **0** | **688** | **2,660** | **297,800** | **1.97** | **701,393** | **24,080** | **725,473** |

The projected ADWF from North Sub-Basins A and B are calculated to be 186,200 and 111,600 gpd, respectively.

## 6.3. North Sewer Basin Existing Infrastructure Analysis

The existing North Sewer Sub-Basin A gravity sewer, lift station, force main, and treatment facility has been analyzed to determine the system capacity. As previously stated, Sub-Basin B is undeveloped and does not contain any existing wastewater infrastructure.

### 6.3.1. Gravity Sewer Interceptors (North Sewer Basin Existing Capacity Analysis)

There is an existing 8-inch gravity interceptor in Vereda de la Patria which conveys flows from east to west and drains into Lift Station No. 4. Lateral sewers provide capacity to Villas 12 and Estates Unit 16.

Table 6-6 provides a summary of the existing spine sewer main capacity.

**Table 6-6. Rio Rico North Sewer Basin Gravity Sewer Capacity Summary**

| North Sewer Sub-basin | Sewer Reach No. | Diameter (inches) | Minimum Slope (%) | Sewer Capacity (gpm) @ 0.75 d/D |
|---|---|---|---|---|
| A | 10 | 8 | 0.50 | 351 |

The gravity sewer system is sufficient to provide existing capacity to customers in Villas 12 and the smaller portion of Estates Unit 16.

### 6.3.2. Sewer Lift Stations (North Sewer Basin Existing Capacity Analysis)

Lift Station No. 4 pumps flows collected from Villas 12 and Estates Units 16 across Josephine Canyon and into the Villas 12 Evaporation Ponds. The capacity of Lift Station No. 4 is summarized in Table 6-7.

**Table 6-7. Rio Rico North Sewer Basin Lift Station Capacity Summary**

| Lift Station No. | Existing Pumps (HP) | Existing Capacity Simplex (gpm) | Pumping Head Simplex (feet) |
|---|---|---|---|
| 4 | 2-20 HP | 500 | 10 |

The pumping capacity and design head are based on the as-built drawings (Circa 1982) and do not account for pump performance degradation. This lift station is showing signs of deterioration and is a candidate for renovation or complete replacement pending a detailed facility analysis.

### 6.3.3. Pressure Sewer Force Main (North Sewer Basin Existing Capacity Analysis)

The force main capacity from Lift Station No. 4 to the Villas 12 evaporation ponds is summarized in Table 6-8.

**Table 6-8. Rio Rico North Sewer Basin Force Main Capacity Summary**

| Lift Station Number/ Capacity (gpm) | Lift Station Pumps to | Force Main Diameter (inches) | Min. Capacity at 3.5 ft/s (gpm) | Max. Capacity at 6.0 ft/s (gpm) |
|---|---|---|---|---|
| 4 (500 gpm) | Villas 12 Evaporation Ponds | 6 | 310 | 615 |

The force main has adequate capacity to serve the existing Villas 12 and the portion of Estates Unit 16.

### 6.3.4. Wastewater Treatment Facilities (North Sewer Basin Existing Capacity Analysis)

The Villas 12 evaporation ponds were constructed in 1986 and consist of three cells collectively totaling 9.1 acres. The Approval of Construction (AOC) from ADEQ indicates the ponds were classified as aerobic stabilization ponds and were originally designed to treat 45,000 gpd. The Rio Rico Villas 12 Wastewater Treatment Facility Feasibility Study prepared by WestLand (2005) provides a more conservative estimate for the treatment capacity of 35,000 gpd.

ADEQ prepared a determination that the existing facility meets the requirements of the Arizona Administrative Code (AAC) R18-9-B301 (I) for a Type 1 General APP (File No. 105005). The flows related to the treatment facility may not exceed 20,000 gpd unless an individual APP is obtained and is discussed in more detail below in Section 6.4.4.

The approximate size of the pond cells 1, 2, and 3, are 1.8, 3.5, and 3.8 acres respectively based on Record Drawings by Cella, Barr, Evans (7/16/80). The drawings indicate the ponds were designed to have a 4-foot water depth and 3-foot freeboard. Each pond is connected by a gravity pipe with shut-off valves to allow flow from one cell to the next.

## 6.4. North Sewer Basin Future Infrastructure Analysis

The following sections provide a summary of the recommended expansions and upgrades to the existing facilities in the North sewer basin.

### 6.4.1. Gravity Sewer Interceptors (North Sewer Basin Future Capacity Analysis)

A summary of the projected PDWF for each sewer reach is compared to the calculated capacity in Table 6-9. Detailed calculations are included in Appendix B.

**Table 6-9. Rio Rico North Sewer Basin Buildout Gravity Main Capacity Summary**

| North Sewer Sub-basin | Sewer Reach No. | Diameter (inches) | Minimum Slope (%) | Sewer Capacity (gpm) @ 0.75 d/D | Buildout PDWF (gpm) |
|---|---|---|---|---|---|
| A | 10 | 8 | 0.50 | 351 | 255 |

The existing 8-inch gravity main in Vereda de la Patria will be sufficient to serve the projected buildout of the North Sub-Basin B. All future lateral sewers should be minimum 8-inch diameter sewers.

The topography may allow Sub-Basin B to drain west and connect to the future North Sewer Sub-basin A. The distance from Lift Station No. 4 to Sub-Basin B is approximately two miles. An interconnect may allow for a combined treatment facility in Sub-Basin B, however, such a gravity main extension would likely be cost prohibitive and is not evaluated in further detail in this master plan.

### 6.4.2. Sewer Lift Stations (North Sewer Basin Future Capacity Analysis)

A summary of the projected 1.15 PWWF for each sewer reach is compared to the calculated capacity in Table 6-10. Detailed calculations for the lift station are included in Appendix B.

**Table 6-10. Rio Rico North Sewer Basin Buildout Lift Station Capacity Summary**

| Lift Station No. | Existing Capacity Simplex (gpm) | Buildout 1.15 PWWF (gpm) |
|---|---|---|
| 4 | **500** | **304** |

Lift Station No. 4 pumping capacity is sufficient for buildout of this Villas 12 and the portion of Estates Unit 16. The pumping capacity for this lift station is significantly greater than the incoming wastewater flows although it should be noted that this higher flow rate is required to provide adequate scour velocities in the existing 6-inch sewer force main. The buildout pumping requirement is calculated to be approximately 305 gpm [1.15 (safety factor) x 380,908 gpd (See Table 6-5 Sub-Basin A PWWF) / 1440 min./day].

A preliminary investigation was performed as part of this master plan to determine whether Lift Station No. 4 could be taken out of service by installing a gravity main and siphon under Josephine Canyon. A review of the Rio Rico Villas Unit No. 12 Force Main and Treatment Facilities plans (circa 1982) indicates that Lift Station No. 4 will be required to pump flows under the wash and up to the headworks of a future treatment plant. The relatively low existing and projected wastewater flows are not anticipated to be adequate to maintain scour velocities within a siphon.

### 6.4.3. Pressure Sewer Force Main (North Sewer Basin Future Capacity Analysis)

The existing force main capacity is compared with the projected buildout 1.15 PWWF in Table 6-11. Detailed calculations are provided in Appendix B (Lift Station Capacity Table).

**Table 6-11. Rio Rico South Sewer Basin Buildout Force Main Capacity Summary**

| Lift Station Number/ Capacity (gpm) | Force Main Diameter (inches) | Existing Simplex Capacity (gpm) | Future Buildout 1.15 PWWF (gpm) | Max. Capacity at 6.0 ft/s (gpm) |
|---|---|---|---|---|
| 4 | 6 | 500 | 304 | 615 |

The existing force main is adequate to provide capacity to the anticipated buildout of Villas 12 and Estates Unit 16.

### 6.4.4. Wastewater Treatment Facilities (North Sewer Basin Future Capacity Analysis)

This report includes an analysis of constructing two separate treatment plants to serve the North Sewer Basins A and B. As previously stated, the cost associated with building the infrastructure required to convey flows from the existing Villas 12 and Estates 16 to the North Industrial Park would likely negate combining flows into a shared wastewater treatment facility.

The main advantage for constructing two separate treatment plants is that the two sub-basins would not require a new conveyance system to convey flows approximately two miles west from Sub-Basin A to Sub-Basin B. Additionally, the timing of construction of the North Industrial Park is unknown but could be prompted by the construction of a new bridge across the Santa Cruz River.

The disadvantage of this alternative is that the utility would be required to build, permit, and operate two new WWTFs. Additionally, the capital cost and operation and maintenance cost of treatment plants are typically higher on a cost per gallon basis for smaller plants when compared to larger combined facilities.

The flow projections provided in this master plan indicate that Rio Rico North Sub-Basin A may have an ADWF of 20,000 gpd by the end of 2009, which is the permitted capacity of Villas 12 ponds. The Villas 12 ponds will require an Individual APP prior to reaching 20,000 gpd or a new treatment plant constructed. As previously stated, WestLand calculated that the existing Villas 12 ponds have an actual treatment capacity of approximately 35,000 gpd which also may be exceeded in the near future.

The utility may pursue obtaining an Individual APP for the Villas 12 ponds which may delay the requirement for a new treatment facility at the Villas 12 ponds. Work associated with obtaining an Individual APP includes performing a site investigation to determine the integrity of the existing system, providing facility specific treatment design calculations, development of Best Available Demonstrated Control Technologies (BADCT), preparation of and submission of the permit to ADEQ, follow-up coordination with ADEQ, and a public hearing. It is estimated that the APP approval process would take approximately 1.5 years.

#### *6.4.4.1. North Sub-Basin A Treatment Facility*

A new treatment plant at the Villas 12 ponds to serve the buildout North Sub-Basin A would be sized to treat approximately 190,000 gpd, which is the calculated buildout ADWF for North Sub-Basin A. The existing gravity sewer system would continue to convey flows to Lift Station No. 4 which could be pumped to the headworks of a new treatment plant. The existing site is already owned by Rio Rico Utilities, meets the setback requirements, has utilities nearby, and is large enough for a new treatment plant.

The main disadvantage of using the Villas 12 pond site is that portions of the site are located in the floodplain. It is likely that the site would need to be raised or a flood control structure constructed to

protect the facilities. Flood protection measures and the final facility layout would need to be evaluated by a qualified hydrologist.

#### *6.4.4.2. North Sub-Basin B Treatment Facility*

The North Industrial Park in Rio Rico North Sub-Basin B is calculated to have a buildout ADWF of approximately 112,000 gpd. This ADWF would be the ultimate capacity of the future North Industrial Park WWTF. A new lift station may be required to pump flows across the Santa Cruz River if any portion of the original North Industrial Park East is ever developed with industrial facilities.

# 7. CAPITAL IMPROVEMENT PLAN

## 7.1. INTRODUCTION

This section presents the infrastructure cost estimates and a capital improvement plan (CIP) for the upgrades to the existing system and facility expansions discussed previously in this master plan. This chapter focuses on future treatment facilities which are anticipated to account for the highest capital expenditure for the utility. It is typically more cost effective on a cost per gallon basis to construct larger treatment plants rather than in several small phases. Generally, conventional treatment facilities are designed such that the initial average flow rate is approximately 20 to 30 percent of the plant capacity and varies depending on the method of treatment. Considerations for a rate of return on investment with respect to being "used, useful, and recoverable" may also be a determining factor in the phasing of infrastructure.

The focus of this chapter is on a five-year CIP and should be updated once the alternatives have been evaluated and a definite course of action has been established by the utility. The wastewater utility currently has adequate wastewater collection facilities to serve the existing customers.

The priorities for the proposed infrastructure projects have been estimated based on the existing system facilities and physical constraints of the utility. A summary spreadsheet of the proposed infrastructure and associated cost projections are provided in Tables 7-1 and 7-2 located at the end of this section. The following sections provide the assumptions made in projecting the infrastructure costs.

## 7.2. COST PROJECTION ASSUMPTIONS

Due to the fact that this planning document includes conceptual layouts and sizing for proposed facilities, assumptions were made to predict probable construction costs. Standard assumptions were made for several categories of improvements based on recent bids of similar projects and discussions with local Contractors. All costs provided in this report and appendices exclude property and easement acquisition. Estimates are based on July 2008 costs.

### 7.2.1. Engineering, Inspection, and Contingencies

Due to the planning nature of the locations of the facilities proposed in the master plan, contingencies are added to reflect conditions that may affect the individual projects. This cost component can include environmental permitting, unforeseen subsurface conditions, floodplain issues, and other unknown conditions.

Modifications to public wastewater conveyance and treatment facilities require design by an Arizona Registered Professional Engineer for approval by ADEQ prior to construction. A Registered Engineer must also certify that each project has been constructed in conformance with the ADEQ approved design

plans and specifications. This requires site inspection of construction, testing and start-up, and Engineer's Certification. Twenty-five (25) percent of the project subtotal has been added to the line items in Tables 7-1 and 7-2 to account for Engineering, Inspection, and Contingencies.

## 7.3. Wastewater Treatment Facility Permitting Cost

It is anticipated that all new wastewater treatment facilities in Rio Rico will require a 208 Area Plan Amendment and Individual APP. Both applications require considerable timeframes. Normal processing time for APP modifications and/or applications can range from 1.5 to two years assuming there are no controversial issues related to the project. It takes approximately 1.5 years to complete the 208 Plan Amendment Process. The APP application can be completed for submittal concurrently with the 208 Plan Amendment, however, ADEQ will not begin the APP substantive review process until the 208 Plan Amendment is approved.

Development of a 208 Plan Amendment document is completed in accordance with the Environmental Protection Agency (EPA) Section 208 Clean Water Act, South Eastern Arizona Governments Organization (SEAGO), and ADEQ. The work includes preparation of the plan amendment, extensive coordination and meetings with SEAGO and ADEQ in addition to at least one public hearing. There may be a significant cost savings by developing the 208 Plan Amendment for multiple facilities as a single 208 Plan Amendment. This CIP assumes that the cost of a 208 Plan Amendment is $40,000 to $50,000 per treatment facility, depending on capacity, and each facility will be permitted separately.

The work associated with obtaining an Individual APP includes development of the application, verifying BADCT, coordination with ADEQ, and attending public hearings as required. The APP approval is contingent on the 208 Area Plan Amendment approval. The APP requires a hydrogeological study to determine aquifer impacts. It is assumed that each APP, including the hydrogeological report will cost from $50,000 to $60,000 depending on plant capacity.

The APP also requires a design report and engineered plans and specifications as a separate attachment. The cost of engineering is included in the Engineering, Inspection, and Contingencies percentage of project cost described above in this CIP.

### 7.3.1. Effluent Disposal Cost

This CIP does not specifically include costs for the wide range of options available for effluent disposal. Effluent disposal alternatives include discharge, reuse, and recharge.

Effluent discharges to tributary drainages to the Santa Cruz River would require an Arizona Pollution Discharge Elimination System Permit (AZPDES) through ADEQ. The cost of AZPDES permitting ranges from approximately $20,000 to $25,000. AZPDES discharge and monitoring requirements are specific to each project.

Another alternative discussed previously in this master plan is the potential for reuse of treated effluent. A reuse permit is developed with the APP. Significant infrastructure upgrades would be required to deliver treated effluent to a facility such as a golf course and are not discussed in detail in this master plan pending further analysis. In addition the reuse permit, an AZPDES permit would also be required if a facility such as a golf course could not accept all effluent generated year round which is most typically during winter months.

Rio Rico Utilities could also dispose of treated effluent using recharge basins. Recharge basins are permitted as part of the disposal component in the APP. Infrastructure components associated with recharge basins typically include conveyance facilities from the treatment plant in addition to the recharge basins. A hydrogeological evaluation is required to determine the soil absorption rate and projected sizing the recharge basins.

Consideration for permit specific monitoring and reporting requirements will also be necessary when selecting the method of disposal. Monitoring and reporting can have significant ongoing operation and maintenance costs. Effluent discharge and recharge may require long-term aquifer monitoring which typically involves the installation of monitoring wells. Costs associated with long-term monitoring and reporting and the infrastructure required to carry out those tasks are not specifically included in this CIP since they are unknown at this time.

## 7.4. South Sewer Basin Capital Improvement Plan

The following sections provide a summary of the infrastructure recommendations and or capacity allocations to increase the wastewater treatment capacity for the South sewer basin in the next five years. The operational considerations for the alternatives have been provided earlier in this report and a brief summary of the cost components associated with those alternatives are provided below.

### 7.4.1. Alternative 1 (Pump All Existing and Future Flows to NIWTP for Treatment)

Rio Rico Utilities currently pumps all of the existing South sewer basin flows (up to 0.55 gpd annualized average daily flow) to the City of Nogales NIWTP. The utility is in negotiation with the City of Nogales to purchase an additional 0.190 mgd at the new upgraded treatment plant which would increase Rio

Rico's South sewer basin treatment capacity to 0.740 gpd. The projected flow by 2013 (See Table 5-3) is approximately 0.80 gpd which is 8 percent higher than 0.740 gpd, the previously planned treatment plant capacity expansion. The actual upgraded treatment capacity should be further evaluated before finalizing any formal agreements.

Rio Rico Utilities indicated that the cost of additional treatment plant capacity at the upgraded NIWTP would be $8.00 per gallon, significantly less than the cost of constructing a new facility. This alternative would represent the least capital cost to RRU although it may not be practical to assume that all future wastewater flows can be treated at the NIWTP due to the extensive coordination with other agencies and effluent control issues discussed previously in this report. Other disadvantages discussed earlier in this report include that RRU will not have full control over the timing of upsizing the plants capacity as necessary to accommodate Rio Rico's growth and a possible loss of capacity due to significant increases in Mexican sewage and/or storm water inundation.

### 7.4.2. Alternative 2 (Construct New WWTF to Treat All of the South Sewer Basin Flows)

Alternative 2 is provided to allow RRU full control over the timing of construction, operation, and control of effluent collected from the South sewer basin by constructing a new treatment facility to treat all of Rio Rico's existing and future wastewater flows. The plant would be constructed in phases and it is assumed that the first phase will be at least 0.80 mgd, the projected ADWF flow rate by 2013 (See Table 5-3 ADWF). The buildout size of this treatment plant is projected to be approximately 1.64 mgd (See Table 5-6 ADWF).

This alternative represents the highest capital cost to the utility and does not take advantage of any pre-purchased capacity at the NIWTP. Another component of work will be augmenting Lift Station No. 1 to pump flows, both existing and future to the headworks of the new treatment plant. Flood protection measures such as raising a site and/or bank protection may also be a significant capital cost depending on the final location of the treatment plant. The extent of flood protection is unknown pending a site specific surface hydrology study and is not specifically accounted for in the cost provided in Table 7-1.

### 7.4.3. Alternative 3 (Pump 0.55 MGD to NIWTP and Construct new WWTF)

This alternative takes advantage of the relatively low capital cost of purchasing additional treatment plant capacity at the NIWTP (up to 0.740 mgd) and provides control over the timing, construction, and operation of future treatment facilities by building a new treatment plant to treat flows greater than 0.740 mgd. This alternative also allows for physical control of the effluent produced at the future wastewater treatment plant. The buildout size of a treatment plant under this alternative would be approximately 1.1 mgd, the buildout ADWF flow rate in Table 5-6 (1.64 mgd) minus the flows pumped to the NIWTP (0.55 mgd). The required plant capacity would be less if the utility also selects to pursue the purchase of the additional 190,000 gpd to bring the total purchased capacity allocation up to 0.740 mgd.

This alternative assumes that Rio Rico's NIWTP capacity allocation remains 0.55 mgd and that the new Rio Rico South sewer basin treatment plant is constructed in three phases of 0.37 mgd each. This alternative would require some modification to Lift Station No. 1 to bypass portion of this basins flow into the headworks of a new treatment plant. As previously discussed above for Alternative 2, flood protection measures are unknown at this time and are not specifically accounted for in Table 7-1.

## 7.5. North Sewer Basin Capital Improvement Plan

The focus of the CIP for the North Sewer basin is increasing the treatment capacity at the Villas 12 ponds. It is assumed that no construction will take place within the North Industrial Park during this time period. As previously stated, the treatment capacity of the ponds is approximately 35,000 gpd although they are only permitted for 20,000 gpd. The required treatment plant capacity may be exceeded in either case by 2013 (See Table 6-2) at which time a new treatment plant will be required. A cost component is provided for obtaining an individual permit for the ponds to increase the permitted capacity from 20,000 gpd to 35,000 gpd which may allow the utility additional time to plan for, design, and permit a new WWTF at the Villas 12 ponds site. It should be noted that ADEQ may not allow the evaporation ponds to be permitted under an Individual APP.

The calculated buildout treatment capacity requirement of the North Sewer Basin A (Villas 12 and Estates 16) is approximately 186,200 gpd (See Table 6-4 ADWF). This CIP assumes that the treatment facility will be constructed in three evenly sized phases of approximately 62,000 gpd each.

Santa Cruz County will likely require that a new treatment facility be located above the 500-year floodplain which may require an unknown degree of flood protection pending a surface water hydrology study. Flood protection is not specifically accounted for in Table 7-2.

It is recommended that a more detailed investigation be prepared to determine whether the Lift Station No. 4 should be rehabilitated or completely replaced with a new lift station to increase the level of service and reliability of this pump station.

**Table 7-1. Five-Year Capital Improvement Plan Cost Projections (South Sewer Basin)**

| Alternative | Description | Units | Quantity | Cost/Unit | Project Sub-Total | 25% Engineering, Inspection, and Contingencies | Total | Timeframe (years) |
|---|---|---|---|---|---|---|---|---|
| 1 | Purchase Additional 190,000 gallons of treatment plant capacity at NIWTP to increase the South Sewer Basin treatment capacity from 0.55 mgd to 0.740 mgd | gallon | 190,000 | $8 | $1,520,000 | $0 | **$1,520,000** | 1-2 |
| 2 | Construct Phase I (0.80 mgd) WWTF. The plant will be expandable to serve all of South sewer basin flows, both existing and future*1 | gallon | 800,000 | $14 | $11,200,000 | $2,800,000 | $14,000,000 | 3-5 |
| | Augment Lift Station No. 1 electrical, controls, and new pumps that pump all flows to WWTF headworks | each | 1 | $150,000 | $150,000 | $37,500 | $187,500 | 2-3 |
| | Provide 208 Area Plan Amendment for WWTF*2 | each | 1 | $45,000 | $45,000 | $0 | $45,000 | 1-2 |
| | Obtain Individual APP for new WWTF | each | 1 | $55,000 | $55,000 | $0 | $55,000 | 1-2 |
| | **Alternative 2 Totals** | - | - | - | - | - | **$14,287,500** | - |
| | Phase I (0.37 MGD) WWTF to serve a portion of South sewer basin flows*1 | gallon | 370,000 | $18 | $6,660,000 | $1,665,000 | $8,325,000 | 2-3 |
| | Augment Lift Station No. 1 and electrical, controls, and new pump(s) to bypass a portion of flows into new WWTF headworks | each | 1 | $100,000 | $100,000 | $25,000 | $125,000 | 2-3 |
| | Provide 208 Area Plan Amendment for new WWTF*2 | each | 1 | $40,000 | $40,000 | $0 | $40,000 | 1-2 |
| | Obtain Individual APP for new WWTF | each | 1 | $45,000 | $45,000 | $0 | $45,000 | 1-2 |
| | **Alternative 3 Total** | - | - | - | - | - | **$8,535,000** | - |

*1 Treatment plant cost does not specifically include permitting, monitoring and reporting, or capital improvement costs required for disposal of effluent.
*2 Assumes Sewer Basin Study will be provided.

**Table 7-2. Five-Year Capital Improvement Plan Cost Projections (North Sewer Basin)**

| Description | Units | Quantity | Cost/Unit | Project Sub-Total | 25% Engineering, Inspection, and Contingencies | Total | Timeframe (years) |
|---|---|---|---|---|---|---|---|
| Obtain Individual APP for full treatment plant capacity of Villas 12 Evaporation Ponds (Approximately 35,000 gpd) | Each | 1 | $45,000 | $45,000 | $0 | $45,000 | 1-2 |
| Phase I (62,000 gpd) WWTF @ Villas 12 Ponds Site*1*2 | gallon | 62,000 | $35 | $2,170,000 | $542,500 | $2,712,500 | 2-3 |
| Provide 208 Area Plan Amendment for new WWTF*3 | Each | 1 | $45,000 | $45,000 | $0 | $45,000 | 1-2 |
| Obtain Individual APP for new WWTF | Each | 1 | $55,000 | $55,000 | $0 | $55,000 | 2-3 |
| **Project Total** | - | - | - | - | - | **$2,888,750** | - |

*1 Lift Station No. 4 is a candidate for varying degrees of rehabilitation or complete replacement pending further site specific analysis and those costs are excluded from this five-year CIP.
*2 Treatment plant cost does not specifically include permitting, monitoring and reporting, or capital improvement costs required for disposal of effluent.
*3 Assumes Sewer Basin Study will be provided.

# APPENDIX A

## Rio Rico Utilities Service Area and Sewer Infrastructure Layout

WestLand Resources Inc.
LIFT STATION #4
Estates Unit 14
Villas Unit 10
Villas Unit 12
Estates Unit 15
Estates Unit 16
REACH 10
Villas Unit 11
Ranchettes Unit 18
VILLAS 12 EVAPORATION PONDS
FUTURE NORTH INDUSTRIAL PARK WASTEWATER TREATMENT PLANT
16" FORCEMAIN FROM LIFT STATION #4
Villas Unit 14
NORTH INDUSTRIAL PARK (WEST)
Ranchettes Unit 17
6" FORCEMAIN FROM LIFT STATION #3 (EMERGENCY FILL FOR VILLAS 13 PONDS)
VILLAS 13 EVAPORATION PONDS
LIFT STATION #5
Ranchettes Unit 10
LIFT STATION #3
Ranchettes Unit 4
Rio Cuquiarachi
REACH 3
2" FORCEMAIN FROM LIFT STATION #5
Villas Unit 13
REACH 9
8" FORCEMAIN FROM LIFT STATION #3
REACH 8
REACH 7
Ranchettes Unit 3
REACH 5
Ranchettes Unit 5
Estates Unit 9
Villas Unit 16
Villas Unit 1
REACH 4
LIFT STATION #2
Estates Unit 3
Ranchettes Unit 14
LIFT STATION #1
8" FORCEMAIN FROM LIFT STATION #2
Unit 6
Ranchettes Unit 7
Estates Unit 4
Unit 7
Unit 12
Estates Unit 10
Ranchettes Unit 14
REACH 2
Estates Unit 6
Unit 7
REACH 6
Estates Unit 7
Villas Unit 8
Villas Unit 16
Ranchettes Unit 15
Ranchettes Unit 12
REACH 1
Estates Unit 13
Estates Unit 8
Ranchettes Unit 5
Estates Unit 11
8" FORCEMAIN FROM LIFT STATION #1
NOGALES INTERNATIONAL WASTEWATER TREATMENT PLANT
LEGEND
SEWER CERTIFICATED AREA
EXIST. PUMP STATION AND EVAPORATION PONDS
SEWER FORCEMAIN
8" SEWER MAIN
10" SEWER MAIN
12" SEWER MAIN
14" SEWER MAIN
16" SEWER MAIN
NORTH SUB-BASIN A
NORTH SUB-BASIN B
SOUTH SUB-BASIN A
SOUTH SUB-BASIN B
SOUTH SUB-BASIN C
SOUTH SUB-BASIN D
N
W
E
S
SCALE: 1" = 6000'
0
6000'
RIO RICO UTILITIES
SEWER SERVICE AREA AND
WASTEWATER INFRASTRUCTURE LAYOUT
JULY 21, 2008

# APPENDIX B

WASTEWATER
FACILITY
BUILDOUT
CAPACITY
SIZING
SPREADSHEETS

## South Sewer Basin Buildout Sewer Capacity (0.75 d/D @ PDWF)

| South Sewer Basin | Sewer Reach No. | Diameter (inches) | Sewer Capacity (gpm) @ 0.75 d/D | Upstream Connections | Residential Connections | Industrial Area (acres) | Comm. Area (acres) | Total Sewered Area (acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | PDWF (GPM) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | 1 | 10 | 569 | South Industrial Park | 0 | 256 | 0 | 256 | - | - | - | - | - |
| | | | | Estates Unit 8 | 38 | 0 | 0 | 55 | - | - | - | - | - |
| | | | | **Sub-Total** | **38** | **256** | **0** | **311** | **106** | **69,400** | **3.53** | **212,131** | **147** |
| | 2 | 12 | 890 | South Industrial Park | 0 | 256 | 0 | 256 | - | - | - | - | - |
| | | | | Estates Unit 8 | 38 | 0 | 0 | 55 | - | - | - | - | - |
| | | | | **Sub-Total** | **38** | **256** | **0** | **311** | **106** | **69,400** | **3.53** | **212,131** | **147** |
| B | 3 | 12 | 731 | **Villas Unit 5** | **1,096** | **0** | **0** | **500** | **3,069** | **214,816** | **1.92** | **412,117** | **286** |
| | 4 | 12 | 925 | Villas Unit 5 | 1,096 | 0 | 0 | 500 | - | - | - | - | - |
| | | | | Unit 3 | 694 | 0 | 0 | 377 | - | - | - | - | - |
| | | | | **Sub-Total** | **1,790** | **0** | **0** | **877** | **5,012** | **350,840** | **1.76** | **615,828** | **428** |
| | 5 | 16 | 2,227 | Villas Unit 5 | 1,096 | 0 | 0 | 500 | - | - | - | - | - |
| | | | | Unit 3 | 694 | 0 | 0 | 377 | - | - | - | - | - |
| | | | | Unit 15 | 707 | 0 | 75 | 375 | - | - | - | - | - |
| | | | | **Sub-Total** | **2,497** | **0** | **75** | **1,252** | **6,992** | **564,412** | **1.65** | **1,033,779** | **718** |
| C | 6 | 12 | 970 | Lift Station No. 2 (926 gpm)[*1] | - | - | - | - | - | - | - | - | 926 |
| | | | | Unit 7 | 275 | 0 | 247 | 400 | - | - | - | - | - |
| | | | | Unit 4 | 370 | 0 | 0 | 260 | - | - | - | - | - |
| | | | | **Sub-Total** | **645** | **0** | **247** | **660** | **1,806** | **373,420** | **2.11** | **1,007,988** | **1,626** |
| D | 7 | 10 | 509 | Villas Unit 18 (Portion) | 0 | 0 | 50 | 50 | - | - | - | - | - |
| | | | | Villas Unit 13 (Portion) | 175 | 0 | 0 | 63 | - | - | - | - | - |
| | | | | **Sub-Total** | **175** | **0** | **50** | **113** | **490** | **84,300** | **2.68** | **241,754** | **168** |
| | 8 | 12 | 716 | Villas Unit 18 | 0 | 0 | 173 | 173 | - | - | - | - | - |
| | | | | Villas Unit 13 (Portion[*1]) | 1,553 | 0 | 0 | 310 | - | - | - | - | - |
| | | | | **Sub-Total** | **1,553** | **0** | **173** | **483** | **4,348** | **477,388** | **1.80** | **1,067,220** | **741** |
| | 9 | 14 | 1,080 | Lift Station No. 5 (27 gpm) | - | - | - | - | - | - | - | - | 27 |
| | | | | Villas Unit 13 (Portion[*1]) | 1,553 | 0 | 0 | 310 | - | - | - | - | - |
| | | | | **Sub-Total** | **1,553** | **0** | **0** | **310** | **4,348** | **304,388** | **1.80** | **548,220** | **408** |

[*1] Lift Station No. 2 will be require an upgrade to meet the pumping capacity of Lift Station No. 3 plus any other gravity flows

[*2] Exclude 135 Units / 80 acres & 10 Commercial Acres North of Peck Canyon Drive which connect to Lift Station No. 3 from the north

## North Sewer Basin Buildout Sewer Capacity (0.75 d/D @ PDWF)

| North Sewer Basin | Sewer Reach No. | Diameter (inches) | Sewer Capacity (gpm) @ 0.75 d/D | Upstream Connections | Residential Connections | Industrial Area (acres) | Comm. Area (acres) | Total Sewered Area (acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | PDWF (GPM) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| A | 10 | 8 | 351 | Villas 12 | 790 | 0 | 0 | 369 | - | - | - | - | - |
| | | | | Estates 16 (Portion) | 160 | 0 | 0 | 40 | - | - | - | - | - |
| | | | | **Sub-Total** | **950** | **0** | **0** | **409** | **2,660** | **186,200** | **1.97** | **366,593** | **255** |

## South Sewer Basin Buildout Lift Station Capacity (1.15 PWWF)

| Lift Station Number | Existing Capacity Simplex (gpm) | Upstream Connections | Residential Connections | Industrial Area (acres) | Comm. Area (acres) | Total Sewered Area (acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) | PWWF (GPM) | 1.15 PWWF (GPM) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 750 | Lift Station No. 2 (926 gpm)*1 | - | - | - | - | - | - | - | - | - | - | - | 926 |
| | | South Industrial Park | 0 | 256 | 0 | 256 | - | - | - | - | - | - | - | - |
| | | Estates Unit 8 | 38 | 0 | 0 | 55 | - | - | - | - | - | - | - | - |
| | | Unit 4 | 370 | 0 | 0 | 260 | - | - | - | - | - | - | - | - |
| | | Unit 7 | 275 | 0 | 247 | 400 | - | - | - | - | - | - | - | - |
| | | Villas Unit 5 | 1,096 | 0 | 0 | 500 | - | - | - | - | - | - | - | - |
| | | Unit 3 | 694 | 0 | 0 | 377 | - | - | - | - | - | - | - | - |
| | | Unit 15 | 707 | 0 | 75 | 375 | - | - | - | - | - | - | - | - |
| | | **Sub-Total** | **3,180** | **256** | **322** | **2,223** | **8,904** | **1,007,232** | **1.58** | **2,137,706** | **77,805** | **2,215,511** | **1,539** | **2,695** |
| 2 | 400 | Lift Station No. 3 (926 gpm)*1 | - | - | - | - | - | - | - | - | - | - | - | **926** |
| 3 | 400 | Lift Station No. 5 (27 gpm) | - | - | - | - | - | - | - | - | - | - | - | **27** |
| | | Villas 18 | 0 | 0 | 173 | 173 | - | - | - | - | - | - | - | - |
| | | Villas 13 (Portion)*2 | 1,688 | 0 | 0 | 390 | - | - | - | - | - | - | - | - |
| | | **Sub-Total** | **1,688** | **0** | **173** | **563** | **4,726** | **503,848** | **1.77** | **1,105,943** | **19,705** | **1,125,648** | **782** | **926** |
| 5 | 27 | Villas 13 (Portion) | 0 | 0 | 10 | 10 | - | - | - | - | - | - | - | - |
| | | **Sub-Total** | **0** | **0** | **10** | **10** | **0** | **10,000** | 0 | **30,000** | **350** | **30,350** | **21** | **24** |

*1 Lift Station No. 2 will be require an upgrade to meet the pumping capacity of Lift Station No. 3 plus any other gravity flows

*2 Excludes 10 commercial acres served by Lift station No. 5

## North Sewer Basin Buildout Lift Station Capacity (1.15 PWWF)

| Lift Station Number | Existing Capacity Simplex (gpm) | Upstream Connections | Residential Connections | Industrial Area (acres) | Comm. Area (acres) | Total Sewered Area (acres) | Population | ADWF (GPD) | Resid. Peak Factor | PDWF (GPD) | Storm Inflow (GPD) | PWWF (GPD) | PWWF (GPM) | 1.15 PWWF (GPM) |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4 | 500 | Villas 12 | 790 | 0 | 0 | 369 | - | - | - | - | - | - | - | - |
| | | Estates 16 (Portion) | 160 | 0 | 0 | 40 | - | - | - | - | - | - | - | - |
| | | **Sub-Total** | **950** | **0** | **0** | **409** | **2,660** | **186,200** | **1.97** | **366,593** | **14,315** | **380,908** | **265** | **304** |

**UTILITIES DIVISION STAFF'S RESPONSES TO**
**RIO RICO UTILITIES, INC.'S INFORMAL DATA REQUEST TO**
**ARIZONA CORPORATION COMMISSION UTILITY DIVISION STAFF**
**DOCKET NO. WS-02676A-09-0257**
**MARCH 8, 2010**

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1. Specifically, how does RRUI's proposed HUF contradict Mr Liu's testimony at SB 2:20-22.

   A: **Staff has never stated that all of the Company's proposed hook up fee tariff contradicts the standard form of tariff.**

   **RESPONDENT: Jian Liu, Utilities Engineer**

2. Specifically, how does RRUI's proposed HUF contradict Mr Liu's testimony at SB 3:1-3.

   A. **Staff has never stated that all of the Company's proposed hook up fee tariff contradicts the standard form of tariff.**

   **RESPONDENT: Jian Liu, Utilities Engineer**

3. If the HUF Tariff is specifically limited to "off-site" facilities, why "must" Staff know the specific plant items to be funded with the HUFs (SB at 3:8-9?

   A: **The purpose of the off-site hook-up fees is to equitably apportion the costs of constructing additional off-site facilities to provide water production, delivery, storage and pressure among all new service connections.**

   **RESPONDENT: Jian Liu, Utilities Engineer**

4. How would Staff have RRUI pay for facilities to support high pressure zones as discussed in Mr Liu's SB at 3:9-12.

   A: **How the Company elects to pay for facilities is within the Company's discretion.**

   **RESPONDENT: Jian Liu, Utilities Engineer**

5. Is it Staff's view that customers living in "higher pressure zones" should pay different rates than other customers? Please explain.

   A: **Utility customers should be charged pursuant to the utility's tariff rate.**

   **RESPONDENT: Jian Liu, Utilities Engineer**



EXHIBIT
A-22
ADMITTED

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6. How much wastewater treatment capacity does RRUI currently have and how much does it need for "reasonable growth for the foreseeable future" (Liu SB at 4:12-13). In responding, please define Staff's terms "reasonable" and "foreseeable".

   A: **The Company should know how much wastewater treatment capacity it has. For planning purposes, Staff analyzes flow data and uses growth projections, starting with the test year and for the next 5 years.**

   RESPONDENT: **Jian Liu, Utilities Engineer**

7. What does Staff's testimony at Liu SB 5:1-6 mean and does Staff have any authority to support its position as expressed in such testimony. In responding, please explain what Staff means by "all necessary off-site facilities".

   A. **Objection, the term "authority" is vague. Notwithstanding the objection, Staff would refer the Company to the standard hook-up fee tariff.**

   RESPONDENT: **Jian Liu, Utilities Engineer**

**INDUSTRY TIMELINESS: 74 (of 98)**

**The Water Utility Industry has not been the best place to reside in recent months. Indeed, the stocks in the group have shown little, if any, share-price appreciation since our October review. Some have even experienced deterioration, as the market continued to reveal signs of awaking from its earlier slumber and investor sentiment swung to more aggressive areas in an attempt to be at the forefront of a potential economic revival.**

**There has not been any major developments or changes to water utility fundamentals of late, suggesting that the weakness is largely a byproduct of improving investor confidence and a brighter outlook for the broader market. But that's not to say that there haven't been some lingering issues at play too. Water infrastructures are aging and in many cases require considerable maintenance and capital investment in order to meet increasingly stringent requirements. The rising costs of doing business are likely to offset most of the benefits stemming form more favorable regulatory backing that has become apparent (see below), limiting shareholder gains for both the near and long-term. It should be noted that these stocks are typically bottom-dwellers in times of prosperity and renewed confidence, with their perceived safety historically faring better in times of economic uncertainty.**

## Undeniable Demand

It's a fact of life, water is one of the biggest necessities to human survival. And, although more than two thirds of the world is made up of the liquid, providers are needed to help safely and effectively deliver water to hundreds of millions of Americans everyday.

Given the dependency on water, each state has a regulatory body in place in order to oversee water utilities and maintain a balance of power between them and customers. However, many of these authorities, responsible for reviewing and ruling on general rate requests made by utilities to help recover costs, long sided with the public, creating a lop-sided and difficult backdrop for providers. That said, more recently most have had a change of heart and have been handing down more business friendly rulings on general rates in far more timely fashion. The recent implementation of accounting mechanisms originally outlined in the Water Action Plan speaks volumes to such and should only help to drive more predictable and improved results in the future.

## Pressures to Keep Up

But not everything is as bright as the improving regulatory environment. In order to meet the demands of the public, providers employ millions of feet of pipes and a plethora of wells to say the least. Many of these systems were built decades ago and over the course of time have begun to decay and require significant maintenance or even complete overhauls. This coupled with the growing threat of bioterrorism will likely continue driving maintenance and infrastructure costs through the roof and forcing most in this space to seek help on the financing front because of inadequate cash levels. Meanwhile, many smaller operations, unable to survive, are closing up shop, presenting opportunities for the larger players with the flexibility to increase their customer base at relatively lower start-up costs. *Aqua America* is a prime example and thus sports some of the best long-term growth prospects. M&A activity is likely to remain hot, as the costs of doing business are expected to climb into the hundreds of millions by the next decade.

## Conclusion

At this juncture, this industry does not cater to the investment demands of most. Just about every stock in the group lacks appreciation potential, whether it be for the coming six to 12 months or the 3- to 5-year pull. The aforementioned *Aqua America*, along with *SouthWest Water Company* and *American Water Works*, top our list for growth potential, but each pales in comparison to the alternatives offered outside the industry. Although the steady stream of income of some in this group may well intrigue investors seeking total return, the risk profiles of each of these stocks are higher than one might think because of a dependency on M&A's, finance concerns, and a lack of track record. Meanwhile, those with a more conservative bent and an affinity for income can do better by looking elsewhere, specifically the Electric Utility segment. As always, we advise potential investors to thumb through reports of each individual stock before making a commitment.

*Andre J. Costanza*

Composite Statistics: Water Utility Industry

| 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|
| 1256.9 | 3454.1 | 3702.5 | 3913.8 | *4150* | *4455* | Revenues ($mill) | *5425* |
| 148.2 | d5.8 | d183.0 | 352.7 | *405* | *470* | Net Profit ($mill) | *625* |
| 40.5% | NMF | NMF | 37.0% | *38.0%* | *38.0%* | Income Tax Rate | *39.0%* |
| 1.1% | NMF | NMF | 6.5% | *8.0%* | *10.0%* | AFUDC % to Net Profit | *15.0%* |
| 50.4% | 54.0% | 51.0% | 52.6% | *55.0%* | *53.0%* | Long-Term Debt Ratio | *50.0%* |
| 49.5% | 45.9% | 49.0% | 47.4% | *45.0%* | *47.0%* | Common Equity Ratio | *50.0%* |
| 3053.8 | 12113.9 | 12985.9 | 12629.1 | *13365* | *13800* | Total Capital ($mill) | *15725* |
| 4200.7 | 13308.3 | 14315.2 | 15356.1 | *16115* | *16950* | Net Plant ($mill) | *19050* |
| 6.3% | 1.6% | .2% | 4.3% | *5.0%* | *5.5%* | Return on Total Cap'l | *6.0%* |
| 9.8% | NMF | NMF | 5.9% | *6.5%* | *7.5%* | Return on Shr. Equity | *8.0%* |
| 9.8% | NMF | NMF | 5.9% | *6.5%* | *7.5%* | Return on Com Equity | *8.0%* |
| 3.7% | NMF | NMF | 2.9% | *3.0%* | *3.5%* | Retained to Com Eq | *4.0%* |
| 62% | NMF | NMF | 51% | *63%* | *60%* | All Div'ds to Net Prof | *55%* |
| 29.4 | NMF | NMF | 21.0 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | *20.0* |
| 1.57 | NMF | NMF | 1.26 | | | Relative P/E Ratio | *1.35* |
| 2.1% | 2.0% | 2.3% | 2.4% | | | Avg Ann'l Div'd Yield | *2.5%* |

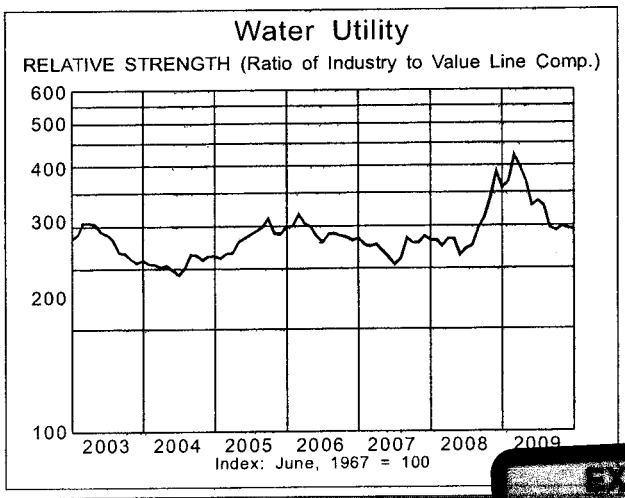


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EXHIBIT A-23 ADMITTED

# AMER. STATES WATER NYSE-AWR

RECENT PRICE 34.75 | P/E RATIO 18.5 (Trailing: 18.6 Median: 22.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.0% | VALUE LINE

**TIMELINESS** 3 Lowered 6/5/09
**SAFETY** 3 New 2/4/00
**TECHNICAL** 3 Raised 12/4/09
**BETA** .80 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 19.5 | 26.5 | 25.3 | 26.4 | 29.0 | 29.0 | 26.8 | 34.6 | 43.8 | 46.1 | 42.0 | 38.8 | |
| Low: | 14.1 | 14.8 | 16.7 | 19.0 | 20.3 | 21.6 | 20.8 | 24.3 | 30.3 | 33.6 | 27.0 | 29.8 | |

**Target Price Range** 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

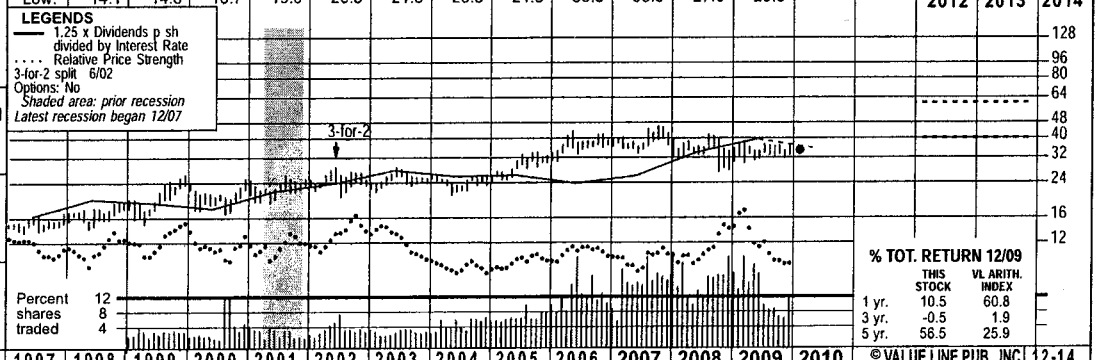
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+75%) | 17% |
| Low | 40 | (+15%) | 6% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 0 | 0 | 0 | 0 | 1 | 0 | 0 |

**Institutional Decisions**

| | 1Q2009 | 2Q2009 | 3Q2009 |
|---|---|---|---|
| to Buy | 55 | 66 | 54 |
| to Sell | 66 | 53 | 53 |
| Hld's(000) | 9283 | 10578 | 10847 |




**% TOT. RETURN 12/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 10.5 | 60.8 |
| 3 yr. | -0.5 | 1.9 |
| 5 yr. | 56.5 | 25.9 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.27 | 10.43 | 11.03 | 11.37 | 11.44 | 11.02 | 12.91 | 12.17 | 13.06 | 13.78 | 13.98 | 13.61 | 14.06 | 15.76 | 17.49 | 18.42 | 19.60 | 20.55 | Revenues per sh | 21.75 |
| 1.67 | 1.68 | 1.75 | 1.75 | 1.85 | 2.04 | 2.26 | 2.20 | 2.53 | 2.54 | 2.08 | 2.23 | 2.64 | 2.89 | 3.31 | 3.37 | 3.65 | 3.90 | "Cash Flow" per sh | 4.60 |
| 1.11 | .95 | 1.03 | 1.13 | 1.04 | 1.08 | 1.19 | 1.28 | 1.35 | 1.34 | .78 | 1.05 | 1.32 | 1.33 | 1.62 | 1.55 | 1.85 | 2.00 | Earnings per sh A | 2.60 |
| .79 | .80 | .81 | .82 | .83 | .84 | .85 | .86 | .87 | .87 | .88 | .89 | .90 | .91 | .96 | 1.00 | 1.01 | 1.05 | Div'd Decl'd per sh B■ | 1.22 |
| 1.90 | 2.43 | 2.19 | 2.40 | 2.58 | 3.11 | 4.30 | 3.03 | 3.18 | 2.68 | 3.76 | 5.03 | 4.24 | 3.91 | 2.89 | 4.45 | 4.05 | 4.25 | Cap'l Spending per sh | 5.00 |
| 9.95 | 10.07 | 10.29 | 11.01 | 11.24 | 11.48 | 11.82 | 12.74 | 13.22 | 14.05 | 13.97 | 15.01 | 15.72 | 16.64 | 17.53 | 17.95 | 19.60 | 20.00 | Book Value per sh | 22.00 |
| 11.71 | 11.77 | 11.77 | 13.33 | 13.44 | 13.44 | 13.44 | 15.12 | 15.12 | 15.18 | 15.21 | 16.75 | 16.80 | 17.05 | 17.23 | 17.30 | 18.60 | 19.00 | Common Shs Outst'g C | 20.00 |
| 13.4 | 12.8 | 11.6 | 12.6 | 14.5 | 15.5 | 17.1 | 15.9 | 16.7 | 18.3 | 31.9 | 23.2 | 21.9 | 27.7 | 24.0 | 22.6 | 18.54 | | Avg Ann'l P/E Ratio | 19.0 |
| .79 | .84 | .78 | .79 | .84 | .81 | .97 | 1.03 | .86 | 1.00 | 1.82 | 1.23 | 1.17 | 1.50 | 1.27 | 1.37 | 1.22 | | Relative P/E Ratio | 1.25 |
| 5.3% | 6.6% | 6.7% | 5.8% | 5.5% | 5.0% | 4.2% | 4.2% | 3.9% | 3.6% | 3.5% | 3.6% | 3.1% | 2.5% | 2.5% | 2.9% | 2.9% | | Avg Ann'l Div'd Yield | 2.4% |
| | | | | | | 173.4 | 184.0 | 197.5 | 209.2 | 212.7 | 228.0 | 236.2 | 268.6 | 301.4 | 318.7 | 365 | 390 | Revenues ($mill) | 450 |
| | | | | | | 16.1 | 18.0 | 20.4 | 20.3 | 11.9 | 16.5 | 22.5 | 23.1 | 28.0 | 26.8 | 35.0 | 39.0 | Net Profit ($mill) | 52.0 |
| | | | | | | 46.0% | 45.7% | 43.0% | 38.9% | 43.5% | 37.4% | 47.0% | 40.5% | 42.6% | 37.8% | 38.5% | 38.5% | Income Tax Rate | 40.0% |
| | | | | | | -- | -- | -- | -- | -- | -- | -- | 12.2% | 8.5% | 6.9% | 5.0% | 5.0% | AFUDC % to Net Profit | 5.0% |
| | | | | | | 51.0% | 47.5% | 54.9% | 52.0% | 52.0% | 47.7% | 50.4% | 48.6% | 46.9% | 46.2% | 46.0% | 44.5% | Long-Term Debt Ratio | 46.5% |
| | | | | | | 48.4% | 51.9% | 44.7% | 48.0% | 48.0% | 52.3% | 49.6% | 51.4% | 53.1% | 53.8% | 54.0% | 55.5% | Common Equity Ratio | 53.5% |
| | | | | | | 328.2 | 371.1 | 447.6 | 444.4 | 442.3 | 480.4 | 532.5 | 551.6 | 569.4 | 577.0 | 675 | 705 | Total Capital ($mill) | 825 |
| | | | | | | 449.6 | 509.1 | 539.8 | 563.3 | 602.3 | 664.2 | 713.2 | 750.6 | 776.4 | 825.3 | 870 | 920 | Net Plant ($mill) | 1025 |
| | | | | | | 6.6% | 6.4% | 6.1% | 6.5% | 4.6% | 5.2% | 5.4% | 6.0% | 6.7% | 6.4% | 7.0% | 7.5% | Return on Total Cap'l | 8.5% |
| | | | | | | 10.0% | 9.2% | 10.1% | 9.5% | 5.6% | 6.6% | 8.5% | 8.1% | 9.3% | 8.6% | 9.5% | 10.5% | Return on Shr. Equity | 12.0% |
| | | | | | | 10.1% | 9.3% | 10.1% | 9.5% | 5.6% | 6.6% | 8.5% | 8.1% | 9.3% | 8.6% | 9.5% | 10.5% | Return on Com Equity | 12.0% |
| | | | | | | 2.9% | 3.0% | 3.6% | 3.3% | NMF | 1.0% | 2.8% | 2.7% | 3.9% | 3.1% | 4.5% | 5.0% | Retained to Com Eq | 6.5% |
| | | | | | | 72% | 68% | 65% | 65% | 113% | 84% | 67% | 67% | 58% | 64% | 54% | 53% | All Div'ds to Net Prof | 47% |

**CAPITAL STRUCTURE as of 9/30/09**
**Total Debt** $327.5 mill. **Due in 5 Yrs** $25.0 mill.
**LT Debt** $306.3 mill. **LT Interest** $23.5 mill.
(LT interest earned: 3.8x: total interest coverage: 3.5x) (46% of Cap'l)

**Leases, Uncapitalized:** Annual rentals $2.9 mill.

**Pension Assets-12/08** $54.2 mill. **Oblig.** $94.5 mill.

**Pfd Stock** None.

**Common Stock** 18,512,032 shs. as of 11/3/09
**MARKET CAP: $650 million (Small Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 1.7 | 7.3 | 7.4 |
| Other | 61.4 | 83.3 | 92.3 |
| Current Assets | 63.1 | 90.6 | 99.7 |
| Accts Payable | 29.1 | 36.6 | 37.4 |
| Debt Due | 37.8 | 75.3 | 21.2 |
| Other | 27.4 | 25.5 | 40.4 |
| Current Liab. | 94.3 | 137.4 | 99.0 |
| Fix. Chg. Cov. | 314% | 293% | 352% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 4.5% | 5.0% | 4.0% |
| "Cash Flow" | 5.5% | 6.0% | 6.5% |
| Earnings | 3.5% | 5.5% | 9.5% |
| Dividends | 1.5% | 2.0% | 4.5% |
| Book Value | 4.5% | 5.0% | 4.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 64.3 | 63.0 | 75.0 | 66.3 | 268.6 |
| 2007 | 72.3 | 79.3 | 75.8 | 74.0 | 301.4 |
| 2008 | 68.9 | 80.3 | 85.3 | 84.2 | 318.7 |
| 2009 | 79.6 | 93.6 | 101.8 | 90.0 | 365 |
| 2010 | 85.0 | 100 | 108 | 97.0 | 390 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .35 | .36 | .32 | .30 | 1.33 |
| 2007 | .40 | .42 | .44 | .35 | 1.62 |
| 2008 | .30 | .53 | .26 | .43 | 1.55 |
| 2009 | .28 | .64 | .52 | .41 | 1.85 |
| 2010 | .30 | .65 | .58 | .47 | 2.00 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .225 | .225 | .225 | .235 | .91 |
| 2007 | .235 | .235 | .235 | .250 | .96 |
| 2008 | .250 | .250 | .250 | .250 | 1.00 |
| 2009 | .250 | .250 | .250 | .260 | 1.01 |
| 2010 | | | | | |

**BUSINESS:** American States Water Co. operates as a holding company. Through its principal subsidiary, Golden State Water Company, it supplies water to more than 250,000 customers in 75 communities in 10 counties. Service areas include the greater metropolitan areas of Los Angeles and Orange Counties. The company also provides electric utility services to nearly 23,250 customers in the city of Big Bear Lake and in areas of San Bernardino County. Acquired Chaparral City Water of Arizona (10/00). Has roughly 675 employees. Officers & directors own 2.5% of common stock (4/09 Proxy). Chairman: Lloyd Ross. President & CEO: Floyd Wicks. Inc: CA. Addr.: 630 East Foothill Boulevard, San Dimas, CA 91773. Tele.: 909-394-3600. Internet: www.aswater.com.

**American States Water posted impressive third-quarter growth.** Indeed, the water utility reported earnings of $0.52 a share, as revenues advanced 17%, to a record $101 million.

**Expectations should be tempered a bit, however.** Last year's third-quarter figures were relatively weak. The December-period comparisons are far more formidable. Plus, although the top line is likely to continue being the beneficiary of favorable general rate case rulings from the California Public Utilities Commission, operating expenses look to be on the rise, as evidenced by the most recent double-digit increase. Already decaying infrastructures are only growing older and requiring more investment. Much in that vein, we anticipate that the company had trouble meeting last year's share-net total in the fourth quarter, despite a healthy high single-digit top-line advance. For many of the same reasons, bottom-line growth for full-year 2010, though healthy, will likely pale in comparison to the levels witnessed in 2009.

**The company's balance sheet is not exactly seductive.** In order to meet the growing infrastructure requirements mentioned above, the cash-strapped entity will have to continue to seek outside financing, with debt and share offerings likely becoming commonplace. The higher interest rate and share count associated with these transactions will limit the benefits of the expansion of the nonregulated business.

**These shares are not too intriguing at this juncture.** Share-price momentum has tapered off in the months following our October review and is likely to remain relatively stagnant over the coming six to 12 months as the emergence from the recession continues to gain steam and investors regain confidence and take a more aggressive stance. The longer-term picture is not much better, with burgeoning financing costs curbing 3- to 5-year shareholder gains. Although risk-averse investors may be intrigued by the issue's income component (in a much anticipated move the board recently raised the quarterly dividend by 4% to $0.26 a share), it should be noted that there are a number of better income sources, particularly in the utility genre, to choose from.

*Andre J. Costanza* *January 22, 2010*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 14¢; '05, 25¢; '06, 6¢; '08, (27¢). Next earnings report due late February. May not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 70 |

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# AQUA AMERICA NYSE-WTR

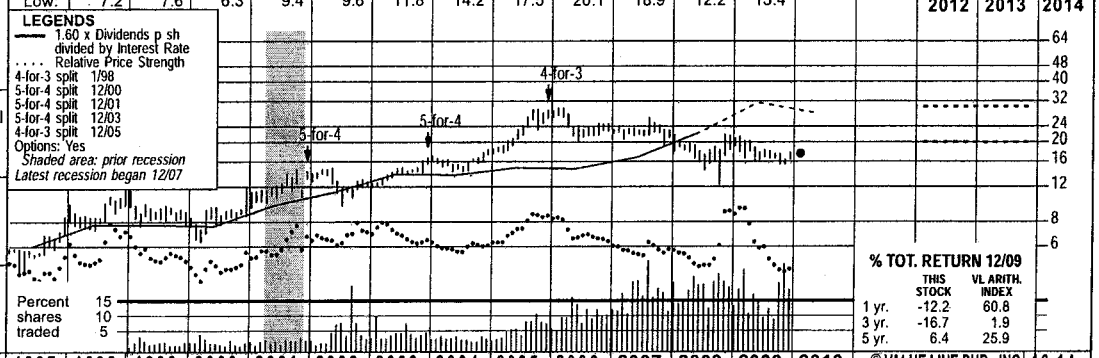
| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|---|
| 17.57 | 20.9 | (Trailing: 23.7 Median: 25.0) | 1.21 | 3.4% | VALUE LINE |

**TIMELINESS** 3 Lowered 6/26/09
**SAFETY** 3 Lowered 8/1/03
**TECHNICAL** 3 Lowered 1/1/10
**BETA** .65 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 11.5 | 11.5 | 12.0 | 14.8 | 15.0 | 16.8 | 18.5 | 29.2 | 29.8 | 26.6 | 22.0 | 21.5 |
| Low: | 7.2 | 7.6 | 6.3 | 9.4 | 9.6 | 11.8 | 14.2 | 17.5 | 20.1 | 18.9 | 12.2 | 15.4 |

**Target Price Range** 2012 | 2013 | 2014

**LEGENDS**
— 1.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
4-for-3 split 1/98
5-for-4 split 12/00
5-for-4 split 12/01
5-for-4 split 12/03
4-for-3 split 12/05
Options: Yes
*Shaded area: prior recession*
*Latest recession began 12/07*




**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 30 | (+70%) | 14% |
| Low | 20 | (+15%) | 3% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2009 | 2Q2009 | 3Q2009 |
|---|---|---|---|
| to Buy | 130 | 117 | 88 |
| to Sell | 134 | 136 | 118 |
| Hld's(000) | 63551 | 61341 | 60196 |

**% TOT. RETURN 12/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -12.2 | 60.8 |
| 3 yr. | -16.7 | 1.9 |
| 5 yr. | 6.4 | 25.9 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.70 | 1.82 | 1.84 | 1.86 | 2.02 | 2.09 | 2.41 | 2.46 | 2.70 | 2.85 | 2.97 | 3.48 | 3.85 | 4.03 | 4.52 | 4.63 | 4.95 | 5.35 | Revenues per sh | 6.45 |
| .42 | .42 | .47 | .50 | .56 | .61 | .72 | .76 | .86 | .94 | .96 | 1.09 | 1.21 | 1.26 | 1.37 | 1.42 | 1.70 | 1.85 | "Cash Flow" per sh | 2.40 |
| .24 | .26 | .29 | .30 | .34 | .40 | .42 | .47 | .51 | .54 | .57 | .64 | .71 | .70 | .71 | .73 | .80 | .90 | Earnings per sh A | 1.25 |
| .21 | .21 | .22 | .23 | .24 | .26 | .27 | .28 | .30 | .32 | .35 | .37 | .40 | .44 | .48 | .51 | .55 | .59 | Div'd Decl'd per sh B■ | .70 |
| .47 | .46 | .52 | .48 | .58 | .82 | .90 | 1.16 | 1.09 | 1.20 | 1.32 | 1.54 | 1.84 | 2.05 | 1.79 | 1.98 | 1.90 | 1.95 | Cap'l Spending per sh | 2.15 |
| 2.29 | 2.41 | 2.46 | 2.69 | 2.84 | 3.21 | 3.42 | 3.85 | 4.15 | 4.36 | 5.34 | 5.89 | 6.30 | 6.96 | 7.32 | 7.82 | 7.90 | 8.35 | Book Value per sh | 10.35 |
| 59.40 | 59.77 | 63.74 | 65.75 | 67.47 | 72.20 | 106.80 | 111.82 | 113.97 | 113.19 | 123.45 | 127.18 | 128.97 | 132.33 | 133.40 | 135.37 | 136.30 | 137.00 | Common Shs Outst'g C | 139.00 |
| 14.4 | 13.5 | 12.0 | 15.6 | 17.8 | 22.5 | 21.2 | 18.2 | 23.6 | 23.6 | 24.5 | 25.1 | 31.8 | 34.7 | 32.0 | 24.9 | 22.2 | | Avg Ann'l P/E Ratio | 21.0 |
| .85 | .89 | .80 | .98 | 1.03 | 1.17 | 1.21 | 1.18 | 1.21 | 1.29 | 1.40 | 1.33 | 1.69 | 1.87 | 1.70 | 1.50 | 1.48 | | Relative P/E Ratio | 1.40 |
| 5.9% | 6.0% | 6.2% | 4.9% | 3.9% | 2.9% | 3.0% | 3.3% | 2.5% | 2.5% | 2.5% | 2.3% | 1.8% | 1.8% | 2.1% | 2.8% | 3.0% | | Avg Ann'l Div'd Yield | 2.0% |

**CAPITAL STRUCTURE as of 9/30/09**
**Total Debt** $1320.2 mill. **Due in 5 Yrs** $245.0 mill.
**LT Debt** $1265.4 mill. **LT Interest** $65.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x) (54% of Cap'l)

**Pension Assets-12/08** $112.2 mill. **Oblig.** $204.7 mill.

**Pfd Stock** None
**Common Stock** 136,270,613 shares as of 10/20/09

**MARKET CAP: $2.4 billion (Mid Cap)**

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 257.3 | 275.5 | 307.3 | 322.0 | 367.2 | 442.0 | 496.8 | 533.5 | 602.5 | 627.0 | 675 | 735 | Revenues ($mill) | 900 |
| 45.0 | 50.7 | 58.5 | 62.7 | 67.3 | 80.0 | 91.2 | 92.0 | 95.0 | 97.9 | 109 | 123 | Net Profit ($mill) | 175 |
| 38.4% | 38.9% | 39.3% | 38.5% | 39.3% | 39.4% | 38.4% | 39.6% | 38.9% | 39.7% | 39.0% | 39.0% | Income Tax Rate | 39.0% |
| -- | -- | -- | -- | -- | -- | -- | -- | 2.9% | 3.1% | 3.0% | 2.6% | AFUDC % to Net Profit | 2.0% |
| 52.9% | 52.0% | 52.2% | 54.2% | 51.4% | 50.0% | 52.0% | 51.6% | 55.4% | 54.1% | 54.0% | 53.0% | Long-Term Debt Ratio | 48.0% |
| 46.7% | 47.8% | 47.7% | 45.8% | 48.6% | 50.0% | 48.0% | 48.4% | 44.6% | 45.9% | 46.0% | 47.0% | Common Equity Ratio | 52.0% |
| 782.7 | 901.1 | 990.4 | 1076.2 | 1355.7 | 1497.3 | 1690.4 | 1904.4 | 2191.4 | 2306.6 | 2276 | 2345 | Total Capital ($mill) | 2765 |
| 1135.4 | 1251.4 | 1368.1 | 1490.8 | 1824.3 | 2069.8 | 2280.0 | 2506.0 | 2792.8 | 2997.4 | 3150 | 3300 | Net Plant ($mill) | 3500 |
| 7.6% | 7.4% | 7.8% | 7.6% | 6.4% | 6.7% | 6.9% | 6.4% | 5.9% | 5.7% | 6.0% | 6.5% | Return on Total Cap'l | 7.5% |
| 12.2% | 11.7% | 12.3% | 12.7% | 10.2% | 10.7% | 11.2% | 10.0% | 9.7% | 9.3% | 10.0% | 10.5% | Return on Shr. Equity | 12.0% |
| 12.3% | 11.7% | 12.4% | 12.7% | 10.2% | 10.7% | 11.2% | 10.0% | 9.7% | 9.3% | 10.0% | 10.5% | Return on Com Equity | 12.0% |
| 4.3% | 4.7% | 5.1% | 5.2% | 4.2% | 4.6% | 4.9% | 3.7% | 3.2% | 2.8% | 3.5% | 3.0% | Retained to Com Eq D | 5.0% |
| 65% | 60% | 59% | 59% | 59% | 57% | 56% | 63% | 67% | 70% | 66% | 69% | All Div'ds to Net Prof | 57% |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 14.5 | 14.9 | 18.0 |
| Receivables | 82.9 | 84.5 | 86.1 |
| Inventory (AvgCst) | 8.8 | 9.8 | 10.3 |
| Other | 9.3 | 11.8 | 10.5 |
| Current Assets | 115.5 | 121.0 | 124.9 |
| Accts Payable | 45.8 | 50.0 | 26.3 |
| Debt Due | 80.8 | 87.9 | 54.8 |
| Other | 56.6 | 55.3 | 149.0 |
| Current Liab. | 183.2 | 193.2 | 230.1 |
| Fix. Chg. Cov. | 323% | 329% | 325% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 8.0% | 9.0% | 6.5% |
| "Cash Flow" | 9.5% | 8.0% | 10.0% |
| Earnings | 7.5% | 5.5% | 10.0% |
| Dividends | 7.0% | 8.0% | 6.5% |
| Book Value | 9.5% | 10.0% | 6.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 117.9 | 131.7 | 147.0 | 136.9 | 533.5 |
| 2007 | 137.3 | 150.6 | 165.5 | 149.1 | 602.5 |
| 2008 | 139.3 | 151.0 | 177.1 | 159.6 | 627.0 |
| 2009 | 154.5 | 167.3 | 180.8 | 172.4 | 675 |
| 2010 | 165 | 185 | 195 | 190 | 735 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .13 | .17 | .21 | .19 | .70 |
| 2007 | .13 | .17 | .22 | .19 | .71 |
| 2008 | .11 | .17 | .26 | .19 | .73 |
| 2009 | .14 | .19 | .25 | .22 | .80 |
| 2010 | .15 | .22 | .28 | .25 | .90 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .107 | .107 | .115 | .115 | .44 |
| 2007 | .115 | .115 | .125 | .125 | .48 |
| 2008 | .125 | .125 | .125 | .135 | .51 |
| 2009 | .135 | .135 | .135 | .145 | .55 |
| 2010 | | | | | |

**BUSINESS:** Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately three million residents in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Florida, Indiana, and five other states. Divested three of four non-water businesses in '91; telemarketing group in '93; and others. Acquired AquaSource, 7/03; Consumers Water, 4/99; and others. Water supply revenues '08: residential, 60%; commercial, 14%; industrial & other, 26%. Officers and directors own 1.3% of the common stock (4/09 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

**During the September interim, Aqua America lost some ground on a year-over-year basis.** Although revenues were up slightly from the prior year, earnings dropped a penny, as unfavorable weather conditions and higher operating costs hurt profits during the third quarter. Looking ahead, though,

**the company probably ended the year on a good note.** A number of rate-relief cases were set to be decided in the fourth quarter which, if approved, should provide a slight last-minute boost to the top and bottom lines. Also, management has been actively working to reduce operating costs, and the benefits of these efforts should help widen margins. For the year, we expect a total increase in revenues and earnings of $48 million and $0.07 a share, respectively, but it should be noted that last year included a gain from the sale of its underperforming Woodhaven system.

**Aqua America should continue to expand its reach through acquisitions and rate-relief cases over the next few years.** The company has acquired a wastewater treatment plant in Lumpkin County, Georgia, and this new subsidiary (Aqua Georgia Inc.) may be bolstered by further purchases in this region. Also, WTR expanded its Aqua Pennsylvania division in December, purchasing the assets of Athens Township Authority, and subsequently signed a 20-year contract to provide water services. Additionally, the $75 million in rate cases filed in 2009 should, if judged in Aqua's favor, boost revenues and earnings over the next few years.

**These shares are a neutral choice for the coming six to 12 month period, but hold some appeal for the long haul.** One attractive trait is the steady dividend yield, which was raised 7.4% during the fourth quarter of 2008. The company has historically raised its payout every year, and this will most likely continue over the coming 3- to 5-year stretch. Also, the top- and bottom-line gains we project over the 2012-2014 horizon give this equity good recovery potential. Conservative investors should also take note of the high scores for Stock Price Stability and Earnings Predictability, as well as the below-the-market average Beta coefficient.

*John D. Burke* *January 22, 2010*

(A) Diluted shares. Excl. nonrec. gains (losses): '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢. Excl. gain from disc. operations: '96, 2¢. Next earnings report due early February.

(B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount).

(C) In millions, adjusted for stock splits.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 100 |

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# CALIFORNIA WATER NYSE-CWT

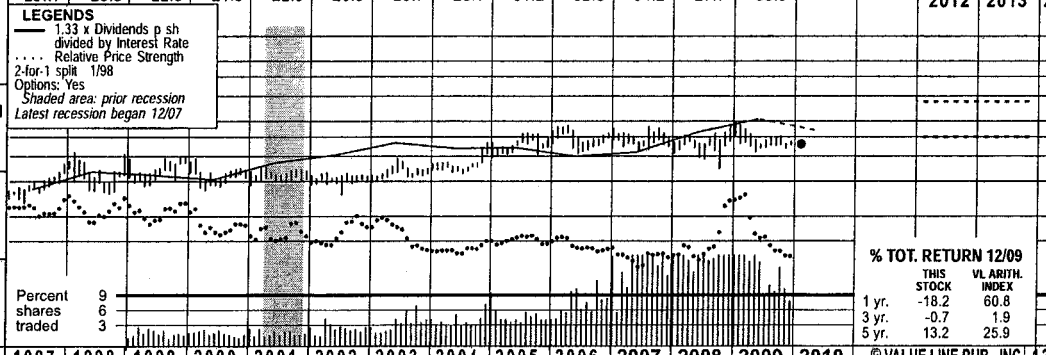
| RECENT PRICE | 36.83 | P/E RATIO | 18.4 (Trailing: 18.5 / Median: 22.0) | RELATIVE P/E RATIO | 1.06 | DIV'D YLD | 3.2% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 4 Lowered 11/6/09
**SAFETY** 3 Lowered 7/27/07
**TECHNICAL** 3 Lowered 12/25/09
**BETA** .75 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 33.8 | 32.0 | 31.4 | 28.6 | 26.9 | 31.4 | 37.9 | 42.1 | 45.8 | 45.4 | 46.6 | 48.3 | |
| Low: | 20.8 | 22.6 | 21.5 | 22.9 | 20.5 | 23.7 | 26.1 | 31.2 | 32.8 | 34.2 | 27.7 | 33.5 | |

**Target Price Range** 2012 | 2013 | 2014

**LEGENDS**
— 1.33 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 1/98
Options: Yes
*Shaded area: prior recession*
*Latest recession began 12/07*




**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+65%) | 15% |
| Low | 40 | (+10%) | 5% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2009 | 2Q2009 | 3Q2009 |
|---|---|---|---|
| to Buy | 83 | 76 | 56 |
| to Sell | 81 | 85 | 75 |
| Hld's(000) | 10000 | 10018 | 9635 |

**% TOT. RETURN 12/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -18.2 | 60.8 |
| 3 yr. | -0.7 | 1.9 |
| 5 yr. | 13.2 | 25.9 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13.34 | 12.59 | 13.17 | 14.48 | 15.48 | 14.76 | 15.96 | 16.16 | 16.26 | 17.33 | 16.37 | 17.18 | 17.44 | 16.20 | 17.76 | 19.80 | 21.35 | 22.10 | Revenues per sh | 23.90 |
| 2.25 | 2.02 | 2.07 | 2.50 | 2.92 | 2.60 | 2.75 | 2.52 | 2.20 | 2.65 | 2.51 | 2.83 | 3.03 | 2.71 | 3.12 | 3.72 | 4.05 | 4.25 | "Cash Flow" per sh | 4.80 |
| 1.35 | 1.22 | 1.17 | 1.51 | 1.83 | 1.45 | 1.53 | 1.31 | .94 | 1.25 | 1.21 | 1.46 | 1.47 | 1.34 | 1.50 | 1.90 | 1.99 | 2.10 | Earnings per sh A | 2.60 |
| .96 | .99 | 1.02 | 1.04 | 1.06 | 1.07 | 1.09 | 1.10 | 1.12 | 1.12 | 1.12 | 1.13 | 1.14 | 1.15 | 1.16 | 1.17 | 1.18 | 1.19 | Div'd Decl'd per sh B ■ | 1.25 |
| 2.53 | 2.26 | 2.17 | 2.83 | 2.61 | 2.74 | 3.44 | 2.45 | 4.09 | 5.82 | 4.39 | 3.73 | 4.01 | 4.28 | 3.68 | 4.82 | 5.20 | 5.25 | Cap'l Spending per sh | 5.25 |
| 10.90 | 11.56 | 11.72 | 12.22 | 13.00 | 13.38 | 13.43 | 12.90 | 12.95 | 13.12 | 14.44 | 15.66 | 15.79 | 18.15 | 18.50 | 19.44 | 20.00 | 19.75 | Book Value per sh C | 21.30 |
| 11.38 | 12.49 | 12.54 | 12.62 | 12.62 | 12.62 | 12.94 | 15.15 | 15.18 | 15.18 | 16.93 | 18.37 | 18.39 | 20.66 | 20.67 | 20.72 | 21.00 | 21.25 | Common Shs Outst'g D | 23.00 |
| 13.6 | 14.1 | 13.7 | 11.9 | 12.6 | 17.8 | 17.8 | 19.6 | 27.1 | 19.8 | 22.1 | 20.1 | 24.9 | 29.2 | 26.1 | 19.8 | 19.3 | | Avg Ann'l P/E Ratio | 19.0 |
| .80 | .92 | .92 | .75 | .73 | .93 | 1.01 | 1.27 | 1.39 | 1.08 | 1.26 | 1.06 | 1.33 | 1.58 | 1.39 | 1.20 | 1.26 | | Relative P/E Ratio | 1.25 |
| 5.2% | 5.8% | 6.4% | 5.8% | 4.6% | 4.2% | 4.0% | 4.3% | 4.4% | 4.5% | 4.2% | 3.9% | 3.1% | 2.9% | 3.0% | 3.1% | 3.1% | | Avg Ann'l Div'd Yield | 2.5% |

**CAPITAL STRUCTURE as of 9/30/09**
**Total Debt** $397.9 mill. **Due in 5 Yrs** $40.0 mill.
**LT Debt** $373.5 mill. **LT Interest** $25.0 mill.

(LT interest earned: 7.8x; total int. cov.: 6.6x)

**Pension Assets-12/08** $66.9 mill. **Oblig.** $192.9 mill.

**Pfd Stock** None

**Common Stock** 20,744,952 shs. as of 11/2/09

**MARKET CAP: $775 million (Small Cap)**

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 206.4 | 244.8 | 246.8 | 263.2 | 277.1 | 315.6 | 320.7 | 334.7 | 367.1 | 410.3 | 448 | 470 | Revenues ($mill) E | 550 |
| 19.9 | 20.0 | 14.4 | 19.1 | 19.4 | 26.0 | 27.2 | 25.6 | 31.2 | 39.8 | 42.0 | 45.0 | Net Profit ($mill) | 60.0 |
| 37.9% | 42.3% | 39.4% | 39.7% | 39.9% | 39.6% | 42.4% | 37.4% | 39.9% | 37.7% | 40.0% | 39.0% | Income Tax Rate | 39.0% |
| -- | -- | -- | -- | 10.3% | 3.2% | 3.3% | 10.6% | 8.3% | 8.6% | 8.5% | 10.0% | AFUDC % to Net Profit | 10.0% |
| 46.9% | 48.9% | 50.3% | 55.3% | 50.2% | 48.6% | 48.3% | 43.5% | 42.9% | 41.6% | 47.0% | 46.5% | Long-Term Debt Ratio | 48.5% |
| 52.0% | 50.2% | 48.8% | 44.0% | 49.1% | 50.8% | 51.1% | 55.9% | 56.6% | 58.4% | 53.0% | 53.5% | Common Equity Ratio | 51.5% |
| 333.8 | 388.8 | 402.7 | 453.1 | 498.4 | 565.9 | 568.1 | 670.1 | 674.9 | 690.4 | 795 | 805 | Total Capital ($mill) | 950 |
| 515.4 | 582.0 | 624.3 | 697.0 | 759.5 | 800.3 | 862.7 | 941.5 | 1010.2 | 1112.4 | 1175 | 1240 | Net Plant ($mill) | 1425 |
| 7.8% | 6.8% | 5.3% | 5.9% | 5.6% | 6.1% | 6.3% | 5.2% | 5.9% | 7.1% | 7.0% | 7.0% | Return on Total Cap'l | 8.0% |
| 11.2% | 10.0% | 7.2% | 9.4% | 7.8% | 8.9% | 9.3% | 6.8% | 8.1% | 9.9% | 10.0% | 10.5% | Return on Shr. Equity | 12.0% |
| 11.4% | 10.1% | 7.2% | 9.5% | 7.9% | 9.0% | 9.3% | 6.8% | 8.1% | 9.9% | 10.0% | 10.5% | Return on Com Equity | 12.0% |
| 3.5% | 1.8% | NMF | 1.0% | .7% | 2.1% | 2.1% | 1.0% | 1.8% | 3.8% | 4.0% | 5.0% | Retained to Com Eq | 6.5% |
| 70% | 82% | 119% | 90% | 91% | 77% | 78% | 86% | 77% | 61% | 59% | 56% | All Div'ds to Net Prof | 48% |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 6.7 | 13.9 | 47.6 |
| Other | 53.3 | 65.9 | 92.8 |
| Current Assets | 60.0 | 79.8 | 140.4 |
| Accts Payable | 36.7 | 45.1 | 54.4 |
| Debt Due | 2.7 | 42.8 | 24.4 |
| Other | 30.3 | 35.3 | 52.0 |
| Current Liab. | 69.7 | 123.2 | 130.8 |
| Fix. Chg. Cov. | 333% | 398% | 430% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 2.0% | 1.5% | 5.0% |
| "Cash Flow" | 2.0% | 5.5% | 7.0% |
| Earnings | -- | 7.0% | 8.5% |
| Dividends | 1.0% | 0.5% | 1.5% |
| Book Value | 4.0% | 6.5% | 2.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.)E Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 65.2 | 81.1 | 107.8 | 80.6 | 334.7 |
| 2007 | 71.6 | 95.8 | 113.8 | 85.9 | 367.1 |
| 2008 | 72.9 | 105.6 | 131.7 | 100.1 | 410.3 |
| 2009 | 86.7 | 116.7 | 139.2 | 105.4 | 448 |
| 2010 | 91.0 | 122 | 146 | 111 | 470 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .04 | .31 | .68 | .31 | 1.34 |
| 2007 | .07 | .37 | .67 | .39 | 1.50 |
| 2008 | .01 | .48 | 1.06 | .35 | 1.90 |
| 2009 | .12 | .58 | .94 | .35 | 1.99 |
| 2010 | .11 | .60 | 1.00 | .39 | 2.10 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .2875 | .2875 | .2875 | .2875 | 1.15 |
| 2007 | .290 | .290 | .290 | .290 | 1.16 |
| 2008 | .293 | .293 | .293 | .293 | 1.17 |
| 2009 | .295 | .295 | .295 | .295 | 1.18 |
| 2010 | | | | | |

**BUSINESS:** California Water Service Group provides regulated and nonregulated water service to roughly 463,600 customers in 83 communities in California, Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '08: residential, 69%; business, 18%; public authorities, 5%; industrial, 5%; other, 3%. '08 reported depreciation rate: 2.4%. Has roughly 929 employees. Chairman: Robert W. Foy. President & CEO: Peter C. Nelson (4/09 Proxy). Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwatergroup.com.

**Improvements on the regulatory front augur well for California Water Service Group's top line.** Indeed, earlier rate increases handed down by the California Public Utilities Commission (CPUC) enabled the water utility to post record-high revenues of $139.2 million in the third quarter, a 6% improvement from the year before. We look for similar growth in the fourth quarter and for full-year 2010. Meanwhile, the company filed its 2009 general rate case during the period, seeking $71 million in 2011 with increases of nearly $25 million in 2012 and 2013. It was CWT's first consolidated request, covering all 24 districts, and a ruling may well take 18 months to be made. We expect a relatively favorable outcome given the CPUC's more recent disposition.

**However, operating costs appear to be on the rise, too.** Despite the top-line benefits mentioned above, share earnings fell 11% in the September period and came in a dime below our estimate. Operating expenses swelled 10%, as aging infrastructures required greater maintenance, and the increased demand drove up distribution costs. We suspect that these trends persisted in the fourth quarter and will only intensify going forward. As a result, we've tempered our expectations, estimating that CWT barely broke even in the final quarter of 2009 and that earnings growth will not be anything to write home about for full-year 2010.

**The stock has fallen a notch for Timeliness and is now ranked 4 (Below Average).** Recent share-price declines, coupled with the tough outlook, make this an unattractive selection for the coming six to 12 months.

**Its 3- to 5-year appeal is better, but still lacking in our opinion.** CWT does not have the finances on hand to meet the rising infrastructure costs that are likely to amount over the next couple of years. The share and/or debt offerings that will be required to help improve the balance sheet will come at a price, with the higher share count and interest rate expenses limiting potential shareholder gains. Although the dividend yield looks healthy at first blush, those seeking an income vehicle have better options available, particularly on a risk-adjusted basis.

*Andre J. Costanza* *January 22, 2010*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (7¢); '01, 4¢; '02, 8¢. Next earnings report due early February.
(B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. deferred charges. In '08: $3.9 mill., $.19/sh.
(D) In millions, adjusted for split.
(E) Excludes non-reg. rev.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 75 |
| Earnings Predictability | 80 |

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# SOUTHWEST WATER NDQ-SWWC

| RECENT PRICE | 6.26 | P/E RATIO | 28.5 (Trailing: 34.8 / Median: 29.0) | RELATIVE P/E RATIO | 1.65 | DIV'D YLD | 3.2% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 3 Raised 11/27/09
**SAFETY** 4 New 10/23/09
**TECHNICAL** 3 Raised 1/1/10
**BETA** 1.10 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 5.6 | 9.2 | 8.3 | 10.2 | 12.4 | 11.2 | 14.3 | 15.2 | 19.1 | 16.4 | 13.4 | 6.3 |
| Low: | 3.5 | 3.6 | 5.1 | 6.9 | 7.6 | 8.1 | 10.3 | 9.0 | 10.8 | 11.5 | 2.7 | 3.1 |

**2012-14 PROJECTIONS**

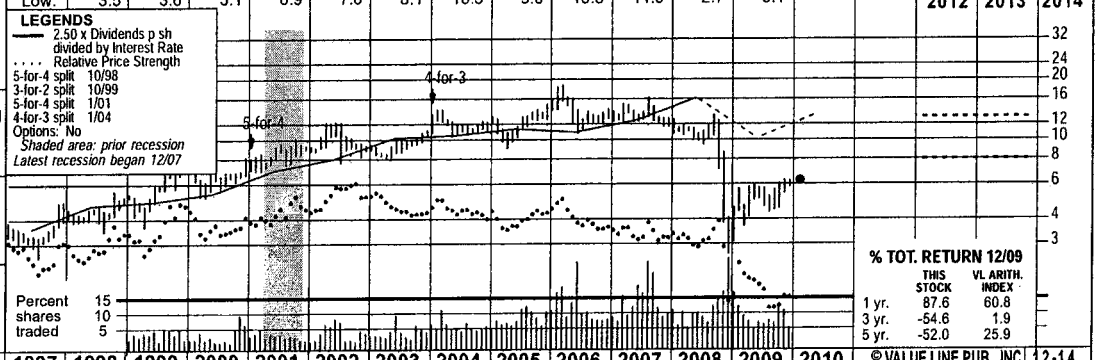
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 13 | 110% | 20% |
| Low | 8 | 30% | 6% |

**Insider Decisions**

| | F | M | A | M | J | J | A | S | O |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 1Q2009 | 2Q2009 | 3Q2009 |
|---|---|---|---|
| to Buy | 39 | 42 | 42 |
| to Sell | 38 | 39 | 31 |
| Hld's(000) | 11007 | 11107 | 10401 |




Target Price Range 2012 | 2013 | 2014

**% TOT. RETURN 12/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 87.6 | 60.8 |
| 3 yr. | -54.6 | 1.9 |
| 5 yr. | -52.0 | 25.9 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4.03 | 4.20 | 4.84 | 5.31 | 5.61 | 5.63 | 6.16 | 7.49 | 8.15 | 9.12 | 10.70 | 9.23 | 9.10 | 9.42 | 8.96 | 8.87 | 8.70 | 8.80 | Revenues per sh | 10.55 |
| .38 | .38 | .44 | .46 | .53 | .59 | .65 | .76 | .87 | .86 | .91 | .67 | .78 | .85 | .69 | .66 | .35 | .50 | "Cash Flow" per sh | 1.00 |
| .08 | .09 | .12 | .15 | .21 | .25 | .31 | .38 | .42 | .39 | .44 | .23 | .34 | .40 | .31 | .04 | .16 | .30 | Earnings per sh A | .50 |
| .14 | .08 | .08 | .09 | .09 | .10 | .11 | .13 | .14 | .15 | .16 | .18 | .20 | .21 | .23 | .24 | .13 | .20 | Div'd Decl'd per sh B | .20 |
| .60 | .72 | .84 | .95 | .74 | .79 | .53 | .55 | 1.06 | 1.78 | 1.14 | 1.26 | 1.66 | 1.87 | 1.70 | 1.35 | .70 | .75 | Cap'l Spending per sh | 1.90 |
| 2.31 | 2.31 | 2.45 | 2.40 | 2.52 | 2.70 | 3.05 | 3.44 | 3.84 | 4.27 | 4.90 | 6.17 | 6.49 | 6.98 | 6.54 | 4.55 | 4.50 | 4.55 | Book Value per sh D | 5.10 |
| 11.97 | 12.13 | 11.74 | 12.45 | 12.65 | 12.83 | 13.12 | 13.99 | 14.17 | 14.35 | 16.17 | 20.36 | 22.33 | 23.80 | 24.27 | 24.90 | 25.00 | 25.50 | Common Shs Outst'g C | 26.50 |
| 35.8 | 22.3 | 14.6 | 16.5 | 16.9 | 17.2 | 19.6 | 17.0 | 19.8 | 24.8 | 21.2 | NMF | 35.5 | 34.8 | 42.1 | NMF | 32.0 | | Avg Ann'l P/E Ratio | 20.0 |
| 2.11 | 1.46 | .98 | 1.03 | .97 | .89 | 1.12 | 1.11 | 1.01 | 1.35 | 1.21 | NMF | 1.89 | 1.88 | 2.23 | NMF | 2.14 | | Relative P/E Ratio | 1.65 |
| 4.7% | 4.2% | 4.7% | 3.4% | 2.7% | 2.3% | 1.8% | 2.0% | 1.7% | 1.5% | 1.7% | 1.5% | 1.6% | 1.5% | 1.8% | 2.4% | 2.5% | | Avg Ann'l Div'd Yield | 2.0% |
| | | | | | | 80.9 | 104.7 | 115.5 | 130.8 | 173.0 | 188.0 | 203.2 | 224.2 | 217.3 | 220.9 | 218 | 225 | Revenues ($mill) | 280 |
| | | | | | | 4.2 | 5.4 | 6.2 | 6.0 | 7.2 | 4.5 | 7.3 | 9.3 | 5.1 | 1.0 | 4.0 | 7.5 | Net Profit ($mill) | 13.0 |
| | | | | | | 39.0% | 37.0% | 36.0% | 34.9% | 35.9% | 36.1% | 36.0% | 35.0% | 56.0% | NMF | NMF | NMF | Income Tax Rate | NMF |
| | | | | | | -- | -- | 14.4% | 3.2% | -- | 11.0% | 9.5% | -- | 12.5% | 10.0% | 13.0% | 13.5% | AFUDC % to Net Profit | 12.0% |
| | | | | | | 45.2% | 48.8% | 51.4% | 56.7% | 47.9% | 47.9% | 44.7% | 43.6% | 47.7% | 62.6% | 61.5% | 60.0% | Long-Term Debt Ratio | 59.5% |
| | | | | | | 54.1% | 50.7% | 48.2% | 42.9% | 51.8% | 52.0% | 55.1% | 56.3% | 52.1% | 37.2% | 38.5% | 40.0% | Common Equity Ratio | 40.5% |
| | | | | | | 73.9 | 95.0 | 113.0 | 142.8 | 152.8 | 242.0 | 262.9 | 295.2 | 304.5 | 304.4 | 295 | 285 | Total Capital ($mill) | 300 |
| | | | | | | 113.7 | 157.8 | 171.1 | 203.9 | 219.5 | 302.6 | 344.8 | 389.6 | 417.9 | 429.3 | 420 | 440 | Net Plant ($mill) | 500 |
| | | | | | | 7.6% | 7.6% | 7.6% | 5.8% | 6.2% | 3.1% | 4.1% | 4.5% | 2.9% | 1.8% | 2.5% | 4.0% | Return on Total Cap'l | 5.5% |
| | | | | | | 10.3% | 11.1% | 11.4% | 9.7% | 9.0% | 3.6% | 5.0% | 5.6% | 3.2% | .9% | 3.5% | 6.5% | Return on Shr. Equity | 10.0% |
| | | | | | | 10.4% | 11.1% | 11.4% | 9.7% | 9.1% | 3.6% | 5.0% | 5.6% | 3.2% | .8% | 3.5% | 6.5% | Return on Com Equity | 10.0% |
| | | | | | | 7.0% | 7.8% | 7.8% | 6.3% | 5.8% | .8% | 2.1% | 2.6% | NMF | NMF | NMF | 2.5% | Retained to Com Eq | 6.0% |
| | | | | | | 33% | 31% | 32% | 36% | 36% | 78% | 58% | 54% | 112% | NMF | NMF | 66% | All Div'ds to Net Prof | 40% |

**CAPITAL STRUCTURE as of 9/30/09**
**Total Debt** $155.7 mill. **Due in 5 Yrs** $153.5 mill.
**LT Debt** $153.5 mill. **LT Interest** $7.0 mill.
(Total interest coverage: 2.7x) (48% of Cap'l)

**Leases, Uncapitalized:** Annual rentals $5.5 mill.
**Pension Liability** None

**Pfd Stock** $.458 mill. **Pfd Div'd** $.020 mill.
**Common Stock** 24,875,369 shs.
**as of 10/31/09**

**MARKET CAP: $150 million (Small Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 2.9 | 1.1 | 1.6 |
| Receivables | 26.0 | 29.7 | 34.0 |
| Inventory (Avg Cst) | -- | -- | -- |
| Other | 32.7 | 26.9 | 25.4 |
| Current Assets | 61.6 | 57.7 | 61.0 |
| Accts Payable | 14.9 | 16.1 | 15.0 |
| Debt Due | 1.9 | 2.2 | 2.2 |
| Other | 29.4 | 28.4 | 18.5 |
| Current Liab. | 46.2 | 46.7 | 35.7 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 5.0% | -0.5% | 2.5% |
| "Cash Flow" | 3.5% | -3.5% | 9.5% |
| Earnings | 2.0% | -10.0% | 12.0% |
| Dividends | 9.5% | 8.5% | -2.0% |
| Book Value | 9.0% | 7.0% | -2.5% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 50.8 | 55.4 | 60.1 | 57.9 | 224.2 |
| 2007 | 48.1 | 55.0 | 57.4 | 56.8 | 217.3 |
| 2008 | 49.6 | 56.9 | 60.4 | 54.0 | 220.9 |
| 2009 | 50.1 | 52.4 | 59.0 | 56.5 | 218 |
| 2010 | 52.0 | 55.0 | 60.0 | 58.0 | 225 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .03 | .08 | .16 | .13 | .40 |
| 2007 | .03 | .09 | .09 | .11 | .31E |
| 2008 | d.04 | .03 | d.02 | .07 | .04 |
| 2009 | .03 | .03 | .05 | .05 | .16 |
| 2010 | .06 | .06 | .08 | .10 | .30 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .052 | .052 | .052 | .058 | .21 |
| 2007 | .058 | .058 | .058 | .058 | .23 |
| 2008 | .06 | .06 | .06 | .06 | .24 |
| 2009 | .025 | .025 | .025 | .05 | .13 |
| 2010 | .05 | | | | |

**BUSINESS:** SouthWest Water Company provides a broad range of services including water production, treatment and distribution; wastewater collection and treatment; utility billing and collection; and utility infrastructure. It operates four groups, Utility, 32% of 2008 revenues; Texas Utility, 16%; O&M Services, 18%; Texas MUD Services, 34%. Utility and Texas Utility own and manage rate-regulated public water utilities in California, Alabama, Oklahoma, and Texas. O&M and Texas MUD Services maintain projects on a contract and fee basis. Officers and directors own 4.2% of common shares (4/09 proxy). CEO/Chrmn: Mark Swatek. Inc.: DE. Addr.: One Wilshire Building, 624 S. Grand Ave. Ste. 2900, Los Angeles, CA 90017. Tel.: 213-929-1800. Internet: www.swwc.com.

**SouthWest Water Company probably finished 2009 on a good note . . .** Although share-profit comparisons likely dropped, year over year, revenues for the fourth quarter probably showed a slight increase. As SouthWest begins to recover from the weakened economy, we expect good quarter-to-quarter earnings gains, excluding charges associated from the delayed quarterly filings in 2008 (due to accounting errors). Severe droughts in California and Texas, two key SWWC markets, reduced water demand in the 12-month period ending in June, 2009. Moreover, the resulting dry soil increased repair costs during the latter half of 2009. Looking ahead,

**. . . In 2010, the top and bottom lines should continue to recover in line with the overall economy.** The company will likely be bolstered from the recently approved rate increase for its California utilities segment. Also, SouthWest plans to focus on reducing operating costs through consolidating office support functions, as well as by divesting underperforming businesses.

**The board voted to increase the dividend payout.** For its November payment, management doubled the amount paid during the prior three quarters. Though we do not expect the dividend rate to fully recover from the reduction in early 2008, this increase may be sustainable over the coming 3 to 5 years. However, even with a much reduced capital spending budget, free cash flow appears to fall short of preferred and common dividend expense.

**These neutrally ranked shares are best suited for risk tolerant investors.** Note, however, that the above-average price recovery potential is offset by the degree of risk attached to these shares. This risk is shown by the Low (C++) rank for Financial Strength, as well as the below-par scores for Stock Price Stability and Earnings Predictability. Business prospects are clouded due to uncertainties related to weather conditions and the housing market.

*John D. Burke* *January 22, 2010*

| CASH POSITION | 5-Year Av'g | 9/30/09 |
|---|---|---|
| Current Assets to Current Liabilities: | 125% | 170% |
| Cash & Equiv's to Current Liabilities: | 10% | 4% |
| Working Capital to Sales: | 5% | 12% |

(A) Diluted earnings. Excludes nonrecurring gains (losses): '00, (3¢); '01, (5¢); '02, 1¢; '05, (23¢); '07, (54¢); '08, ($1.35); 1Q '09 (24¢); 2Q '09, (54¢). Next earnings report late February.
(B) Dividends historically paid in late January, April, July, and October.
(C) In millions, adjusted for splits.
(D) Includes intangibles. In 2008: $19.3 million, $0.83/share.
(E) Earnings may not add due to rounding.

| | |
|---|---|
| Company's Financial Strength | C++ |
| Stock's Price Stability | 45 |
| Price Growth Persistence | 35 |
| Earnings Predictability | 45 |

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# CONN. WATER SERVICES NDQ--CTWS

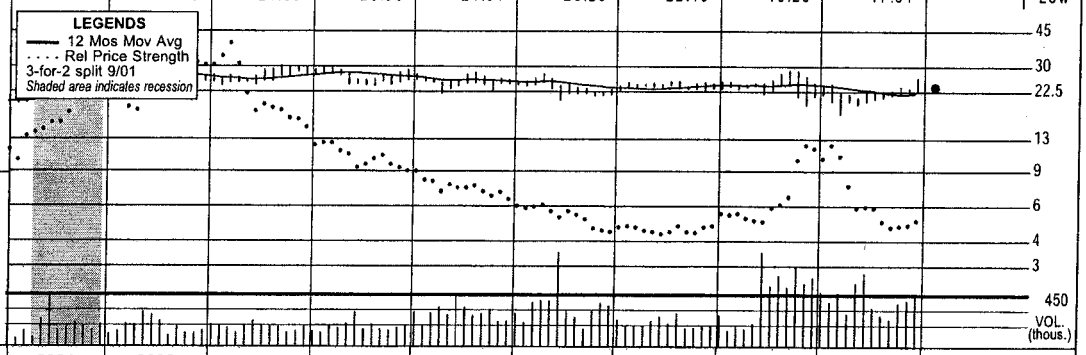
| RECENT PRICE | TRAILING P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|
| 23.77 | 20.0 | 1.11 | 3.8% | VALUE LINE |

**RANKS**

| | | |
|---|---|---|
| PERFORMANCE | 3 | Average |
| Technical | 3 | Average |
| SAFETY | 2 | Above Average |
| BETA .80 | (1.00 = Market) | |

| | |
|---|---|
| Financial Strength | B+ |
| Price Stability | 90 |
| Price Growth Persistence | 35 |
| Earnings Predictability | 80 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 32.21 | 31.09 | 30.41 | 29.76 | 28.17 | 27.71 | 25.61 | 28.95 | 26.44 | High |
| 19.50 | 20.35 | 24.00 | 23.83 | 21.91 | 20.29 | 22.40 | 19.26 | 17.31 | Low |




| © VALUE LINE PUBLISHING, INC. | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010/2011 |
|---|---|---|---|---|---|---|---|---|---|---|
| SALES PER SH | 5.93 | 5.77 | 5.91 | 6.04 | 5.81 | 5.68 | 7.05 | 7.24 | -- | |
| "CASH FLOW" PER SH | 1.78 | 1.78 | 1.89 | 1.91 | 1.62 | 1.52 | 1.90 | 1.95 | -- | |
| EARNINGS PER SH | 1.13 | 1.12 | 1.15 | 1.16 | .88 | .81 | 1.05 | 1.11 | ***1.19*** [A,B] | ***1.08*** [C]***/NA*** |
| DIV'DS DECL'D PER SH | .80 | .81 | .83 | .84 | .85 | .86 | .87 | .88 | -- | |
| CAP'L SPENDING PER SH | 1.86 | 1.98 | 1.49 | 1.58 | 1.96 | 1.96 | 2.24 | 2.44 | -- | |
| BOOK VALUE PER SH | 9.25 | 10.06 | 10.46 | 10.94 | 11.52 | 11.60 | 11.95 | 12.23 | -- | |
| COMMON SHS OUTST'G (MILL) | 7.65 | 7.94 | 7.97 | 8.04 | 8.17 | 8.27 | 8.38 | 8.46 | -- | |
| AVG ANN'L P/E RATIO | 21.5 | 24.3 | 23.5 | 22.9 | 28.6 | 29.0 | 23.0 | 22.2 | ***20.0*** | ***22.0/NA*** |
| RELATIVE P/E RATIO | 1.10 | 1.33 | 1.34 | 1.21 | 1.51 | 1.57 | 1.22 | 1.34 | -- | |
| AVG ANN'L DIV'D YIELD | 3.3% | 3.0% | 3.0% | 3.1% | 3.4% | 3.6% | 3.6% | 3.6% | -- | |
| SALES ($MILL) | 45.4 | 45.8 | 47.1 | 48.5 | 47.5 | 46.9 | 59.0 | 61.3 | -- | ***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.*** |
| OPERATING MARGIN | 56.1% | 57.7% | 52.1% | 51.0% | 48.3% | 43.7% | 40.8% | 49.0% | -- | |
| DEPRECIATION ($MILL) | 5.0 | 5.4 | 5.9 | 6.0 | 6.1 | 5.9 | 7.2 | 7.1 | -- | |
| NET PROFIT ($MILL) | 8.7 | 8.8 | 9.2 | 9.4 | 7.2 | 6.7 | 8.8 | 9.4 | -- | |
| INCOME TAX RATE | 36.1% | 33.8% | 17.9% | 22.9% | -- | 23.5% | 32.4% | 27.2% | -- | |
| NET PROFIT MARGIN | 19.1% | 19.2% | 19.5% | 19.4% | 15.1% | 14.3% | 14.9% | 15.4% | -- | |
| WORKING CAP'L ($MILL) | d3.3 | d5.1 | d3.9 | d.7 | 13.0 | 1.2 | 8.1 | d3.3 | -- | |
| LONG-TERM DEBT ($MILL) | 64.0 | 64.8 | 64.8 | 66.4 | 77.4 | 77.3 | 92.3 | 92.2 | -- | |
| SHR. EQUITY ($MILL) | 71.6 | 80.7 | 84.2 | 88.7 | 94.9 | 96.7 | 100.9 | 104.2 | -- | |
| RETURN ON TOTAL CAP'L | 7.9% | 7.4% | 7.5% | 7.0% | 5.0% | 4.9% | 5.5% | 5.9% | -- | |
| RETURN ON SHR. EQUITY | 12.1% | 10.9% | 10.9% | 10.6% | 7.5% | 6.9% | 8.7% | 9.0% | -- | |
| RETAINED TO COM EQ | 3.6% | 3.1% | 3.2% | 3.1% | .3% | NMF | 1.6% | 1.9% | -- | |
| ALL DIV'DS TO NET PROF | 71% | 72% | 71% | 71% | 95% | 105% | 82% | 79% | -- | |

[A]*No. of analysts changing earn. est. in last 9 days: 0 up, 0 down, consensus 5-year earnings growth 9.0% per year.* [B]*Based upon 2 analysts' estimates.* [C]*Based upon 2 analysts' estimates.*

**ANNUAL RATES**

| *of change (per share)* | 5 Yrs. | 1 Yr. |
|---|---|---|
| Sales | 2.5% | 2.5% |
| "Cash Flow" | -0.5% | 2.5% |
| Earnings | -2.5% | 5.5% |
| Dividends | 1.5% | 1.0% |
| Book Value | 3.5% | 2.5% |

| Fiscal Year | QUARTERLY SALES ($mill.) 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 12/31/07 | 13.2 | 14.4 | 17.0 | 14.4 | 59.0 |
| 12/31/08 | 13.6 | 16.0 | 17.0 | 14.7 | 61.3 |
| 12/31/09 | 13.4 | 15.1 | 16.6 | | |
| 12/31/10 | | | | | |

| Fiscal Year | EARNINGS PER SHARE 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 12/31/06 | .21 | .12 | .45 | .03 | .81 |
| 12/31/07 | .18 | .22 | .46 | .19 | 1.05 |
| 12/31/08 | .20 | .35 | .34 | .22 | 1.11 |
| 12/31/09 | .13 | .27 | .57 | ***.12*** | |
| 12/31/10 | ***.13*** | ***.28*** | | | |

| Cal-endar | QUARTERLY DIVIDENDS PAID 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 2007 | .215 | .215 | .218 | .218 | .87 |
| 2008 | .218 | .218 | .222 | .222 | .88 |
| 2009 | .222 | .222 | .228 | .228 | .90 |
| 2010 | | | | | |

**INSTITUTIONAL DECISIONS**

| | 1Q'09 | 2Q'09 | 3Q'09 |
|---|---|---|---|
| to Buy | 31 | 29 | 26 |
| to Sell | 24 | 23 | 19 |
| Hld's(000) | 2678 | 2776 | 2860 |

| ASSETS ($mill.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 8.6 | .7 | 8.1 |
| Receivables | 11.1 | 12.0 | 13.6 |
| Inventory (Avg cost) | 1.0 | 1.1 | 1.2 |
| Other | 2.3 | 2.0 | 3.0 |
| Current Assets | 23.0 | 15.8 | 25.9 |
| Property, Plant & Equip, at cost | 392.5 | 418.1 | -- |
| Accum Depreciation | 108.2 | 115.8 | -- |
| Net Property | 284.3 | 302.3 | 323.6 |
| Other | 53.5 | 54.3 | 51.0 |
| Total Assets | 360.8 | 372.4 | 400.5 |
| **LIABILITIES ($mill.)** | | | |
| Accts Payable | 6.0 | 5.7 | 6.8 |
| Debt Due | 6.5 | 12.1 | 31.6 |
| Other | 2.4 | 1.3 | 2.8 |
| Current Liab | 14.9 | 19.1 | 41.2 |

**LONG-TERM DEBT AND EQUITY as of 9/30/09**

**Total Debt** $123.6 mill. **Due in 5 Yrs.** NA
**LT Debt** $92.0 mill.
**Including Cap. Leases** NA (46% of Cap'l)

**Leases, Uncapitalized** Annual rentals NA

**Pension Liability** $16.7 mill. in '08 vs. None in '07

**Pfd Stock** $.8 mill. **Pfd Div'd Paid** NMF

**Common Stock** 8,541,346 shares (54% of Cap'l)

## INDUSTRY: Water Utility

**BUSINESS:** Connecticut Water Service, Inc. primarily operates as a water utility company in Connecticut. It operates through three segments: Water Activities, Real Estate Transactions, and Services and Rentals. The Water Activities segment supplies public drinking water to its customers. The Real Estate Transactions segment involves in the sale of its limited excess real estate holdings. The Services and Rentals segment provides contracted services to water and wastewater utilities and other clients, as well as leases certain of its properties to third parties. This segment's services include contract operations of water and wastewater facilities; Linebacker, its service line protection plan for public drinking water customers; and provision of bulk deliveries of emergency drinking water to businesses and residences via tanker truck. As of July 8, it provided water to to more than 88,000 customers, or about 300,000 people, in 54 towns throughout Connecticut. Has 226 employees. Chairman, C.E.O. & President: Eric W. Thornburg. Inc.: CT. Address: 93 West Main Street, Clinton, CT 06413. Tel.: (860) 669-8636. Internet: http://www.ctwater.com. *W.T.*

*January 22, 2010*

**TOTAL SHAREHOLDER RETURN**

*Dividends plus appreciation as of 12/31/2009*

| 3 Mos. | 6 Mos. | 1 Yr. | 3 Yrs. | 5 Yrs. |
|---|---|---|---|---|
| 11.75% | 16.53% | 9.40% | 21.84% | 12.17% |

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# MIDDLESEX WATER NDQ-MSEX

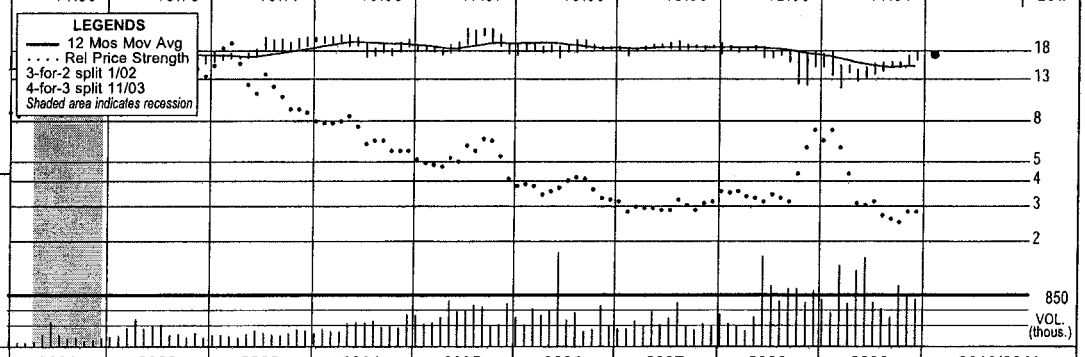
| RECENT PRICE | TRAILING P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD | VALUE LINE |
|---|---|---|---|---|
| 17.21 | 23.6 | 1.31 | 4.2% | |

**RANKS**

| | | |
|---|---|---|
| PERFORMANCE | 3 | Average |
| Technical | 3 | Average |
| SAFETY | 2 | Above Average |
| BETA .80 | (1.00 = Market) | |

| | |
|---|---|
| Financial Strength | B+ |
| Price Stability | 95 |
| Price Growth Persistence | 40 |
| Earnings Predictability | 90 |

| | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 |
|---|---|---|---|---|---|---|---|---|---|
| High | 18.73 | 20.04 | 21.23 | 21.81 | 23.47 | 20.50 | 20.24 | 19.83 | 17.91 |
| Low | 14.69 | 13.73 | 15.77 | 16.65 | 17.07 | 16.50 | 16.93 | 12.05 | 11.64 |




| © VALUE LINE PUBLISHING, INC. | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010/2011 |
|---|---|---|---|---|---|---|---|---|---|---|
| SALES PER SH | 5.87 | 5.98 | 6.12 | 6.25 | 6.44 | 6.16 | 6.50 | 6.79 | -- | |
| "CASH FLOW" PER SH | 1.18 | 1.20 | 1.15 | 1.28 | 1.33 | 1.33 | 1.49 | 1.53 | -- | |
| EARNINGS PER SH | .66 | .73 | .61 | .73 | .71 | .82 | .87 | .89 | *.70* A,B | *.80* C/NA |
| DIV'DS DECL'D PER SH | .62 | .63 | .65 | .66 | .67 | .68 | .69 | .70 | -- | |
| CAP'L SPENDING PER SH | 1.25 | 1.59 | 1.87 | 2.54 | 2.18 | 2.31 | 1.66 | 2.12 | -- | |
| BOOK VALUE PER SH | 7.11 | 7.39 | 7.60 | 8.38 | 8.60 | 9.82 | 10.05 | 10.28 | -- | |
| COMMON SHS OUTST'G (MILL) | 10.17 | 10.36 | 10.48 | 11.36 | 11.58 | 13.17 | 13.25 | 13.40 | -- | |
| AVG ANN'L P/E RATIO | 24.6 | 23.5 | 30.0 | 26.4 | 27.4 | 22.7 | 21.6 | 19.8 | ***24.6*** | ***21.5/NA*** |
| RELATIVE P/E RATIO | 1.26 | 1.28 | 1.71 | 1.39 | 1.45 | 1.23 | 1.15 | 1.19 | -- | |
| AVG ANN'L DIV'D YIELD | 3.8% | 3.7% | 3.5% | 3.4% | 3.5% | 3.7% | 3.7% | 4.0% | -- | |
| SALES ($MILL) | 59.6 | 61.9 | 64.1 | 71.0 | 74.6 | 81.1 | 86.1 | 91.0 | -- | ***Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.*** |
| OPERATING MARGIN | 47.2% | 47.1% | 44.0% | 44.4% | 44.4% | 47.4% | 47.0% | 46.9% | -- | |
| DEPRECIATION ($MILL) | 5.3 | 5.0 | 5.6 | 6.4 | 7.2 | 7.8 | 8.2 | 8.5 | -- | |
| NET PROFIT ($MILL) | 7.0 | 7.8 | 6.6 | 8.4 | 8.5 | 10.0 | 11.8 | 12.2 | -- | |
| INCOME TAX RATE | 34.8% | 33.3% | 32.8% | 31.1% | 27.6% | 33.4% | 32.6% | 33.2% | -- | |
| NET PROFIT MARGIN | 11.7% | 12.5% | 10.3% | 11.9% | 11.4% | 12.4% | 13.8% | 13.4% | -- | |
| WORKING CAP'L ($MILL) | d.9 | d9.3 | d13.3 | d11.8 | d4.5 | 2.8 | d9.6 | d40.9 | -- | |
| LONG-TERM DEBT ($MILL) | 88.1 | 87.5 | 97.4 | 115.3 | 128.2 | 130.7 | 131.6 | 118.2 | -- | |
| SHR. EQUITY ($MILL) | 76.4 | 80.6 | 83.7 | 99.2 | 103.6 | 133.3 | 137.1 | 141.2 | -- | |
| RETURN ON TOTAL CAP'L | 5.6% | 6.0% | 5.0% | 5.1% | 5.0% | 5.1% | 5.6% | 5.8% | -- | |
| RETURN ON SHR. EQUITY | 9.1% | 9.6% | 7.9% | 8.5% | 8.2% | 7.5% | 8.6% | 8.6% | -- | |
| RETAINED TO COM EQ | .5% | 1.3% | NMF | .9% | .5% | 1.2% | 1.8% | 1.9% | -- | |
| ALL DIV'DS TO NET PROF | 94% | 87% | 106% | 90% | 94% | 84% | 79% | 78% | -- | |

*A No. of analysts changing earn. est. in last 9 days: 0 up, 0 down, consensus 5-year earnings growth 9.0% per year. B Based upon 3 analysts' estimates. C Based upon 3 analysts' estimates.*

**ANNUAL RATES**

| of change (per share) | 5 Yrs. | 1 Yr. |
|---|---|---|
| Sales | 1.5% | 4.5% |
| "Cash Flow" | 4.5% | 2.5% |
| Earnings | 5.5% | 2.5% |
| Dividends | 2.0% | 1.5% |
| Book Value | 6.5% | 2.5% |

| Fiscal Year | QUARTERLY SALES ($mill.) 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 12/31/07 | 19.0 | 21.8 | 24.1 | 21.2 | 86.1 |
| 12/31/08 | 20.8 | 23.0 | 25.7 | 21.5 | 91.0 |
| 12/31/09 | 20.6 | 23.1 | 25.5 | | |
| 12/31/10 | | | | | |

| Fiscal Year | EARNINGS PER SHARE 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 12/31/06 | .15 | .25 | .28 | .14 | .82 |
| 12/31/07 | .13 | .24 | .31 | .19 | .87 |
| 12/31/08 | .15 | .26 | .35 | .13 | .89 |
| 12/31/09 | .10 | .21 | .29 | *.10* | |
| 12/31/10 | *.08* | *.22* | | | |

| Cal-endar | QUARTERLY DIVIDENDS PAID 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 2007 | .173 | .173 | .173 | .175 | .69 |
| 2008 | .175 | .175 | .175 | .178 | .70 |
| 2009 | .178 | .178 | .178 | .18 | .71 |
| 2010 | | | | | |

**INSTITUTIONAL DECISIONS**

| | 1Q'09 | 2Q'09 | 3Q'09 |
|---|---|---|---|
| to Buy | 41 | 41 | 30 |
| to Sell | 27 | 33 | 28 |
| Hld's(000) | 4505 | 4902 | 4958 |

| ASSETS ($mill.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 2.0 | 3.3 | 3.1 |
| Receivables | 12.8 | 14.3 | 18.2 |
| Inventory (Avg cost) | 1.2 | 1.5 | 1.6 |
| Other | 1.4 | 1.5 | 1.7 |
| Current Assets | 17.4 | 20.6 | 24.6 |
| Property, Plant & Equip, at cost | 398.6 | 436.8 | -- |
| Accum Depreciation | 64.7 | 70.5 | -- |
| Net Property | 333.9 | 366.3 | 380.0 |
| Other | 41.4 | 53.1 | 52.2 |
| Total Assets | 392.7 | 440.0 | 456.8 |
| **LIABILITIES ($mill.)** | | | |
| Accts Payable | 6.5 | 5.7 | 4.5 |
| Debt Due | 9.0 | 43.9 | 47.4 |
| Other | 11.5 | 11.9 | 11.0 |
| Current Liab | 27.0 | 61.5 | 62.9 |

**LONG-TERM DEBT AND EQUITY as of 9/30/09**

**Total Debt** $174.1 mill. **Due in 5 Yrs.** NA
**LT Debt** $126.7 mill.
**Including Cap. Leases** NA
(47% of Cap'l)
**Leases, Uncapitalized** Annual rentals NA

**Pension Liability** $25.5 mill. in '08 vs. $13.3 mill. in '07

**Pfd Stock** None **Pfd Div'd Paid** None

**Common Stock** 13,469,000 shares
(53% of Cap'l)

**INDUSTRY: Water Utility**

**BUSINESS:** Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey (NJ) and Delaware, and a regulated wastewater utility in NJ. It offers contract operations services and a service line maintenance program through its nonregulated subsidiary, Utility Service Affiliates, Inc. Its water utility system treats, stores, and distributes water for residential, commercial, industrial, and fire prevention purposes. It also provides water treatment and pumping services to the Township of East Brunswick. Its other NJ subsidiaries offer water and wastewater services to residents in Southampton Township. Its Delaware subsidiaries provide water services to retail customers in New Castle, Kent, and Sussex counties. In November, the company announced the acquisition of the assets of Twin Lakes Water Services, Inc., which serves approximately 330 people in Shohola, Pennsylvania. Has 269 employees. Chairman: J. Richard Tompkins. Address: 1500 Ronson Rd, P.O. BOX 1500, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: http://www.middlesexwater.com.

*W.T.*

*January 22, 2010*

**TOTAL SHAREHOLDER RETURN**

*Dividends plus appreciation as of 12/31/2009*

| 3 Mos. | 6 Mos. | 1 Yr. | 3 Yrs. | 5 Yrs. |
|---|---|---|---|---|
| 18.15% | 24.79% | 7.19% | 5.45% | 11.94% |

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# SJW CORP. NYSE--SJW

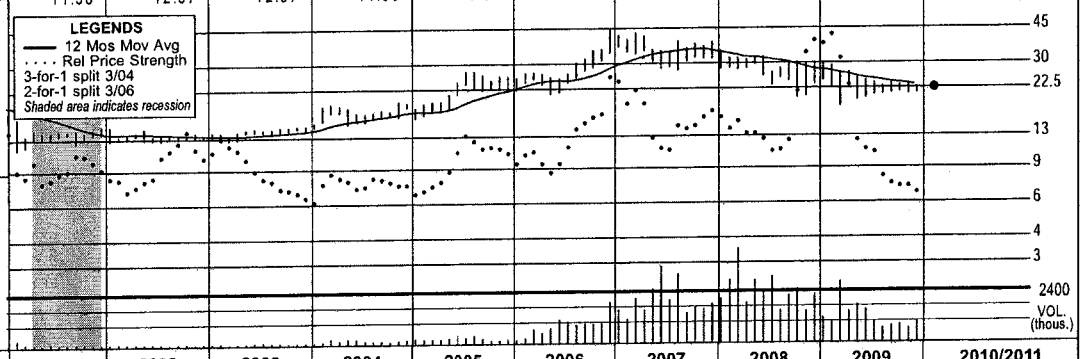
| RECENT PRICE | TRAILING P/E RATIO | RELATIVE P/E RATIO | DIV'D YLD | VALUE LINE |
|---|---|---|---|---|
| 22.54 | 28.2 | 1.57 | 2.9% | |

**RANKS**

| | | |
|---|---|---|
| PERFORMANCE | 3 | Average |
| Technical | 3 | Average |
| SAFETY | 3 | Average |
| BETA .95 | (1.00 = Market) | |

| | |
|---|---|
| Financial Strength | B+ |
| Price Stability | 70 |
| Price Growth Persistence | 75 |
| Earnings Predictability | 85 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| 17.83 | 15.07 | 14.95 | 19.64 | 27.80 | 45.33 | 43.00 | 35.11 | 30.44 | High |
| 11.58 | 12.67 | 12.57 | 14.60 | 16.07 | 21.16 | 27.65 | 20.05 | 18.22 | Low |




| © VALUE LINE PUBLISHING, INC. | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010/2011 |
|---|---|---|---|---|---|---|---|---|---|---|
| SALES PER SH | 7.45 | 7.97 | 8.20 | 9.14 | 9.86 | 10.35 | 11.25 | 12.12 | -- | |
| "CASH FLOW" PER SH | 1.49 | 1.55 | 1.75 | 1.89 | 2.21 | 2.38 | 2.30 | 2.44 | -- | |
| EARNINGS PER SH | .77 | .78 | .91 | .87 | 1.12 | 1.19 | 1.04 | 1.08 | *.80* A,B | *1.17* C/NA |
| DIV'DS DECL'D PER SH | .43 | .46 | .49 | .51 | .53 | .57 | .61 | .65 | -- | |
| CAP'L SPENDING PER SH | 2.63 | 2.06 | 3.41 | 2.31 | 2.83 | 3.87 | 6.62 | 3.79 | -- | |
| BOOK VALUE PER SH | 8.17 | 8.40 | 9.11 | 10.11 | 10.72 | 12.48 | 12.90 | 13.99 | -- | |
| COMMON SHS OUTST'G (MILL) | 18.27 | 18.27 | 18.27 | 18.27 | 18.27 | 18.28 | 18.36 | 18.18 | -- | |
| AVG ANN'L P/E RATIO | 18.5 | 17.3 | 15.4 | 19.6 | 19.7 | 23.5 | 33.4 | 26.2 | *28.2* | *19.3/NA* |
| RELATIVE P/E RATIO | .95 | .94 | .88 | 1.04 | 1.04 | 1.27 | 1.77 | 1.58 | -- | |
| AVG ANN'L DIV'D YIELD | 3.0% | 3.4% | 3.5% | 3.0% | 2.4% | 2.0% | 1.7% | 2.3% | -- | |
| SALES ($MILL) | 136.1 | 145.7 | 149.7 | 166.9 | 180.1 | 189.2 | 206.6 | 220.3 | -- | *Bold figures are consensus earnings estimates and, using the recent prices, P/E ratios.* |
| OPERATING MARGIN | 64.4% | 63.7% | 56.0% | 56.4% | 55.9% | 57.0% | 41.8% | 42.4% | -- | |
| DEPRECIATION ($MILL) | 13.2 | 14.0 | 15.2 | 18.5 | 19.7 | 21.3 | 22.9 | 24.0 | -- | |
| NET PROFIT ($MILL) | 14.0 | 14.2 | 16.7 | 16.0 | 20.7 | 22.2 | 19.3 | 20.2 | -- | |
| INCOME TAX RATE | 34.5% | 40.4% | 36.2% | 42.1% | 41.6% | 40.8% | 39.4% | 39.5% | -- | |
| NET PROFIT MARGIN | 10.3% | 9.8% | 11.2% | 9.6% | 11.5% | 11.7% | 9.4% | 9.2% | -- | |
| WORKING CAP'L ($MILL) | d3.8 | d4.9 | 12.0 | 13.0 | 10.8 | 22.2 | d1.4 | d11.3 | -- | |
| LONG-TERM DEBT ($MILL) | 110.0 | 110.0 | 139.6 | 143.6 | 145.3 | 163.6 | 216.3 | 216.6 | -- | |
| SHR. EQUITY ($MILL) | 149.4 | 153.5 | 166.4 | 184.7 | 195.9 | 228.2 | 236.9 | 254.3 | -- | |
| RETURN ON TOTAL CAP'L | 6.7% | 6.9% | 6.9% | 6.5% | 7.6% | 7.0% | 5.7% | 5.8% | -- | |
| RETURN ON SHR. EQUITY | 9.4% | 9.3% | 10.0% | 8.7% | 10.6% | 9.7% | 8.2% | 8.0% | -- | |
| RETAINED TO COM EQ | 4.1% | 3.8% | 4.7% | 3.6% | 5.6% | 5.2% | 3.5% | 3.3% | -- | |
| ALL DIV'DS TO NET PROF | 56% | 59% | 53% | 58% | 47% | 46% | 57% | 59% | -- | |

A No. of analysts changing earn. est. in last 9 days: 0 up, 0 down, consensus 5-year earnings growth not available. B Based upon 2 analysts' estimates. C Based upon 2 analysts' estimates.

**ANNUAL RATES**

| of change (per share) | 5 Yrs. | 1 Yr. |
|---|---|---|
| Sales | 7.5% | 7.5% |
| "Cash Flow" | 8.5% | 6.0% |
| Earnings | 6.0% | 4.0% |
| Dividends | 5.5% | 6.5% |
| Book Value | 9.0% | 8.5% |

| Fiscal Year | QUARTERLY SALES ($mill.) 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 12/31/07 | 39.0 | 55.1 | 64.9 | 47.6 | 206.6 |
| 12/31/08 | 41.3 | 60.0 | 69.5 | 49.5 | 220.3 |
| 12/31/09 | 40.0 | 58.2 | 69.3 | | |
| 12/31/10 | | | | | |

| Fiscal Year | EARNINGS PER SHARE 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 12/31/06 | .14 | .35 | .48 | .22 | 1.19 |
| 12/31/07 | .12 | .29 | .43 | .20 | 1.04 |
| 12/31/08 | .15 | .34 | .44 | .15 | 1.08 |
| 12/31/09 | d.01 | .23 | .43 | *.13* | |
| 12/31/10 | *.09* | *.32* | | | |

| Cal-endar | QUARTERLY DIVIDENDS PAID 1Q | 2Q | 3Q | 4Q | Full Year |
|---|---|---|---|---|---|
| 2007 | .151 | .151 | .151 | .151 | .60 |
| 2008 | .161 | .161 | .161 | .161 | .64 |
| 2009 | .165 | .165 | .165 | .165 | .66 |
| 2010 | | | | | |

**INSTITUTIONAL DECISIONS**

| | 1Q'09 | 2Q'09 | 3Q'09 |
|---|---|---|---|
| to Buy | 45 | 43 | 34 |
| to Sell | 32 | 40 | 29 |
| Hld's(000) | 8505 | 8694 | 8607 |

| ASSETS ($mill.) | 2007 | 2008 | 9/30/09 |
|---|---|---|---|
| Cash Assets | 2.4 | 3.4 | 1.9 |
| Receivables | 23.0 | 24.5 | 34.6 |
| Inventory | .8 | .9 | .9 |
| Other | 5.4 | 3.2 | 2.5 |
| Current Assets | 31.6 | 32.0 | 39.9 |
| Property, Plant & Equip, at cost | 904.3 | 958.7 | -- |
| Accum Depreciation | 258.8 | 274.5 | -- |
| Net Property | 645.5 | 684.2 | 719.5 |
| Other | 90.2 | 134.7 | 121.9 |
| Total Assets | 767.3 | 850.9 | 881.3 |
| **LIABILITIES ($mill.)** | | | |
| Accts Payable | 9.3 | 5.8 | 9.1 |
| Debt Due | 5.6 | 19.1 | 5.1 |
| Other | 18.1 | 18.4 | 23.1 |
| Current Liab | 33.0 | 43.3 | 37.3 |

**LONG-TERM DEBT AND EQUITY as of 9/30/09**

**Total Debt** $251.1 mill. **Due in 5 Yrs.** NA
**LT Debt** $246.0 mill.
**Including Cap. Leases** NA (49% of Cap'l)

**Leases, Uncapitalized** Annual rentals NA

**Pension Liability** $42.3 mill. in '08 vs. $23.4 mill. in '07

**Pfd Stock** None **Pfd Div'd Paid** None

**Common Stock** 18,498,897 shares (51% of Cap'l)

**INDUSTRY: Water Utility**

**BUSINESS:** SJW Corporation, through its subsidiaries, engages in the production, purchase, storage, purification, distribution, and retail sale of water. The company offers nonregulated water-related services, including water system operations, cash remittances, and maintenance contract services. SJW also owns undeveloped land; a 70% limited partnership interest in 444 West Santa Clara Street, L.P.; and operates commercial buildings in Arizona, California, Connecticut, Florida, Tennessee, and Texas. As of December 31, 2008, SJW provided water service to approximately 226,000 connections that served a population of approximately one million people in the San Jose area. It also provides water service to approximately 8,700 connections that serve approximately 36,000 residents in a service area in the region between San Antonio and Austin, Texas. Has 379 employees. Chairman: Charles J. Toeniskoetter. Inc.: CA. Address: 110 W. Taylor Street, San Jose, CA 95110. Tel.: (408) 279-7800. Internet: http://www.sjwater.com.

*W.T.*

*January 22, 2010*

**TOTAL SHAREHOLDER RETURN**

*Dividends plus appreciation as of 12/31/2009*

| 3 Mos. | 6 Mos. | 1 Yr. | 3 Yrs. | 5 Yrs. |
|---|---|---|---|---|
| -0.50% | 0.94% | -22.41% | -37.54% | 39.31% |

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# RIO RICO UTILITIES, INC.

## DOCKET NO. WS-02676A-03-0434

## DIRECT TESTIMONY

## OF

## WILLIAM A. RIGSBY

## ON BEHALF OF

## THE

## RESIDENTIAL UTILITY CONSUMER OFFICE

EXHIBIT
A-24
ADMITTED

MARCH 11, 2004

over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the water utilities included in my sample ranged from 0.65 to 0.75 with an average beta of 0.68.

Q. What are the results of your CAPM analysis?

A. As shown on Pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean for $r_m$ results in an average expected return of 7.25 percent. My calculation using the arithmetic mean results in an average expected return of 8.62 percent. Although there is some debate on this point, I believe that the consensus among financial analysts appears to be that the arithmetic mean is the better of the two averages. For this reason, I believe that the 8.62 percent figure is the better check on the result of my DCF analysis.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

| METHOD | RESULTS |
|---|---|
| DCF | 9.04% |
| CAPM | 7.25% – 8.62% |

Based on these results, my best estimate of an appropriate range for the cost of equity is from 7.25 percent to 9.04 percent. My final recommendation is an 8.83 percent return for Rio Rico's cost of equity capital.

Q How did you arrive at your recommended 8.83 percent cost of common equity?

A. My recommended 8.83 percent cost of common equity was arrived at by taking a mean average of the results of my 9.04 percent DCF figure and the higher 8.62 percent result of my CAPM analysis which was calculated with an arithmetic mean.[13]

Q. Is this the method that you have typically used to determine the cost of equity capital in prior rate case proceedings?

A. No. In prior rate case proceedings, I have typically recommended the cost of equity that is derived solely from my DCF analysis.

[13] [ ( 9.04 % + 8.62% ) ÷ 2 ] = ( 17.66% ) ÷ 2 = 8.83%

Q. Why have you departed from your typical practice in this proceeding?

A. My decision to average the results of my DCF analysis and my CAPM analysis (calculated with an arithmetic mean), was based on the fact that my recommended capital structure for Rio Rico is comprised of 100 percent equity capital. Because the Company faces no financial risk (i.e. the risk of not being able to meet debt service obligations) I do not believe that a return on common equity that is based on the high end of my analysis is warranted in this case.

Q. Have you made adjustments to your DCF results in prior cases?

A. Yes. In the last water utility rate case that I testified in, I increased my DCF result by fifty basis points to recognize the additional financial risk faced by Arizona-American Water Company, Inc ("Arizona-American"). My fifty basis point adjustment in that case took into consideration Arizona-American's highly leveraged capital structure (which was comprised of 60.0 percent debt and 40.0 percent equity). In this case, a fifty basis point downward adjustment to my 9.04 percent DCF figure would have resulted in a cost of equity of 8.54 percent which falls between the high and low ends of my CAPM results. Given this fact, I believe that a more reasonable figure is one that falls in the higher range between my DCF and arithmetic mean CAPM results. As I will discuss later in my testimony, Rio Rico, with my recommended capital structure of 100

percent equity, faces less risk than the other publicly-traded companies included in my proxy. For the reasons I have just stated, I believe that a twenty-one basis point downward adjustment to my DCF result of 9.04 percent is justified in this case.

**Current Economic Environment**

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are investing in non-regulated entities also.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a review of the economic events that have occurred since 1990. Schedule WAR-9 displays various economic indicators and other data that I will refer to during this portion of my testimony.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

MARC SPITZER
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN MAYES
Commissioner

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF<br>RIO RICO UTILITIES INC. FOR PERMANENT<br>INCREASES FOR WATER AND<br>WASTEWATER UTILITY SERVICES | )<br>)<br>)<br>)<br>) | DOCKET NO. WS-02676A-03-0434 |

DIRECT

TESTIMONY

OF

JOEL M. REIKER

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 11, 2004

EXHIBIT
A-25
ADMITTED

Rio Rico Utility Company
Average Capital Structure of Sample Water Utilities

| Line No. | [A] Company | [B] Long-Term Debt | [C] Common Equity |
|---|---|---|---|
| 1 | American States Water | 50.8% | 49.2% |
| 2 | California Water | 54.1% | 45.9% |
| 3 | Philadelphia Suburban | 52.4% | 47.6% |
| 4 | Connecticut Water | 44.9% | 55.1% |
| 5 | Middlesex Water | 54.8% | 45.2% |
| 6 | SJW Corp | 43.6% | 56.4% |
| 7 | | | |
| 8 | Average Sample Water Utilities | 50.1% | 49.9% |
| 9 | | | |
| 10 | Rio Rico Utilities, Inc. | 0.0% | 100.0% |
| 11 | | | |
| 12 | | | |
| 13 | | | |
| 14 | | | |
| 15 | | | |
| 16 | | | |
| 17 | Source: Value Line, Rio Rico's application | | |

Rio Rico Utility Company
Final Cost of Equity Estimates
Sample Water Utilities

| Line No. | [A] | [B] | | [C] | | [D] | | [E] |
|---|---|---|---|---|---|---|---|---|
| | **Constant Growth DCF** | | | $D_1/P_0$ | + | g | = | k |
| 1 | Constant Growth DCF Estimate | | | 3.4% | + | 5.1% | = | 8.5% |
| 2 | Multi-Stage DCF Estimate | | | | | | = | 9.6% |
| 3 | **Average of DCF Estimates** | | | | | | | **9.1%** |
| 4 | | | | | | | | |
| 5 | **CAPM Method** | **Rf** | + | $\beta$ | x | **(Rp)** | = | k |
| 6 | Historical Market Risk Premium | 3.5% | + | 0.62 | x | 7.4% | = | 8.0% |
| 7 | Current Market Risk Premium | 3.5% | + | 0.62 | x | 4.6% | = | 6.3% |
| 8 | **Average of CAPM Estimates** | | | | | | | **7.2%** |
| 9 | | | | | | | | |
| 10 | | | | | | | | |
| 11 | | | | | | **Average** | | **8.1%** |
| 12 | | | | | | | | |
| 13 | Source: The Wall Street Journal, Value Line, Yahoo Finance, Ibbotson Associates SBBI 2003 Yearbook | | | | | | | |
| 14 | Supporting Schedules: Schedule JMR-6 | | | | | | | |

GOLD CANYON SEWER COMPANY

DOCKET NO. SW-02519A-06-0015

SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

AUGUST 30, 2006

EXHIBIT
A-26
ADMITTED

## INTRODUCTION

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

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

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to Gold Canyon Sewer Corporation's ("Gold Canyon" or "Company") rebuttal testimony on RUCO's recommended rate of return on invested capital (including RUCO's recommended capital structure and cost of debt) for the Company's wastewater operation located in Pinal County.

Q. Will your surrrebuttal testimony address the rate base, operating revenue, operating expense, or rate design issues in the case?

A. No. Those issues and the issue of excess capacity will be addressed in the surrebuttal testimony of RUCO witness Rodney L. Moore.

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

A. Yes, on June 16, 2006, I filed direct testimony with the Arizona Corporation Commission ("ACC" or "Commission") on Gold Canyon's application requesting a permanent rate increase. My direct testimony addressed the cost of capital issues associated with Gold Canyon's filing.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains three parts: the introduction that I have just presented, a summary of Gold Canyon's rebuttal testimony, and a section on the cost of capital issues.

**SUMMARY OF GOLD CANYON'S REBUTTAL TESTIMONY**

Q. Have you reviewed Gold Canyon's rebuttal testimony?

A. Yes. I have reviewed the Company's rebuttal testimony, which was filed on July 27, 2006.

Q. Briefly summarize the Company's rebuttal testimony.

A. The Company's cost of capital witness, Mr. Thomas J. Bourassa, disagrees with my recommendations on capital structure, hypothetical cost of debt and cost of common equity. He is also critical of the methods that I have used to derive my original recommended 9.04 percent cost of common equity for Gold Canyon.

**COST OF CAPITAL**

Q. Have you made any changes to the cost of common equity that you recommended in your direct testimony?

A. Yes. I have revised my recommended cost of common equity downward from 9.04 percent to 8.60 percent. The 8.60 percent figure was derived from an updated discounted cash flow model ('DCF") analysis, which used

an eight-week average of closing stock prices, data published in The Value Line Investment Survey ("Value Line") July 28, 2006 water utility industry update (Attachment A), and updated data from Zacks Investment Research, Inc. (Attachment B). My revised 8.60 percent estimate also takes into consideration forward-looking Value Line projections for the time frame that runs from 2006 through 2011. In addition to updating the stock price data used in the DCF model, I have also updated all of the components used in my capital asset pricing model ("CAPM") analysis, which is also impacted by stock price and interest rate (i.e. treasury yield) activity. Surrebuttal Schedules WAR-1 through WAR-9 will provide support for my revised 8.60 percent figure.

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

A. Yes. On Tuesday, August 8, 2006, the Federal Reserve ("Fed") halted its series of seventeen consecutive quarter-point rate increases, which have boosted the federal funds rate from a level of 1.00 percent in mid-2004 to the current rate of 5.25 percent. The Fed's action was influenced by economic data on a slowing U.S. economy that could result in lower levels of inflation. While there is a debate among Fed watchers as to the impact of this pause, some analysts believe that the Fed had actually

gone too far in its rate increase campaign and that rate cuts could be a possibility depending on the direction that the economy takes[1].

Q. Please explain the main reason why your revised DCF results are lower than the DCF results that were presented in your direct testimony.

A. The main reason is that the stock prices of the publicly traded water utilities included in my sample have declined in recent months as a result of rising interest rates. Investors who found the yields of these stocks attractive because of lower interest rates, created a demand that forced the prices of these stocks up. Now that interest rates have increased, the shine is off on water stocks and these same investors are selling their shares and putting their funds into instruments with more attractive yields.

Q. Wouldn't the yields on the water utility stocks in your sample be higher because of the stock price declines?

A. Yes. That is true. Since the dividends on these stocks have remained constant, the dividend yield component ($D_1 \div P_0$) of my DCF model has increased from an average of 2.03 percent in my direct testimony, to my revised average of 2.36 percent. However, the lower stock prices and the updated Value Line estimates produced a lower DCF growth estimate (g).

[1] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

Q. Please explain how the lower stock prices and the updated Value Line estimates produced a lower DCF growth estimate?

A. The growth component of my DCF model declined from the 7.01 percent estimate presented in my direct testimony to my revised figure of 6.25 percent. The July 28, 2006 Value Line estimates have resulted in a lower internal growth (br) estimate that has dropped from 5.00 percent in my direct testimony to my revised estimate of 4.68 percent. My revised external growth estimates are partially a result of the lower stock prices that have produced lower market to book ratios for all four of the water utilities in my sample (i.e. the market-to-book ratios are moving closer to a ratio of 1.0). The lower market-to-book ratios have contributed to my lower external (sv) growth estimate of 1.57 percent estimate that is 43 basis points lower than the 2.00 percent estimate presented in my direct testimony.

Q. Please summarize the results of your revised cost of capital analysis.

A. A summary of my revised cost of capital analysis, on water utilities, is as follows:

| METHOD | RESULTS |
|---|---|
| DCF | 8.60% |
| CAPM | 9.11% – 10.56% |

Q. Has Gold Canyon's witness made any changes to the Company-proposed cost of common equity as a result of the Value Line update?

A. The Company's witness stated that he had updated his models using data from Value Line's April 28, 2006 water utility industry update for the prior quarter, but is still proposing a 10.50 percent cost of common equity.

Q. Briefly summarize the positions of the parties to the case in regard to capital structure, cost of debt, cost of equity and weighted cost of capital.

A. Both ACC Staff and the Company are recommending debt-free capital structures comprised of 100 percent common equity. RUCO is recommending a hypothetical capital structure comprised of 40 percent debt and 60 percent common equity, with a hypothetical cost of debt of 8.45 percent. The costs of common equity being recommended are as follows:

| | |
|---|---|
| Gold Canyon | 10.50% |
| ACC Staff | 8.40% |
| RUCO (revised) | 8.60% |

The weighted costs of capital being recommended by the parties to the case are as follows:

BEFORE THE ARIZONA CORPORATION COMMISSION

Arizona Corporation Commission
DOCKETED
JUL 28 2006
DOCKETED BY ne

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MARC SPITZER
MIKE GLEASON
KRISTIN K. MAYES

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES BASED THEREON FOR UTILITY SERVICE BY ITS PARADISE VALLEY WATER DISTRICT. | DOCKET NO. W-01303A-05-0405 |
| IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY FOR APPROVAL OF AN AGREEMENT WITH THE PARADISE VALLEY COUNTRY CLUB. | DOCKET NO. W-01303A-05-0910<br><br>DECISION NO. 68858<br><br>**OPINION AND ORDER** |

DATES OF HEARING: March 27, 28, 29, and April 3, 2006

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Teena Wolfe

APPEARANCES: Mr. Craig A. Marks, Corporate Counsel, on behalf of Arizona-American Water Company;

Mr. Daniel Pozefsky, Attorney, on behalf of the Residential Utility Consumer Office; and

Ms. Maureen A. Scott, Senior Staff Counsel, and Mr. Keith A. Layton, Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

EXHIBIT
A-27
ADMITTED

## TABLE OF CONTENTS


I. INTRODUCTION ..... 4
- A. Procedural History ..... 4
- B. Rate Application ..... 4

II. RATE BASE ..... 6
- A. Plant in Service ..... 6
  - 1. Post-Test Year Plant – Fire Flow Improvement Projects ..... 6
    - a. Discussion ..... 6
    - b. Conclusion ..... 11
  - 2. Plant Held for Future Use – Backup Pumping Equipment ..... 12
  - 3. Conclusion ..... 13
- B. Gain on Sale of Land ..... 14
- C. Cash Working Capital ..... 14

III. ORIGINAL COST RATE BASE ..... 15

IV. FAIR VALUE RATE BASE ..... 15

V. OPERATING INCOME ..... 15
- A. Rate Case Expense ..... 15
- B. Labor and Pension Expenses ..... 17
- C. Property Tax Expense ..... 18
  - 1. Property Tax Calculation ..... 18
  - 2. Miller Road Treatment Facility Property Taxes ..... 19
- D. Administrative and General Expenses (A&G) ..... 20
  - 1. AIP, Performance Pay and Stay Bonus ..... 20
  - 2. Reorganizing/Downsizing Expenses ..... 21
  - 3. Ice ..... 21
  - 4. Security Renovations and Repairs and Indoor Plant Maintenance ..... 21
  - 5. Conclusion ..... 22
- E. Statement of Operating Income ..... 22

VI. COST OF CAPITAL ..... 22
- A. Capital Structure and Cost of Debt ..... 22
- B. Cost of Equity ..... 22
  - 1. Arizona-American ..... 22
  - 2. RUCO ..... 22
  - 3. Staff ..... 22
  - 4. Discussion ..... 27
- C. Cost of Capital Summary ..... 29

VII. AUTHORIZED INCREASE ..... 29

VIII. RATE DESIGN ..... 29
- A. General Rate Design ..... 29
- B. Surcharges ..... 30
  - 1. Company Surcharge Proposal ..... 30
  - 2. Staff Recommendation ..... 30
  - 3. Staff's Alternative Fire Flow Surcharge Proposal (Exhibit B) ..... 31
  - 4. Accounting Order Modifying AFUDC Methodology ..... 32
  - 5. Analysis and Conclusion ..... 32

IX. OTHER ISSUES ..... 33
- A. Arsenic Cost Recovery Mechanism ("ACRM") ..... 33

B. PVCC Special Contract .....35
FINDINGS OF FACT .....36
CONCLUSIONS OF LAW .....41
ORDER .....41

**Exhibits to Decision**

**Exhibit A** **Copy of Decision No. 68303 (November 14, 2005)**

**Exhibit B** **Alternative Fire Flow Surcharge (Copy of Hearing Exh. S-9)**

**BY THE COMMISSION:**

## I. INTRODUCTION

On June 3, 2005, Arizona-American Water Company ("Arizona-American" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a rate increase in its Paradise Valley Water District ("District"). The application also requests approval for the District of an Arsenic Cost Recovery Mechanism for investments required by the Company to comply with federal water arsenic reduction requirements; a High Block surcharge that would be imposed for conservation purposes on usage in the highest consumption block; and a Public Safety surcharge for investments by the Company related to improvement of fire flow facilities.

Arizona-American serves approximately 131,000 customers throughout the State of Arizona pursuant to various Certificates of Convenience and Necessity granted by the Commission to the Company and its predecessors in interest. The District serves approximately 4,737 metered customers, 93 percent of whom are residential customers, located in portions of the Town of Paradise Valley, the City of Scottsdale, and unincorporated Maricopa County.

### A. Procedural History

By Procedural Order issued August 15, 2005, a hearing was set in this matter to commence on March 27, 2006. A Procedural Order was issued on February 28, 2006 consolidating the Company's rate application with the above-captioned application filed by the Company on December 22, 2005, requesting Commission approval of an agreement between the Company and the Paradise Valley Country Club ("PVCC") that would allow PVCC a 15 percent discount from the Company's standard turf rates.

Intervention was requested by and granted to the Residential Utility Consumer Office ("RUCO") and PVCC. The Town of Paradise Valley ("Town") filed a letter requesting intervention on March 20, 2006, but later filed a letter on March 27, 2006 withdrawing its intervention request. No other intervention requests were filed.

On October 26, 2005, the Company docketed an affidavit certifying that a copy of the notice required by the August 15, 2005 Procedural Order was included in each September 2005 bill mailed to customers in the Company's Paradise Valley Water District.

The rate application originally included a request for an Accounting Order authorizing the deferral of capital costs incurred by the District related to public safety associated with fire flow. However, on September 16, 2005, the Company filed a letter in this docket including details regarding the requested Accounting Order, and on October 4, 2005, the Company filed in a separate docket, Docket No. W-1303A-05-0704, a request to bifurcate the Accounting Order request from the rate application. The Commission subsequently issued Decision No. 68303 on November 14, 2005, granting the Company's request for an Accounting Order allowing it to defer capital costs related to public safety associated with fire flows. Decision No. 68303 limited the authorized deferral amounts to depreciation expense and a post in-service allowance for funds used during construction ("AFUDC") with interest rates set at the Company's cost of debt concurrent with the deferral period. For convenience of reference, a copy of Decision No. 68303 is attached hereto as Exhibit A.

A hearing was held as scheduled commencing on March 27, 2006 and continuing on March 28, March 29 and April 3, 2006. Several members of the public appeared on the first day of hearing and provided public comment on the application.

The Company, RUCO and the Commission's Utilities Division Staff ("Staff") appeared at the hearing and presented evidence before an Administrative Law Judge of the Commission. Following post-hearing filings, which included initial and reply briefs timely filed by the parties on May 5 and May 26, 2006, respectively, the consolidated matters were taken under advisement.

On July 3, 2006, the Town filed in these consolidated dockets a Motion for Leave to File Amicus Curiae Brief, to which was attached an amicus curiae brief.[1]

**B. <u>Rate Application</u>**

The current rates and charges for the District were authorized in Decision No. 61831 (July 20, 1999), based on a test year ended June 30, 1998, and became effective on August 1, 1999. The current rate application is based on a twelve month test year ended December 10, 2004. The Company is requesting an increase in revenues for the District of $427,939, for an increase of 8.43 percent over test year adjusted revenues of $5,079,195, for a total revenue requirement of $5,507,134.

[1] Due to the lateness of the filing in relation to the timing requirements for the docketing of a recommended Opinion and Order for Commission consideration, the amicus curiae brief could not be considered in the preparation of the recommended Opinion and Order.

RUCO is recommending a decrease in revenues of $436,352, or 8.59 percent, from test year adjusted revenues of $5,079,195, for a total revenue requirement of $4,642,843. Staff is recommending a revenue increase of $254,164, or 5.0 percent over test year adjusted revenues of $5,079,195, for a total revenue requirement of $5,333,359. Based on adjustments to the Company's filing as set forth herein, we authorize an increase in revenues of $199,371, which is a 3.93 percent increase over test year adjusted revenues of $5,079,195, for a total revenue requirement of $5,278,566.

## II. RATE BASE

The Company proposes an adjusted test year Original Cost Rate Base ("OCRB") of $14,412,903. Staff is in agreement with this amount. RUCO proposes an adjusted test year OCRB of $10,809,498.

### A. Plant in Service

The Company proposes adjusted test year plant in service of $32,508,049. Staff also recommends $32,508,049, and RUCO recommends $29,358,325.

#### 1. Post-Test Year Plant – Fire Flow Improvement Projects

The OCRB proposed by the Company includes $3,018,867 of post-test year plant consisting of fire flow improvement projects known as the Jackrabbit/Invergordon project.

##### a. Discussion

Staff verified that the post-test year plant at issue entered into service in 2005, is revenue neutral, and does not materially reduce operating expenses (Direct Testimony of James J. Dorf, Hearing Exh. S-1 at 4-5). Staff recommends inclusion of the fire flow projects in rate base to encourage improvement in public fire safety and to minimize the deferral of costs to future periods pursuant to the Accounting Order adopted by the Commission in Decision No. 68303 (*id.* at 5). The Company initially requested inclusion of post-test year plant amounts in addition to the $3,018,867 amount recommended by Staff. Those additional amounts include $105,164 for work orders the Company asserts are associated with the Jackrabbit/Invergordon project, and an additional fire flow improvement project, known as the Nauni Valley Drive improvements, at the Company's asserted cost of $420,755 (Rebuttal Testimony of Joel M. Reiker, Hearing Exh. A-15 at 8-9). Staff opposed the inclusion of the additional post-test year Jackrabbit/Invergordon work order costs and the Nauni

Valley Drive costs in the Company's plant in service at this time, because the additional project's in-service date, as well as the dates of the work orders, were more than 90 days past the date the rate application was found sufficient.[2] The Company ultimately agreed to Staff's position, based on the fact that the Jackrabbit/Invergordon work order costs and the Nauni Valley Drive costs may be deferred pursuant to the Decision No. 68303 Accounting Order, and on the Company's understanding that the disputed amounts will be eligible for recovery as CIAC through funds generated by the Public Safety surcharge for which the Company is requesting approval in this proceeding (Tr. at 274). The Public Safety surcharge is discussed in a separate section below.

The Company states that its request to include the post-test year fire flow improvements in rate base is supported by the fact that the projects were requested by and supported by residential customers; the projects will protect the lives and properties of residential customers; and the District's residential customers are willing to pay for the improvement projects. The Company states that the Town also requested the two other water utility service providers operating in the Town, Berneil Water Company and the City of Phoenix, to make fire flow improvements, and that the decision to request the fire flow improvements was the result of a collaborative, grass-roots process. The Company asserts that the Town cannot legally fund the fire flow improvements; that the Town and its residents are aware of the rate increases needed to fund the improvements, which are estimated to eventually total up to $16 million at completion (Direct Testimony of David P. Stephenson, Hearing Exh. A-19 at 24); and that the improvements will enable the District's infrastructure to support the Town Code's requirement to provide a minimum flow of 1,500 gallons per minute.[3]

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[2] Staff based its position on language in Decision No. 61831, the District's prior rate case, which stated:

> Further, in order to allow Staff and intervenors an adequate time to review and audit any such adjustments, the Company shall limit its adjustments to add post-TY plant to include only plant that is used and useful and in service within 90 days of the date that the rate application is deemed sufficient.

Decision No. 61831 at 4.

[3] *See* Chapter 13, Article 13-1, Section 13 of the Paradise Valley Town Code which provides:

> A. The minimum fire flow from all hydrants in the Town will be 1,500 gallons per minute (5,678.1 liters per minute).
>
> B. The Chief may increase or decrease minimum hydrant flows based on review of hazard and water distribution system.

RUCO believes that the fire flow improvements are discretionary expenditures which should not be included in the District's rate base at this time or at any time in the future. RUCO proposes instead that the Town, as the entity requesting the fire flow improvements, should contribute the projects' costs to the Company, paid for through taxes (RUCO Br. at 9). RUCO argues that there is no Commission rule, policy or statute that governs or sets a fire flow standard, and no regulatory rate making principle that requires or supports a fire flow standard. RUCO asserts that typically when a third party requests the construction of additional water infrastructure from a regulated utility, the Commission requires an advance in aid of construction ("AIAC") or a contribution in aid of construction ("CIAC"); that such rate treatment is especially appropriate when the cost of expenditures outweighs the expected revenue from the project (Direct Testimony of Marylee Diaz Cortez, Hearing Exh. R-11 at 8); and that it is appropriate in this case because the fire flow improvements are non-revenue producing. RUCO argues that while ratepayers in the District may be able to absorb increased rates associated with placing the fire flow improvements in rate base, ratepayers in other communities may not be able to do so. RUCO fears that allowing the District to include the improvements in rate base will lead to unaffordable water service in Arizona (RUCO Initial Br. at 5).

The Company states that the Town has informed the Company that A.R.S. § 9-514 and/or the Gift Clause in the Arizona Constitution would prohibit the Town from spending general fund money to build the fire infrastructure that would be owned by the Company (*See* Hearing Exh. R-1. *See also* Hearing Exh. A-29, a copy of a letter from the Town to Chairman Hatch-Miller dated February 15, 2006 and signed by Town Manager Thomas M. Martinson, which states; "The Town government cannot, for both statutory and public policy reasons, fund water system improvements for a private utility."). RUCO disagrees with this legal reasoning. RUCO argues that the Commission should reject the Town's "claim"[4] that A.R.S. § 9-514 prevents it from funding the fire flow improvements, based on the Arizona Supreme Court's holding in *Town of Gila Bend v. Walled Lake Door Co.*, 107 Ariz. 545 (1971), 490 P.2d 551 that A.R.S. § 9-514 deals with the power of municipalities to engage

[4] It must be noted that the Town is not a party to this proceeding.

in competition with businesses of a public nature. Regarding the Gift Clause,[5] RUCO argues that because the provision of water to provide fire protection is a public purpose for which public monies can legally be spent, the Gift Clause does not prohibit the Town from paying for the fire flow improvements, citing *Gila Bend* at 549-550, 490 P.2d 551, 555-556. RUCO contends that if the Town were to provide the fire flow related mains to the Company as CIAC, the Company would not benefit from the Town's expenditure, because the Company's books would reflect the contribution as an offset to plant in service, and the Company would not earn a return on the contribution. RUCO also argues that the Town's minimum fire flow ordinance does not require the Company to pay for the costs of fire flow improvements.[6]

The Company disagrees with RUCO's interpretation of *Gila Bend* that would allow a municipality to contribute plant to an investor-owned water utility, arguing that the facts in *Gila Bend* distinguish it from the facts in this case (Company Reply Br. at 3). Staff also believes the facts of *Gila Bend* are significantly different from the facts in this case, primarily because in this case, unlike in *Gila Bend,* the Company, and not the Town, will ultimately hold and control the plant. Staff disagrees with RUCO's interpretation of the legal holdings of the case, and believes that *Gila Bend* supports the Town's legal position regarding both A.R.S. § 9-514 and the Gift Clause.

The Company also disagrees with RUCO's contention that the Town's funding of a $46,175 interconnection from the City of Scottsdale to the Berneil Water Company system demonstrates that the Gift Clause does not prohibit the Town from funding the District's improvements (*see* RUCO Br. at 8-9). The Company points out that the interconnection RUCO refers to would be built and owned

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[5] Ariz. Const. Art. 9, § 7 provides as follows:

> Neither the state, nor any county, city, town, municipality, or other subdivision of the state shall ever give or loan its credit in the aid of, or make any donation or grant, by subsidy or otherwise, to any individual, association, or corporation, or become a subscriber to, or a shareholder in, any company or corporation, or become a joint owner with any person, company, or corporation, except as to such ownerships as may accrue to the state by operation or provision of law or as authorized by law solely for investment of the monies in the various funds of the state.

[6] RUCO argues that "[i]nterpreting the Town Code to impose such obligations and effectually raise rates impairs the Commission's exclusive and absolute power to set rates as set forth in Article 15, Section 3 of the Constitution." (RUCO Br. at 11, fn 8). If this were true, one could likewise argue that the federal Safe Drinking Water Act or the U.S. Environmental Protection Agency's rules governing maximum contaminant levels for water pollutants impair this Commission's constitutional authority. RUCO makes no similar argument against approval of the Arsenic Cost Recovery Mechanism the Company is proposing in this proceeding.

by the City of Scottsdale, not the Berneil Water Company (*see* Hearing Exh. A-31, Town Council minutes from May 12, 2005), and argues that the Gift Clause therefore would not apply.

Staff, while acknowledging that the Company's fire flow improvement plan requires a major investment and overhaul of the District's system, recommends including prudently incurred costs for fire flow plant that is used and useful because the investment is necessary to comply with the Town ordinance. Staff states that the Town's fire flow ordinance brings its fire flow standards up to Uniform Fire Code standards,[7] based upon recommendations of a task force comprised of Town officials, Company representatives and Town residents. Staff points out that the Town is requiring all three water utilities serving the Town to meet minimum fire flow standards, and that much of the District's infrastructure is 40-50 years old. Staff states that Town residents' safety and the protection of their property are highly dependent upon the fire flow improvement program (citing Decision No. 68303 at 2). Staff contends that if the Town is legally prohibited from funding the fire flow investments as the Town stated in its February 15, 2006 letter,[8] allowing rate recovery of the investment may be the only option available to bring the District's water system up to Uniform Fire Code standards in order to provide fire flow protection to the District's customers. Staff further states that it is aware of no previous Commission Decision denying a water company's request for recovery of its investment in fire flow improvements, and that a recent Commission Decision has recognized that this is an important public safety issue that must be addressed.[9]

Staff takes issue with RUCO's argument that the Commission typically requires AIAC or CIAC when a third party requests the construction of additional water infrastructure from a regulated utility, pointing out that under A.A.C. R14-2-406, main extension agreements are discretionary and not mandatory. Staff further argues that it has been the practice of this Commission to limit CIAC for new development, and to require utility investment when necessary to maintain balanced capital

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[7] Staff notes that the Town's ordinance is consistent with the fire flow requirements of the Town of Scottsdale.

[8] *See* Exhibit A-29.

[9] Decision No. 67093 at 31 (June 30, 2004) (*Arizona-American Water Company, Inc.*, Docket Nos. WS-01303A-02-0867 *et al.*) (ordering the Company to form a fire flow task force to determine whether water production capacity, storage capacity, water lines, water pressure, and fire hydrants in the communities served by the systems involved in that rate case are sufficient to provide the fire protection capacity desired by each community).

structures. In addressing RUCO's position that there is no regulatory rate making principle that requires or supports a fire flow standard, Staff responds that although there is no specific Commission Rule, policy or standard that directly addresses fire flow, the Town's fire flow ordinance addresses public health and safety, and A.R.S. § 40-336[10] and A.R.S. § 40-361.B[11] give the Commission discretion to approve use of ratepayer funds for fire flow improvement, which is a public health and safety issue. Staff believes that the Company has discretion to upgrade its existing system to meet fire flow requirements, as A.A.C. R14-2-606(H) provides that "[t]he Company may install main extensions of any diameter meeting the requirements of the Commission or any other public agencies having authority over the construction and operation of the water system and mains" and supports the Company's exercise of such discretion as long as the plant is used and useful and necessary for the service that is required by ordinances and rules and regulations regarding water quality or quantity (Staff Reply Br. at 9; Tr. at 535-536, 542).

b. Conclusion

The question before this Commission is not the hypothetical issue of whether A.R.S. § 9-514 or the Gift Clause would apply if the Town were to pay for the fire flow improvements as RUCO advocates. The question before this Commission is whether the Company's actual deferred expenses pursuant to Decision No. 68303, which the Company incurred to comply with the Town's fire flow ordinance, should be allowed in rate base as the Company requests. The record here indicates that the improvements are necessary to ensure the public health and safety of the District's ratepayers, are used and useful to the ratepayers in the District, and that the District's ratepayers are largely in support of the improvements and are willing to pay for them through their water utility rates.[12]

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[10] A.R.S. § 40-336 provides:

> The commission may by order, rule or regulation, require every public service corporation to maintain and operate its line, plant, system, equipment, and premises in a manner which will promote and safeguard the health and safety of its employees, passengers, customers and the public . . .

[11] A.R.S. § 40-361.B provides:

> Every public service corporation shall furnish and maintain such service, equipment and facilities as will promote the safety, health, comfort and convenience of its patrons, employees and the public, as will be in all respects adequate, efficient and reasonable.

[12] Tr. at 100; Tr. at 310-314; Hearing Exh. A-29 (copy of a letter from the Town to Chairman Hatch-Miller dated February 15, 2006 and signed by Town Manager Thomas M. Martinson, also filed in this docket on February 22, 2006).

Several District customers who are City of Scottsdale residents provided public comment at the hearing in opposition to the fire flow improvements, stating that the improvements would not benefit them. The record in this case shows, however, that improvements in fire flow will assist all customers who are part of an interconnected grid, regardless of where on the system they are located.[13] Moreover, as the Company argues, most City of Scottsdale customers of the District will be exempt from the Public Safety Surcharge for which the Company is requesting approval in this proceeding.[14]

RUCO expresses a concern that allowing the investments in rate base will set a precedent for future rate proceedings for other water utilities. Our Decision in this matter is limited to the facts before us in this proceeding, and is not intended to, and should not be interpreted to, set policy with regard to fire flow improvements. In the event a similar issue arises in another rate case proceeding for another regulated water utility, the Commission will consider the issue based on the totality of the facts and circumstances at that time.

It is reasonable to include $3,018,867 of post-test year plant consisting of fire flow improvement projects, known as the Jackrabbit/Invergordon project, in test year plant in service.

**2. Plant Held for Future Use - Backup Pumping Equipment**

The OCRB proposed by the Company includes $132,682 for two backup submersible pumps, motors, and a transformer for the District's Well No. 17. Staff ultimately determined that the equipment is used and useful because it was used as backup during the test year, and that due to the size of the wells and pumps, holding the equipment as backup is useful to ratepayers because with the equipment on site, the Company can get a well up and running very quickly compared to the time it would take to get replacements (Tr. at 381-382). Staff recommends that the equipment be included in rate base, but transferred from the plant held for future use account to the appropriate plant account (Tr. at 479). On brief, RUCO agreed that the backup equipment is used and useful and has agreed that it should be included in rate base (RUCO Reply Br. at 14). According to the evidence presented, the backup equipment is used and useful and should be included in plant in service. As Staff

[13] Cross-examination testimony of Paul G. Townsley, Tr. at 115.

[14] *See* Hearing Exh. A-33.

recommends, these plant items should be removed from the plant held for future use account and placed in the appropriate account.

**3. Conclusion**

Based on the evidence presented, $32,508,049 is reasonable for adjusted test year plant in service for the District. Staff and RUCO accepted the Company's proposed AFUDC debt of $950 and accumulated depreciation balance of $10,021,184. These adjustments to plant in service will be adopted, for a test year adjusted plant in service balance of $22,487,815.

**B. Gain on Sale of Land**

The Company sold its former operations/customer center on Casa Blanca Drive for $900,000 in 2004, with a net after tax gain on the sale of $481,681, and is proposing sharing the gain with ratepayers on a 50/50 basis, through a surcredit refund over five years (Direct Testimony of David P. Stephenson, Hearing Exh. A-19 at 35-36). Staff accepted the Company's surcredit proposal and proposed a three year amortization period instead of five years (Exh. S-1 at 8). The Company subsequently accepted the three year amortization (Rejoinder Testimony of Joel M. Reiker, Hearing Exh. A-16 at 5).

RUCO accepts the three year amortization period, and the 50/50 sharing. Rather than a surcredit, however, RUCO proposes that the Company offset ratebase by the ratepayers' portion of the pre-tax gain, by means of an amortized deferred liability account, and also that the annual distribution of the gain be recorded on the Company's income statement as a credit to operating expense (Direct Testimony of Timothy J. Coley, Hearing Exh. R-7 at 8). RUCO is concerned that the proposed surcredit would allow the Company to hold ratepayer money interest-free while the gain is being repaid through the surcredit (Tr. at 334), and argues that it is therefore appropriate to reduce ratebase to reflect the gain as a means to compensate ratepayers (RUCO Reply Br. at 7-8).

The Company disagrees with RUCO's proposal, pointing out that it requires the Company to pay the capital-gains taxes associated with the sale and then share the pre-tax gain with the customers, and that RUCO admits that its proposed treatment is inconsistent with Commission precedent. Staff also disagrees with RUCO's proposal, and believes that the Staff recommendation provides a simpler and more appropriate method of refunding ratepayers' share of the gain (Tr. at

481, 483). Staff states that the proposed surcredit mechanism appropriately recognizes the net tax effect of the gain on the revenue requirement, because as revenue is reduced, the surcredit is amortized, and there would be no tax impact (Tr. at 484, 486).

With the three year amortization period proposed by Staff, the surcredit mechanism proposed by the Company for a 50/50 sharing of the post-tax gain on the land sale is a more reasonable and appropriate means of sharing the gain than that proposed by RUCO, and provides a fair resolution for both ratepayers and the Company.

C. **Cash Working Capital**

Arizona-American performed a lead/lag study, and initially requested working capital in the amount of $350,946, which included $160,359 cash working capital. The Company subsequently proposed a revised cash working capital lead/lag study, and based on that study revised its proposed cash working capital to $115,182 (Rebuttal Testimony of Joel M. Reiker, Hearing Exh. A-15 at 16-19), but ultimately accepted Staff's recommendation to completely eliminate a cash working capital allowance, for total working capital of $190,587.

RUCO recommends a negative cash working capital allowance of ($61,432), for total working capital of $129,155. RUCO states that the most accurate way to measure a company's cash working capital requirement, or the amount of cash a company must have on hand to cover any differences in the time period between when revenues are received and expenses must be paid, is via a lead/lag study (Direct Testimony of Timothy J. Coley, Hearing Exh. R-7 at 9). RUCO states that it analyzed and reviewed the Company's initial and revised lead/lag studies, and that its proposed ($61,432) cash working capital recommendation results from adjusting the Company's lead/lag study to include only those items the Commission has allowed in the past (RUCO Br. at 25). RUCO contends that the reason for the disparity between the cash working capital calculations of the Company and RUCO is that the Company's calculations include non-cash items (*id.* at 24).

We agree with RUCO that a lead/lag study is the most accurate way to determine a working capital requirement, and that a lead/lag study is appropriate for a company of Arizona-American's size. While the Company takes issue with items in RUCO's lead/lag study, the Company proposed no alternative cash working capital allowance based on a lead/lag study (*see* Company Reply Br. at 5-

6). Because RUCO's recommendation is based on a lead/lag study, we find its recommendation more reasonable than the alternative proposals of the Company and Staff, and will adopt it, for total working capital of $129,155.

## III. ORIGINAL COST RATE BASE

The Company's proposed adjusted test year balances for the District, for CIAC of $6,486,559; AIAC of $635,912; customer deposits of $3,500, and deferred income tax credits of $1,139,528 were not contested and will be adopted, for a total deduction from net plant in service of $8,265,499. As discussed above, we adopt adjusted test year working capital of $129,155, which is added to net plant in service for an OCRB of $14,351,471.

## IV. FAIR VALUE RATE BASE

The Company did not propose a reconstruction cost new less depreciation rate base for the District, as is allowed by A.A.C. R14-2-103 (Direct Testimony of John A. Chelus, Hearing Exh. S-6 at 6). Therefore, the District's fair value rate base ("FVRB") is the same as its OCRB, or $14,351,471.

## V. OPERATING INCOME

The Company proposed adjusted test year operating income of $866,762 (*see* Company Br. at 6). Staff recommends $886,714, and RUCO recommends $1,035,400.

### A. Rate Case Expense

The parties agree on a three-year amortization of rate case expense but disagree on the amount of recoverable expense. The Company is requesting rate case expense of $301,832. RUCO proposes rate case expense of $73,179, and Staff proposes $208,700.

The Company originally estimated its rate case expense to be $282,841 (Direct Testimony of Stacey A. Fulter, Hearing Exh. A-22 at 3). This estimate included a 50/50 sharing between ratepayers and investors of its initial estimated costs of $158,766 for the Company's cost of capital witnesses (*id.*). The Company subsequently updated its estimate, and no longer proposes the 50/50 sharing of the $158,267 costs for its cost of capital witnesses (Rebuttal Testimony of Thomas Broderick, Hearing Exh. A-17 at 2 and Exh.TMB-1). The Company argues that its requested rate case expense is reasonable based on the complex issues in this case, the number of testimony

documents, the amount of discovery, the length of the hearing, and the need to file post hearing briefs, and contends that the expenses are not out of line with rate case expense allowed in recent Commission cases (Company Br. at 12, citing $250,000 in rate case expense allowed in Decision No. 68302 (November 14, 2005) and $285,000 in Decision No. 68176 (September 30, 2005)). The Company argues that the $158,267 expense for retaining its cost of capital witnesses was necessary because of the importance of the issue presented (Company Br. at 8). The Company states that because the issue was one of first impression for the Commission and one that has implications for all future rate cases, the Company retained the foremost experts in the field, which was expensive, and that presentation of the issue required two expert witnesses, one to explain the methodology of adjusting returns on equity for differences in capital structure, and one to apply it (*id.*).

Staff made 10 adjustments to the Company's original rate case expense estimates (*see* Direct Testimony of Alexander Ibhade Igwe, Hearing Exh. S-6, Schedule AII-9), and recommended recovery of $208,700. Staff also reviewed the Company's revised request of $301,832, and continues to support recovery of $208,700, noting that the Company's proposal to recover $158,267 for cost of capital analysis is significantly higher than normal and would unduly burden ratepayers (Surrebuttal Testimony of Darron W. Carlson, Hearing Exh. S-8 at 7; Hearing Exh. S-6 at 10). Staff also noted that the Company's proposal to increase its initial estimate of $14,985 for cost of service analysis and rate design up to $42,677, or 185 percent over its original proposal, was excessive (Hearing Exh. S-6 at 10-11). Staff's recommendation includes the Company's original proposal for 50/50 sharing of the costs of the Company's cost of capital witnesses, based on Staff's belief that the benefits of the cost of capital portion of rate case expenses flow to both investors and ratepayers (Hearing Exh. S-8 at 7). Staff further argues that the Company failed to mitigate its costs in expending $158,767 on its cost of capital consultants, who have presented their methodology in a number of regulatory forums that have rejected it or failed to implement it (Staff Reply Br. at 22-23; Staff Br. at 15).

RUCO's arguments regarding the Company's expenses for its cost of capital, cost of service and rate design analysis and testimony are in accord with Staff's arguments (RUCO Br. at 13-15). RUCO also argues that the issues in this case are not complex, and disagrees with the Company's comparison of the complexity of this case to the complexity of the case leading to Decision No.

68176 (RUCO Br. at 15-16, RUCO Reply Br. at 8-9). RUCO based its recommendation for allowable rate case expense on the amount allowed in the District's previous rate case, grossed-up for inflation (Direct Testimony of Rodney L. Moore, Hearing Exh. R-5 at 9-12). RUCO believes that the costs incurred by the Company to argue its request to recover capital investments associated with fire flow improvements are not a justifiable expense (Surrebuttal Testimony of Rodney L. Moore, Hearing Exh. R-6 at 5).

For the reasons argued by Staff and RUCO, the Company's original proposal to share the costs of its cost of capital analysis and testimony 50/50 with ratepayers is reasonable, and in this case, provides an appropriate means for the Company to mitigate the expenses associated with retaining outside consultants. Staff's recommendation regarding costs related to cost of service and rate design analysis and testimony also addresses appropriate mitigation of consultant costs. We agree with the Company that this case is more complicated and contentious than the District's previous rate case, which the District and Staff settled, and in which only two contested issues were litigated in a hearing lasting one day. We disagree with RUCO that recovery of expenses the Company incurred requesting recovery of capital investments associated with fire flow improvements should be disallowed, and find instead that reasonable costs for this purpose are justifiable and should be recoverable, as recommended by Staff. We will therefore, in this case, reject RUCO's proposed methodology for measuring rate case expense. We find that Staff's rate case expense recommendation is reasonable and will adopt it, allowing rate case expense for this case of $208,700.

**B. <u>Labor and Pension Expenses</u>**

RUCO opposes inclusion in test year expenses of employment expenses associated with an arsenic plant operator the Company hired for the District on October 10, 2005. RUCO recommends deductions to payroll expense, payroll tax expense, and pension expense totaling $48,103. As discussed in the section below related to the Company's requested Arsenic Cost Recovery Mechanism ("ACRM"), the United States Environmental Protection Agency ("EPA") has mandated a new standard reducing the maximum contaminant level ("MCL") for arsenic from 50 parts per billion ("ppb") to 10 ppb, effective January 23, 2006, and the Company has budgeted $19 million for capital investment in new arsenic remediation facilities for the District. The Company argues that it is fair to

include employment expense for the arsenic plant operator in this case prior to allowing costs for the arsenic treatment plant, because it would have been imprudent to postpone until 2006 hiring and training an employee to operate a multi-million dollar plant using new technology (Company Br. at 13). The Company's witness testified that hiring the employee in 2005 has allowed the employee not only to familiarize himself with the District's entire water system, but also to learn about the operations of the other arsenic treatment plants that are coming online in the Company's other water districts located in the valley (Rebuttal Testimony of Brian K. Biesemeyer, Hearing Exh. A-5 at 2-3). The Company argues that absent inclusion of labor expenses for this employee in this case, the Company will be unable to recover costs associated with this employee, who is required by an unfunded federal mandate, until resolution of the Company's next rate case (Company Br. at 13). We wish to encourage water utilities to make the necessary financial commitments to satisfy the federal arsenic mandate, and find that under these specific circumstances, it is equitable to include the costs of this employee in test year expenses.

### C. Property Tax Expense

#### 1. Property Tax Calculation

RUCO argues that the Commission should reject the Company's and Staff's recommended estimates of property tax, based on the calculation methodology adopted by the Commission in prior rate proceedings, and instead accept RUCO's recommended property tax expense estimates, which are $2,561 lower, based on a calculation methodology rejected in numerous prior rate proceedings. The methodology used by the Company and Staff to estimate property tax expense, which is to use adjusted test year revenues and the projected revenues under the newly approved rates as inputs to the Arizona Department of Revenue ("ADOR") assessment formula, is the same methodology adopted in numerous prior cases over the objections of RUCO.[15] RUCO proposes, as it has many times before,

[15] *E.g., Arizona Water Company,* Decision No. 68302 (November 14, 2005) (finding that RUCO's calculation methodology, which uses only historical revenues, unfairly and unreasonably understates property tax expense, and is therefore inappropriate for ratemaking purposes); *Chaparral City Water,* Decision No. 68176 (September 30, 2005) (same finding); *Rio Rico Utilities,* Decision No. 67279 (October 5, 2004) (finding that use of only historic revenues understates the expense level); *Arizona American Water Company,* Decision No. 67093 (June 30, 2004); *Bella Vista Water Company,* Decision No. 65350 (November 1, 2002); *Arizona Water Company,* Decision No. 64282 (December 28, 2001). RUCO has not appealed any of these Decisions.

to instead use revenues from the test year and the two years prior to the test year to calculate property tax expense (RUCO Br. at 22).

Using only historical revenues to calculate property taxes to include in the cost of service fails to capture the effects of future revenue from new rates. RUCO's calculation methodology, which uses only historical revenues, unfairly and unreasonably understates property tax expense, and is therefore inappropriate for ratemaking purposes. RUCO has not demonstrated a basis for departure from our prior determinations on this issue.[16] The Company and Staff's calculation for property tax expense yields the best estimate of the Company's property tax expense for the period in which new rates will be in effect, and we will use that calculation.

**2. Miller Road Treatment Facility Property Taxes**

RUCO advocates reducing property tax expense by $42,000, which is the amount of property tax RUCO claims is attributable to property located on Miller Road that the Company owns and leases to Motorola. RUCO argues that the property taxes attributable to the property should be considered as part of Motorola's operating expenses and therefore reimbursed by Motorola (RUCO Br. at 12). The Company disagrees with RUCO's proposed adjustment, arguing that it is unnecessary because the property tax expense calculation proposed by the Company and Staff, unlike the calculation proposed by RUCO, uses adjusted test year revenues, and therefore does not include any amount related to either Motorola, the property the Company leases to Motorola, or any other non-regulated activity of the Company (Rejoinder Testimony of Joel M. Reiker, Hearing Exh. A-16 at 9). We agree with the Company that the adjustment proposed by RUCO would be inappropriate because no property taxes related to the Miller Road property are included in the Company's proposed property tax expense.

[16]RUCO used its preferred methodology to estimate the District's 2005 taxes, and states that its methodology resulted in an estimate closer to the Company's actual 2005 property taxes than the calculation methodology adopted by the Commission in prior rate proceedings and used by the Company and Staff in this proceeding (RUCO Br. at 22-23). RUCO argues that this proves that its methodology results in a more accurate level of property tax expense than the Company and Staff's methodology. RUCO's argument fails to address the fact that new rates will be set in this proceeding, and that the Commission must establish a level of property tax expense (which is based on revenues) in this proceeding that estimates the Company's property tax expense for the period in which new rates will be in effect, not for the year 2005.

1 **D. Administrative and General Expenses (A&G)**

2 **1. AIP, Performance Pay and Stay Bonus**

3 The Company is requesting recovery of $18,517 for Arizona Corporate allocated management
4 fees related to Annual Incentive Program ("AIP") expenses and $1,520 for Arizona Corporate
5 allocated management fees related to Performance Pay and Stay Bonus expenses. The Company's
6 president testified that the Company's AIP is a component of its overall employee compensation that
7 is necessary to allow the District to compete for employees in Arizona's tight labor market, and that
8 if it were eliminated, the Company would have to raise base salaries to be competitive in the market,
9 and that the plan provides benefits to customers by focusing employees on goals that improve the
10 Company's ability to deliver high quality customer service (Rejoinder Testimony of Paul G.
11 Townsley, Hearing Exh. A-3 at 5).

12 RUCO recommends that $12,795 of the Company's proposed $20,037 AIP, Performance Pay
13 and Stay Bonuses be disallowed. RUCO recommends disallowing 30 percent, or $5,555 of the
14 $18,517 in Arizona Corporate allocated management fees related to the Company's Annual Incentive
15 Plan expenses, because 30 percent of the AIP is directly related to Company financial performance
16 measures and 70 percent to operational and individual performance measures (RUCO Br. at 18).
17 RUCO argues that the 30 percent portion of AIP expenses based on financial performance measures
18 benefit only shareholders (*id.*). Of the remaining $12,962 in AIP expenses, and Performance Pay and
19 Stay Bonus allocated management fees of $1,520, RUCO contends that half should be disallowed as
20 a way of sharing the costs 50/50 between ratepayers and shareholders, both of whom RUCO believes
21 benefit from the Performance Pay and Stay Bonus expenses and the portion of AIP expenses that are
22 based on operational and individual performance measures (RUCO Br. at 18-20).

23 We agree with RUCO that shareholders are the primary beneficiaries of additional profit the
24 Company achieves as the result of the Company meeting its financial targets, and therefore find
25 RUCO's proposal to disallow the 30 percent of the AIP that is based on the Company's financial
26 performance measures to be reasonable and appropriate. We do not agree, however, with RUCO's
27 proposal to disallow half of the remaining expenses as a means of sharing them 50/50 between
28 shareholders and ratepayers, because testimony in this proceeding demonstrates that the remaining

expenses are closely related to salary expense, which is not appropriately shared. An adjustment reducing AIP expenses by $5,555 is appropriate and should be adopted.

**2. Reorganizing/Downsizing Expenses**

RUCO recommends disallowing $42,441 from Arizona Corporate allocated management fees related to the Company's reorganization/downsizing and non-incentive pay expenses, based on RUCO's assertion that these expenses are non-recurring and atypical of test year expenses (Surrebuttal Testimony of Rodney L. Moore, Hearing Exh. R-6 at 21). In response, the Company provides no argument in support of allowing these expenses other than a statement that neither the Company nor Staff accept the disallowance (Company Br. at 43, Reply Br. at 12). Standard ratemaking principles do not allow nonrecurring expenses incurred during the test year to be included when determining a company's test year operating expenses, absent justification to the contrary. RUCO's proposed adjustment of $42,441 is reasonable and should be adopted.

**3. Ice**

RUCO recommends disallowing $161 from the Company's Central Division Corporate district allocated miscellaneous expenses for the annual cost of ice. RUCO argues that it is a discretionary expense, that its concern is not the money, but the principle, and that ratepayers should not be burdened with unnecessary costs (RUCO Br. at 20). The Company provided uncontroverted testimony that ice is used to keep water samples at proper temperature until they arrive at laboratories for testing, and that ice is also used to cool down water in large igloo thermoses that utility workers carry on their trucks to keep outdoor workers hydrated (Rebuttal Testimony of Brian K. Biesemeyer, Hearing Exh. A-5 at 3). This is a necessary and reasonable expense, and RUCO's proposed adjustment will not be adopted.

**4. Security Renovations and Repairs and Indoor Plant Maintenance**

RUCO recommends disallowing $127 from the Company's Arizona Corporate allocated miscellaneous expenses. The recommended disallowance includes both the annual cost of indoor plant maintenance and security renovations and remodeling costs incurred during the test year. RUCO contends that the Company's proposed indoor plant maintenance expense is not a necessary expense in the provisioning of water service, and that the proposed security renovation and

remodeling expenses are nonrecurring. We agree. RUCO's recommended adjustment of $127 should be adopted.

**5. Conclusion**

For the reasons discussed above, we find that reductions totaling $48,123 to the Company's proposed allocated A&G expense are reasonable, and will adopt them.

**E. Statement of Operating Income**

All parties agree that the District's adjusted test year operating revenues were $5,079,195. In accordance with the discussion herein, the District's adjusted test year operating expenses for ratemaking purposes total $4,163,282, for an adjusted test year net operating income of $915,913.

## VI. COST OF CAPITAL

Arizona-American, Staff and RUCO presented cost of capital analyses for purposes of determining a fair value rate of return in this proceeding. Arizona-American proposes an overall cost of capital and rate of return of 7.84 percent; Staff recommends 7.24 percent; and RUCO recommends 7.10 percent.

**A. Capital Structure and Cost of Debt**

The parties agree that the Company's capital structure for the test year was comprised of 36.7 percent equity and 63.3 percent debt. The parties are also in agreement that the Company's cost of debt for the test year was 5.42 percent.

**B. Cost of Equity**

Setting the cost of equity component for purposes of determining a just and reasonable rate of return requires estimation relying on financial analysis. Disagreement exists in this case as to an appropriate methodology to be used, and in what manner it should be used, in order to reach a cost of equity estimate. The expert witnesses testifying on behalf of the Company, RUCO and Staff reached different conclusions based on the use of their models. The Company advocates a cost of equity of 12 percent, based on the analysis of its witnesses. Staff advocates a cost of equity of 10.4 percent and RUCO advocates a cost of equity of 10.0 percent, based on the analyses of their respective witnesses.

**1. Arizona-American**

The Company presented testimony in support of its cost of equity proposal through two

witnesses from the Brattle Group, Dr. Lawrence Kolbe and Dr. Michael Vilbert. Dr. Kolbe's testimony promotes a theory of equitable leverage compensation to support the Brattle Group's cost of capital analysis. Dr. Kolbe bases his "equitable leverage compensation" theory on the premises that as the amount of debt (leverage) increases, investors demand a correspondingly higher return on equity to compensate for increased risk associated with more debt. Dr. Kolbe believes that because the market value of a firm is independent of the debt/equity ratio over a wide range of percentages, the cost of capital to be recovered from ratepayers should be constant over a large range of equity ratios.

Dr. Vilbert applied the equitable leverage compensation theory discussed by Dr. Kolbe in calculating the Company's proposed cost of equity. Dr. Vilbert applied both single stage and multi-stage discounted cash flow ("DCF") models, the capital asset pricing model ("CAPM") and an "empirical" CAPM ("ECAPM") to a sample of water companies and also to a sample of gas companies. Dr. Vilbert states that although he considered evidence from both the CAPM and DCF methods, he relied primarily on the CAPM results, because he does not believe that the DCF method is completely reliable at this time (Direct Testimony of Michael J. Vilbert, Hearing Exh. A-9 at 6). Dr. Vilbert used the gas company sample as a check on the results of the water sample, but gave the results from the water company sample predominant weight (*id.* at 5-6). Applying each model to both sample groups, Dr. Vilbert's cost of equity estimates for his water company sample ranged from 7.2 percent using the CAPM with a short-term risk-free rate (*id.*, App. C, Table MJV-9, Panel B) to 10.8 percent using a simple DCF model (*id.*, App. C, Table MJV-7, Panel A). For his gas company sample, Dr. Vilbert's cost of equity estimates ranged from 7.7 percent using the CAPM with a short-term risk-free rate (*id.*, App. C, Table MJV-20, Panel B), to 9.6 percent utilizing a simple DCF model (*id.*, App. C, Table MJV-18, Panel A). Dr. Vilbert contends that CAPM estimates that rely on the short-term risk-free rate are unreliable at this time because some of the resulting cost of equity estimates are less than the corresponding sample companies' cost of debt and because he believes the short-term risk-free rate is likely to increase substantially in the near term (*id.* at 7).

After estimating the cost of capital for the sample groups, Dr. Vilbert computed an after tax weighted average cost of capital ("ATWACC") for each firm in the water and gas samples using the

firms' "market value capital structure," and then calculated the sample average ATWACC and the cost of equity for a capital structure with 36.7 percent equity (*id.* at 6; App. C, Tables MJV-8 and MJV 19 (DCF), and MJV-11 and MJV 22 (CAPM and ECAPM)), in order to compute Arizona-American's cost of equity so that its ATWACC equals that of the sample's ATWACC (Company Br. at 23). Using this methodology for the water company sample, Dr. Vilbert reached cost of equity estimates for Arizona-American ranging from 10.2 percent to 16.5 percent (Direct Testimony of Michael J. Vilbert, Hearing Exh. A-9, App. C, Tables MJV-8 and MJV 11). For the gas company sample, Dr. Vilbert reached cost of equity estimates for Arizona-American ranging from 10.1 percent to 13.3 percent using the ATWACC (*id.*, App. C, Tables MJV-19 and MJV-22).

Dr. Vilbert concluded that the midpoint of his water company sample's overall cost of capital is 6 ¾ percent with a range of 6 ½ to 7 percent, and the midpoint of the gas company sample's overall cost of capital is 6 ½ percent with a range of 6 ¼ to 6 ¾ percent, for an overall range of 6 ¼ to 7 percent. Dr. Vilbert asserts that the corresponding cost of equity at the Company's 36.7 percent equity thickness is 12 ½ percent (with a range of 12 to 13 percent) for the water company sample and 12 percent (with a range of 11 ½ to 12 ½ percent) for the gas company sample, for an overall range of 11 ½ to 13 percent (*id.* at 7, 59). Based on Dr. Vilbert's analysis, Arizona-American proposes that its cost of equity be set at 12.0 percent for purposes of determining a just and reasonable rate of return.

The Company contends that while Staff and RUCO adjusted their cost of equity estimates to compensate for Arizona-American's higher leverage risk due to its debt-heavy capital structure, the traditional compensatory methods they used do not go far enough.

**2. RUCO**

RUCO based its cost of equity recommendation on the DCF and CAPM analyses performed by its witness William Rigsby, and contends that its proposed 10.0 percent cost of equity is appropriate given the current environment of low inflation and low interest rates (Direct Testimony of William A. Rigsby, Hearing Exh. R-9 at 47). Mr. Rigsby's DCF analysis yielded a 9.5 percent cost of equity result for his water company sample and a 9.35 percent result for his gas company sample (*id.* at 27, Sched. WAR-2). His CAPM analysis resulted in a range from 8.63 percent to

10.08 percent for his water company sample and a range from 8.99 percent to 10.55 percent for his gas company sample (*id.* at 31-32, Sched. WAR-7). Using his CAPM results as a check on the results of his DCF analysis, Mr. Rigsby based his recommendation on the 9.50 percent result of his DCF analysis for water companies (*id.*). Just as he did in Arizona-American's most recent rate proceeding,[17] Mr. Rigsby added 50 basis points to his cost of equity estimate to account for the increased financial risk faced by Arizona-American as a result of the Company's debt-heavy capital structure (*id.* at 32-34). RUCO believes that the 10 percent cost of common equity estimated by Mr. Rigsby is very reasonable when the Company's capital structure of 36.7 percent equity and 63.3 percent debt is compared with the capital structures of other publicly traded water providers used in Mr. Rigsby's analysis, which averaged 49.9 percent equity and 50.1 percent debt (*id.* at 48).

**3. Staff**

Staff's cost of capital witness Dennis Rogers states that he chose the DCF model and the CAPM model to estimate the Company's cost of equity because the models are widely recognized and accepted as appropriate financial models to estimate cost of equity and this Commission has consistently relied on their results (Direct Testimony of Dennis Rogers, Hearing Exh. S-3 at 13). To calculate his DCF estimate of Arizona-American's cost of equity, Staff's witness used both a constant-growth DCF model and a multi-stage or non-constant growth DCF model using six publicly traded water utilities (*id.* at 13-14, Sched. DRR-3). Staff's resulting constant growth DCF estimate was 9.7 percent (*id.* at 24, Sched. DRR-2) and its multi-stage DCF estimate was 9.4 percent (*id.* at 26, Sched. DRR-8). Mr. Rogers calculated Staff's overall DCF estimate by averaging his constant-growth DCF estimate with his multi-stage DCF estimate, and reached an overall DCF estimate of 9.6 percent (*id.* at 26, Sched. DRR-2). Mr. Rogers then used the same sample companies to compute the CAPM to estimate the Company's cost of equity, reaching an overall CAPM estimate of 10.0 percent (*id.* at 27-31). Mr. Rogers obtained the risk-free rate of interest used in his CAPM calculations by averaging three intermediate-term U.S. Treasury securities' spot rates as published in the November 2, 2005 edition of the *Wall Street Journal* (*id.* at 29). Mr. Rogers states that while the Company's

[17] Decision No. 67093 (June 30, 2004).

witness criticized Staff's use of intermediate term Treasury securities, their time to maturity approximates investors' holding period and thus investor expectations (*id.*). Staff averaged the *Value Line* betas[18] of its sample water companies as the proxy for the Company's beta and estimated a beta of 0.71 (*id.*). Staff's overall CAPM estimate is the average of the historical market risk premium CAPM estimate of 9.7 percent and the current market risk premium CAPM estimate of 10.2 percent (*id.* at 33, Sched. DRR-2). Staff averaged its overall CAPM estimate of 10.0 with its overall DCF estimate of 9.6 to reach its average estimate of the cost of equity to the sample water utilities of 9.8 percent (*id.* at 34). Staff reached its 10.4 percent cost of equity recommendation for the Company by addition of a financial risk adjustment of 60 basis points to Staff's average estimate of the cost of equity to the sample water utilities (*id.* at 34-35).

Staff is critical of Dr. Vilbert's method of estimating the market value capital structure for each of his sample companies by estimating the market values of common equity (using price per share times the number of shares outstanding), preferred equity (using book value) and debt (using book value) from the most recent publicly available data. Staff states that the Company's use of market value capital structures has no relation to the actual book value capital structure and their use produces a return on equity estimate that is conjectural and speculative in nature. Staff witness Rogers explained that use of a market value capital structure to estimate the cost of equity is predicated on the underlying erroneous logic that the Commission is obligated to maintain stock prices and perpetuate an ongoing rising spiral between revenues and stock prices (*id.* at 37). Staff also points to a lack of logic in the equitable leverage compensation method's assumption that the market value of the Company's stock equals its book value because it is not publicly traded, while Dr. Vilbert estimated market values for the sample companies that exceed book values.

Regarding Dr. Vilbert's use of the ECAPM, Staff states that the adjustment used in the ECAPM has the effect of flattening the risk/return relationship, which has the effect of raising the estimated cost of equity for companies with betas below 1.0 and lowering it for companies with betas above 1.0. As stated above, Staff's estimated beta for the Company is 0.71. Staff also points out that

[18] Beta measures the systematic risk of a company. The market's beta is 1.0; therefore, a security with a beta higher than 1.0 is riskier than the market, and a security with a beta lower than 1.0 is less risky than the market.

the betas published by *Value Line* that are used by its witness in his CAPM calculations are already adjusted, and there is nothing in the record to indicate that Dr. Vilbert's adjustment under his ECAPM is superior to the method currently used by Staff and accepted by the Commission in the past. Staff asserts that the Company has produced no evidence that its estimates using the ECAPM are representative of the risk/return relationship for utility investments, and the Commission should therefore reject Dr. Vilbert's proposed ECAPM methodology.

Staff notes that the Company failed to use any historical growth rates or examine forecasts of dividend growth in its DCF estimates, but instead chose to rely on less reliable forecasted growth rates from Institutional Brokers' Estimate System and *Value Line.* Staff also notes that the Company's estimates did not consider dividend per share growth in its DCF analysis, despite the fact that it is a fundamental component of a constant-growth DCF method.

**4. Discussion**

Both RUCO and Staff used long-standing methodologies approved by the Commission to reach their estimates and resulting recommendations for 10.0 percent and 10.4 percent respectively, while the Company is using a novel and not widely recognized methodology to attain its 12.0 percent cost of equity recommendation. The equitable leverage compensation model used by the Company's witnesses to reach the proposed 12 percent cost of equity for the District produces an inflated estimate that would overcompensate for the Company's financial risk and would require the Company's customers to overcompensate its investors.

The Company claims the Commission has been "overcompensating investors in low-leverage utilities and under-compensating investors in high-leverage utilities" by rewarding companies with higher returns on equity as equity ratios increase (Company Br. at 43). The Company argues that because interest on debt is tax free companies should be encouraged, within reason, to borrow funds rather than finance new investments with equity, but that because the Commission rewards companies with higher returns as equity ratios increase, Arizona companies are reluctant to issue low-cost debt (*id.*). Arizona-American's capital structure itself, with its 63.3 percent debt, belies this argument.

The Company cites as justification for its requested 12.0 percent cost of equity the fact that

federal mandates are forcing the Company to heavily invest in new arsenic remediation facilities, and that its customers are demanding massive new infrastructure investments to satisfy new fire flow requirements. In this very proceeding, however, we are granting the District's request to implement an ACRM mechanism which enables the Company to seek approval for expedited recovery of capital costs and a significant portion of O&M costs associated with arsenic remediation. We are also approving both a High Block surcharge and a Public Safety surcharge to pay for fire flow investments. These mechanisms mitigate the risks associated with those capital investment requirements, and eliminate the need for the higher rates of return the Company advocates.

The Company has provided inadequate justification for acceptance of its "equitable leverage compensation" methodology, which would constitute a break with long-standing precedent. As Staff points out, the methodology proposed by the Company has been rejected or not adopted by every state commission before which it has been presented with the exception of one; by the FERC; and by regulatory bodies outside the United States (Staff Br. at 15). RUCO and Staff appropriately addressed the Company's higher debt ratio by the generally accepted regulatory means of accounting for financial risk, adding basis points to the results of their CAPM and DCF analyses. The Company's methodology would result in an upward adjustment of 360 basis points as compared with Staff's proposed upward adjustment of 60 basis points and RUCO's proposed 50 basis point adjustment. We find such an upward adjustment to be outside the zone of reasonableness and must reject it.

Finally, while the Company complains that the most recent authorized returns on equity authorized by this Commission for other Arizona-American operating districts are at the lower end of the range that has been authorized for its subsidiaries throughout the United States, Staff demonstrated at the hearing that the median rate of return on equity for the subsidiaries is currently at 10.09 percent, and Staff's recommended 10.4 percent return on equity would put the District in the upper range of authorized returns on equity for Arizona-American's other subsidiaries nationwide (Hearing Exh. S-12 at 2). We find that Staff's recommended cost of equity capital in this proceeding achieves an appropriate result that is supported by the evidence, and that adoption of Staff's recommendation results in a just and reasonable return for the District based on the record in this

proceeding.

We therefore adopt a cost of equity of 10.4 percent, which results in an overall weighted cost of capital of 7.24 percent.

### C. Cost of Capital Summary

| | Percentage | Cost | Weighted Cost |
|---|---|---|---|
| Long-Term Debt | 63.3 % | 5.4 % | 3.42% |
| Common Equity | 36.7 % | 10.4 % | 3.82 % |
| Weighted Average Cost of Capital | | | 7.24 % |

## VII. AUTHORIZED INCREASE

With the adjustments adopted herein, the District's adjusted test year operating income is $915,913. Applying the fair value rate of return of 7.24 percent to the District's FVRB of $14,351,471 produces a required operating income of $1,038,329. This is $122,416 more than the adjusted test year income under existing rates. The required increase in gross annual revenues for the District is $199,371, for a 3.93 percent increase over test year adjusted revenues.[19]

## VIII. RATE DESIGN

### A. General Rate Design

Rate design was not a contested issue in this proceeding. The District currently has a conservation oriented three-tier inverted block rate design, with no gallons included in the minimum. An exception to this is the District's former Mummy Mountain Water Company customers, who currently have a single tier commodity rate and 1,000 gallons included in the minimum. The Company is proposing to align their rates with the rates charged to the District's other ratepayers. The Company also proposes the addition of a second (high block) tier of 25,000,000 gallons/month to its turf irrigation tariff commodity rate, but at the same commodity rate as the first tier, so that a portion of the PVCC's monthly usage may be subject to the High Block surcharge, discussed below (Rebuttal Testimony of Thomas M. Broderick, Hearing Exh. A-17 at 4). The Company's witness stated that the addition of the second tier will promote conservation in the summer months so that

[19] Using a revenue conversion factor of 1.62863.

PVCC will remain within the limit set by the Arizona Department of Water Resources ("ADWR") and will also contribute funding to fire flow projects if the High Block surcharge is approved (*id.*).

The rate design proposed by the Company, including the addition of a second tier to the turf irrigation commodity rate, is reasonable and will be adopted.

**B. Surcharges**

**1. Company Surcharge Proposal**

In the past, the District's high water usage patterns have not been responsive to the imposition of a conservation-oriented rate design (Direct Testimony of Darron A. Carlson, Hearing Exh. S-7 at 3). In order to better promote water conservation, the Company proposes a High Block surcharge on residential usage greater than 80,000 gallons ("High Block" usage), with any funds generated by the proposed surcharges to be treated as CIAC, which would reduce rate base and subsequently lower revenue requirements in the future (Direct Testimony of David P. Stephenson, Hearing Exh. A-18 at 34-35). The Company also proposed a series of Public Safety surcharges for recovery of its fire flow investments, with separate surcharges going into effect after corresponding phases of the fire flow improvement project go into service (*id.* at 20-33).

**2. Staff Recommendation**

Staff concurred with the Company's proposed High Block surcharge, and its proposal to treat revenues from the High Block surcharge as CIAC (Direct Testimony of Darron A. Carlson, Hearing Exh. S-7 at 3). Staff also recommended that the funds collected through the High Block surcharge be used directly to offset fire flow plant additions and minimize the post in service AFUDC accruals authorized by Decision No. 68303 (*id.*). Staff proposed a simplified version of the Company's proposed High Block surcharge, with $2.15 per 1,000 gallons for all High Block (over 80,000 gallons/month) consumption, in addition to the normal tier charge (*id.*). Staff estimated that this proposed surcharge could produce approximately $1.7 million per year (*id.*), and would have a minimal impact upon the average or median customer bill (Staff Brief at 21).

Staff testified that the Company's proposed Public Safety surcharge is unnecessary because under the Accounting Order issued in Decision No. 68303, the Company is authorized to accrue AFUDC on fire flow plant in service until the plant is placed in rate base and reflected in rates, such

that the Company will be compensated for the time value of its investment (*id.*).

**3. Staff's Alternative Fire Flow Surcharge Proposal (Exhibit B)**

In rejoinder testimony, the Company stated that without approval of the Public Safety surcharge in addition to the High Block surcharge, two major projects in its fire flow improvement plan on Lincoln Drive and Tatum Boulevard will have to be postponed from summer 2007 to summer 2008, which will push back all its other projects by one year, and the Company will need to recast its overall multi-year plans and schedules for fire flow improvements (Rejoinder Testimony of Paul G. Townsley, Hearing Exh. A-3 at 2). In response to the Company's concerns over the delays in implementing its fire flow improvement plan if projects are funded solely from High Block surcharge revenues, Staff offered an alternative surcharge proposal for Commission consideration. Staff's alternative proposal, as set forth in Hearing Exh. S-9, includes a new Public Safety surcharge. For convenience of reference, a copy of Hearing Exh. S-9 is attached hereto as Exhibit B.

The alternative surcharge proposal as set forth in Exhibit B would institute, effective October 1, 2007, a Public Safety surcharge of $1.00 per 1,000 gallons on both the second tier and third residential commodity rate and on the second tier commercial commodity rate. Under the alternative proposal, once the Company has fully recovered its fire flow project costs, the Public Safety surcharge would terminate. Staff estimates that implementation of the Public Safety surchage would generate an additional $1.8 million annually, for a total of $3.5 million annually. Staff notes that the Public Safety surcharge would have no impact on the average (22,193 gallons/month) residential bill or the median (11,500 gallons/month) residential bill, because the surcharge for the second tier residential commodity charge starts at 25,000 gallons/month.

Staff states that notwithstanding its presentation of the alternative surcharge proposal, Staff continues to recommend implementation of its recommended $2.15 High Block surcharge when new rates take effect, and that the monies collected thereby be used to offset the cost of the fire flow projects.

The Company accepts the alternative proposal in Exhibit B and urges the Commission to approve it so that fire flow projects can be completed without undue delay (Company Br. at 39).

**4. Accounting Order Modifying AFUDC Methodology**

Staff recommends modification of the AFUDC methodology granted in Decision No. 68303 to take into account amounts collected by any fire flow related surcharges that are approved in this proceeding, either the High Block surcharge, the Public Safety surcharge, or both (Hearing Exh. S-10). Staff states that it is necessary for the Company to deduct surcharge collections when calculating the balance to which the AFUDC fire flow rate is applied, in order to allow the Company to recover capital costs only on its net investment in fire flow projects (*id.*).

**5. Analysis and Conclusion**

As Staff states in Exhibit B, there are several potential benefits from implementing the High Block surcharge and the Public Safety surcharge presented therein. First, implementation of these surcharges would permit implementation of the Company's planned fire safety related infrastructure in a timely manner. As we discussed earlier, the record in this proceeding demonstrates that the improvements are necessary to ensure the public health and safety of the District's ratepayers, and that the District's ratepayers are largely in support of the improvements and are willing to pay for them through their water utility rates. As we also discussed earlier, most City of Scottsdale customers of the District will be exempt from the Public Safety surcharge for which the Company is requesting approval in this proceeding.[20] In addition, implementing the High Block surcharge and the Public Safety surcharge as set forth in Exhibit B would encourage conservation in the District, which has historical high usage, and would increase CIAC, which would in turn alleviate future rate increases for all the ratepayers in the District.

For these reasons, we will order the Company to implement the alternative recommendation presented by Staff commencing October 1, 2007. Once the Company has fully recovered its fire flow project costs, the Public Safety surcharge will terminate, but revenues collected under the reduced High Block surcharge will continue to be treated as CIAC in order to alleviate future rate increases, as proposed by the Company (Direct Testimony of David P. Stephenson, Hearing Exh. A-18 at 34-35). We will also order the Company, in its application of the methodology approved in Decision

[20] *See* Hearing Exh. A-33.

68303, to deduct collections from the High Block surcharge and the Public Safety surcharge when calculating the balance to which the AFUDC fire flow rate is applied, so that it will recover capital costs only on its net investment in fire flow projects, as Staff recommends.

## IX. OTHER ISSUES

### A. Arsenic Cost Recovery Mechanism ("ACRM")

The most recent lab analysis for the District indicates that six of its seven wells have arsenic levels at or above 10 ppb (Direct Testimony of John A. Chelus, Hearing Exh. S-5 at 4). The Company is requesting approval of an ACRM for the District similar to the ACRM previously approved for the Company's Havasu Water, Agua Fria Water, Sun City West Water, and Sun City Water districts in Decision No. 68310 (November 14, 2005). The Company's request is predicated on the EPA's new standard reducing the MCL for arsenic from 50 ppb to 10 ppb, effective January 23, 2006. The Company has budgeted approximately $19 million for capital investment in new arsenic remediation facilities for the District. The Company asserts that an ACRM is necessary to allow it to recover the capital costs of the facilities and related operation and maintenance ("O&M") costs. The Company is also requesting authority to defer all capital costs relating to arsenic removal facilities placed in service prior to the effective date of an ACRM surcharge. Upon approval of the ACRM, the Company plans to make a series of filings for specific ACRM surcharges to recover the District's arsenic remediation-related capital costs and O&M expenses.

The Company proposes an ACRM for the District consisting of the following (per Direct Testimony of David P. Stephenson, Hearing Exh. A-19 at 15-16):

1. The ACRM is based solely on actual costs and costs eligible for recovery, which are depreciation, gross return, and recoverable O&M costs;
2. Actual rate recovery via the ACRM commences after new arsenic facilities are in service and are in compliance with the new EPA MCL for arsenic;
3. Establishment of deadlines for filing the next rate case, without limit on the Company's ability to file earlier, as per existing Commission orders;
4. An ACRM rate design composed of a 50/50 split of the recovery between monthly minimum charges and volumetric charges, with the volumetric charges based on the

same inclining block rate design as approved in this proceeding;

5. A financial presentation composed of ten standard schedules;

6. Recoverable O&M costs to include only media replacement or regeneration, media replacement or regeneration service, and waste disposal;

7. A deferral for future recovery of up to 12 months of recoverable O&M, without return, commencing with the in-service date of facilities;

8. Two step-rate increases;

9. No true-up of the ACRM for under- or over- collection; and

10. Gross return included in the ACRM based on the return authorized in this proceeding.

Staff states that in general, an ACRM provides a methodology for recovering certain defined costs related to arsenic treatment as well as to establish a mechanism for recovery of arsenic treatment related costs from customers, and that recovery of those costs through an ACRM surcharge terminates upon inclusion of the arsenic remediation related plant in rate base (Direct Testimony of Alexander Igwe, Hearing Exh. S-6 at 20).

In relation to the Company's proposed ACRM, Staff recommends the following (*id.* at 22-24):

1. Authorization of an ACRM;

2. The Company should file, by July 1 of each year subsequent to any year that has ACRM collections, a report with Docket Control showing its ending capital structure (equity, long-term debt, and short-term debt) by month for the prior year;

3. The Earnings Test schedule filed in support of the ACRM should incorporate adjustments conforming to Decision No. 67093 (June 30, 2004). For example, the acquisition adjustment should be removed from rate base and the amortization of the adjustment should be removed from the income statement. The actual period results, adjustments, and adjusted period should be clearly shown on each Earnings Test schedule. The earnings test places a cap on the ACRM surcharge based on the existing rate of return;

4. Microsoft Excel or compatible electronic versions of the filings and all work papers should be concurrently provided to Staff with all ACRM filings;

5. The Company should file hard copies of the ten schedules discussed in its application.[21] In addition, Staff reserves the right for further discovery as it deems necessary related to the ACRM filings;

6. Rate design volumetric charges must be applied equally to all usage tiers; and

7. The Company should file an application for a permanent rate increase no later than September 30, 2008.

There was no objection to Staff's recommendations regarding the ACRM.[22] Staff's recommendations are reasonable and should be adopted. The ACRM proposed by the Company will be approved consistent with the Staff recommendations.

**B. PVCC Special Contract**

The Company filed an application on December 22, 2005, requesting approval of an agreement between the Company and PVCC. After Staff filed a Staff Report on the issue on January 31, 2006, the Company requested consolidation of the PVCC application with this rate application, and the cases were consolidated by Procedural Order. The agreement has a term of 15 years, and is written to become effective upon approval of new rates in this proceeding. The agreement allows PVCC a 15 percent discount from the Company's standard turf rates, and requires PVCC to accept delivery of service during off-peak hours, except in circumstances where it can demonstrate to the Company that its then-existing needs cannot be satisfied during such period. PVCC has constructed, at its sole expense, a storage reservoir and associated facilities, which allow it to take water from the Company during off-peak hours and store it for future use.

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[21] Staff states that the schedules the Company proposes to file are as follows:

1. Balance Sheet – The most recent balance sheet for the total Company at the time of filing the ACRM request;
2. Income Statement – The most recent income statement for the total Company and for the District;
3. Earnings Test – An earnings test calculation for the District;
4. Rate Review Filing – A rate review calculation for the District;
5. Arsenic Compliance Revenue Requirement – An arsenic compliance revenue requirement calculation for the District that is based upon arsenic plant and recoverable arsenic operating expenses;
6. Surcharge Calculation – A detailed calculation of the surcharge;
7. Rate Base Schedule – A schedule showing the elements and the calculation of the rate base;
8. CWIP Ledger – A ledger showing the transactions recorded in the construction work in progress account.

[22] While RUCO initially expressed concern with the review process for ACRM filings (*see* Hearing Exh. R-6 at 31), Staff's witness Steve Olea testified at the hearing regarding the contemplated due process for the Company's ACRM surcharge filings (Tr. at 378-379), and RUCO did not address the issue in post-hearing briefing.

The Staff Report states that treated effluent is not available in the area, and that PVCC has no alternative source of water for turf irrigation. Staff states that PVCC explored using Central Arizona Project ("CAP") water, but was unable to obtain all the necessary approvals.

Under the terms of the agreement, PVCC has the ability to terminate the agreement upon 60 days' written notice and payment of a termination fee of $1,000. The agreement calls for binding arbitration in the event of dispute.

Staff recommended approval of the agreement, and further recommended that the Company be required to request Commission approval of any future amendments to the agreement. Staff also recommended that the Company be required to file with the Commission an executed copy of the agreement within 30 days of its execution.

The Company did not object to the recommendations in the Staff Report. PVCC was granted intervention in this proceeding, but filed no testimony and did not appear at the hearing. RUCO did not take a position on this issue. Staff's recommendations are reasonable and will be adopted.

* * * * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

## FINDINGS OF FACT

1. On June 3, 2005, Arizona-American filed with the Commission an application for a rate increase for the District. The application also requests approval for the District of a public safety surcharge for investments by the Company related to improvement of fire flow facilities; an Arsenic Cost Recovery Mechanism for investments required by the Company to comply with federal water arsenic reduction requirements; and approval of a conservation surcharge that would be imposed for usage in the highest consumption block.

2. On June 17, 2005 the Company filed cost of service testimony and Schedules G and H.

3. On July 14, 2005, the Company filed revised H Schedules.

4. On July 18, 2005, Staff docketed a copy of a letter informing the Company that its application as amended on June 17, 2005 met the sufficiency requirements set forth in the

Commission's rules.

5. On August 1, 2005, RUCO requested intervention, which was granted by Procedural Order issued August 15, 2006.

6. A Procedural Order was issued on August 15, 2005, setting a hearing in these consolidated matters to commence on March 27, 2006, and setting associated procedural and filing deadlines.

7. On August 22, 2005, the Company docketed a copy of a letter to the Company from the Town.

8. On September 16, 2005, the Company docketed a copy of a letter mailed to each of its customers in the District. Also on September 16, 2005, the Company docketed a letter including details regarding its request for an accounting order related to the public safety surcharge requested in its application.

9. On October 26, 2005, the Company docketed an affidavit certifying that a copy of the notice required by the August 15, 2005 Procedural Order was included in each September 2005 bill mailed to customers in the Company's Paradise Valley Water District.

10. On November 14, 2005, the Commission issued Decision No. 68303, which granted the Company's request to be allowed to defer capital costs incurred by the District related to public safety associated with fire flows. Decision No. 68303 limited the deferral amounts to depreciation expense and a post-in-service allowance for funds used during construction with the rates set at the Company's cost of debt concurrent with the deferral period.

11. On December 16, 2005, PVCC filed an Application to Intervene, which was granted by Procedural Order issued January 4, 2006.

12. On February 22, 2006, a copy of a letter dated February 15, 2006 from the Town to Chairman Hatch-Miller was docketed.

13. A Procedural Order was issued on February 28, 2006, consolidating the Company's rate application with the above-captioned application filed by the Company on December 22, 2005. The December 22, 2005 application requested Commission approval of an agreement between the Company and PVCC which would allow PVCC a 15 percent discount from the Company's standard

turf rates.

14. On March 20, 2006, the Town filed a letter requesting intervention.

15. On March 24, 2006, Eric Nesvig filed written public comment in this docket.

16. On March 27, 2006, the Town filed a letter withdrawing its intervention request. Also on March 27, 2006, the Town filed a letter in the docket regarding fire flow improvements.

17. A hearing was held as scheduled before a duly authorized Administrative Law Judge of the Commission commencing on March 27, 2006, and continuing on March 28, March 29 and April 3, 2006. Several members of the public appeared on the first day of hearing and provided public comment on the application.

18. The Company, RUCO and Staff appeared and presented evidence at the hearing.

19. Following the hearing, on March 30, 2005, the Company caused discovery items from the litigation entitled *Kueffner v. Arizona-American,* pending in Maricopa Superior Court, to be filed in this docket, as specified during the taking of public comments at the hearing in this matter. These materials include, among other items, the Company's Paradise Valley Water Company 1999 Comprehensive Planning Study and a copy of report prepared by Brown and Caldwell titled Arizona-American Water Paradise Valley Water System Fire Flow Capacity Assessment dated March 2004.

20. On April 11, 2006, the Company filed Notice of Availability of *Kueffner v. Arizona-American* Discovery Materials.

21. On April 21, 2006, RUCO and Staff filed their respective post-hearing schedules. The Company had previously provided its post-hearing schedules on April 3, 2006, the final day of hearing.

22. On May 5, 2006, the parties filed their initial post-hearing briefs.

23. On May 26, 2006, the parties filed their reply briefs, and these consolidated matters were taken under advisement.

24. On July 3, 2006, the Town filed in these consolidated dockets a Motion for Leave to File Amicus Curiae Brief, to which was attached an amicus curiae brief.

25. Based on the adjusted test year data, as determined herein, the operating income under existing rates for the District is $915,913.

26. Based on the adjusted test year data, as determined herein, the FVRB for the District is $14,351,471.

27. A fair and reasonable fair value rate of return is 7.24 percent.

28. The increase proposed by Arizona-American would produce an excessive return on FVRB.

29. The authorized increase in gross annual revenues for the District is $199,371.

30. The rates set herein produce an increase in annual revenues of 3.93 percent which results in a monthly increase from $24.61 to $26.37, or 7.13 percent, for the average usage (22,193 gallons/month) 5/8 x 3/4-inch meter customer, and a monthly increase from $16.81 to $18.24, or 8.54 percent, for the median usage (11,500 gallons/month) 5/8 x 3/4-inch meter customer.

31. The High Block surcharge approved herein will apply to residential usage in the third tier (over 80,000 gallons/month), in addition to the normal third tier charge, and will be $2.15 per 1,000 gallons/month.

32. The High Block surcharge approved herein will apply to commercial usage in the second tier (over 400,000 gallons/month), in addition to the normal second tier charge, and will be $2.15 per 1,000 gallons/month.

33. The Public Safety Fire Flow surcharge approved herein will apply to residential usage in the second and third tier (over 25,000 gallons/month), in addition to normal second and third tier charges, and will be $1.00 per 1,000 gallons/month from October 1, 2007 until recovery of fire flow project costs is complete, at which time it will terminate.

34. The Public Safety Fire Flow surcharge approved herein will apply to commercial usage in the second tier (over 400,000 gallons/month), in addition to the normal second tier charge, and will be $1.00 per 1,000 gallons/month from October 1, 2007 until recovery of fire flow project costs is complete, at which time it will terminate.

35. It is in the public interest to implement a rate design that promotes long-term conservation goals by sending appropriate price signals to heavier water users.

36. The rate design approved herein addresses the goals of conservation, efficient water use, affordability, fairness, simplicity, and rate stability, and is in the public interest.

37. The rates and charges approved herein, including the High Block surcharge and the Public Safety Fire Flow surcharge as discussed herein, are just and reasonable and shall be approved.

38. The ACRM proposed by the Company is reasonable and shall be approved consistent with the Staff recommendations.

39. The PVCC special contract as discussed herein is reasonable and shall be approved.

40. Based on information provided by the Company, water use for the year 2004 totaled 3,165,233,000 gallons, and the Company reported producing 3,512,659,000 gallons. This resulted in a water loss of 9.89 percent, which is acceptable to Staff (Direct Testimony of John A. Chelus, Hearing Exh. S-5 at 4).

41. Based on data submitted by the Maricopa County Environmental Services Department ("MCESD"), MCESD has determined that the District is currently delivering water that meets the water quality standards required by Title 18, Chapter 4 of the Arizona Administrative Code (*id.* at 5).

42. The District is located within the Phoenix Active Management Area ("AMA") and consequently is subject to reporting and conservation rules administered by ADWR. The Phoenix AMA reported that the District is in total compliance with the ADWR reporting and conservation rules (*id.* at 4).

43. The District is using depreciation rates it developed, and Staff recommended that the District continue to use these rates (*id.* at 5 and Exhibit 4 to Hearing Exh. S-5). No party objected to these depreciation rates, and the District should continue to use them.

44. The District has no outstanding compliance issues with the Commission.

45. The Company has an approved curtailment plan tariff on file that applies to all its service areas, including the District.

46. Because an allowance for the property tax expense of the District is included in the District's rates and will be collected from its customers, the Commission seeks assurances from the Company that any taxes collected from ratepayers have been remitted to the appropriate taxing authority. It has come to the Commission's attention that a number of water companies have been unwilling or unable to fulfill their obligation to pay the taxes that were collected from ratepayers, some for as many as twenty years. It is reasonable, therefore, that as a preventive measure Arizona-

American annually file, as part of its annual report, an affidavit with the Utilities Division attesting that the Company is current in paying its property taxes in Arizona.

## CONCLUSIONS OF LAW

1. Arizona-American Water Company is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. Sections 40-250 and 40-241.

2. The Commission has jurisdiction over the Company and the subject matter of the applications.

3. Notice of the applications was provided in the manner prescribed by law.

4. The rates and charges for the Paradise Valley Water District approved herein, including the High Block surcharge and the Public Safety Fire Flow surcharge as discussed herein, are just and reasonable and shall be approved.

## ORDER

IT IS THEREFORE ORDERED that Arizona-American Water Company is hereby directed to file with the Commission on or before July 31, 2006, revised schedules of rates and charges consistent with the schedule set forth below and the discussion herein.

| | Rates |
|---|---|
| MONTHLY USAGE CHARGE: | |
| 5/8" x ¾" Meter | $ 9.50 |
| ¾" Meter | 9.83 |
| 1" Meter | 15.85 |
| 1 ½" Meter | 32.00 |
| 2" Meter | 51.00 |
| 3" Meter | 94.50 |
| 4" Meter | 157.25 |
| 6" Meter | 315.00 |
| Paradise Valley Country Club | See Below |
| Fire Protection | $ 5.00 |
| COMMODITY RATES | |
| Residential – All Meter Sizes | |
| Gallonage Charge – per 1,000 Gallons | |
| From 1 to 25,000 Gallons | $ 0.76 |
| From 25,001 to 80,000 Gallons | 1.65 |
| Over 80,000 Gallons | 2.18 |

Commercial – All Meter Sizes
Gallonage Charge – per 1,000 Gallons

| | |
|---|---|
| From 1 to 400,000 Gallons | $ 1.27 |
| Over 400,000 Gallons | 1.56 |

Turf Facility Customers
Gallonage Charge – per 1,000 Gallons

| | |
|---|---|
| All Gallons | $ 1.00 |

Paradise Valley Country Club (Contract Rate)
Minimum of Charges Based Upon Applicable Meter Size

| | |
|---|---|
| From 1 to 2,500,000 Gallons | Turf Rate Less 15 Percent |
| Over 2,500,000 Gallons | Turf Rate Less 15 Percent |
| All Surcharges Applicable to Commercial Customers | Less 15 Percent |

Other General Metered
Gallonage Charge – per 1,000 Gallons

| | |
|---|---|
| All Gallons | $1.46 |

Fire Protection
Gallonage Charge – per 1,000 Gallons

| | |
|---|---|
| All Gallons | No Charge |

Resale Customers
Gallonage Charge – per 1,000 Gallons

| | |
|---|---|
| All Gallons | $1.46 |

Service Line and Meter Installation Charges:
(Refundable pursuant to A.A.C. R14-2-405)

| | |
|---|---|
| 5/8" x ¾" Meter | $480.00 |
| ¾" Meter | 560.00 |
| 1" Meter | 650.00 |
| 1 ½" Meter | 895.00 |
| 2" Meter | 1,555.00 |
| 3" Meter | 2,235.00 |
| 4" Meter | 3,440.00 |
| 6" Meter | 6,195.00 |

SERVICE CHARGES:

| | |
|---|---|
| Establishment | $20.00 |
| Establishment (After Hours) | 40.00 |
| Reconnection (Delinquent) | 30.00 |
| Reconnection (Delinquent & After Hours) | 60.00 |

| | |
|---|---|
| Meter Test, if meter is correct | 15.00 |
| Deposit | * |
| Deposit Interest | * |
| Reestablishment (Within 12 Months) | ** |
| NSF Check | 12.00 |
| Deferred Payment, Per Month | 1.50% |
| Meter Reread (If Correct) | 10.00 |
| Late Charge per month | 1.50% |

Monthly Service Charges for Fire Sprinkler

| | |
|---|---|
| 4" or Smaller | *** |
| 6" | *** |
| 8" | *** |
| 10" | *** |
| Larger than 12" | *** |

* Per Commission rule A.A.C. R-14-2-403(B).

** Months off system times the monthly minimum per Commission rule A.A.C. R14-2-403(D).

*** 1% of Monthly Minimum for a Comparable Size Meter Connection, but no less than $5.00 per month. The Service Charge for Fire Sprinklers is only applicable for service lines separate and distinct for the primary water service line.

CAP Surcharge

There are two current unchanged CAP surcharges which are calculated under a separate docket.

High Block Usage Surcharge Treated as Contributions in Aid of Construction

Per Customer

Residential Customers:

All residential customers with usage in the third tier will pay a surcharge on their third tier usage.

All usage in the third tier, in addition to normal third tier charge: $2.15 per 1,000 gallons

Commercial Customers:

All commercial customers with usage in the second tier will pay a surcharge on their second tier usage.

All usage in the second tier, in addition to normal second tier charge: $2.15 per 1,000 gallons

Public Safety Fire Flow Surcharge Treated as Contributions in Aid of Construction

Per Customer

Residential Customers:
All residential customers with usage in the second and third tier will pay a surcharge on second and third tier usage.

All usage in the second and third tier, in addition to normal second and third tier charges

From October 1, 2007 until recovery of fire flow projects is complete $1.00 per 1,000 gallons

Commercial Customers:
All commercial customers with usage in the second tier will pay a surcharge on second tier usage.

All usage in the second tier, in addition to normal second tier charges

From October 1, 2007 until recovery of fire flow projects is complete $1.00 per 1,000 gallons

IT IS FURTHER ORDERED that the revised schedule of rates and charges shall be effective for all service rendered on and after August 1, 2006.

IT IS FURTHER ORDERED that Arizona-American Water Company shall notify its affected customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing in a form and manner acceptable to the Commission's Utilities Division Staff.

IT IS FURTHER ORDERED that Arizona-American Water Company's request for authority to implement an ACRM is approved, to the extent described herein.

IT IS FURTHER ORDERED that Arizona-American Water Company shall comply with all requirements discussed in this Order as a condition of approval of the Arsenic Cost Recovery Mechanism.

IT IS FURTHER ORDERED that Arizona-American Water Company shall file, by July 1st of each year subsequent to any year in which it collects surcharges under an ACRM, a report with Docket Control showing the Company's ending capital structure (equity, long-term debt, and short-term debt) by month for the prior year.

IT IS FURTHER ORDERED that, as part of the Earnings Test schedule filed in support of the ACRM, Arizona-American Water Company shall incorporate adjustments conforming to Decision

No. 67093, as discussed in Staff's recommendations set forth herein.

IT IS FURTHER ORDERED that Arizona-American Water Company shall file in this docket hard copies of the schedules discussed in its application, as set forth in Staff's recommendations herein, and shall concurrently provide Microsoft Excel or compatible electronic versions of the filings and all work papers to Staff with all ACRM filings.

IT IS FURTHER ORDERED that all ACRM surcharges shall be designed to apply rate design volumetric charges equally to all usage tiers.

IT IS FURTHER ORDERED that Arizona-American Water Company shall file the schedules and information described above, as well as any additional relevant data requested by Staff, as part of any request for an Arsenic Cost Recovery Mechanism step increase.

IT IS FURTHER ORDERED that Arizona-American Water Company shall file a permanent rate application for its Paradise Valley Water District no later than September 30, 2008.

IT IS FURTHER ORDERED that Arizona-American Water Company shall annually file as part of its annual report, an affidavit with the Utilities Division attesting that the Company is current in paying its property taxes in Arizona.

IT IS FURTHER ORDERED that the special contract agreement between Arizona-American Water Company and Paradise Valley Country Club discussed herein is hereby approved, and that Arizona-American Water Company shall request Commission approval of any future amendments to the agreement.

IT IS FURTHER ORDERED that Arizona-American Water Company shall file with Commission Docket Control, within 30 days of its execution, an executed copy of the special contract agreement with Paradise Valley Country Club discussed and approved herein, as a compliance item in this case.

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IT IS FURTHER ORDERED that Arizona-American Water Company shall continue to use the depreciation rates for its Paradise Valley Water District set forth in Exhibit 4 to Hearing Exh. S-6.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN

COMMISSIONER

Commissioner Spitzer resigned effective 7-21-2006

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 28th day of July, 2006.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: ARIZONA-AMERICAN WATER COMPANY (Paradise Valley Water District)

DOCKET NO.: W-01303A-05-0405 ET AL.

Craig A. Marks
Arizona-American Water Company
101 Corporate Center
19820 North 7th Street, Ste. 201
Phoenix, AZ 85024

Scott S. Wakefield
RUCO
1110 West Washington Street, Ste. 220
Phoenix, AZ 85007

Robert J. Metli
SNELL & WILMER, LLP
One Arizona Center
400 E. Van Buren
Phoenix, AZ 85004
Attorneys for Paradise Valley Country Club

Christopher Kempley, Chief Counsel
Maureen A. Scott, Senior Staff Attorney
Keith A. Layton, Attorney
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

Ernest G. Johnson, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007

HEARING

DOCKET NO. W-01303A-05-0405 et al

EXHIBIT A

**BEFORE THE ARIZONA CORPORATION COMMISSION**

JEFF HATCH-MILLER
Chairman
WILLIAM A. MUNDELL
Commissioner
MARC SPITZER
Commissioner
MIKE GLEASON
Commissioner
KRISTIN K. MAYES
Commissioner

Arizona Corporation Commission
DOCKETED
NOV 14 2005
DOCKETED BY

RECEIVED
NOV 16 2005
ARIZONA CORPORATION COMMISSION
HEARING DIVISION

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY, INC.'S REQUEST FOR AN ACCOUNTING ORDER AUTHORIZING THE DEFERRAL OF COSTS ASSOCIATED WITH PUBLIC SAFETY/FIRE FLOW IMPROVEMENTS IN ITS PARADISE VALLEY WATER DISTRICT | DOCKET NO. W-01303A-05-0704<br>DECISION NO. 68303<br>PUBLIC SAFETY/FIRE FLOWS<br>ACCOUNTING ORDER |

Open Meeting
November 8 and 9, 2005
Phoenix, Arizona

BY THE COMMISSION:

On June 3, 2005, Arizona-American Water Company ("Arizona-American" or "Company") filed a rate application, Docket No. W-01303A-05-0405, with the Arizona Corporation Commission ("Commission") for a determination of the current fair value of its utility plant and property and for increases in its rates and charges based thereon for utility service by its Paradise Valley water district. Within that application was a request for an accounting order authorizing the deferral of capital costs incurred by the Company's Paradise Valley system related to public safety associated with fire flows.

A hearing on the rate application is scheduled to commence on March 27, 2006.

Pursuant to Staff's request to aid the Company in its request for expedited action, on October 5, 2005, the Company filed a request to bifurcate its rate application and to separate the accounting order portion from the rate application. The Company requests an accounting order authorizing the deferral of capital costs by the Company's Paradise Valley system related to public safety associated with fire flows.

The Town of Paradise Valley ("Town") has requested the fire-flow improvements since they are needed to reduce the risk to life and property. Mr. Thomas M. Martinsen, the town manager of the Town has requested expedited review. Town residents' safety and the protection of their property are highly dependent on this program.

* * * * * * * * * *

Having considered the Company's application and Staff's memorandum dated October 20, 2005, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. Arizona-American is a Class-A regulated water and wastewater utility which serves approximately 131,000 customers throughout the state of Arizona pursuant to various Certificates of Convenience and Necessity granted by the Commission to the Company and its predecessors in interest.

2. The Company's deferral request in this docket pertains only to the Company's Paradise Valley water district, where the Company provides service to approximately 5,000 customers in portions of Paradise Valley, Scottsdale and unincorporated Maricopa County.

3. The Company seeks an accounting order in this proceeding authorizing the deferral of capital costs and expenses it expects to incur before these costs can be recognized in rates. An accounting order is a rate-making mechanism whereby a regulatory commission provides specific deferral authorization to treat costs in a manner that differs from generally accepted accounting principles. Such a deferral mechanism, pursuant to an authorized accounting order, is permitted under National Association of Regulatory Commissioners ("NARUC") Uniform System of Accounts ("USOA") guidelines.

4. Arizona-American seeks an accounting order authorizing it to defer capital costs, specifically depreciation expense and "gross return" related to public safety/fire flow improvement facilities placed into service in Paradise Valley.

5. The Town has requested the fire-flow improvements since the improvements are needed to reduce the risk to life and property.

. . .

6. The Company proposes to include capital expenditures for projects that a) improve fire flows, b) produce no significant additional revenues, and c) do not materially reduce operating expenses. Records will be maintained to segregate the cost of eligible capital investments and capital investments that would otherwise be made during the due course of the Paradise Valley on-going operations.

7. Staff's recommendation for approval of an accounting order for Arizona-American is subject to the following conditions:

a) The deferral is limited to eligible Company expenditures in the Paradise Valley water district related to public safety/fire flow.

b) The Company shall be required to prepare and retain accounting records sufficient to permit detailed review, in a rate proceeding, of all deferred costs related to public safety/fire flow improvement facilities.

c) The deferral is related to projects that are revenue neutral.

d) The deferral is related to projects that do not materially reduce operating expenses.

e) The Company's deferral is limited to depreciation expense (at authorized depreciation rates) and a post-in-service allowance for funds used during construction ("AFUDC"), with the rate set at its cost of debt concurrent with the deferral period.

f) The post-in-service AFUDC will automatically cease when, and if, the related plant is placed in rate base and recognized in a rate proceeding.

8. While issuance of an accounting order authorizing deferral of the costs being incurred will not assure the Company that those costs will be recovered in rates, without such an accounting order, the Company would be foreclosed from possible future recovery of such costs as a regulatory asset.

9. A determination regarding the recovery of the deferral will be made in the Company's instant rate case or the Company's future rate cases for the Paradise Valley water district.

## CONCLUSIONS OF LAW

1. The Company is a public water service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250 and 40-252.

2. The Commission has jurisdiction over the Company and of the subject matter of the application.

3. The cost deferral authorization granted herein does not constitute a finding or determination that such costs are reasonable, appropriate, or prudent.

4. It is in the public interest to allow the Company to record the capital costs for projects that improve fire flows, produce no significant additional revenues, and do not materially reduce operating expenses in a deferred account for the Paradise Valley water district, subject to the conditions recommended by Staff as set forth and discussed herein.

ORDER

IT IS THEREFORE ORDERED that the application by Arizona-American Water Company for an accounting order to improve fire flows for public safety is approved, authorizing the deferral of depreciation expense (at authorized depreciation rates) and a post-in-service AFUDC, with the rate set at its cost of debt concurrent with the deferral period, subject to the conditions and requirements recommended by Staff, as described herein.

IT IS FURTHER ORDERED that the cost deferral authorization granted herein does not constitute a finding or determination that the deferred costs are reasonable, appropriate, or prudent.

IT IS FURTHER ORDERED that this Decision shall not be construed as providing the Arizona-American Water Company any relief through rates with respect to the ultimate recovery of the above-authorized cost deferrals.

IT IS FURTHER ORDERED that the Company shall prepare and retain accounting records sufficient to permit detailed review, in a rate proceeding, of all deferred costs recorded as authorized above.

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IT IS FURTHER ORDERED that a determination of recovery of the deferral will be made in the Company's instant rate case or the Company's future rate cases for the Paradise Valley water district.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

**BY THE ORDER OF THE ARIZONA CORPORATION COMMISSION**

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto, set my hand and caused the official seal of this Commission to be affixed at the Capitol, in the City of Phoenix, this 14th day of November, 2005.

BRIAN C. McNEIL
Executive Director

DISSENT: _____

DISSENT: _____

EGJ:JRM:rdp/

DECISION NO. 68858

SERVICE LIST FOR: Arizona-American Water Company, Inc.
DOCKET NO. W-01303A-05-0704

Mr. Craig A. Marks
Arizona-American Water Company
101 Corporate Center
19820 North 7th Street, Suite 201
Phoenix, Arizona 85024

Mr. Scott S. Wakefield
RUCO
1110 West Washington Street
Suite 220
Phoenix, Arizona 85007

Mr. Ernest G. Johnson
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Mr. Christopher C. Kempley
Chief Counsel
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

DECISION NO. 68858

EXHIBIT B

EXHIBIT No. S-9

ALTERNATIVE FIRE FLOW SURCHARGE
DOCKET NO. W-01303A-05-0405

In its direct testimony, Staff proposed a "High-Block" surcharge of $2.15 to be applied to all gallons in the top tier of each rate schedule to be implemented coincident with the new rates in Arizona-American Water Company's ("Company") application. Amounts collected are to be treated as Contributions in Aid of Construction ("CIAC"). In its surrebuttal testimony Staff recommended that the "High Block" surcharge collections be used to offset the fire flow projects.

The Company had proposed a two step "Public Safety" fire flow surcharge. However, in discussing Staff's proposal, the Company's rebuttal testimony indicated that it would defer the timing of the fire flow projects since the High Block surcharge would not produce adequate cash flow. Mr. Townsley's testimony indicates that "the Company has slowed the pace of these projects until the Commission's wishes are more clearly stated".

The Company has asked Staff to explore possible acceleration of the fire flow surcharge collections to assist in completing the project on a more timely basis. As an alternative, in the event the Commission believes a surcharge is appropriate, Staff suggests a second phase, which would also be used specifically for fire flow surcharges, that would take effect on October 1, 2007. The second phase would increase the High Block surcharge from $2.15 to $3.15 per 1,000 gallons. A new "Public Safety" surcharge for the 2nd Tier residential rate of $1.00 per 1,000 gallons and for the 1st Tier of commercial rate of $1.00 per 1,000 gallons would also begin October 1, 2007.

Staff estimates that the High Block surcharge of $2.15 would generate approximately $1.7 million annually. Implementation of the October 1, 2007 increases would generate an additional $1.8 million annually for a total of $3.5 million annually. See Attached Schedule DWC.

The potential benefits from a phase-in fire flow surcharge include the following:

- Encourage conservation in a water district with historically high usage.
- Increase contributions in aid of construction which will reduce future rate increases.
- Permit more timely implementation of fire safety related infrastructure.

The surcharges will have no effect on the median (11,500 gallons) or average (22,193 gallons) residential bills since the surcharge for the 2nd Tier residential starts at 25,000 gallons. Thus, the median and average residential users will not be impacted.

Not withstanding this alternative, Staff continues to recommend a $2.15 "High Block" surcharge be implemented when new rates take effect and for the monies collected by this surcharge to be used to offset the cost of the fire flow project.



DECISION NO. 68858

If the Commission adopts this alternative, Staff recommends that that the Public Safety surcharge be terminated and the High Block surcharge be reduced back to $2.15 once the Company has fully recovered its fire flow project costs.

Arizona-American Water Company/Paradise Valley Water District
Docket No. W-01303A-05-0405

Schedule DWC

APPROXIMATE CASH FLOW
FIRE FLOW SURCHARGE

Assumes implementation of a top tier $2.15 surcharge in August, 2006
Implementation of the following revised surcharge in October, 2007:

| | |
|---|---|
| Top Tier-all Rate Schedules | $3.15 |
| 2nd Tier-Residential Rates | $1.00 |
| 1st Tier-Commercial Rates | $1.00 |

ESTIMATED MONTHLY CASH FLOW

| | Top Tier at $2.15 | Top Tier at $3.15 | 2nd Tier Res at $1.00 | 1st Tier Com. at $1.00 | Cummulative |
|---|---|---|---|---|---|
| September 2006 | 170,000 | | | | 170,000 |
| October 2006 | 113,333 | | | | 283,333 |
| November 2006 | 113,333 | | | | 396,666 |
| December 2006 | 113,333 | | | | 509,999 |
| January 2007 | 113,333 | | | | 623,332 |
| February 2007 | 113,333 | | | | 736,665 |
| March 2007 | 113,333 | | | | 849,998 |
| April 2007 | 170,000 | | | | 1,019,998 |
| May 2007 | 170,000 | | | | 1,189,998 |
| June 2007 | 170,000 | | | | 1,359,998 |
| July 2007 | 170,000 | | | | 1,529,998 |
| August 2007 | 170,000 | | | | 1,699,998 |
| September 2007 | 170,000 | | | | 1,869,998 |
| October 2007 | 113,333 | | | | 1,983,331 |
| November 2007 | | 166,666 | 52,800 | 12,000 | 2,214,797 |
| December 2007 | | 166,666 | 52,800 | 12,000 | 2,446,263 |
| January 2008 | | 166,666 | 52,800 | 12,000 | 2,677,729 |
| February 2008 | | 166,666 | 52,800 | 12,000 | 2,909,195 |
| March 2008 | | 166,666 | 52,800 | 12,000 | 3,140,661 |
| April 2008 | | 250,000 | 79,200 | 18,000 | 3,487,861 |
| May 2008 | | 250,000 | 79,200 | 18,000 | 3,835,061 |
| June 2008 | | 250,000 | 79,200 | 18,000 | 4,182,261 |
| July 2008 | | 250,000 | 79,200 | 18,000 | 4,529,461 |
| August 2008 | | 250,000 | 79,200 | 18,000 | 4,876,661 |
| September 2008 | | 250,000 | 79,200 | 18,000 | 5,223,861 |
| October 2008 | | 166,666 | 52,800 | 12,000 | 5,455,327 |
| | 1,983,331 | 2,499,996 | 792,000 | 180,000 | |
| | | | 3,471,000 | | |



DECISION NO. 68858

AZ - American
Sun City

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
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IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES BASED THEREON FOR UTILITY SERVICE BY ITS SUN CITY WATER DISTRICT.

DOCKET NO. W-01303A-07-0209

DECISION NO. 70351

**OPINION AND ORDER**

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| DATE OF PUBLIC COMMENT: | May 16, 2007 |
| PLACE OF PUBLIC COMMENT: | Sun City West, Arizona |
| DATE OF HEARING: | January 7-11, 2008 |
| PLACE OF HEARING: | Phoenix, Arizona |
| ADMINISTRATIVE LAW JUDGE: | Jane L. Rodda |
| IN ATTENDENCE | Chairman Mike Gleason<br>Commissioner William Mundell<br>Commissioner Kristin Mayes<br>Commissioner Gary Pierce |
| APPEARANCES: | Craig Marks, CRAIG MARKS PLC and Paul Li, Arizona-American Water Company, on behalf of Arizona-American Water Co;<br><br>William Sullivan, CURTIS, GOODWIN, SULLIVAN, UDALL & SCWHAB, PLC, on behalf of The Town of Youngtown;<br><br>Daniel Pozefsky, Staff Counsel, on behalf of the Residential Utility Consumer Office; and<br><br>Robin Mitchell and Keith Layton, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission. |

EXHIBIT
A-28
ADMITTED

**BY THE COMMISSION:**

I. Procedural History

On April 2, 2007, Arizona-American Water Company ("Arizona-American" or "Company") filed an application for a rate increase for its Sun City Water District.

On April 30, 2007, the Commission's Utilities Division ("Staff") filed a letter stating that the application met the sufficiency requirements outlined in A.A.C. R14-2-103, and classifying the Company as a Class A utility.

On May 16, 2007, the Commission convened a Special Open Meeting for the purpose of taking public comment on the rate increase in this matter as well as Docket No. WS-01303A-06-0491, Arizona-American's then pending rate case for its Sun City and Sun City West Wastewater Districts.

By Procedural Order dated June 5, 2007, the Commission set the matter for hearing on January 7, 2008, established procedural guidelines and deadlines for filing testimony and granted intervention to the Residential Utility Consumer Office ("RUCO") and the Sun City Taxpayers Association, Inc. ("SCTA").

On September 13, 2007, the Commission granted intervention to the Town of Youngtown ("Youngtown" or "Town").

On September 19, 2007, Arizona-American filed Notice of Filing Affidavit of Publication, indicating that notice of the hearing in this matter was published on September 11, 2007, in the *Daily News-Sun*.

On September 21, 2007, Arizona-American filed Notice of Filing Affidavit of Customer Notice, indicating that the notice of the hearing had been mailed to Arizona-American's Sun City District customers.

On October 3, 2007, William E. Downey of Sun City, Arizona, filed a Motion to Intervene.

On October 15, 2007, RUCO filed the Direct Testimony of Marylee Diaz Cortez, William Rigsby and Timothy Coley; Youngtown filed the Direct Testimony of Mayor Michael LeVault and Deputy Fire Marshall Ken Rice; and Staff filed the Direct Testimony of Alexander Igwe, Stephen Irvine on cost of capital and Dorothy Hains.

C. Cost of Capital

1. Capital Structure

Arizona-American supports a capital structure of 58.3 percent debt and 41.7 percent equity. This reflects an equity infusion of $15,000,000, which was completed in December 2007.

Staff supports a capital structure comprised of 61.0 percent debt and 39.0 percent equity. Staff also includes the $15,000,000 equity infusion in 2007. The main difference between Staff and Arizona-American is Staff's inclusion of $28,124,006 of short-term debt in Arizona-American's capital structure.

RUCO supports a capital structure of 57.7 percent debt and 42.3 percent equity. RUCO asserts that whether to include short-term debt in a company's capital structure should be considered on a case-by-case basis. Based on the facts of this case, RUCO recommends that the Commission should not include the short-term debt in the Company's capital structure. RUCO states that the short-term debt relates to the Company's plan to finance a Central Arizona Project treatment facility, known as the White Tanks Plant, through the use of hook-up fees. RUCO asserts that the short-term debt related to the White Tanks Plant will be paid off by the eventual collection of hook-up fees which will be treated as a source of cost-free capital, thus, RUCO believes that the short-term debt associated with the White Tanks Plant should not be included in the Company's capital structure.

Arizona-American believes that Staff's position is a new one, and it argues that short–term debt should not be included in a company's capital structure. The Company argues it should not be included unless it is being used to finance long-term assets, in which case, the return on rate base should recognize the cost of the short-term debt that financed those assets. The Company argues that short-term debt used to finance Working Capital and Construction Work in Progress ("CWIP") should not be included in the capital structure. Arizona-American states that in Arizona, CWIP is not included in rate base, so no return should be provided by customers on CWIP financed by short-term debt. Arizona-American argues that Staff did not meet its burden of identifying the balance of short-term debt, if any, being used to finance long-term assets.

Staff argues that short-term debt is a component of the capital structure and that the use of funds from short-term debt is irrelevant. Staff states that it subscribes to a financial theory that

money is fungible and a dollar collected from any particular source cannot be assigned to a particular project. Staff asserts that it does not adjust a company's capital structure based on what the funds are used for and whether those uses are included in rate base. Staff maintains, in response to RUCO, that it is impossible to determine what dollars in the available pool of capital are assigned to the White Tank treatment project. Staff continues to believe that including short-term debt gives a more accurate view of the Company's financial position.[17]

We concur with Staff's position. We are not convinced by the Company's arguments that short-term debt should be excluded from the capital structure. Short-term debt is another source of funds available to the Company, and the cost of those funds should be recognized. Our determination to include short-term debt is consistent with our prior practices, most recently and relevantly, with our Decision in the Sun City Wastewater and Sun City West Wastewater Districts rate case.[18]

2. Cost of Debt

The parties agreed that the cost of debt is 5.5 percent.

3. Cost of Equity

Staff recommended a cost of equity of 10.8 percent. Arizona-American agreed to Staff's position. Staff's witness, Mr. Irvine, utilized the Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") to derive his estimated industry return on equity ("ROE") of 9.9 percent. Mr. Irvine then added 90 basis points, or 0.9 percent, to the industry ROE to reflect Arizona-American's greater leverage than the sample utilities.

RUCO's witness, Mr. Rigsby, also utilized a DCF and CAPM analyses to calculate an industry sample group return on equity of 9.39 percent. Mr. Rigsby added 50 basis points, 0.5 percent, to adjust for Arizona-American's greater leverage, and recommends adopting a cost of equity of 9.89 percent. RUCO argues that its recommended cost of equity is appropriate given the current environment of historically low inflation and low interest rates.

Arizona-American argues that RUCO's 50 basis point adjustment is arbitrary, not based on any recognized methodology, and inconsistent with Commission precedent. Arizona-American

[17] Staff Reply Brief at 5.
[18] See Decision No. 70209.

states it is well below the adjustments the Commission recently approved for Arizona-American's other Districts. In Decision No. 69440 (May 1, 2007), the Commission approved an adjustment of 100 basis points for Arizona-American's additional leverage risk. Arizona-American also criticizes Mr. Rigsby's DCF analysis for equally weighting the DCF evaluations of his water utility and gas utility samples and for only using four water companies in the sample.

We find that Staff's cost of equity recommendation is reasonable and consistent with prior Commission decisions regarding cost of equity. Staff utilized reasonable inputs for its DCF and CAPM models and for its financial risk adjustment.[19] Consequently, we adopt a cost of equity of 10.8 percent.

4. Overall Cost of Capital

Based on the foregoing, we adopt an overall cost of capital for Arizona-American of 7.6 percent, calculated as follows:

| | Percentage | Cost | Weighted Cost |
|---|---|---|---|
| Debt | 61.0 % | 5.50% | 3.4% |
| Common Equity | 39.0 % | 10.80% | 4.2% |
| Weighted Average Cost of Capital | 100.0% | | 7.6% |

D. Authorized Increase

Based on the foregoing, we approve a rate increase of $1,907,192, as set forth below:

| | |
|---|---|
| OCRB | $25,295,922 |
| Adjusted Test Year Operating Income | $755,506 |
| Required Operating Income | $1,922,490 |
| Required Rate of Return | 7.6% |
| Operating Income Deficiency | $1,166,984 |
| Gross Revenue Conversion Factor | 1.6343 |
| Increase in Gross Revenue Requirement | $1,907,202 |
| Adjusted Test Year Revenue | $7,688,479 |
| Approved Annual Revenue | $9,595,681 |
| Percentage Increase in Revenue | 24.81 |

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[19] In Decision No. 70209, the Commission approved a risk adjustment of 80 basis points for the Sun City and Sun city West Wastewater Districts.

**BEFORE THE ARIZONA CORPORATION C**

Arizona Corporation Commission
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COMMISSIONERS

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

IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES BASED THEREON FOR UTILITY SERVICE BY ITS SUN CITY WASTEWATER AND SUN CITY WEST WASTEWATER DISTRICTS.

DOCKET NO. WS-01303A-06-0491

DECISION NO. 70209

**OPINION AND ORDER**

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|---|---|
| DATES OF HEARING: | August 17, 2007 (Pre-Hearing Conference), August 23, 24, 27, 28, and September 5, 2007. |
| PLACE OF HEARING: | Phoenix, Arizona |
| DATE OF PUBLIC COMMENT HEARINGS: | May 16, 2007 |
| PLACE OF PUBLIC COMMENT HEARINGS: | Sun City, Arizona |
| ADMINISTRATIVE LAW JUDGE: | Teena Wolfe |
| IN ATTENDANCE: | Mike Gleason, Chairman<br>William A. Mundell, Commissioner<br>Jeff Hatch-Miller, Commissioner<br>Kristin K. Mayes, Commissioner<br>Gary Pierce, Commissioner |
| APPEARANCES: | Mr. Craig A. Marks, CRAIG MARKS, PLC, and Mr. Paul Li, on behalf of Arizona-American Water Company;<br><br>Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;<br><br>Ms. Tracy Spoon, for the Sun City Taxpayers Association;<br><br>Mr. Philip Jansen, pro per;<br><br>Ms. Maureen Scott, Senior Staff Counsel, and Mr. Keith Layton, Staff Attorney, on behalf of the Utilities Division of the Arizona Corporation Commission. |

**BY THE COMMISSION:**

## I. INTRODUCTION

On July 28, 2006, Arizona-American Water Company ("Arizona-American" or "Company") filed an application with the Arizona Corporation Commission ("Commission") for an increase in its rates for utility service by its Sun City Wastewater and Sun City West Wastewater Districts.

Intervention in this matter was granted to the Residential Utility Consumer Office ("RUCO"), Mr. Philip Jansen, and the Sun City Taxpayers Association ("SCTA").[1]

On February 2, 2007, the Commission's Utilities Division ("Staff") filed a Letter of Sufficiency, and by Procedural Order issued February 15, 2007, the hearing in this matter was scheduled to commence on August 23, 2007.

Public Comment Hearings on the application were held in Sun City and Sun City West, Arizona on May 16, 2007. Public comment was also taken at the beginning the evidentiary hearing, which commenced on August 23, 2007, as scheduled, and continued through August 24, 27, 28, and September 5, 2007.

Following the hearing, closing briefs and reply briefs were filed, and the matter was taken under advisement.

## II. APPLICATION

Arizona-American is requesting annual revenues of $6,001,082 for its Sun City Wastewater District, which is an increase in annual revenues of $1,493,529, or 33.13 percent over adjusted test year revenues, and annual revenues of $5,818,464 for its Sun City West Wastewater District, which is an increase of $1,271,824, or 27.98 percent, over adjusted test year revenues, in its Sun City West Wastewater District. RUCO recommends a revenue requirement of $5,741,494 for Sun City Wastewater, which is an increase of $1,233,925, or 27.37 percent over adjusted test year revenues. For Sun City West Wastewater, RUCO recommends a revenue requirement of $5,964,454, which is an increase of $1,417,929, or 31.19 percent, over adjusted test year revenues. Staff recommends a revenue requirement of $5,869,400 for Sun City Wastewater, an increase of $1,386,545, or 30.93

[1] On December 11, 2007, SCTA filed its Withdrawal of Motion to Intervene.

percent, over adjusted test year revenues. For Sun City West Wastewater, Staff recommends a revenue requirement of $5,617,155, an increase of $1,078,750, or 23.77 percent, over adjusted test year revenues.

## III. RATE BASE ISSUES

For its Sun City Wastewater rate base, Arizona-American proposes $12,346,101. RUCO proposes $12,195,256. Staff proposes $12,405,348.

For its Sun City West Wastewater rate base, Arizona-American proposes $16,544,545. RUCO proposes $16,440,658. Staff proposes $16,409,137. The differences in the parties' rate base proposals stem from their differing positions on imputed advances in aid of construction ("AIAC") and contributions in aid of construction ("CIAC") balances, removal of certain plant from plant in service, and an appropriate accumulated depreciation balance.

### A. Plant in Service

#### 1. Northwest Regional Wastewater Treatment Facility Allocation

The Northwest Regional Wastewater Treatment Facility ("Northwest Plant") serves both the Sun City West Wastewater District and the Anthem/Agua Fria Wastewater District.[2] In December 2004, Arizona-American expanded the Northwest Plant, which was formerly known as the Sun City West Water Reclamation Facility, to accommodate flows from the Agua Fria Wastewater District in addition to Sun City West flows, which reach the plant after leaving the single lift station located at the corner of Bell Road and El Mirage Road. (Direct Testimony of Company witness Brian K. Beisemeyer, Exh. A-2 at 5; Tr. at 20.) The expansion increased the capacity of the Northwest Plant from 3.14 million gallons per day ("mgd") to 5.0 mgd. In this rate case, the Company initially allocated 97.75 percent of operating expenses and rate base for the plant to Sun City West, based on actual flows during the test year. (Direct Testimony of Company witness Joel M. Reiker, Exh. A-8 at 3; Tr. at 152.) Staff Engineering inspected the plant and determined that the expansion and accompanying upgrades are used and useful. (Direct Testimony of Staff witness Dorothy Hains, Exhibit S-1, Exhibit DMH-2 (Engineering Report) at 1.) Arizona-American and Staff are in

[2] The Company has a rate case pending for the Anthem/Agua Fria Wastewater District in Docket No. WS-01303-06-0403.

Commission precedent and use adjusted test year revenues in determining property tax expense.

Staff proposes that the Commission adopt the inclusion of a factor for property taxes in the Gross Revenue Conversion Factor ("GRCF") which is used to calculate the gross revenue required to obtain the proper level of operating income. Staff's proposed factor for property taxes in the GCRF automatically adjusts the revenue requirement for changes in revenue in the same way that income taxes are adjusted for changes in operating income. (Direct Testimony of Staff witness Gerald Becker, Exh. S-8 at 15-16.) In turn, the Company proposed an adjustment to property tax expense for the GCRF in order to appropriately reflect income taxes on the incremental property taxes that result from applying the property tax factor through the revenue conversion factor. (Co. Br. at 19; Rebuttal Testimony of Company witness Sheryl Hubbard, Exh. A-9 at 5, Exhibits SLH-R1 and SLH-2, Sched. C-2, page 2 of 4, line 36.) Neither RUCO nor Staff commented on the Company's adjustment to Staff's proposed GCRF methodology. Staff's proposal to include a property tax factor in the GCRF, along with the Company's proposed adjustment thereto, is reasonable and will be adopted.

**F. Net Operating Income**

Arizona-American's Sun City Wastewater District test year revenues were $4,507,569. In accordance with the discussion herein, the Sun City Wastewater District's adjusted test year operating expenses for ratemaking purposes total $4,399,211, for an adjusted test year operating income of $108,358. For Arizona-American's Sun City West Wastewater District, test year revenues were $4,546,525. In accordance with the discussion herein, the Sun City West Wastewater District's adjusted test year operating expenses for ratemaking purposes total $3,965,617, for an adjusted test year operating income of $580,908.

## VII. COST OF CAPITAL

### A. Capital Structure and Cost of Debt

1. Capital Structure

a. Arizona-American

The Company recommends a capital structure of 41.1 percent equity and 58.9 percent debt. The Company's recommendation reflects an expected 2007 equity infusion of $15 million.

(Company Final Schedules D-1 for both Sun City Wastewater and Sun City West Wastewater.) The Company agrees with Staff that its $3 million Phoenix Interconnection Agreement[4] should be classified as zero-cost debt, but would prefer to classify it as long-term, and not short-term debt. (Exh. A-13 at 5.) The Company opposes Staff's inclusion of short-term debt in the capital structure. The Company argues that it is not using short term debt to finance rate base, which is demonstrated by the fact that its Construction Work in Progress ("CWIP") balance was over twice its short term debt balance at May 2007. The Company also argues that short term debt can change significantly from month to month, and that Staff's proposal to use a short-term debt balance as of a particular point in time is inappropriate, unless the balance can be shown to be typical. The Company also contends that including short-term debt in the capital structure makes it more difficult to achieve the goals of the Company's 2005 Equity Plan filed in accordance with Commission Decision No. 68310 (November 14, 2005).[5] The Company states that if short-term debt is included in the Company's capital structure, the Company will need more time to comply with the Commission's directive in Decision No. 68310 to achieve and maintain a 40 percent equity target. (Exh. A-13 at 12-13.)

b. RUCO

RUCO recommends a hypothetical capital structure of 60 percent debt and 40 percent equity. (Exh. R-12 at 6.) RUCO disagrees with the Company's capital structure proposal because it is based on a future debt restructuring and infusion of equity. However, RUCO states that if the Commission agrees with Staff's recommendation to remove the $3 million Phoenix Interconnection Agreement from rate base, and treat it instead as zero-cost capital, that a hypothetical capital structure would not be appropriate, and RUCO would then support Staff's recommended capital structure. (Exh. R-11 at 7.)

c. Staff

Staff recommends a capital structure of 38.5 percent equity and 61.5 percent debt, which includes outstanding long-term and short-term debt as of June 30, 2007. (Surrebuttal Testimony of

[4] The Phoenix Interconnection Agreement is the subject of testimony in the Company's pending Anthem rate case, Docket No. WS-01303A-06-0403.

[5] Decision No. 68310 ordered the Company to file an equity plan "that describes how the Company expects to attain and maintain a capital structure (equity, long-term debt, and short-term debt) with equity representing between 40 and 60 percent of total capital." (Decision No. 68310 at 15.)

Staff Witness Pedro M. Chaves, Exh. S-13 at 7, Table 1; Exh. S-97, Sched. PMC-9.) Staff's recommendation includes the Company's expected 2007 equity infusion of $15 million. (Exh. S-12 at 7, Table 4, fn 2.) Staff argues against exclusion of the Company's short-term debt from the capital structure, because Staff believes doing so would indirectly and inappropriately place the burden of achieving the targeted 40 percent equity ratio on ratepayers, via a higher return. (Exh. S-13 at 3.) In response to the Company's argument that short-term debt fluctuates as working capital needs change, Staff states that working capital is not the only potential use of short-term debt, which is only one component of the Company's capital pool. (Surrebuttal Testimony of Staff witness Pedro Chaves, Exh. S-13 at 4-5.) Staff argues that dollars from individual capital sources that comprise the Company's capital pool cannot be attached to specific uses, (*Id.*), points out that sample schedules in the Commission's rate case rules, (A.A.C. R14-2-103, Schedule D-2), show short-term debt as a component of the cost of capital, and that Decision No. 68310 contemplated that the Company's capital structure would include short-term debt, (Exh. S-13 at 5, citing Decision No. 68310 at 15).

Staff states that for purposes of this proceeding, Staff is recommending a financial risk adjustment to recognize the additional risk represented by the Company's additional leverage compared with the sample companies Staff used to estimate cost of equity, and that the adjustment already increases the Company's revenue requirement to provide additional income to grow equity. (Exh. S-12 at 37.) Staff believes that adopting the Company's proposed capital structure, in addition to the financial risk adjustment, would result in ratepayers compensating the Company for a relatively weak financial position by paying inflated rates based on a hypothetical capital structure that depicts a more financially sound service provider than actually exists, (*Id.*), and would in effect compensate shareholders for a non-existing equity investment, (Staff Reply Br. at 10). Staff therefore has provided an alternative cost of equity recommendation in the event that a hypothetical capital structure is adopted. (Staff Br. at 21.)

d. Analysis and Conclusion

Staff's recommended capital structure provides the most accurate representation of the districts' actual capital structure. Decision No. 68310 contemplated that the Company's capital structure would include short-term debt. Short-term debt is shown as a component of the cost of

capital in the schedules required by A.A.C. R14-2-103. In the face of these facts, we are not convinced by the Company's arguments for exclusion of short-term debt from the Company's capital structure. For purposes of this proceeding, we adopt a capital structure for the Company of 38.5 percent equity and 61.5 percent debt.

2. Cost of Debt

Arizona-American proposes 5.45 percent as the cost of long-term debt. RUCO's recommended cost of debt is 5.37 percent. (Exh. R-11 at 10.) Staff proposes a 5.5 percent average cost of debt. (Exh. S-97, Sched. PMC-9.) Arizona-American argues that RUCO's calculation should be rejected in favor of the Company and Staff's calculations, because they are based on more current information, while RUCO used historic data. (Co. Br. at 29.) Staff's recommendation of 5.5 percent cost of debt is based on the districts' actual cost of total debt and will be adopted for purposes of this proceeding.

**B. Cost of Equity**

The Sun City Wastewater District and the Sun City West Wastewater District do not have publicly traded stock, so their cost of equity must be estimated. The parties therefore used data from selected sample groups of publicly traded companies in order to estimate the districts' cost of equity.

1. Arizona-American

The Company estimated the cost of capital for the Sun City and Sun City West Wastewater Districts, using two benchmark samples, one of regulated water utilities[6] and one of regulated natural gas local distribution companies ("LDCs").[7] (Direct Testimony of Company witness Dr. Bente

[6] The regulated water utility companies the Company chose for its cost of equity analysis are American States Water Company, California Water Service Group, Connecticut Water Service Inc., Middlesex Water Company, Aqua America Inc., SJW Corporation, Southwest Water Company, and York Water Company. To select her water utility sample, Dr. Villadsen used both the Standard and the Small and Mid-Cap Editions of *Value Line Investment Survey ("Value Line")* and *Value Line – Plus Edition.* (Exh. A-15 at 20.) Dr. Villadsen explained that she did not apply her normal selection criteria to the water company sample because if she were to do so, she would be left with at most two companies, a sample too small to provide reliable results. (*Id.*)

[7] The natural gas LDCs the Company chose for its analysis are Cascade Natural Gas Corporation, Laclede Group, Inc., Northwest Natural Gas Company, Peoples Energy Corporation, South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc. Dr. Villadsen stated that in choosing the sample, she applied her normal selection criteria, including only companies in the Standard Edition of *Value Line*'s universe of natural gas LDCs with necessary data available, an investment bond rating, no recent mergers or acquisitions, no recent dividend cuts, at least 60 percent

Villadsen, Exh. A-15 at 3.) Dr. Villadsen gave the results of the water sample the most weight, and used the gas LDC sample as a check on the results from the water sample. (*Id.*) Dr. Villadsen estimated the cost of equity for her chosen sample companies[8] using the discounted cash flow ("DCF") methodology, and approaches to which she refers as risk-positioning methods, including the capital asset pricing model ("CAPM").

The DCF model considered by Dr. Villadsen in reaching her cost of equity recommendation is a variant of the multi-stage DCF method that uses the proxy companies' individual growth rates during the first five years, converges to a perpetual growth rate in years six through ten, and then uses the gross domestic product ("GDP") rate as the perpetual growth rate after year 10. (Exh. A-15 at 38.) Dr. Villadsen believes that over periods with widely varying rates of inflation, it is unlikely that current growth rate expectations can be properly estimated by using average historical growth rates in observable variables such as dividends per share ("DPS") or earnings per share ("EPS"); or by the sustainable growth estimation method, which uses the average book rate of return times the fraction of earnings retained within the firm. (*Id.* at 38). Dr. Villadsen prefers instead to use earnings growth rate forecasts from *Institutional Brokers' Estimate System ("IBES")* and *Value Line*. (*Id.* at 39.) She disagrees with Staff's use of an average of historical DPS and EPS growth and forecasted DPS and EPS growth, because she believes using historical data provides no additional information to that captured in analyst forecasts, and application of the model requires that dividends and earnings grow at the same rate at some point in the future. (*Id.* at 40.) While conceding that analyst forecasts have been optimistic on average in the past, (*Id.*), Dr. Villadsen states that the problem of over-optimism has been "less acute" for regulated companies, and that use of a two-stage DCF model that substitutes the forecast growth of GDP mitigates analyst optimism, (*Id.* at 41). Dr. Villadsen believes that due to consolidation among privately held water utilities, the need for significant infrastructure improvements, the possibility of new safety and security requirements in the industry in the future, and differing regulatory requirements by state all create uncertainty, which means that it may be

revenues from regulated operations, and no other activity that could cause the estimation parameters to be biased. (Exh. A-15 at 21.)

[8] Dr. Villadsen excluded Connecticut Water Services and SJW Corporation from her DCF analysis because they did not have long-term growth forecasts from *Institutional Brokers' Estimate System*. (Exh. A-15 at 44; Exh A-15, App. B at 10.)

some time before the water industry settles into a "stable equilibrium necessary for the reliable application of the DCF model." (*Id.* at 43.) She views the DCF method as inherently less reliable than her risk positioning approach, but states that she submitted DCF evidence because it has been widely used in the past and because she uses the estimates to serve as a check on the values provided by risk positioning methods. (*Id.* at 44.) Dr. Villadsen found that the results of her multi-stage DCF model are in line with the results from her risk positioning model, whereas her simple DCF model provides uniformly higher cost of equity estimates. (Exh. A-15 at 58.) The cost of equity estimates Dr. Villadsen reached with her multi-stage DCF model range from 11.5 to 12 percent for the water utility sample and from 12 to 13 percent for the gas LDC sample. (*Id.*) Dr. Villadsen views her DCF estimates as confirmation that the natural gas LDC sample provides more stable results than the water utility sample, and that her risk positioning results are reasonable. (*Id.*)

Dr. Villadsen explains that the risk positioning method estimates the cost of equity as the sum of a current interest rate and a risk premium, and that the most widely used version of the "formal" risk positioning models is the CAPM.[9] (Exh. A-15 at 28.) In addition to the CAPM, Dr. Villadsen relied on a variety of the CAPM, to which she refers as the empirical capital asset pricing model ("ECAPM").[10] (*Id.* at 33.) According to Dr. Villadsen, the ECAPM is based on the empirical finding that risk premiums are related to beta, but are not as sensitive to beta[11] as the CAPM predicts. (*Id.*) Dr. Villadsen asserts that the ECAPM corrects predictions of the CAPM, which she believes underestimates the cost of capital for low beta stocks and overestimates the cost of capital for high

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[9] The equation for the CAPM is

$$k = r_F + \beta \times MRP$$

where $k$ is the cost of capital; $r_F$ is the risk-free interest rate; $MRP$ is the market risk premium, *.i.e.*, the excess of the expected return on the average common stock over the risk-free interest rate; and $\beta$ is the measure of relative risk. (Exh. A-15 at 29.)

[10] The equation for the ECAPM is

$$k = r_F + \acute{\alpha} + \beta \times MRP$$

where $\acute{\alpha}$ is the "empirical adjustment factor." (Exh. A-15 at 34.) Dr. Villadsen used baseline values of 2 percent for the short-term risk-free rate and 0.5 percent for the long-term risk-free rate. (*Id.*)

[11] Beta is a measure of the systematic risk of a stock – the extent to which a stock's value fluctuates more or less than average when the market fluctuates. (Exh. A-15 at 32.) Beta is a measure of the risks that cannot be eliminated by diversification, (*Id.*), and reflects both the business risk and financial risk of an entity, (Direct Testimony of Staff Witness Pedro M. Chaves, Exh. S-12 at 12). Since the market's beta is 1.0, a security with a beta higher than 1.0 is riskier than the market and a security with a beta lower than 1.0 is less risky than the market. (Exh. A-15 at 30.) Dr. Villadsen uses the betas reported by *Value Line,* (Exh. A-15 at 33), but reverses the adjustment that *Value Line* makes to estimated betas, to obtain "unadjusted" betas, (Exh. A-15 at 48).

beta stocks. (*Id.* at 34.) Dr. Villadsen notes that there is currently little consensus on the best practice for estimating the market risk premium ("MRP") used in the CAPM and the ECAPM, (*Id.* at 30-31), but concludes that S&P 500 stocks of average risk today command a premium of 8.0 percent over the short-term risk-free rate and 6.5 percent over the long-term government rate, (*Id.*).

Dr. Villadsen states that based on her analysis, the risk-positioning model provides cost of equity estimates in the range of 11.25 to 12.75 percent with a midpoint between 11.75 and 12 percent for the natural gas LDC sample, while the water utility sample estimates were higher, with a midpoint at about 12.5 percent. (Exh. A-15 at 54.) Dr. Villadsen concludes that the best point estimate is in the range of 11.75 to 12 percent, which is consistent with her multi-stage DCF cost of equity estimates for the water utility sample and a bit below the comparable cost of equity estimates for the natural gas LDC sample. (Exh. A-15 at 61.) Dr. Villadsen believes that the cost of equity estimates of the sample companies at their actual market-value capital structures is not necessarily reflected in the regulatory capital structure proposed in the application. (Exh. A-15 at 15.) She therefore utilizes an "after-tax weighted-average cost of capital" ("ATWACC") calculation, using market value capital structures, in her DCF, CAPM and ECAPM analyses for the proxy groups to reach her estimated cost of equity for the districts based on a hypothetical capital structure of 40 percent equity and 60 percent debt, (*Id.* at 49).

The Company disagrees with both Staff's and RUCO's risk adjustment methodology, (Co. Br. at 31, 35), and argues that the methodology used by the Commission to estimate equity returns has resulted in overcompensation of investors in low-leverage utilities and undercompensation of investors in high-leverage utilities, (Co. Br. at 32). The Company further argues that because interest on debt is tax deductible, the actual cost to customers of its low-cost debt is 3.32 percent. (*Id.*)

Based on the results of her cost of capital estimation procedures, which she states are confirmed by recent Arizona decisions on water utilities' cost of equity, the Company's witness, Dr. Villadsen, concludes that an 11.75 percent return on equity for the Company is reasonable at 40 percent equity. (Exh. A-15 at 65.) The Company proposes an overall cost of capital for the districts as follows:

| | Percentage | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt | 58.6% | 5.45% | 3.19% |
| Common Equity | 41.4% | 11.75% | 4.86% |
| Weighted Average Cost of Capital | | | 8.06% |

2. RUCO

RUCO's witness performed a DCF analysis and a CAPM analysis using a proxy group of water utilities and natural gas LDCs. RUCO's proxy group of water utility companies includes American States Water Company, Aqua America, Inc., California Water Service Group, and Southwest Water Company. (Direct Testimony of RUCO witness William A. Rigsby, Exh. R-12 at 21.) RUCO's witness states that these proxy companies face the same types of risk that Arizona-American faces. (*Id.*) RUCO excluded from its water company proxy group two additional companies that Dr. Villadsen used in her DCF analysis, Middlesex Water Company and York Water Company, and excluded two other companies that she used in her CAPM and ECAPM analyses, Connecticut Water Service, Inc., and SJW Corp., because *Value Line* does not provide long-term estimates on return on common equity and share growth for those companies. (*Id.* at 22.) RUCO's natural gas LDC proxy group consists of AGL Resources, Inc., Atmos Energy Corp., Laclede Group, Inc., New Jersey Resources Corporation, Nicor, Inc., Northwest Natural Gas Co., Piedmont Natural Gas Company, South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc. (*Id.* at 23.) RUCO's natural gas LDC sample is larger than Dr. Villadsen's and includes five of the seven LDCs she included in her proxy group. (*Id.*) RUCO excluded two of the companies Dr. Villadsen used, Cascade Natural Gas Corporation and Peoples Energy Corporation, due to acquisition and merger activity involving those companies. (*Id.*)

RUCO's recommended cost of equity is the average of its DCF and CAPM analyses, plus an additional 50 basis points. (*Id.* at 36.) In assessing cost of equity, RUCO compared the capital structures of the water utilities in its proxy group to the capital structure of the Company, and found that the water utilities RUCO used in its proxy on the whole had a lower level of financial risk than the Company because of their overall lower levels of debt. (Exh. R-12 at 55-56). To account for the

discrepancy in perceived risk between the Company and RUCO's proxy, RUCO made a 50 basis point upward adjustment to its recommended cost of equity. (*Id.* at 56.) RUCO made this upward adjustment in addition proposing a hypothetical capital structure, which contains more equity than the Company's actual capital structure. (*Id.*)

RUCO recommends that the Commission adopt its recommended cost of equity of 10.03 percent and weighted average cost of capital of 7.23 percent, as follows:

| | Percentage | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt | 60.0% | 5.37% | 3.22% |
| Common Equity | 40.0% | 10.03% | 4.01% |
| Weighted Average Cost of Capital | | | 7.23% |

3. Staff

In its cost of equity analysis, Staff used the same group of water companies as the Company's witness, with the exclusion of Southwest Water Company and York Water Company. (Direct Testimony of Staff witness Pedro M. Chaves, Exh. S-12 at 14.) Staff chose those six publicly traded water companies because they derive most of their earnings from regulated operations, and they are currently analyzed by both the Standard and the Small and Mid-Cap Editions of *Value Line*. (*Id.*) In reaching its cost of equity estimate, Staff used two versions of the DCF model; a constant growth DCF model,[12] and a multi-stage, or non-constant growth DCF model. (*Id.* at 15-16.) Staff also used the CAPM, with a historical MRP and a current MRP. (*Id.* at 28-32.)

To calculate the dividend yield component of the DCF formula, Staff used a spot stock price instead of a historical average of stock prices, because Staff believes a historical average is stale and representative of underlying conditions that may have changed, and it illogically discounts the most

[12] The constant-growth DCF formula Staff used in its analysis is:

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

where: $K$ = the cost of equity
$D_1$ = the expected annual dividend (*Value Line* Summary & Index 4-27-07)
$P_0$ = the current stock price (the spot stock price after the close of the market May 11, 2007, as reported by *MSN Money*.)
$g$ = the expected infinite annual growth rate of dividends

recent information in favor of less recent information. (*Id.* at 17). The dividend growth component Staff used in its constant-growth DCF model is the average of six different estimation methods, including both historical and projected growth estimates on DPS, EPS, and sustainable growth bases. (*Id.* at 17.) Staff believes that EPS growth is an appropriate consideration for estimating expected dividend growth because dividends are dependent on earnings, and dividend distribution in excess of earnings leads to capital contraction, which is not sustainable in the long run, and is inconsistent with the constant-growth DCF model. (*Id.*) Staff excluded the negative results from the calculation of average growth in EPS for two of the sample companies because negative growth is inconsistent with the DCF model. (*Id.* at 18, fn 8.) In response to Company witness Dr. Villadsen's criticism of Staff's use of historical DPS and EPS growth to calculate dividend growth, Staff responds that if historical DPS and EPS growth, (the two lowest growth components), were to be excluded from the calculation, it would also be appropriate to exclude projected earnings and sustainable growth, (the two highest growth components), in order to maintain a balanced outcome. (Exh. S-13 at 8-9.)

Staff's constant-growth DCF estimate of the cost of equity to the sample water utilities is 8.4 percent, and its multi-stage DCF estimate is 9.5 percent. (Surrebuttal Testimony of Staff witness Pedro M. Chaves, Exh. S-13, Surrebuttal Schedule PCM-2.) Staff averaged the two DCF estimates to reach its overall DCF estimate of 9.0 percent. (*Id.*)

In its historical MRP CAPM analysis, Staff used an estimated risk-free rate of 5.0 percent. (*Id.*) For its current MRP CAPM method, Staff used the spot rate on 30-year U.S. Treasury notes. (*Id.*) Staff's estimated beta for the districts is 0.84. (*Id.*) Staff calculated a historical MRP of 7.6 percent, and a current MRP of 5.2 percent. (*Id.*) Staff's overall CAPM estimate is 10.5 percent, which is an average of the historical MRP CAPM (11.4 percent) and the current MRP CAPM (9.6 percent). (*Id.*)

Staff's average estimate of the cost of equity to the sample water utilities is 9.6 percent, reached by averaging Staff's DCF estimate of 9.0 percent with its CAPM estimate of 10.5 percent. (*Id.*) Mr. Chaves states that financial risk increases as an entity includes a greater proportion of fixed obligation financing in its capital structure, *i.e.*, as it becomes more leveraged. (Exh. S-12 at 12.) Mr. Chaves states that due to the districts' capital structure, their shareholders bear more financial risk

than the shareholders of the sample companies. (*Id.* at 13.) Mr. Chaves states that Staff quantified the effect of the difference in financial risk due to the districts' capital structure, using the methodology developed by Professor Robert Hamada of the University of Chicago, which incorporates capital structure theory with the CAPM. (*Id.* at 35.) Using that methodology, Staff calculated a financial risk adjustment of positive 80 basis points, which, when added to Staff's cost of equity estimate for the sample companies, results in Staff's recommended cost of equity of 10.6 percent. (Exh. S-13 at 2.) Staff originally calculated a 70 basis point Hamada adjustment, but subsequently increased the adjustment to 80 basis points to account for the fact that a rational investor, when seeing the $8.56 million associated with the Tolleson Agreement on the Company's balance sheet, would consider it additional risk. (Staff Reply Br. at 9, 11.)

Staff states that the Company's ATWCC methodology, using market-value capital structures in order to determine rates of return, has not been extensively used or reviewed in the regulatory environment, is inconsistent with the practice known to investors that regulators authorize returns on the book value of property devoted to public service, and has been rejected by this Commission in prior proceedings. (Staff Br. at 25, Staff Reply Br. at 11.) Staff argues that authorization of returns on equity to match a market value, when the market value differs from book value, only serves to maintain stock prices, which is not the mandate of the Commission. (Exh. S-13 at 8.)

Staff recommends adoption of its 10.6 percent cost of equity estimate, for a 7.5 percent weighted average cost of capital, as follows:

| | **Percentage** | **Cost** | **Weighted Cost** |
|---|---|---|---|
| Long-term Debt | 61.5% | 5.5% | 3.4% |
| Common Equity | 38.5% | 10.6% | 4.1% |
| Weighted Average Cost of Capital | | | 7.5% |

4. Discussion

The Company states that finding the correct growth rate or rates is the "hard part" of a DCF application (Exh. A-15 at 38), and Staff states that the growth factor is the most controversial aspect of a DCF analysis. (Exh. S-13 at 8.) Dr. Villadsen is critical of Mr. Chaves' use of historical EPS and

DPS inputs in its estimation of growth rates. She believes that historical data are incorporated in analysts' forecasts, and that to implement a truly forward looking DCF model, only forward-looking growth rates should be included. (Exh. A-16 at 29.) However, she also states that no publicly available analysts' forecasts provide information beyond at most five years, and consequently, assumptions have to be made regarding the growth rate of companies beyond that horizon. (*Id.* at 23.) Dr. Villadsen chose, for her multi-stage DCF model, a perpetual growth rate based on forecasted GDP. (Exh. A-15 at 38.) Dr. Villadsen believes the use of forecasted GDP mitigates analysts' growth forecasts, which she admits have been optimistic on average in the past. (Exh. A-15 at 40-41.) Staff chose, for its constant-growth DCF model, a methodology that gives equal weight to historical and projected DPS, EPS, and sustainable growth. (Exh. S-12 at 17.) After considering the parties' DCF methodologies, we find Staff's method of choosing DCF growth rate inputs to be more balanced than the Company's, and more likely than the Company's to dispel the effects of the optimism known to be present in analysts' forecasts.

The Company argues that its ATWCC methodology provides a superior means to account for the Company's financial risk than the risk adjustment methodology employed by Staff and RUCO. We disagree, and find that it would overcompensate the Company for financial risk. Staff appropriately addressed the Company's financial risk by the generally accepted regulatory means of adding basis points to the results of its cost of equity analysis.

For the reasons discussed herein, we find that adoption of Staff's recommendation for a 10.6 percent cost of equity capital is reasonable and should be adopted in this proceeding. Staff's recommendation is based on well-established and widely accepted methodologies for the estimation of cost of equity capital. Based on the record of this proceeding, adoption of Staff's cost of equity capital recommendation results in a just and reasonable return for Arizona-American.

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### C. Cost of Capital Summary

| | Percentage | Cost | Weighted Cost |
|---|---|---|---|
| Long-term Debt | 61.5% | 5.5% | 3.4% |
| Common Equity | 38.5% | 10.6% | 4.1% |
| **Weighted Average Cost of Capital** | | | **7.5%** |

## VIII. AUTHORIZED INCREASE

Based on our findings herein, we determine that Arizona-American's Sun City Wastewater District's gross revenue should increase by $1,348,830, and Arizona- American's Sun City West Wastewater District's gross revenue should increase by $1,067,148.

Sun City Wastewater

| | |
|---|---|
| Fair Value Rate Base | $12,349,585 |
| Adjusted Operating Income | 108,358 |
| Required Rate of Return | 7.5% |
| Required Operating Income | 926,219 |
| Operating Income Deficiency | 817,861 |
| Gross Revenue Conversion Factor | 1.6492 |
| Gross Revenue Increase | $ 1,348,830 |

Sun City West Wastewater

| | |
|---|---|
| Fair Value Rate Base | $16,331,876 |
| Adjusted Operating Income | 580,908 |
| Required Rate of Return | 7.5% |
| Required Operating Income | 1,224,891 |
| Operating Income Deficiency | 643,982 |
| Gross Revenue Conversion Factor | 1.6571 |
| Gross Revenue Increase | $ 1,067,148 |

## IX. RATE DESIGN

Decision No. 67093 (June 30, 2004) ordered as follows:

> IT IS FURTHER ORDERED that the next rate case filings for the Sun City West, Sun City and Anthem/Agua Fria wastewater Districts shall include a rate design proposal that presents information on 1) whether wastewater rates based on water consumption encourage water conservation; 2) whether higher bills for those who use the system more is a fairer way to collect revenue; and 3) what tiered wastewater rates based on water consumption would look like compared to a flat rate design.

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

JEFF HATCH-MILLER, Chairman
WILLIAM A. MUNDELL
MIKE GLEASON
KRISTIN K. MAYES
BARRY WONG

Arizona Corporation Commission
DOCKETED
DEC - 5 2006
DOCKETED BY nr

EXHIBIT
RUCO-1
ADMITTED

IN THE MATTER OF THE APPLICATION OF BLACK MOUNTAIN SEWER CORPORATION, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.

DOCKET NO. SW-02361A-05-0657

DECISION NO. 69164

**OPINION AND ORDER**

DATE OF HEARING: June 7, 8, 9, and 20, 2006

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

APPEARANCES: Jay Shapiro, FENNEMORE CRAIG, P.C., on behalf of Black Mountain Sewer Corporation;

Daniel Pozefsky, on behalf of the Residential Utility Consumer Office;

David W. Garbarino, MOHR, HACKETTT, PEDERSON, BLAKLEY & RANDOLPH, P.C., on behalf of Intervenor Town of Carefree;

Robert Williams, on behalf of Intervenor Boulders Homeowners Association; and

Keith Layton, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

**BY THE COMMISSION:**

On September 16, 2005, Black Mountain Sewer Corporation ("BMSC" or "Company") filed an application with the Arizona Corporation Commission ("Commission") for a rate increase. BMSC currently provides wastewater service to approximately 1,957 customers in and around Carefree, Arizona, 1,836 of which are residential customers and 121 are commercial (Ex. A-4, at 3).

BMSC's current rates and charges were authorized in Decision No. 59944 (December 26,

1996) for Boulders Carefree Sewer Corporation ("Boulders Carefree"). In 2001, the common stock of Boulders Carefree was acquired by Algonquin Water Resources of America ("AWRA"), which is a wholly owned subsidiary of Algonquin Power Income Fund ("APIF"). APIF owns energy, water and wastewater, and related assets of approximately $800 million in the United States and Canada. In Arizona, APIF owns seven water and wastewater companies serving approximately 50,000 customers[1]. APIF also owns 10 other water and wastewater utilities in Texas, Illinois, and Missouri (Ex. A-4, at 3; Ex. A-5, at 2-3).

On September 26, 2005, the Residential Utility Consumer Office ("RUCO") filed an Application to Intervene, which was granted by Procedural Order issued October 7, 2005.

On October 14, 2005, the Commission's Utilities Division ("Staff") filed a Deficiency Letter, stating that the application did not meet the sufficiency requirements set forth in A.A.C. R14-2-103 because the Company had failed to include a cost of service study with its application. The Deficiency Letter also stated that Staff would not require a cost of service study if BMSC provided the information attached to the Letter.

On October 28, 2005, a Procedural Order was issued addressing an agreement between the Company and Staff whereby the application would be deemed sufficient, subject to the condition that the information requested by Staff must be submitted within 60 days of a Procedural Order approving the Stipulation, and failure to submit the required information would result in suspension of the applicable time clock. The Procedural Order declined to approve the Stipulation between BMSC and Staff, on the basis that such approval would require an advance determination of the Commission's time clock rule in the absence of a factual justification being presented.

On November 1, 2005, Staff issued a Letter of Sufficiency and classified BMSC as a Class B utility.

On November 2, 2005, a Procedural Order was issued setting a hearing to commence on June 7, 2006, directing the Company to publish and mail notice of the hearing, and establishing other procedural deadlines.

[1] In addition to BMSC, AWRA also controls in Arizona Bella Vista Water Company, Litchfield Park Service Company, and Gold Canyon Sewer Company (Ex. S-13). AWRA added Northern Sunrise Water Company and Southern Sunrise Water Company after the close of the hearing (Decision No. 68826 – June 29, 2006).

On December 30, 2005, BMSC filed a "simplified cost of service study" as requested by Staff.

On January 24, 2006, BMSC filed a Certification of Publication and Proof of Mailing, attesting to compliance with the notice requirements set forth in the November 2, 2005 Procedural Order.

On February 14, 2006, Robert Williams filed a letter requesting intervention on behalf of the Boulders Homeowners Association ("Boulders HOA" or "HOA").

On February 16, 2006, the Town of Carefree ("Town" or "Carefree") filed an Application to Intervene.

On February 21, 2006, M. M. Schirtzinger filed a letter requesting intervention as an individual customer of BMSC.

On March 8, 2006, a Procedural Order was issued granting intervention to the Boulders HOA, Carefree, and M. M. Schirtzinger.

With its application, BMSC filed the Direct Testimony of Michael Weber and Thomas Bourassa.

On March 9, 2006, Staff filed the Direct Testimony of Crystal Brown, Marlin Scott, Jr., and Pedro Chaves; RUCO filed the Direct Testimony of William Rigsby and Marylee Diaz Cortez; and Carefree filed Affidavits of Stan Francom, Jonathon Pearson, and Jason Bethke, as well as several attachments.

On April 6, 2006, BMSC filed the Rebuttal Testimony of Michael Weber, Joel Wade, and Thomas Bourassa.

On May 4, 2006, Staff filed the Surrebuttal Testimony of Marlin Scott, Jr., and Pedro Chaves; RUCO filed the Surrebuttal Testimony of William Rigsby and Marylee Diaz Cortez; and Carefree filed the Surrebuttal Testimony of Stan Francom and Jonathon Pearson.

On May 5, 2006, Staff filed the Surrebuttal Testimony of Crystal Brown.

On May 26, 2006, BMSC filed the Rejoinder Testimony of Joel Wade and Thomas Bourassa.

On June 2, 2006, BMSC filed a Motion to Strike Affidavit of M. M. Schirtzinger, dated May 31, 2006, based on the failure to file the statement within the timeframe established for intervenor

testimony[2].

A prehearing conference was conducted on June 5, 2006.

The hearing commenced on June 7, 2006, and additional hearing days were held on June 8, 9, and 20, 2006.

On June 15, 2006, Staff filed updated Surrebuttal Schedules.

On July 26, 2006, Staff filed Post-Hearing Recommendations based on documentation provided by the Company on June 22, 2006. The adjustments to Staff's recommendations were presented to reflect Staff witness Crystal Brown's testimony during the hearing that Staff would review its position on several items if the Company could support its position with documentation. The adjustments recommended by Staff are reflected in Staff's final schedules attached to its Post-Hearing Brief.

Initial Post-Hearing Briefs were filed on August 18, 2006 by the Boulders HOA, and on August 21, 2006 by BMSC, Staff, RUCO, and Carefree.

Reply Briefs were filed on September 5, 2006 by BMSC, Staff, RUCO, Carefree, and the Boulders HOA.

**Rate Application**

According to the Company's application, as modified, in the test year ended December 31, 2004 BMSC had adjusted operating income of $11,595 on an adjusted Fair Value Rate Base ("FVRB") and Original Cost Rate Base ("OCRB") of $1,568,502, for a 0.74 percent rate of return. Pursuant to its final schedules, BMSC requests a gross revenue increase of $256,063 (21.54 percent). Staff recommends a gross revenue increase of $250,195 (20.76 percent), and RUCO recommends an increase of $5,470 (0.45 percent). A summary of the parties' final revenue requirement positions follows[3]:

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[2] Docket Control records do not reflect that an Affidavit was filed on May 31, 2006, and M. M. Schirtzinger did not appear at the hearing. Mr. Williams, appearing on behalf of intervenor Boulders HOA, did not submit pre-filed testimony but was given the opportunity to present a statement in the public comment portion of the hearing (Tr. 30-44). Mr. Williams also posed cross-examination questions to various witnesses during the hearing.

[3] Intervenors Carefree and the Boulders HOA raised only non-revenue requirement issues (*i.e.*, odor problems) which are discussed below.

| | Company Proposed | Staff Proposed | RUCO Proposed |
|---|---|---|---|
| FVRB/OCRB | | | |
| Adjusted Rate Base | $1,568,502 | $1,550,710 | $1,372,834 |
| Rate of Return | 11.00% | 9.60% | 9.45% |
| Req'd Operating Inc. | 172,535 | 148,868 | 129,733 |
| Op. Income Available | 11,595 | 4,819 | 125,730 |
| Operating Inc. Def. | 160,940 | 144,049 | 4,003 |
| Rev.Conver. Factor | 1.5911 | 1.73688 | 1.3663 |
| Gross Rev. Increase | 256,063 | 250,195 | 5,470 |

## REVENUE REQUIREMENT

**Rate Base Issues**

As indicated above, BMSC proposes an OCRB of $1,568,502; Staff proposes an OCRB of $1,550,710; and RUCO proposes an OCRB of $1,372,834. Each of the disputed issues regarding rate base items is discussed below.

Accumulated Deferred Income Taxes

Accumulated deferred income taxes ("ADIT") reflect the timing difference between when income taxes are calculated for ratemaking purposes and the actual federal and state income taxes paid by the Company. The timing difference is primarily due to the fact that straight line depreciation is used for ratemaking purposes, whereas accelerated depreciation is used for income tax reporting purposes (Ex. S-9, at 19). According to Staff witness Crystal Brown, the Statement of Financial Accounting Standards ("SFAS") No. 109, Accounting for Income Taxes, requires companies to use deferred tax accounting to recognize income tax timing differences.

Ms. Brown stated that although BMSC did not initially reflect an ADIT liability in its application, in response to a RUCO data request the Company stated that it had a deferred income tax credit (liability) of $360,000. However, BMSC's response also indicated that it had a deferred tax asset of $524,000 resulting from the Company's advances in aid of construction ("AIAC") account. According to Staff, the net difference between the $360,000 deferred tax liability and the $524,000 deferred tax asset, is a net deferred tax asset of $164,000, and therefore an increase to the Company's rate base of that amount (*Id.* at 20-21).

RUCO witness Marylee Diaz Cortez disagrees with the Company's and Staff's proposed

ADIT asset and RUCO instead recommends an ADIT liability of $161,250 (reduction to rate base). RUCO's recommendation is based on BMSC's parent company's (APIF's) 2004 Annual Report, which reflects a net tax liability. RUCO developed its proposal in this case by allocating BMSC's portion of the tax liability based on the ratio of the price paid by APIF for BMSC's stock compared to APIF's total assets (RUCO Ex. 12, at 4-7; Tr. 417-418). Ms. Diaz Cortez stated that utility companies "almost unfailingly create net deferred tax liabilities" (RUCO Ex. 12, at 4).

Whether other utilities normally report net deferred tax liabilities is not a controlling factor in determining whether BMSC should have a net asset or liability in this case. BMSC's ultimate parent, APIF, controls myriad companies (*see, e.g.* Ex. S-13) and the fact that its Annual Report reflects a net deferred tax liability is not necessarily indicative of whether its individual subsidiaries have a net liability or asset on their respective books. As Mr. Bourassa explained, "[w]hen a significant amount of plant has been financed by CIAC [contributions in aid of construction] and AIAC, or when there are net operating losses, DIT assets are common" (Ex. A-2, at 4). We agree with the Company and Staff that BMSC properly included $164,000 as a net deferred income tax asset for purposes of setting rates in this case.

Cash Working Capital

Cash working capital represents the amount of cash a company must have on hand to pay its bills when they are due (Tr. 386). All parties agree that using a lead/lag study, which measures the timing of funds received compared to expenses paid, is the most accurate method of determining cash working capital.

In this case, BMSC did not conduct a lead/lag study. In its application, BMSC calculated a positive cash working capital requirement of $130,508, based on the "formula method." The formula method calculates cash working capital based on one-eighth of the Company's operating expenses less depreciation, taxes, purchased water, and purchased pumping power expense, plus one twenty-fourth of purchased water and purchased pumping power expense (Ex. S-9, at 23).

In her direct testimony, Staff witness Crystal Brown stated that use of the formula method is not appropriate for BMSC and is, in general, appropriate only for Class D and E utilities that do not have the resources to conduct a lead/lag study (*Id.*). Ms. Brown indicated that, "[h]ad a lead-lag

study been conducted, it might have shown that Cash Working Capital is a negative component of rate base" (*Id.* at 24). Therefore, Staff recommended removal of BMSC's proposed working capital requirement, in effect resulting in a zero working capital requirement (*Id.*). On rebuttal, Company witness Bourassa accepted Staff's zero working capital recommendation (Ex. A-2, at 11).

RUCO believes that BMSC has a negative cash working capital requirement because the Company "receives its revenues prior to having to pay its expenses" (RUCO Ex. 12, at 8). According to RUCO witness Diaz Cortez, unlike many utilities that bill after service is rendered, BMSC customers are required to pay for service in a given month prior to receiving an entire month of service. Ms. Diaz Cortez testified that the formula method assumes that there exists an average lag of 45 days for operating and maintenance ("O&M") expenses, and an average lag of 15 days for purchased power expenses. Ms. Diaz Cortez stated that RUCO performed a modified lead/lag study in which a sampling of actual customer bills was reviewed showing the service period, bill date, and payment due date (*Id.*). Based on this review, RUCO calculated an average revenue collection lead of 7.83 days (Tr. 382). RUCO also used the formula method's 45 lag days for O&M expenses and 15 lag days for purchased power expenses, which the Company was initially advocating in this case and, based on its analysis proposes a negative cash working capital for BMSC of $87,253 (RUCO Ex. 11, at 14).

We agree with RUCO's negative working capital proposal in this proceeding based on its analysis which, while not as accurate as a full scale lead/lag study, provides a more accurate representation of BMSC's actual cash working capital situation. Although BMSC argues in its brief that "RUCO has not met its burden of proof" on this issue (BMSC Reply Brief at 10), it is the Company which has failed to sustain its burden of presenting evidence to support its zero working capital proposal as a more accurate reflection of BMSC's actual working capital requirement. BMSC is critical of RUCO's acceptance of 45 O&M lag days and 15 purchased power lag days, yet its own witness initially proposed using the formula method, which employs those very estimates (Tr. 126-127). We therefore adopt RUCO's proposal regarding the working capital issue.

Scottsdale Treatment Capacity

In order to serve its approximately 2,000 customers, BMSC currently operates one 120,000

gallon per day ("gpd") wastewater treatment facility located near the Boulders Resort. The remainder of the Company's wastewater flows are diverted into the City of Scottsdale's ("City" or "Scottsdale") wastewater treatment system and ultimately delivered to the City of Phoenix Regional 91st Avenue Wastewater Treatment Plant (Ex. A-4, at 3).

In order to divert wastewater flows into Scottsdale's system, BMSC's predecessor, Boulders Carefree, entered into a 20-year Agreement with Scottsdale in 1996 that allows the Company to deliver up to 1,000,000 gpd to the City (Ex. A-15). According to the Agreement, no "right, title or interest in the other party's utility plant or facilities" is granted to either party (*Id.* at 2).

In the Company's prior rate case, both the Company and RUCO sought to have the amounts paid under the contract treated as plant and included in rate base. However, in Decision No. 59944 (December 26, 1996), the Commission agreed with Staff and treated the debt service on the debt used to fund the Scottsdale treatment capacity as an operating lease, that is included in operating expenses as lease expense (Ex. A-2, at 22). Mr. Bourassa stated that the Commission's treatment of the capacity as a lease expense has resulted in lower rates to customers and lower revenues to the Company compared to a rate base treatment scenario (*Id.* at 25-27). Staff agrees with the Company that the Scottsdale capacity should continue to be treated as a lease expense consistent with the Commission's prior Order (Ex. S-9, at 32-33).

RUCO claims that the operating lease treatment of the Scottsdale capacity costs was a "fallacy" in 1996, and is an even greater fallacy now because of BMSC's acquisition of Boulder Carefree (RUCO Ex. 11, at 3-4). Ms. Diaz Cortez contends that because the original capacity was purchased with a loan from Boulders Carefree's parent, and because BMSC's acquisition was financed with equity from AWRA, there is no basis for continuing to treat the capacity as an operating lease because to do so would not provide a credit to ratepayers for capacity that is already paid for (*Id.* at 7).

We disagree with RUCO's proposed treatment of the Scottsdale treatment capacity. As Mr. Bourassa points out, if rate base treatment of the Scottsdale capacity costs had been approved in the Company's prior rate case, the revenue requirement would have included a return on and of the capacity costs, thereby resulting in significantly higher rates in the interim period since the last case.

In this case, RUCO's proposal to accord rate base treatment to the capacity rights would result in a reduction to the Company's revenue requirement because the original cost of the Scottsdale capacity has been amortized. To switch ratemaking treatment after more than a decade, would be arbitrary and inherently unfair to the Company. We therefore reject RUCO's position on this issue.

Gross-Up Factor for Income Taxes

With respect to the income tax effect for the Scottsdale capacity operating lease, the Company proposed to include $27,801 in operating expenses as a gross-up for income taxes. Under the Company's proposal, income taxes would be included on the principal amount of loan payments for the Scottsdale treatment capacity agreement (Ex. S-9, at 32).

Staff recommended a treatment that does not require a gross-up factor and which Staff believes is a simpler and cleaner method. Under Staff's proposal, the loan payments would not be included in the ratemaking calculation of taxable income, which would result in a higher taxable income and an offsetting, higher income tax expense to be included in rates (*Id.*). Staff argues that the Company's method would understate income tax expense, and adoption of Staff's recommendation would result in a more realistic level of income taxes expense for ratemaking purposes (*Id.* at 33).

The Company did not brief this issue and we assume that it therefore accepts Staff's proposed treatment of this issue. We will adopt Staff's recommendation.

Summary of Rate Base Adjustments

Based on the foregoing discussion, we adopt an adjusted OCRB and FVRB of $1,472,969 for BMSC in this proceeding.

| | Commission Approved |
|---|---|
| OCRB | |
| Plant in Service | $8,630,686 |
| Less: Accumulated Depreciation | 4,331,129 |
| Net Plant in Service | 4,299,557 |
| Deductions: | |
| AIAC | 1,311349 |
| CIAC | 4,857,632 |
| Less: Accumulated Amortization | 3,256,134 |
| Net CIAC | 1,601,498 |
| Total AIAC and CIAC | 2,912,847 |

| | |
|---|---|
| ADIT | 164,000 |
| Additions: | |
| Prepayments | 9,512 |
| Working Capital | (87,253) |
| Total OCRB | $1,472,969 |

**Operating Income Issues**

In the test year, the Company's adjusted operating revenues were $1,205,452. In its final schedules, BMSC reported adjusted test year operating expenses of $1,221,973, and test year net operating income of negative $14,233. As set forth in its final schedules, Staff's proposed adjusted test year operating expenses are $1,200,633, resulting in test year operating income of $4,819. RUCO's schedules show proposed adjusted test year total operating expenses of $1,083,477, yielding test year operating income of $129,733. The disputed expense adjustments are discussed below.

Property Tax Expense

The Arizona Department of Revenue ("ADOR") determines the value of utility property for tax purposes using a formula that is based on the utility's historical revenues. BMSC and Staff propose to follow a line of recent Commission decisions to use adjusted test year revenues in the application of the ADOR formula in order to determine the allowable property tax expense in this proceeding (*See, e.g.*, *Chaparral City Water Company*, Decision No. 68176 (September 30, 2005); *Rio Rico Utilities Co.*, Decision No. 67279 (October 5, 2004); *Arizona-American Water Company*, Decision No. 67093 (June 30, 2004); *Bella Vista Water Company*, Decision No. 65350 (November 1, 2002); *Arizona Water Company*, Decision No. 64282 (December 28, 2001)). RUCO continues to disagree with the Commission's use of adjusted test year revenues in the application of the ADOR formula for estimating property tax expense for ratemaking purposes, and argues as it has in a number of prior cases that only historical revenues should be used (RUCO Ex. 13, at 13-17).

RUCO compared the results of its methodology, based on the Company's historical revenues for the test year, and the two years prior, with the results of the Commission's methodology. RUCO contends that since its methodology more accurately predicted the actual 2005 assessment, the Commission should adopt its approach on this issue (*Id.* at 15).

We once again disagree with RUCO's position. Consistent with numerous prior decisions, we do not believe RUCO's backward-looking methodology properly recognizes that, barring

extraordinary circumstances, any increase granted in this case will increase the Company's property taxes. As we stated in the *Chaparral City* case cited above, "RUCO's calculation methodology, which uses only historical revenues, unfairly and unreasonably understates property tax expense, and is therefore inappropriate for ratemaking purposes" (Decision No. 68176, at 14). RUCO has not demonstrated a basis for departure from our prior determinations on this issue and we will therefore adopt the recommendations of the Company and Staff to follow Commission precedent and use adjusted test year revenues in determining property tax expense.

Rate Case Expense

In its direct case, BMSC estimated rate case expense in the amount of $120,000, but indicated that it would true-up costs as the case progressed (Ex. A-1, at 10-12). On rebuttal, Mr. Bourassa adjusted the Company's estimated rate case expense upward, to $150,000, which would be amortized over four years. Mr. Bourassa claimed that the additional rate case expense allowance is justified because the Company has incurred additional expenses due to the intervention of Carefree and the Boulders HOA, as well as more extensive discovery than expected by Staff and RUCO (Ex. A-2, at 31-32). BMSC attached to its Opening Brief an exhibit (Brief Exhibit 3) that purports to show that it had incurred actual rate case expenses of more than $194,000 through the end of July 2006, prior to the filing of briefs in this case.

Staff recommends that the Company be allowed rate case expense of $124,800, amortized over four years. Staff witness Brown stated that the additional $4,800 over the Company's original estimate is sufficient to cover any additional expenses incurred by the Company to address the issues raised by the Town's and Boulders HOA's intervention (Ex. S-10, at 16-18). Ms. Brown testified that the $4,800 figure is based on a $400 hourly rate, multiplied by an additional 24 hours that Staff believes is sufficient to address intervenor issues, less removal of half of the additional amount "to reflect only the amount that customers should pay" (*Id.* at 18).

RUCO witness William Rigsby filed testimony recommending recognition of only the Company's original estimate of $120,000, amortized over four years. Mr. Rigsby stated that RUCO found the original estimate to be reasonable and "decided that the prudent approach would be to wait until a final figure can be accurately calculated and compared to the Company's request" (RUCO Ex.

13, at 17). However, once the Company presented an updated estimate of rate case expenses due primarily to odor issues raised by the intervenors, RUCO continued to propose that only the original $120,000 estimate should be recognized.

We believe the Company has justified recognition of its proposed rate case expense of $150,000 in this proceeding. Mr. Bourassa testified that BMSC had incurred actual rate case expenses of approximately $115,000 through April 2006, more than a month before the evidentiary hearing commenced and several months before post-hearing briefs were prepared (Ex. A-3, at 19). We believe that the Company's $150,000 rate case expense represents a reasonable allowance under the facts and circumstances of this case and is consistent with rate case expense allowances in other proceedings. *See, e.g., Arizona-American Water Company* ($419,000), Decision No. 67093 June 30, 2004); *Arizona Water Company* ($250,000), Decision No. 66849 (March 19, 2004). To hold a company strictly to its original estimate, regardless of intervening events, would create an incentive for over-estimating costs on the front end rather than attempting to provide a good faith estimate subject to reconciliation based on actual events. We do not believe Staff's or RUCO's proposals provide adequate recognition of the additional costs incurred by BMSC in prosecuting its rate case and we will therefore adopt the Company's position on this issue.

Removal of Legal Costs

Staff witness Brown recommended removal from test year expenses of $3,228 in legal costs associated with negotiating an operating agreement with Carefree. She proposed, instead, that the legal costs should be capitalized and amortized over the life of the agreement (Ex. S-9, at 31). The Company did not oppose Staff's recommendation and we will therefore adopt Staff's position.

Affiliate Company Profits

As described above, AWRA [Algonquin Water Resources of America, Inc.] is a wholly owned subsidiary of APIF [Algonquin Power Income Fund]. In Arizona, AWRA owns and operates Black Mountain Sewer Corporation, Bella Vista Water Company, Litchfield Park Service Company, Gold Canyon Sewer Company, Northern Sunrise Water Company and Southern Sunrise Water Company.

AWRA employs an organizational model that is unique in Arizona. AWRA, BMSC's sole

shareholder, has no employees. BMSC, as well as all of the other regulated utility companies listed above, have no employees. Instead, almost all operational services are provided by an allegedly unregulated affiliate called Algonquin Water Services ("AWS") that has between 70 and 90 employees and which, apparently, provides similar services received by the regulated public service corporations owned by Algonquin in Arizona, including BMSC (Tr. 529-530)[4]. The written contract that exists between BMSC and AWS for provision of wastewater services was not negotiated, but was based on a template that is used by the Algonquin Power System to manage its hydroelectric plants in Canada (Tr. 510).

Staff's Position

Based on its analysis, Staff recommends that the Commission disallow $20,871 that the Company is seeking in rate base for capitalized affiliate profit, and $21,761 the Company seeks to recover in operating expenses for affiliate profit (Staff Ex. 9, at 27; Staff Br. Sched. CSB-6)[5]. Staff points out that BMSC has in effect turned over the entirety of its operations and management to an (allegedly) unregulated affiliate, and that the affiliate's shareholders have imposed a contract on BMSC, without negotiation, that provides the affiliate with guaranteed profits at the expense of BMSC's captive ratepayers (Ex. S-10, at 4-5). Ms. Brown stated that BMSC's affiliate is essentially operating as an unregulated monopoly based on the Company's claims that there are no other companies or individuals that could provide comparable services to BMSC[6]. Ms. Brown dismissed the Company's claims that the affiliate arrangement resulted in $222,000 in savings as unsupported assertions but, regardless of savings, Staff contends that it is reasonable for the affiliate to recover only the reasonable actual costs from customers (*Id.* at 7-8). Staff also asserts that there may be additional affiliate profit that it was unable to specifically identify. As an example, Staff cites to a billing rate for a "general manager" of $150 per hour that was charged to BMSC by its affiliate. Ms.

[4] Staff witness Crystal Brown indicated that, during the test year, the Company was billed $275,460 by AWS, $32,017 by Algonquin Power Trust, and $27,311 by Algonquin Power Systems, for a total of $332,604 in billings by the Company's affiliates (Ex. S-9, at 26).

[5] The capitalized affiliate profit represents 8 percent of project costs billed to BMSC and, for operating expenses the affiliate billings included a 6.5 percent profit (*Id.*; Ex. A-2, at 17).

[6] As evidence of the potentially manipulative effect of affiliate control, Ms. Brown pointed out that the affiliate increased its management fees to BMSC from $7,500 per month in 2003 to $13,062 per month in 2004, the test year (Ex. S-10, at 6).

Brown stated that the $150 hourly rate equates to $312,000 on an annual basis to perform management duties for BMSC (*Id.* at 8).

In support of its recommended disallowance of capitalized and expensed affiliate profits, Staff argues that the record supports piercing the corporate veil and treating all of the Algonquin affiliates as a single entity. Staff cites to a prior case involving *Consolidated Water Utilities, LTD*, Decision No. 57666 (December 19, 1991), wherein the Commission stated: "We do not believe it is appropriate for ratepayers to pay a profit margin for each layer of related companies. Hence we totally agree with Staff that all of the profit margin of CUC should be disallowed as part of the allocation." (*Id.* at 18-19). Staff also cites *Walker v. Southwest Mines Development Co.*, 52 Ariz. 403, 81 P.2d 90 (1938), wherein the Arizona Supreme Court stated:

> [W]hen one corporation so dominates and controls another to make that other a simple instrumentality or adjunct to it, the courts will look beyond the legal fiction of distinct corporate existence, as the interests of justice require; and where stock ownership is resorted to not for the purpose of participating in the affairs of the corporation in the customary and usual manner, but for the purpose of controlling the subsidiary company so that it may be used as a mere agency or instrumentality of the owning company, the court will not permit itself to be blinded by mere corporate form, but will, in a proper case, disregard corporate entity, and treat the two entities as one.[7]

According to Staff, the case of *Deutsche Credit Corp. v. Case Power & Equip. Co.*, 179 Ariz. 155, 876 P.2d 1190 (App. 1994), provides additional support for this view. In that case, the Arizona Court of Appeals quoted *Jabczenski v. Southern Pacific Memorial Hospital, Inc.*, 119 Ariz. 15, 21, 579 P.2d 53, 59 (App. 1978), as follows:

> Two corporations can be regarded as the same if "[e]ither the dominant corporation ... so control[s] and use[s] the other as a mere tool or instrument in carrying out its own plans and purposes that justice requires it be held liable for the results, or, there [is] such a confusion of identities and acts as to work a fraud upon third persons."

Staff further argues that, pursuant to *Gatecliff v. Great Republic Life Insurance Co.*, 170 Ariz. 34, 37, 821 P.2d 725, 728 (1991), the standard for imposing the alter ego theory requires a showing of unity of control and that the corporate form would sanction a fraud or promote injustice.

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[7] *Id.*, 52 Ariz. At 414-415, 81 P.2d at 95, quoting *Platt v. Bradner Co.*, 131 Wash. 573, 230 P. 633 (Wash. 1924).

Staff also cites a decision by the Washington Utilities and Transportation Commission, in *Washington Water Power Co.*, 24 P.U.R. 4th 427 (at page 13) (1978), in which the Washington Commission, citing *Mississippi River Fuel Corp. v. Federal Power Comm'n*, 102 US App 238, 252 F.2d 619 (D.C. Cir. 1957), made the following finding:

> [T]he clearly stated concern appears to be not the level of price at which the transaction is accomplished in comparison with prices in nonaffiliated transactions, but instead a level of earnings by the unregulated arm of the utility at a rate higher than the utility is authorized and would be allowed to achieve if no corporate device were utilized. In effect, the courts approve for rate-making purposes the placement of a 100 percent affiliate in the same position as an integrated [part] of a utility.

Based on these decisions, as well as several others cited in its Brief, Staff claims that the corporate veil should be pierced to avoid an injustice. Staff points to the fact that neither BMSC nor AWRA have any employees and, as a result, the Algonquin affiliates provide virtually all of the services needed to serve the Company's customers; contracts between BMSC and AWC are presented to the Company without negotiation based on a template provided by the ultimate parent, APIF; that AWS was "specifically created" to provide the majority of services to BMSC; and the vice-president and general manager of AWS directs day-to-day management and operations of the water and wastewater systems owned by AWRA (including BMSC) (Ex. A-5, at 1). Staff asserts that the record supports the conclusion that BMSC is merely an agency or instrumentality of the Algonquin affiliates, and the corporate structure created by the Algonquin companies results in an injustice to ratepayers by creating a layer of profit that is inconsistent with Arizona's regulatory ratemaking standards.

Finally, Staff expressed concern with BMSC's suggestion in this case that, if the Commission disallows the Company's requested affiliate profit request, Algonquin will reorganize its corporate structure in a manner that will be more costly to ratepayers. As described in the Company's testimony, "[e]ither operating expenses increase because BMSC will have to hire personnel to perform all of the essential services or many of the services that benefit the Company and ratepayers will not be provided. There really is no other possible outcome because AWS is not going to stay in business if it cannot realize a return on its investment." (Ex. A-5, at 5). Staff requests that the

Commission make a finding in this Decision that it expects AWRA to operate its affiliate companies as efficiently as possible.

BMSC's Position

The Company contends that Staff's recommendation should be disregarded because common ownership alone is not a sufficient reason to pierce the corporate veil of the Company and its affiliates. BMSC claims that Staff failed to meet the burden of proving its proposal because, once Staff raised the issue of affiliate profit disallowance, the Company presented evidence as to the reasonableness of its affiliate costs. According to Mr. Bourassa, the Company is not aware of any local companies that could provide the type of services supplied by the Algonquin affiliates. However, he indicated that the Company attempted to compare its costs with those of a management services firm and estimated that such a firm would charge approximately $10 to $12 per customer per month, compared to $10 to $11 for the BMSC affiliate (Ex. A-2, at 34). Mr. Bourassa testified that Chaparral City Water Company has operational costs of approximately $14 to $16 per customer and he believed some other companies had costs of more than $18 per customer (Tr. 171-172).

The Company argues that, once this evidence was presented, it was incumbent upon Staff to present evidence showing why BMSC's proposed costs are unreasonable. BMSC claims that Staff could have sought to audit the affiliate companies' books and records, but Staff did not do so. The Company contends that the only evidence in the record shows that bids for comparable services were not available and, in any event, there is no evidence of excessive profits.

With respect to Staff's proposal to pierce the Company's corporate veil, BMSC asserts that the cases cited by Staff stand for the proposition that corporate structures will not be ignored unless they were created for essentially fraudulent purposes. BMSC cites *Arizona Public Service Co. v. Arizona Corp. Comm'n*, 155 Ariz. 263, 267, 746 P.2d 4, 8 (App. 1987), wherein the court declined to pierce the corporate veil because the Commission did not show undercapitalization, fraud, misconduct or impropriety in the management of the affiliated companies. The Company also claims the court in *Deutsche Credit, supra,* held that "[t]he concept of a corporation as a separate entity is a legal fact, not a fiction." *Deutsche Credit* at 160. In addition, BMSC cites *Kearns v. Tempe Technical Institute, Inc.*, 993 F.Supp. 714, 723 (D. Ariz. 1997), in which the court stated that

"corporate status will not be lightly disregarded."

With respect to the *Washington Water Power* case cited by Staff, as well as *Central Louisiana Electric Co.*, 373 So.2d 123 (La. 1979), BMSC argues that the central holding of both cases is that the regulatory commission must assure that rates are just and reasonable, and the evidence presented in this proceeding supports a finding that BMSC's affiliate company expenses are reasonable. The Company also contends that the profit on the affiliated transactions is not guaranteed because all costs are subject to intense scrutiny in the ratemaking process and all costs can go up or down during intervening periods between rate cases. BMSC asserts that Staff has not provided evidence to disprove the reasonableness of the affiliate costs, including the requested profits, and thus Staff's recommendation should be rejected.

RUCO's Position

RUCO did not present testimony or take a position on this issue.

Resolution

We agree with Staff that, at a minimum, the profit component of both capitalized costs and expenses by the BMSC affiliate companies should be disallowed. We will not countenance a corporate shell game that allows companies to hide behind corporate structures in order to avoid scrutiny of what would normally be the function of the regulated public service company. BMSC criticizes Staff's failure to present evidence as to the unreasonableness of the subsidiary costs. Although Staff could have pursued discovery of the affiliate companies, given Staff's heavy caseload and the constraints for processing this matter under the time clock rules, it was not unreasonable for Staff to pursue other means of supporting its recommendation to disallow affiliate company profits.

Presumably, the Algonquin companies conducted a due diligence analysis prior to acquiring BMSC and understood the regulatory framework in Arizona. The rate base/rate of return regulatory scheme provides that, in exchange for being granted an exclusive service territory with monopoly status, public service corporations are granted an opportunity to earn an authorized return on investment used and useful, plus reasonable operating expenses. We believe it is inherently unreasonable for an affiliate company that performs all of the operational functions of the utility company, under a non-negotiated contract, to seek an additional profit margin simply because the

affiliate was structured as a separate corporate entity. The question that must be asked is whether an affiliate company under common ownership and control should be permitted to add an additional layer of profit, and to do what a regulated public service corporation is otherwise legally prohibited from doing (*i.e.*, recover an additional profit margin for its services), based solely on the parent company's decision to create a separate affiliate company. Our answer is a resounding no.

We believe our finding is consistent with the line of cases which indicate regulatory commissions have broad authority to scrutinize transactions between a regulated company and its unregulated affiliates, and to disallow excessive costs. *See, e.g., U.S. West Communications, Inc. v. Arizona Corporation Comm'n*, 185 Ariz. 277, 282, 915 P.2d 1232 (App. 1996); *General Telephone Co. of New York v. Public Service Commission of New York*, 17 N.Y.2d 373, 378 (N.Y. 1966) ("[w]hen a utility and its suppliers are both owned and controlled by the same holding company, the safeguards provided by arm's length bargaining are absent, and ever present is the danger that the utility will be charged exorbitant prices which will, by inclusion in its operating costs, become the predicate for excessive rates."). *See also, State of North Carolina v. Morg*an, 177 S.E.2d 405, 416 (Supreme Court of North Carolina, 1970) ("the doctrine of the corporate entity may not be used as a means for defeating the public interest and circumventing public policy. In order to prevent such a result, a parent corporation and its wholly owned subsidiaries may be treated as one." [citations omitted]); *Washington Water Power, supra,* at page 15, quoting the Public Utilities Commission of Ohio's decision in *Columbus Gas & Fuel Co.*, PUR1933A 337 ("[A] company enjoying the immunities of a public utility has no right to impose upon the consumers a heavier burden than that which would be justly borne, and that will produce a proper rate of return, considering the value of the property devoted to this public service and to the risks involved."). Moreover, as this Commission stated in the *Consolidated Water* case, "[w]e do not believe it is appropriate for ratepayers to pay a profit margin for each layer of related companies....[and] all of the profit margin of CUC [the affiliate company] should be disallowed as part of the allocation." (Decision No. 57666, at 18-19).

We also share the concern raised by Staff that there may be additional profit margins built into the affiliate billings that have not been specifically identified. Because we do not have any

specific record evidence of additional inappropriate profits in this case, we will exclude only the "profits" that have been clearly identified by Staff. In doing so, however, we make no finding as to the reasonableness of the Algonquin affiliate structure and, in future cases involving the Algonquin companies, we expect all affiliate salaries, expenses, and billings to be scrutinized to avoid potential abuses.

Net Operating Income

Consistent with the foregoing discussion, we will allow adjusted test year operating expenses of $1,205,533, which based on test year revenues of $1,205,452, results in test year adjusted operating income of negative $81, for no rate of return on FVRB.

## COST OF CAPITAL

BMSC recommends that the Commission determine the Company's cost of common equity to be 11.0 percent. Staff recommends a cost of common equity rate of 9.6 percent. Both the Company and Staff recommend a capital structure of 100 percent equity and no debt. RUCO proposes a return on equity of 9.49 percent, with a hypothetical capital structure of 43 percent debt and 57 percent equity, resulting in an 8.92 percent weighted cost of capital (RUCO Ex. 14, at 9-10)[8].

Capital Structure

Company witness Bourassa stated that BMSC's capital structure consists of 100 percent equity because, although the Company has $1,184,732 of long-term debt on its books due to acquisition of the Scottsdale treatment capacity, that debt service is included in operating expenses pursuant to prior Commission Order and there is no other long-term debt (Ex. A-2, at 39). Staff agrees with the Company's proposed 100 percent equity capital structure (Ex. S-4, at 6). RUCO, however, proposes the use of a hypothetical structure of 43 percent debt and 57 percent equity (RUCO Ex. 14, at 9-11).

According to Mr. Rigsby, the Commission should adopt a hypothetical capital structure based on the Algonquin parent company's capital structure. Mr. Rigsby claims that adoption of a

[8] Mr. Rigsby recommended that, if the Commission adopts RUCO's position on the Scottsdale capacity issue, the capital structure should be weighted at 44 percent debt and 56 percent equity, with a 9.45 percent weighted cost of capital (RUCO Ex. 14, at 9; Tr. 539). Since we have adopted the Company's position regarding the Scottsdale capacity issue, RUCO's position is as stated above.

hypothetical capital structure is appropriate in this case because his estimate of a 9.49 percent return on common equity ("ROE") was derived from a sample group of companies that have capital structures that consist of approximately 50 percent debt and 50 percent equity. He therefore proposed using the weighted cost of debt reported in APIF's 2004 Annual Report (Tr. 550-553).

We agree with Staff and the Company that a capital structure comprised of 100 percent equity should be used for calculating BMSC's cost of equity capital in this proceeding. Although RUCO proposes using a hypothetical capital structure based on the 2004 APIF Annual Report, its witness admitted that the APIF capital structure would incorporate the debt and equity of a variety of companies under the Algonquin umbrella, including a Canadian waste reclamation company, a hydroelectric company in New Hampshire, and a sewer company in Texas (Tr. 553-554). In fact, the plant in BMSC's rate base is financed entirely by equity. Although there is some long-term debt on the Company's books associated with the Scottsdale treatment capacity, as explained above that debt has been treated as an operating lease for nearly a decade pursuant to prior Commission Decisions and, therefore, there is no plant in rate base associated with the Scottsdale capacity debt. We believe RUCO's hypothetical capital structure recommendation is results oriented and is not consistent with the Company's actual capital structure. We therefore adopt a 100 percent equity capital structure for BMSC in this case.

Cost of Common Equity

Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimation that is both art and science. As evidenced by the competing methodologies employed in this case, and most other rate cases, there is no clear-cut answer as to which formula should be used for reaching the appropriate outcome. Rather, the three expert cost of capital witnesses, Messrs. Bourassa, Chavez, and Rigsby, each rely on various analyses for their recommendations.

BMSC's Position

The Company's expert witness, Mr. Bourassa, based his common equity cost recommendation of 11.00 percent on the results of his discounted cash flow ("DCF") model using six proxy companies (American States Water, Aqua America, California Water, Connecticut Water,

Middlesex Water, and SJW Corp.). Mr. Bourassa employed a risk premium analysis and a comparable earnings analysis as a check on the reasonableness of the DCF results (Ex. A-1, at 13-14; Ex. A-3, at 21-25).

The Company's DCF analysis produced ROE results for the proxy companies ranging from 8.5 to 11.0 percent (Ex. A-3, at 22). Mr. Bourassa's risk premium analysis resulted in an ROE range of 10.2 to 11.0 percent; while the earnings analysis produced results in the 7.8 to 12.7 percent range (*Id.*). He also looked at *Value Line* projections for ROE in the water industry for 2006, 2007, and 2009, and found projected returns of 10.0, 10.5, and 11.5 percent, respectively (*Id.*). BMSC argues that Mr. Bourassa's analysis supports the Company's proposed 11.0 ROE in this case considering BMSC's risks and investor expectations.

BMSC criticizes the recommendations of both Staff and RUCO (9.6 and 9.49 percent ROE, respectively), because the Company claims that Staff and RUCO blindly followed the results of their models without regard for whether their proxy companies are actually comparable in terms of investment risk. The Company contends that the Staff and RUCO recommendations, compared to ROE proposals in prior cases, have not kept pace with rising interest rates over the past several years, thereby producing skewed results. BMSC asserts that the Staff and RUCO analyses ignore firm-specific risk based on their claim that under modern finance theory all risk is reflected in a stock's "beta" (which estimates risk by comparing a stock's volatility relative to the market in which it is traded). The Company argues that the Staff and RUCO beta assumption ignores factors such as firm size; diversification of the utility; regulatory risk; and liquidity risk (Ex. A-2, at 48). BMSC cites additional alleged defects with the Staff and RUCO methodologies, including: the sample group consists primarily of water utilities; only one of the companies in the group has operations in Arizona; the stock of the sample companies is traded on a national exchange; and all but one of the companies has published credit ratings (Ex. A-1, Sched. D-4.1).

BMSC is critical of Staff's use of a multi-stage DCF model, which assumes that earnings and dividend growth will occur in multiple stages, compared to the constant growth version of the DCF model, which assumes constant growth of earnings and dividends (Ex. A-1, at 31). The Company also claims that while its analysis relies on forward-looking growth, Staff's methodology gives a 50

percent weighting to historical growth (1995 to 2005) which produces unrealistic results and depresses the equity cost estimate. BMSC claims that giving a 50 percent weighting to historical growth effectively double counts what has happened in the past, because historical information is already embedded in the stock prices used to calculate the dividend yield (*Id.*).

With respect to Staff's use of the Capital Asset Pricing Model ("CAPM"), the Company asserts that the CAPM is difficult to implement in practice, especially when applied to a small, closely-held firm (*Id.*). The CAPM is calculated using the subject company's beta (measurement of a security's volatility in relation to the market); the risk free rate (the return an investor expects to earn on a theoretical "riskless" investment); and the average market return (from which the market risk premium is calculated). BMSC claims that the 0.74 beta for Staff's six proxy companies (as calculated by *Value Line*) should not be applied to BMSC because it is not publicly traded and has no estimated beta. With respect to the risk free rate selected by Staff (average yield on 5, 7 and 10-year Treasury securities), the Company claims that because a corporation has an indefinite life, the use of intermediate Treasury securities is inappropriate.

According to BMSC, the inputs Staff used in its CAPM produce results that are contrary to the CAPM theory. The Company claims that, although under the CAPM theory cost of equity moves in the same direction as interest rates and estimated beta, Staff's CAPM estimates move in the opposite direction of both interest rates and beta risk. In addition to the alleged application problems perceived by BMSC, the Company contends that the CAPM has empirical shortcomings that invalidate its use for estimating ROE. BMSC cites to several articles in Economics journals to support its claim the CAPM is flawed. The Company argues that the Risk Premium Model ("RPM") is superior to CAPM because under the RPM the risk premium is directly estimated by comparing authorized and actual returns on equity with the current yield of investment grade bonds or other debt instruments.

BMSC is also critical of the RUCO DCF analysis because the Company claims that Mr. Rigsby substituted his own subjective judgment for market data in its DCF model. The Company claims that RUCO used the sustainable growth method to estimate dividend growth, but substituted its witness' subjective dividend growth rate, thereby understating substantially the Company's cost of

equity. BMSC argues that RUCO's witness ignored the actual and forecasted stock financing rates reported in his own schedules.

RUCO's Position

RUCO witness Rigsby based his ROE recommendation on the results of his DCF and CAPM analyses, which ranged from 8.89 percent to 10.69 percent for his sample group of publicly traded water and gas companies. His 9.49 percent ROE recommendation is the result of the DCF analysis, which utilized a sample of publicly traded water companies (RUCO Ex. 14, at 8).

RUCO contends that Mr. Rigsby's DCF model relied on objective estimates of external growth using *Value Line* analyst projections as a guide (RUCO Ex. 15, at 24). RUCO argues that Mr. Rigsby's growth estimates properly recognize that the market price of a utility's common stock will tend to move towards book value if regulators allow a rate of return that is equal to the cost of capital (*Id.* at 19-20). According to RUCO, the Commission recently adopted the same methodology in determining the cost of common equity for Southwest Gas Company in Decision No. 68487 (February 23, 2006).

RUCO asserts that the Company's criticism of the CAPM employed by RUCO and Staff is unfounded. RUCO claims that the Company's risk premium analysis is simply a variation of the CAPM, but the RPM fails to account for the additional market-based information that is included in the CAPM. RUCO contends that the estimated return produced by either the CAPM or the RPM is one of a number of factors that investors take into consideration when evaluating a company's stock. RUCO also argues that, despite *Value Line* projections of lower ROEs for water utilities, the Company made no comparable downward adjustment to its original 11.0 percent recommendation. RUCO claims that its cost of capital recommendation is reasonable and should be adopted by the Commission.

Staff's Position

In formulating its ROE recommendation in this case, Staff employed a constant growth DCF model, a multi-stage DCF model, and a two-part CAPM analysis. The two CAPM estimates were based on an historical market risk premium and a current market risk premium. Staff's DCF model produced a ROE of 9.6 percent; the average of its two CAPM results was 9.5 percent; and the

average of the DCF and CAPM results was 9.6 percent, which is its recommendation in this proceeding. For purposes of its analysis, Staff selected six publicly traded water companies that derive most of their earnings from regulated operations and which are analyzed by *Value Line* publications (Ex. S-4, at 13)[9].

Staff's cost of capital witness, Pedro Chaves, calculated the growth factor for his DCF model by averaging the results of six growth projection methods[10] (*Id.* at 16). Mr. Chavez explained that the most controversial element of a DCF analysis is the choice of inputs for the growth rate. He stated that Staff's use of both historical and projected EPS, DPS and sustainable growth components provide a balanced outcome that avoids a skewed result which could occur if only historical or projected growth results are analyzed (Ex. S-5, at 4).

In response to BMSC's criticisms, Staff contends that its methodologies reflect a properly balanced analysis compared to the Company's proposal. Staff refutes the Company's claim that it blindly followed the results of its models and argues that Mr. Bourassa used professional judgment inappropriately. According to Staff, its inputs were chosen by identifying available market data, and then analyzing whether investors could be expected to rely on such data prior to inputting the data into its models. Staff argues that the Company's methodology, on the other hand, is results oriented in order to produce the highest ROE result possible. Mr. Chaves testified that Staff selects the dates for its inputs before the date occurs, and attempts to use the most recent dates before its testimony is finalized (Tr. 717-718). Staff also disagrees that its CAPM is subject to manipulation, as suggested by the Company, because it picks dates for the inputs without regard to the end result that will fall out from the analysis.

With respect to the Company's criticism that rising interest rates are not reflected in Staff's cost of capital analysis, Staff contends that three of the CAPM variables do not necessarily move in the same direction at the same time. Although Mr. Chaves conceded that there is a relationship between interest rates and the cost of equity capital, he stated that cost of equity would tend to move

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[9] The six proxy companies chosen by Staff are American States Water, California Water, Aqua America, Connecticut Water, Middlesex Water, and SJW Corp. (*Id.*, Sched. PMC-3).

[10] The six methods involve calculations of historical and projected dividends per share ("DPS"), historical and projected earnings per share ("EPS"), and historical and projected sustainable growth (Ex. S-5, Sched. PMC-7).

in the same direction as interest rates only if all other variables are constant (Tr. 684). According to Mr. Chaves, while interest rates increased between the filing of his direct and surrebuttal testimonies from 3.3 to 4.7 percent, Staff's current MRP declined from 13.1 to 5.7 percent, thereby offsetting the interest rate increase (Tr. 719-722).

Staff asserts that the Commission should reject BMSC's proposed 11.0 percent ROE because it is based on inputs that artificially inflate the required return. Staff points out that the Company's DCF results are identical to Staff's DCF results (*i.e.*, 9.6 percent) (Tr. 144). However, Mr. Bourassa excluded Middlesex Water because its cost of equity was only 40 basis points above the projected cost of Baa investment grade bonds (Ex. A-3, Sched.D-4.9). Mr. Chaves stated that he believed the reason for exclusion of Middlesex was insufficient, and if Middlesex were included in the Company's DCF analysis, the overall results would drop from 9.6 to 9.5 percent (Tr. 712-713; Ex. S-8).

Staff argues that the Company's use of the risk premium and comparable earnings analyses, as well as the Company's size, for purposes of inflating its ROE proposal have been rejected by the Commission in the past. *See, e.g., Southwest Gas Corp.*, Decision No. 68487 (February 23, 2006). Staff claims that BMSC's witness used only forecasted EPS growth estimates, while excluding historical DPS, EPS, and forecasted DPS growth. Staff also points out that although his DCF analysis produced a range of 8.5 to 11.0 percent for the sample group of companies, Mr. Bourassa chose the highest point in that range for his ROE recommendation. Staff therefore recommends that the Commission adopt its 9.6 percent cost of capital recommendation in this proceeding.

Conclusion on Cost of Capital

We believe that Staff's recommended cost of capital achieves an appropriate result that is supported by the evidence in the record. Staff's witness' use of the DCF model as the primary basis for determining the Company's reasonable estimated cost of equity capital is a methodology that has been used for many years by this Commission, as well as other regulatory commissions across the country.

With respect to the methodology employed for calculating the return on common equity, we believe Staff's analysis is appropriate and consistent with prior Commission decisions regarding cost of capital. The companies included in Staff's sample group are appropriate because they have

objective data that is publicly available through *Value Line* and other investor publications. We agree with Staff that the Company's proposal to exclude Middlesex Water, because its cost of equity was perceived by the Company to be too low for inclusion in its DCF analysis, is an artificial means of skewing the end result in the Company's favor.

We are not persuaded by the Company's legal arguments that adoption of Staff's cost of equity recommendation would result in a violation of the Commission's authority under the Arizona Constitution, the case law interpreting that authority, or of the *Hope, Bluefield, and Duquesne* decisions[11]. Article 15, Section 3 of the Arizona Constitution provides in relevant part that the Commission "shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein." In determining just and reasonable rates, the Commission has broad discretion subject to the obligation to ascertain the fair value of the utility's property, and establishing rates that "meet the overall operating costs of the utility and produce a reasonable rate of return." *Scates, et al. v. Arizona Corp. Comm'n*, 118 Ariz. 531, 534, 578 P.2d 612 (Ct. App. 1978). Under the Arizona Constitution, a utility company is entitled to a fair rate of return on the fair value of its properties, "no more and no less." *Litchfield Park Service Co. v. Arizona Corp. Comm'n*, 178 Ariz. 431, 434, 874 P.2d 988 (Ct. App. 1994), *citing Arizona Corp. Comm'n v. Citizens Utilities Co.*, 120 Ariz. 184 (Ct. App. 1978). The oft cited *Hope* and *Bluefield* cases provide that the return determined by the Commission must be equal to an investment with similar risks made at generally the same time, and should be sufficient under efficient management to enable the Company to maintain its credit standing and raise funds needed for the proper discharge of its duties.

For the reasons described above, we believe that adoption of Staff's recommendation for a 9.60 cost of equity capital, which is also its overall cost of capital with a 100 percent equity capital structure, complies with these obligations. Staff's expert witness, although primarily relying on the well-established DCF method for calculating his cost of equity capital, also employed two other tests

[11] *Federal Power Commission et al. v. Hope Natural Gas Co.*, 320 U.S. 591 (1944); *Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, et al.*, 262 U.S. 679 (1923); *Duquesne Light Co. v. Barasch*, 488 U.S. 299 (1989).

as a check on the reasonableness of his results. Staff pointed out that the Company's witness arbitrarily excluded one of the companies in his proxy group because inclusion of that company resulted in a lower DCF and ROE result, and thus skewed downward the overall results on his analysis. We believe that adoption of Staff's recommendation results in a just and reasonable return for BMSC based on the record of this proceeding.

We therefore adopt a cost of equity of 9.60 percent, which also results in an overall weighted cost of capital of 9.60 percent.

## AUTHORIZED INCREASE

Based on our findings herein, we determine that BMSC is entitled to a gross revenue increase of $141,486.

| | |
|---|---|
| Fair Value Rate Base | $1,472,969 |
| Adjusted Operating Income | (81) |
| Required Rate of Return | 9.60% |
| Required Operating Income | $141,405 |
| Operating Income Deficiency | 141,486 |
| Gross Revenue Conversion Factor | 1.74051 |
| Gross Revenue Increase | $246,257 |

## RATE DESIGN ISSUES

The current monthly customer charge for residential customers is $38.00 with no commodity charge. Regular commercial customers currently pay $0.15236 per gallon of sewer flow (based on ADEQ Engineering average daily flows for various types of customers), and no monthly service charge. In addition, there are 14 special commercial customers that pay a monthly customer charge only, that varies by customer, based on an estimate for each customer's sewer volume flow (Ex. S-9, at 35; Sched. CSB-24).

As updated in their final schedules, the Company and Staff recommended percentage increases of 21.42 percent and 20.41 percent, respectively, be applied to all customers under their existing rate structures (Co. Final Sched. H3; Staff Brief Sched. CSB-25). RUCO recommended that its proposed revenue requirement be applied under the Company's current rate design.

In accordance with the revenue requirement determined above, the increase will be applied to all classes equally. Accordingly, the current residential rate of $38.00 per month will increase by

20.1 percent, to $45.64, and the regular commercial customer rate will increase from $0.15236 to $0.18298, also an increase of 20.1 percent. The special commercial customer rates will be increased by the same percentage.

Refund of Hook-Up Fee Funds

In her Direct Testimony, Staff witness Crystal Brown stated that BMSC's predecessor was authorized in the Decision in 1980 granting the original Certificate of Convenience and Necessity ("CC&N") to charge a hook-up fee. Ms. Brown indicated that at the time the Company was relatively small and had little ability to attract capital needed to build infrastructure and to fund growth (Ex. S-9, at 36). Use of hook-up fee funds is generally limited to costs associated with building infrastructure to serve growth in the utility's service area.

Ms. Brown also pointed out that, in the Company's last rate case (Decision No. 59944), the Commission stated that the Company's hook-up fee may be rescinded for reasons including, but not limited to, "failure to track and account for hook-up fees, misuse of hook-up fees, or no need for additional capital" (*Id.* at 10). During its investigation in this proceeding, Staff discovered that the Company had purchased computer equipment totaling approximately $142,232, vehicles totaling approximately $20,000, and land totaling $451,000 from the hook-up fees (Ex. S-9, at 35-38). Ms. Brown recommended that these funds be refunded to customers (*Id.*).

In his Rebuttal Testimony, Mr. Bourassa proposed a reduction to CIAC of $833,367 to account for $452,467 of land purchased with hook-up fee funds, and $380,900 for unexpended hook-up fees. The Company agreed that this amount should be refunded to customers. Although BMSC does not agree that the identified amounts for land purchases were improper, it agreed with Staff's recommendation to avoid litigation of the issue (Ex. A-2, at 18-22). As a result, the Company's parent would be required to provide paid in capital of $452,467 to replace the hook-up fees used for land purchases (*Id.*). Regarding the remaining $380,900, the refunds will come from funds held in a restricted cash account (*Id.* at 19).

In her Surrebuttal Testimony, Ms. Brown agreed with the Company's proposed refund amount, but disagreed with the Company's recommendation as to how the individual refunds are to be calculated. She stated that the refunds should be calculated based upon the amount contributed by

each customer class, and that the Company should "propose an equitable way to calculate the CIAC refunds" (Ex. S-10, at 18). She also indicated that the rates from this case should not go into effect until after the refunds are made.

Mr. Bourassa responded that the proposed refund should be calculated on a per customer basis, irrespective of customer class. He explained that the information regarding contributions by customer class is not available, but since over 92 percent of the customer base is residential and most of the growth is in the residential class, the refund will be made primarily to residential customers (Ex. A-3, at 7-8).

RUCO opposes a refund of any of the hook-up fees. Although RUCO did not file testimony on the issue, at hearing Ms. Diaz Cortez testified that refunding hook-up fees is contrary to the spirit of why the fees were collected in the first place (*i.e.*, to defray costs of future plant) (Tr. 390). RUCO contends that the Company will likely have a need for the accumulated hook-up fees in the future and the Commission should reject the proposal by Staff and the Company to terminate and refund the hook-up fees.

We agree with Staff and the Company that $833,367 should be refunded to customers to account for $452,467 of land purchased with hook-up fee funds, and $380,900 for unexpended hook-up fees. BMSC indicated it does not need the hook-up fee funds to resolve odor problems (see discussion below) because the Company is adequately capitalized to make necessary capital investments for infrastructure (Tr. 470).

We agree with BMSC that the proposed refund should be calculated on a per customer basis, irrespective of customer class. Further, as recommended by Staff, the rates from this case should not go into effect until after the refunds are made.

Withdrawn Staff Alternative Proposal

On the third day of the hearing, Staff witness Marlin Scott, Jr. stated in his direct testimony on the stand that, in response to concerns expressed by the Town and customers, Staff proposed that instead of refunding the hook-up fees, perhaps those funds could be used to fund system improvements needed to alleviate noise and odor problems described at the hearing (see discussion below) (Tr. 617-618). Because Staff developed the alternative recommendation on the morning of

the third day of the hearing, it did not have any specific ideas of how the proposal may be accomplished. The Administrative Law Judge therefore directed Staff to file a written description of its alternative recommendation prior to the close of the hearing (Tr. 624).

Staff decided to withdraw its alternative recommendation and, on the final day of the hearing, a discussion occurred regarding the issue (Tr. 653-674). In general terms, RUCO, the Town and the Boulders HOA were interested in pursuing the Staff alternative. However, the Company objected to Staff's "eleventh hour" proposal and to the attempt by the Town and the HOA to resurrect the issue after it was withdrawn by Staff (*Id.*). The Company also raised the issue of whether the hook-up fee funds could legally be used for the purposes suggested in Staff's alternative. In any event, the Company represented that financial resources to make necessary system improvements are not lacking (Tr. 470).

Given Staff's withdrawal of its alternative recommendation, the hearing concluded without further consideration of the proposal.

## OTHER ISSUES

Odor Issues

The most contentious issue in this proceeding involves claims made by a number of the Company's customers, as well as the Town of Carefree and the Boulders HOA, that the BMSC system emits significant odors. For the Town and the HOA, the odor problem was the only issue pursued. In addition to Mr. Williams on behalf of the Boulders HOA, public comment was given at the hearing by seven customers, each of whom described various experiences regarding odors at their properties due to the BMSC wastewater system (Tr. 30-80). In addition, a number of other customers submitted written comments or contacted the Commission's Consumer Services Division to register complaints regarding odors and/or the Company's proposed rate increase.

In response to the odor complaints, the Company initially took the position that any odor problems that may exist were not related to the BMSC system (Ex. A-6, at 2). In its rejoinder testimony, the Company's witness indicated that BMSC does not have an odor problem, "it has an odor complaint problem" (Ex. A-7, at 1). In opening statements, the Company's counsel reiterated BMSC's position that "we don't have a problem with odors; we have a problem with odor

complaints" (Tr. 15). During cross-examination, the Company's position appeared to soften as evidenced by the testimony given by Robert Dodds, APIF's director of operations and president of several of Algonquin's operating companies. Although Mr. Dodds was hesitant to commit unlimited resources to resolve the odor issues, he conceded that "there is an issue [and] obviously customers are smelling odors" (Tr. 482). However, in its initial post-hearing brief the Company appeared to move closer to its pre-hearing position, arguing that it is not possible to set a standard that would satisfy everyone, "[n]or is it possible to eliminate odors from a wastewater collection and treatment system" (BMSC Closing Brief, at 4). In response to arguments by the Town and the HOA that rate relief should be delayed until the odor issues are resolved, or that conditions should be imposed in conjunction with any rate increase granted in this case, the Company argues that the Commission should defer to the Maricopa County Environmental Services Department ("MCESD") which has determined that the Company meets the applicable odor control standards (*Id.* at 5).

Cause of Odors

Based on the public comments received, as well as the sworn testimony presented by various witnesses, there appears to be general agreement that the odor problems reported by customers stem from two separate sources, the CIE Lift Station and the wastewater line that flows under Boulder Drive in the Boulders subdivision.

CIE Lift Station

During prior updates to the wastewater system by BMSC's predecessor, all but one of the older lift stations (CIE lift station) was replaced. Operational problems at the CIE lift station have caused frequent odor issues and have required the Company to pump raw sewage from the site into trucks, which then deposit the sewage into other locations in the system. The Town's witness, Stan Francom stated that the CIE lift station should be replaced or bypassed because of regular breakdowns at the facility, and the inability to continue patching the lift station to keep it operational (Tr. 292, 334). An engineering report commissioned by the Town ("Carter Burgess Report") recommended replacing the CIE Lift Station due to operational problems (Ex. T-3, Ex. A., at 14).

BMSC witness Dodds also recognized the problems associated with the CIE Lift Station and indicated that the Company was studying ways to bypass or eliminate the facility (Tr. 466-467). The

Company attached to its initial Closing Brief an agreement dated August 9, 2006 between Algonquin and an engineering company to eliminate and bypass the CIE Lift Station (BMSC Closing Brief, Ex. 2).

Given the Company's decision to eliminate the CIE Lift Station, that particular source of odors should be eliminated in the near future. The Company should notify the Commission and all other parties, within 30 days of the effective date of this Decision, as to the status of the CIE Lift Station project and projected completion date. The project should be completed within 180 days of the effective date of this Decision unless an extension is granted upon an appropriate timely request.

Boulders Community

The more complicated odor issue involves ongoing complaints by residents in the Boulders subdivision, especially along Boulders Drive where the sewer line flows from the CIE Lift Station to the Boulders wastewater treatment plant ("Boulders WWTP" or "WWTP"). According to Carefree witness Francom, the odors in the Boulders community are attributable to two problems: the long retention time that sewage sits in the Boulders line, thereby allowing the sewage to become septic (Tr. 283-285); and "positive pressure" between the CIE Lift Station and the Boulders WWTP due to the fact that the lines between the lift station and discharge manholes in the Boulders community are pressurized, but are gravity lines from the Boulders manholes to the WWTP (*Id.*). Mr. Francom explained that, once sewage is released suddenly into the Boulders discharge manholes, turbulence is created because the sewage displaces gasses within the system thereby pushing odors out into the community through any gaps, such as unsealed manhole covers or residential vent stacks (Id. at 286).

The Town asserts that Mr. Francom's analysis is confirmed by an engineering study by Lamb Technical Services, Inc. ("LTS Report"), which was commissioned by BMSC (Ex. A-6, Ex. 1, Attach. F). The LTS Report indicated that hydrogen sulfide concentrations are "extremely high" at the locations where the force mains discharge into the gravity lines upstream from the WWTP, and those locations "had positive pressures that tend to drive the odors and hydrogen sulfide concentrations out through the manhole cover pickholes" (*Id.*). The LTS Report noted that the Company's addition of the chemical treatment Thioguard in the Boulders area was partially successful in reducing hydrogen sulfide concentrations. However, LTS indicated that even with

those reductions the odors being driven out of residential vent stacks were still significant, and a redesign at the Boulder/Quartz discharge location "is recommended if turbulence could be reduced" (*Id.* at 5). The LTS Report stated that "[e]ven with reduced concentrations due to less turbulence a fan generating negative pressures will still most likely be needed at the Quartz and Boulder Drive location to prevent odors from being forced out the local vent stacks" (*Id.*).

Mr. Francom testified that there were two possible solutions to the Boulders odor problems: replacement of the gravity flow lines with pressure lines all the way to the Boulders WWTP; or installation of fans and carbon filters to create a negative pressure filtration system within the sewer lines between the discharge manholes and the WWTP (Tr. 334-335). Mr. Francom pointed out that the Town offered to install a temporary fan system to test the effectiveness of that method of odor remediation, but the offer was previously rejected by the Company on the basis that no odor problems existed (Tr. 315-318).

BMSC contends that it takes the odor complaints seriously and has been taking reasonable steps to address those complaints. The Company states that AWRA has invested more than $1.4 million on system improvements, much of which was designed to address odor issues (Ex. A-4, at 4). The Company argues that the standards suggested by the Town and the HOA for resolving the odor issues are too vague, because they would presumably require every customer to be totally satisfied, possibly well in excess of applicable government standards. BMSC argues that the public comment relied upon by the Town and HOA is not evidence in this proceeding, and the Company points out that it has never been found to be in violation of MCESD odor regulations (Tr. 322-323, 354, 620). The Company asserts that it would be unfair for the Commission to impose additional requirements, especially when such requirements may be beyond the Commission's jurisdiction. The Company claims that it has already addressed the odor problems by starting to remove the CIE Lift Station, and that it is willing to commence "yet another engineering study to evaluate allegations of continuing odors from facilities located within Boulders Drive" (BMSC Reply Brief, at 6). However, BMSC argues that ordering the specific steps recommended by the Town and HOA is "not related to ratemaking, and in the absence of any evidence that BMSC's operations violate the governing standards, would constitute improper interference with management of the utility" (*Id.*).

The Town and the Boulders HOA cite to several statutes that they argue give the Commission authority to impose remedial measures in cases such as this. Pursuant to A.R.S. §40-361(B), the intervenors argue that BMSC is obligated to "furnish and maintain such service, equipment and facilities as will promote the safety, health, comfort and convenience of its patrons...." They also contend that, under A.R.S. §40-334(B), BMSC may not "maintain any unreasonable difference as to ... service, facilities or in any other respect, either between localities...." The Town argues that this provision is applicable because customers in different areas of the BMSC service territory are affected by odors disproportionately. The intervenors further claim that Maricopa County regulations prohibit wastewater treatment facilities from producing air pollution that unreasonably interferes with property owners' enjoyment of life or property.

The Town claims that its recommendations are not vague because they propose specific remedies for resolving the odor issues raised in this proceeding. Therefore, Carefree requests that a condition be placed on any rate increase granted to BMSC requiring the Company to either replace the gravity line discussed above with pressure lines and/or install fans and carbon filters to create a negative filtration system between the Boulders discharge manhole and the Boulders WWTP. The HOA also argues that any rate increase granted in this case should be conditioned on BMSC being required to undertake an audit of the Company's sewer system; if the hook-up fee refund plan is rejected, all funds derived from the rate increase should be escrowed and used only for system improvements; an independent audit of BMSC's management structure should be conducted; the $833,000 in hook-up fees should be used to fix the odor problems identified in this case; the Town's grease trap ordinance inspection and compliance reports should be monitored and publicized; and an expedited hearing should be conducted if BMSC fails to comply with the proposed conditions.

Resolution

We believe the evidentiary record in this case amply supports the appropriateness of, and the need for, imposition of odor remediation requirements as a condition of granting the rate relief approved herein. We turn first to the evidentiary standard for dealing with public comment since that issue was raised by the Company in its post-hearing Brief. Although we agree with BMSC that unsworn public comments made by ratepayers are not treated as evidence in a strict sense, we believe

ratepayer input is important to consider as an indication of how customers view the operations of a regulated utility company. For example, it may not be appropriate to rely solely on unsubstantiated claims made in public comments, because such comments are not subject to cross-examination. However, if corroborating sworn testimony or documentary evidence is presented in the course of the hearing, it is entirely appropriate to treat the public comments as an indicator of customer perception and experience in dealing with regulated monopoly utility companies. Indeed, such comments are invaluable for the Commission to understand both positive and negative experiences of customers, especially since those customers have no choice but to take service from the utility holding an exclusive Certificate to provide service.

We disagree with BMSC that the intervenor proposals are impossibly vague and would impose an undue compliance burden on the Company. As the Town points out, at least one of its proposed remedies for reducing odors in the Boulders subdivision was cited in both the Carter Burgess Report and LTS Report. The evidence in the record suggests that, despite the Company's attempts to solve the odor problems in that area through the introduction of Thioguard, there is an ongoing problem that cannot be solved by chemical injections alone. In addition to replacement of the CIE Lift Station, the prior engineering studies appear to have pinpointed not only the remaining cause of the odor problems (*i.e.*, pumping of sewage into the Boulders discharge manhole), but a possible solution (*i.e.*, fans to create negative pressure in the line leading from the Boulders manhole to the WWTP). Mr. Francom indicated that another solution may be the installation of a pressurized line to the WWTP, to replace the existing gravity line. As such, it hardly requires speculation to address the source of, and the solution for, the odor issues in the Boulders community. Rather, there is ample record evidence to support the conclusion that the Company should take action consistent with the prior engineering reports, as well as the credible testimony presented by the Town's witness, in order to remedy the odor problems discussed herein.

We are not persuaded by the Company's arguments that the Commission is without authority to take action to protect the public health and welfare of customers served by utilities under its jurisdiction. With respect to a public service corporation's adequacy of service, A.R.S. §40-321(A) states:

> When the commission finds that the equipment, appliances, facilities or service of any public service corporation, or the methods of manufacture, distribution, transmission, storage or supply employed by it are unjust, unreasonable, unsafe, improper, inadequate or insufficient, the commission shall determine what is just, reasonable, safe, proper, adequate or sufficient, and shall enforce its determination by order or regulation.

As set forth in A.R.S. §40-331(A):

> When the Commission finds that additions or improvements to or changes in the existing plant or physical property of a public service corporation ought reasonably to be made, or that a new structure or structures should be erected, to promote the security or convenience of its employees or the public, the commission shall make and serve an order directing that such changes be made or such structure be erected in the manner and within the time specified in the order. If the commission orders erection of a new structure, it may also fix the site thereof.

In addition, A.R.S. §40-361(B) provides as follows:

> Every public service corporation shall furnish and maintain such service, equipment and facilities as will promote the safety, health, comfort and convenience of its patrons, employees and the public, and as will be in all respects adequate, efficient and reasonable.

As these statutes make abundantly clear, the Commission has the authority and the duty to protect the health, safety and welfare of a public service corporation's customers. And, contrary to BMSC's "micromanagement" arguments, the law just as clearly states that in order to protect the security or convenience of the public, the Commission may specify not only the type of facilities that are required, but the timeframe in which the facilities must be constructed.

A.R.S. §40-202(A), provides additional supervisory authority to the Commission for regulation of public service corporations[12]. The authority granted to the Commission under these statutes, as well as the Commission's constitutional powers pursuant to Article 15, §3 of the Arizona Constitution, was discussed in *Arizona Corp. Comm'n v. Palm Springs Utility Co., Inc.*, 24 Ariz. App. 124, 128, 536 P.2d 245, 249 (App. 1975). In that case, the court held that "the regulatory powers of the Commission are not limited to making orders respecting the health and safety, but also

[12] A.R.S. §40-202(A), provides in relevant part: "The commission may supervise and regulate every public service corporation in the state and do all things, whether specifically designated in this title or in addition thereto, necessary and convenient in the exercise of that power and jurisdiction."

include the power to make orders respecting comfort, convenience, adequacy and reasonableness of service...." (*Id.*). Given our determination that our constitutional and statutory powers provide the requisite authority to require actions by the Company to resolve the odor problems cited herein, we need not decide whether the Maricopa County rules and regulations cited by the intervenors are implicated by the facts presented in this case.

Having determined that the record supports a finding that odor problems exist on the BMSC system, and that we have legal authority to craft a remedy for those problems, we turn next to the appropriate directives that should be given to the Company as a condition of our approval of the rate increase discussed hereinabove. We find that the Boulders odor problems should be addressed by the Company's adoption of one of the two solutions suggested by Mr. Francom. As he explained on the record, the odors being experienced by members of that community may be solved by implementing a pressurized line to replace the gravity line that currently exists between the Boulders discharge manhole and the Boulders WWTP, or by installing fans and carbon filters to create a negative pressure filtration system between the Boulders discharge manhole and the Boulders WWTP[13].

The implementation of these remedies should be completed within 180 days of the effective date of this Decision although, for good cause shown and with the agreement of all other parties to this proceeding, the timeline may be extended by the Commission upon timely receipt of a request for extension of time. We also wish to make clear that failure by BMSC to comply with this order, or to otherwise continue to operate its system in a manner that fails to reasonably mitigate odors affecting customer residences and properties, may result in penalties or other action deemed necessary by the Commission to enforce this Decision.

By imposing this requirement, we wish to make clear that we are not attempting to manage the Company's affairs. However, based on the record, we believe action needs to be taken to advance a solution that will enable all customers on the BMSC system to enjoy fully their property without enduring offensive odors.

* * * * * * * * * *

[13] With the mutual agreement of all other parties to this proceeding, an alternative remedy may be employed to accomplish the desired goal of odor remediation in the Boulders community.

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

**FINDINGS OF FACT**

1. On September 16, 2005, BMSC filed an application with the Commission for an increase in rates.

2. On October 14, 2005, the Commission's Utilities Division Staff filed a Letter of Insufficiency.

3. Following an agreement between the Company and Staff regarding the submission of information, Staff issued a Letter of Sufficiency on November 1, 2005, and classified BMSC as a Class B utility.

4. By Procedural Order issued November 2, 2005, procedural timeframes were established and a hearing was scheduled to commence on June 7, 2006.

5. Intervention was granted to RUCO, the Town of Carefree, the Boulders HOA, and M.M. Schirtzinger.

6. On December 30, 2005, BMSC filed a "simplified cost of service study" as requested by Staff.

7. On January 24, 2006, BMSC filed a Certification of Publication and Proof of Mailing, attesting to compliance with the notice requirements set forth in the November 2, 2005 Procedural Order.

8. With its application, BMSC filed the Direct Testimony of Michael Weber and Thomas Bourassa, and, on March 9, 2006, Staff filed the Direct Testimony of Crystal Brown, Marlin Scott, Jr., and Pedro Chaves; RUCO filed the Direct Testimony of William Rigsby and Marylee Diaz Cortez; and Carefree filed Affidavits of Stan Francom, Jonathon Pearson, and Jason Bethke, as well as several attachments.

9. On April 6, 2006, BMSC filed the Rebuttal Testimony of Michael Weber, Joel Wade, and Thomas Bourassa. On May 4, 2006, Staff filed the Surrebuttal Testimony of Marlin Scott, Jr., and Pedro Chaves; RUCO filed the Surrebuttal Testimony of William Rigsby and Marylee Diaz Cortez; and Carefree filed the Surrebuttal Testimony of Stan Francom and Jonathon Pearson. On

May 5, 2006, Staff filed the Surrebuttal Testimony of Crystal Brown. On May 26, 2006, BMSC filed the Rejoinder Testimony of Joel Wade and Thomas Bourassa.

10. The hearing commenced on June 7, 2006, and additional hearing days were held on June 8, 9, and 20, 2006.

11. On June 15, 2006, Staff filed updated Surrebuttal Schedules. On July 26, 2006, Staff filed Post-Hearing Recommendations based on documentation provided by the Company on June 22, 2006.

12. Initial Post-Hearing Briefs were filed on August 18, 2006 by the Boulders HOA, and on August 21, 2006 by BMSC, Staff, RUCO, and Carefree.

13. Reply Briefs were filed on September 5, 2006 by BMSC, Staff, RUCO, Carefree, and the Boulders HOA.

14. According to the Company's application, as modified, in the test year ending December 31, 2005, BMSC had adjusted operating income of $11,595 on an adjusted FVRB and OCRB of $1,568,502, for a 0.74 percent rate of return.

15. In its application, as modified, the Company requested a gross revenue increase of $256,063 (21.54 percent), based on OCRB of $1,568,502, and a recommended return on common equity of 11.00 percent.

16. Staff recommends a gross revenue increase of $250,195 (20.76 percent), based on OCRB of $1,550,710, and a recommended return on common equity of 9.60 percent.

17. RUCO recommends a gross revenue increase of $5,470 (0.45 percent), based on OCRB of $1,372,834, and a recommended return on common equity of 9.45 percent.

18. For purposes of this proceeding, we determine that BMSC has a FVRB and OCRB of $1,472,969.

19. A rate of return on FVRB of 9.60 percent, based on a capital structure of 100 percent common equity, is reasonable and appropriate.

20. BMSC is entitled to a gross revenue increase of $246,257.

21. The rate design recommended by Staff should be adopted in this proceeding.

22. Staff's recommendation to exclude affiliate profits is adopted, and no finding is made

regarding the reasonableness of the Algonquin affiliate structure. In future cases involving the Algonquin companies, the Commission will scrutinize all affiliate salaries, expenses and billings.

23. The record supports a finding that customers should be refunded $833,367 for hook-up fees that were used to purchase land and that have not been expended. The refunds should be distributed in the manner proposed by the Company, on a per customer basis irrespective of customer class. The rates granted in this Decision should not go into effect until the refunds have been distributed.

24. The record supports a finding that BMSC should, within 30 days, notify the Commission and all other parties as to the status of the CIE Lift Station project and projected completion date.

25. The record supports a finding that odor problems exist on BMSC's system, and that the steps taken by the Company to date have not been sufficient to resolve the problems. BMSC should therefore be required to pursue one of the remedies proposed by the Town of Carefree in order to mitigate the odor problems that currently exist in the Boulders community. The implementation of the remedies should be completed within 180 days from the effective date of this Decision.

## CONCLUSIONS OF LAW

1. BMSC is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§40-250, 40-251, 40-367, 40-202, 40-321, 40-331, and 40-361.

2. The Commission has jurisdiction over BMSC and the subject matter contained in the Company's rate application.

3. Pursuant to A.R.S. §§40-202(A), 40-321(A), 40-331(A), 40-361(B), and the authority under Article 15 of the Arizona Constitution, the Commission has jurisdiction to impose requirements for public service corporations to improve and repair facilities necessary to protect the health and safety of the public, and provide for the comfort and convenience of customers.

4. The rates, charges and conditions of service established herein are just and reasonable and in the public interest.

## ORDER

IT IS THEREFORE ORDERED that Black Mountain Sewer Corporation is hereby authorized

and directed to file with the Commission, on or before November 30, 2006, revised schedules of rates and charges consistent with the discussion herein, as set forth below.

| | |
|---|---|
| **Residential Service** – Per Month | $45.64 |
| **Commercial - Regular** (c) | $0.18298 |

| **Commercial – Special Rates** | Gallons Per Day | Rate Per Day | Monthly Charge |
|---|---|---|---|
| Name of Business | | | |
| BH Enterprises – West | 2,525 | $0.14034 | $354.35 |
| BH Enterprises – East | 1,400 | $0.14034 | $196.47 |
| Barb's Pet Grooming | 250 | $0.14034 | $35.08 |
| Boulders Resort | 29,345 | $0.14223 | $4,173.87 |
| Carefree Dental | 1,625 | $0.14034 | $228.05 |
| Ridgecrest Realty | 450 | $0.14193 | $63.87 |
| Desert Forest | 7,000 | $0.16344 | $1,144.11 |
| Desert Hills Pharmacy | 800 | $0.17061 | $136.49 |
| El Pedregal | 15,787 | $0.14034 | $2,215.50 |
| Lemon Tree | 300 | $0.13691 | $41.07 |
| Body Shop | 1,000 | $0.17467 | $174.67 |
| Spanish Village | 4,985 | $0.14034 | $699.58 |
| Boulders Club | 1,200 | $0.14034 | $168.40 |
| Anthony Vuitaggio | 300 | $015597 | $46.79 |

| | |
|---|---|
| **Effluent Sales** | |
| Per thousand gallons | $0.374400 |

| | |
|---|---|
| **Service Charges** | |
| Establishment | $25.00 |
| Re-establishment | $25.00 |
| Re-connection | No Charge |
| Minimum Deposit (Residential) | (a) |
| Minimum Deposit (Non-Residential) | (a) |
| Deposit Interest | (a) |
| NSF Check Charge | $10.00 |
| Deferred Payment Finance Charge | 1.50% |
| Late Charge | 1.50% |
| Main Extension Tariff (b) | Cost |
| Hook-up Fee for New Service | Discontinue |

(a) Per A.A.C. R14-2-603B; Residential – two times average bill, Non-residential – two and one-half times average bill;
(b) Per A.A.C. R14-2-406(B);
(c) Per Gallon per Day. Wastewater flows are based on Engineering Bulletin 12, Table 1 for purposes of determining a monthly charge for individual customers on this rate.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after December 1, 2006, subject to the requirement that Black Mountain Sewer Corporation has mailed to each customer prior to that date a refund check for the hook-up fee funds, consistent with and in the manner described hereinabove. The new rates may not go into effect until the Company has provided, to the satisfaction of the Director of the Utilities Division, sufficient information to show that the refunds have been issued in accordance with the discussion set forth herein.

IT IS FURTHER ORDERED that Black Mountain Sewer Corporation shall notify its customers of the revised schedules of rates and charges authorized herein by means of an insert in its next regularly scheduled billing, or by separate mailing, in a form acceptable to Staff.

IT IS FURTHER ORDERED that Black Mountain Sewer Corporation shall, within 30 days of the effective date of this Decision, notify the Commission and all other parties as to the status of the CIE Lift Station project and projected completion date. The project shall be completed within 180 days of the effective date of this Decision unless an extension is granted upon an appropriate timely request.

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IT IS FURTHER ORDERED that Black Mountain Sewer Corporation shall pursue one of the remedies proposed by the Town of Carefree in order to mitigate the odor problems that currently exist in the Boulders community, and notify the Commission and all parties, within 90 days, regarding the option chosen through a filing in this docket. The implementation of the remedies shall be completed within 180 days from the effective date of this Decision unless an extension is granted upon an appropriate request. The Company shall file as a compliance item in this docket, notification of completion of the Boulders community odor mitigation project, within 30 days of completion of the project.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 5th day of Dec., 2006.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: BLACK MOUNTAIN SEWER CORPORATION

DOCKET NO.: SW-02361A-05-0657

Jay Shapiro
FENNEMORE CRAIG, P.C.
3003 North Central Avenue, Ste. 2600
Phoenix, AZ 85012
Attorneys for Black Mountain Sewer Corporation

Daniel Pozefsky, Attorney
RUCO
1110 West Washington Street, Ste. 220
Phoenix, AZ 85007

Robert E. Williams
P.O. Box 1170
Carefree, AZ 85377

M. M. Shirtzinger
34773 N. Indian Camp Trail
Scottsdale, AZ 85262

Thomas K. Chenal
David W. Garbarino
MOHR, HACKETT, PEDERSON,
BLAKLEY & RANDOLPH, P.C.
7047 East Greenway Parkway, Ste. 155
Scottsdale, AZ 85254
Attorneys for the Town of Carefree

Christopher Kempley, Chief Counsel
Keith Layton, Attorney
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

Ernest G. Johnson, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007

**Rio Rico Utilities - Water Division**
Test Year Ended December 31, 2008
Comparative Balance Sheets

Exhibit
Schedule E-1
Page 1
Witness: Bourassa

| Line No. | | Test Year Ended 12/31/2008 | Year Ended 12/31/2007 | Year Ended 12/31/2006 |
|---|---|---|---|---|
| 1 | **ASSETS** | | | |
| 2 | Plant In Service | $ 34,023,226 | $ 31,033,505 | $ 30,269,691 |
| 3 | Non-Utility Plant | - | - | - |
| 4 | Construction Work in Progress | 95,024 | 647,216 | 397,779 |
| 5 | Less: Accumulated Depreciation | (10,986,265) | (10,312,729) | (9,698,350) |
| 6 | Net Plant | $ 23,131,985 | $ 21,367,992 | $ 20,969,120 |
| 7 | | | | |
| 8 | | | | |
| 9 | Debt Reserve Funds | $ - | $ - | $ - |
| 10 | | | | |
| 11 | CURRENT ASSETS | | | |
| 12 | Cash and Equivalents | $ 84,332 | $ 81,200 | $ 70,997 |
| 13 | Restricted Cash | - | - | - |
| 14 | Short-term Investments | - | - | - |
| 15 | Accounts Receivable, Net | 336,968 | 300,109 | 310,821 |
| 16 | Accounts Receivable -Other | - | - | - |
| 17 | Materials and Supplies | - | - | - |
| 18 | Prepayments | 10,289 | 18,049 | 2,815 |
| 19 | Other Current Assets | 1,457,163 | 1,870,488 | 1,539,567 |
| 20 | Total Current Assets | $ 1,888,752 | $ 2,269,845 | $ 1,924,200 |
| 21 | | | | |
| 22 | Deferred Debits | $ (491,447) | $ (422,974) | $ (345,977) |
| 23 | | | | |
| 24 | Other Assets | $ 1,029,413 | $ 752,965 | $ 528,854 |
| 25 | | | | |
| 26 | TOTAL ASSETS | $ 25,558,703 | $ 23,967,828 | $ 23,076,196 |
| 27 | | | | |
| 28 | **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | |
| 29 | Common Equity | $ 9,356,741 | $ 7,970,067 | $ 6,201,629 |
| 30 | | | | |
| 31 | Long-Term Debt, less current | $ - | $ - | $ - |
| 32 | | | | |
| 33 | CURRENT LIABILITIES | | | |
| 34 | Accounts Payable | $ 2,291,807 | $ 1,604,763 | $ 1,953,554 |
| 35 | Current Portion of Long-Term Debt | - | - | - |
| 36 | Current Portion of AIAC | - | - | - |
| 37 | Payables to Associated Companies | - | - | 50,483 |
| 38 | Customer Meter Deposits, Current | - | - | - |
| 39 | Taxes Payable | 7,145 | 7,258 | 6,909 |
| 40 | Accrued Employee expenses | - | - | - |
| 41 | Accrued Interest | - | - | - |
| 42 | Other Current Liabilities | - | - | - |
| 43 | Total Current Liabilities | $ 2,298,952 | $ 1,612,021 | $ 2,010,946 |
| 44 | DEFERRED CREDITS | | | |
| 45 | Customer Meter Deposits, less current | $ 275,455 | $ 197,889 | $ 181,779 |
| 46 | Advances in Aid of Construction | 73,648 | 135,487 | 131,037 |
| 47 | Accumulated Deferred Income Taxes | - | - | - |
| 48 | Contributions In Aid of Construction | 20,188,921 | 20,188,921 | 20,188,906 |
| 49 | Accumulated Amortization of CIAC | (6,635,014) | (6,136,557) | (5,638,101) |
| 50 | | | | |
| 51 | Total Deferred Credits | $ 13,903,010 | $ 14,385,740 | $ 14,863,621 |
| 52 | | | | |
| 53 | Total Liabilities & Common Equity | $ 25,558,703 | $ 23,967,828 | $ 23,076,196 |
| 54 | | | | |
| 55 | SUPPORTING SCHEDULES: | | RECAP SCHEDULES: | |
| 56 | E-5 | | A-3 | |
| 57 | | | | |
| 58 | | | | |

EXHIBIT
RUCO-3
ADMITTED

**RIO RICO UTILITIES, INC.**
**DOCKET NO. WS-02676A-09-0257**
**RESPONSE TO RUCO'S EIGHTH SET OF DATA REQUESTS**

March 4, 2010

| | |
|---|---|
| Response provided by: | Thomas J. Bourassa, CPA |
| Title: | Rate Consultant |
| Company Name: | Thomas J. Bourassa, CPA |
| Address: | 139 W. Wood Drive<br>Phoenix, Arizona 85029 |

Company Response Number: 8.01

---

Q. 2009 Customer Counts – Please provide the 2009 monthly customer counts for both the Water and Wastewater Divisions.

**OBJECTION: The ACC sets rates based on a historical test year, therefore, the information requested does not appear reasonably calculated to lead to the discovery of admissible evidence.**

RESPONSE: Notwithstanding the objection, please see the attached water and sewer customer count and revenue summary for 2009.

**Rio Rico Utilities - Water Division**
**2009 Customer Counts and Revenues**

| Rate Code | Bills Jan | Bills Feb | Bills Mar | Bills Apr | Bills May | Bills Jun | Bills Jul | Bills Aug | Bills Sep | Bills Oct | Bills Nov | Bills Dec | Revenue Jan | Revenue Feb | Revenue Mar | Revenue Apr | Revenue May | Revenue Jun | Revenue Jul | Revenue Aug | Revenue Sep | Revenue Oct | Revenue Nov | Revenue Dec | Total Revenues |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **WC 1 Total** | 42 | 42 | 43 | 43 | 42 | 42 | 41 | 42 | 40 | 40 | 41 | 41 | 2,006 | 1,888 | 1,926 | 2,369 | 2,321 | 2,527 | 2,152 | 2,727 | 3,726 | 1,589 | 1,651 | 1,537 | 26,420 |
| **WC 1 1/2 Total** | 10 | 10 | 10 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 11 | 859 | 677 | 920 | 873 | 999 | 1,127 | 996 | 883 | 883 | 975 | 1,054 | 891 | 11,136 |
| **WC 2 Total** | 36 | 37 | 37 | 36 | 37 | 34 | 33 | 34 | 34 | 34 | 34 | 34 | 10,072 | 7,662 | 10,098 | 11,406 | 11,698 | 6,840 | 4,703 | 5,769 | 6,040 | 5,005 | 5,091 | 5,317 | 89,700 |
| **WC 3 Total** | 13 | 15 | 16 | 17 | 16 | 14 | 14 | 16 | 15 | 15 | 14 | 15 | 5,786 | 3,138 | 3,780 | 3,854 | 5,098 | 11,863 | 7,594 | 7,889 | 5,545 | 6,404 | 5,643 | 5,104 | 71,699 |
| **WC 4 Total** | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 2,923 | 2,899 | 3,365 | 3,181 | 3,116 | 4,726 | 3,779 | 4,198 | 3,913 | 3,756 | 3,334 | 2,895 | 42,086 |
| **WC 5/8 Total** | 95 | 94 | 94 | 93 | 94 | 93 | 87 | 88 | 87 | 83 | 86 | 86 | 2,133 | 2,180 | 2,030 | 2,245 | 2,202 | 2,527 | 2,106 | 2,063 | 1,918 | 1,942 | 1,846 | 1,826 | 25,018 |
| **WC 6 Total** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1,538 | 897 | 1,444 | 1,520 | 1,767 | 2,320 | 2,158 | 2,246 | 2,097 | 2,225 | 1,052 | 1,165 | 20,530 |
| **WF 1-8 Total** | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 110 | 110 | 110 | 110 | 116 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 1,373 |
| **WI 2 Total** | 0 | 0 | 0 | 0 | 0 | 3 | 3 | 5 | 5 | 5 | 5 | 4 | 0 | 0 | 0 | 0 | 0 | 3,251 | 2,960 | 3,272 | 2,851 | 2,315 | 1,810 | 1,017 | 17,476 |
| **WI 5/8 Total** | 0 | 0 | 0 | 0 | 0 | 14 | 11 | 18 | 18 | 18 | 18 | 18 | 0 | 0 | 0 | 0 | 0 | 522 | 382 | 767 | 584 | 487 | 472 | 418 | 3,632 |
| **WM 1 1/2 Total** | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 53 | 52 | 48 | 45 | 43 | 53 | 52 | 59 | 57 | 53 | 45 | 48 | 609 |
| **WM 5/8 Total** | 9 | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 210 | 248 | 306 | 337 | 225 | 239 | 228 | 244 | 230 | 214 | 188 | 174 | 2,842 |
| **WR 1 Total** | 36 | 37 | 37 | 37 | 38 | 37 | 37 | 37 | 36 | 37 | 37 | 37 | 1,034 | 1,129 | 1,089 | 1,302 | 1,663 | 1,800 | 1,675 | 1,377 | 1,418 | 1,527 | 1,600 | 1,354 | 16,968 |
| **WR 1 1/2 Total** | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 170 | 176 | 172 | 214 | 233 | 280 | 266 | 315 | 307 | 221 | 271 | 186 | 2,810 |
| **WR 2 Total** | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 348 | 333 | 340 | 360 | 428 | 423 | 423 | 438 | 462 | 392 | 391 | 358 | 4,697 |
| **WR 3/4 Total** | 8 | 8 | 8 | 8 | 6 | 6 | 7 | 8 | 7 | 7 | 7 | 8 | 128 | 127 | 123 | 136 | 89 | 99 | 94 | 118 | 107 | 112 | 103 | 113 | 1,348 |
| **WR 5/8 Total** | 5,837 | 5,829 | 5,864 | 5,873 | 5,890 | 5,855 | 5,822 | 5,860 | 5,844 | 5,842 | 5,846 | 5,862 | 103,797 | 96,390 | 104,561 | 118,535 | 129,654 | 146,591 | 133,876 | 128,910 | 125,373 | 123,824 | 114,400 | 101,849 | 1,427,761 |
| **Grand Total** | 6,107 | 6,103 | 6,140 | 6,149 | 6,166 | 6,141 | 6,097 | 6,150 | 6,128 | 6,123 | 6,130 | 6,147 | 131,170 | 118,004 | 130,311 | 146,486 | 159,650 | 185,307 | 163,560 | 161,391 | 155,627 | 151,158 | 139,067 | 124,369 | 1,766,104 |
| **Summary** | | | | | | | | | | | | | | | | | | | | | | | | | |
| **Residential** | 5,889 | 5,882 | 5,917 | 5,926 | 5,942 | 5,906 | 5,874 | 5,913 | 5,895 | 5,894 | 5,898 | 5,915 | 105,478 | 98,154 | 106,284 | 120,547 | 132,067 | 149,194 | 136,333 | 131,158 | 127,666 | 126,077 | 116,765 | 103,860 | 1,453,564 |
| **Commercial** | 202 | 204 | 206 | 206 | 206 | 200 | 192 | 197 | 193 | 189 | 192 | 193 | 25,318 | 19,440 | 23,563 | 25,448 | 27,200 | 31,932 | 23,489 | 25,774 | 24,122 | 21,895 | 19,671 | 18,735 | 286,589 |
| **Multi-Family** | 10 | 11 | 11 | 11 | 11 | 11 | 10 | 10 | 10 | 10 | 10 | 10 | 263 | 299 | 354 | 382 | 268 | 292 | 279 | 303 | 286 | 267 | 233 | 223 | 3,450 |
| **Irrigation** | 0 | 0 | 0 | 0 | 0 | 17 | 14 | 23 | 23 | 23 | 23 | 22 | 0 | 0 | 0 | 0 | 0 | 3,772 | 3,342 | 4,039 | 3,435 | 2,802 | 2,282 | 1,435 | 21,108 |
| **Fire** | 6 | 6 | 6 | 6 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 110 | 110 | 110 | 110 | 116 | 117 | 117 | 117 | 117 | 117 | 117 | 117 | 1,373 |

Legend
WC = Water Commercial
WR = Water Residential
WM = Water Multi-family
WI = Water Irrigation
WF = Water Fire

**Rio Rico Utilities - Sewer Division**
**2009 Customer Counts and Revenues**

| Rate Code | Bills Jan | Bills Feb | Bills Mar | Bills Apr | Bills May | Bills Jun | Bills Jul | Bills Aug | Bills Sep | Bills Oct | Bills Nov | Bills Dec | Revenue Jan | Revenue Feb | Revenue Mar | Revenue Apr | Revenue May | Revenue Jun | Revenue Jul | Revenue Aug | Revenue Sep | Revenue Oct | Revenue Nov | Revenue Dec | Total Revenues |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| SC 1 Total | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 34 | 33 | 33 | 34 | 34 | 4,856 | 5,119 | 4,697 | 5,479 | 5,496 | 6,225 | 5,234 | 4,734 | 4,996 | 4,020 | 3,875 | 3,955 | 58,689 |
| SC 1 1/2 Total | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 2,077 | 1,523 | 1,711 | 1,906 | 2,111 | 2,448 | 2,094 | 1,814 | 1,791 | 1,946 | 2,180 | 1,711 | 23,312 |
| SC 2 Total | 22 | 22 | 21 | 21 | 22 | 22 | 22 | 22 | 22 | 22 | 21 | 22 | 11,440 | 10,726 | 13,034 | 13,720 | 13,610 | 10,743 | 8,579 | 10,424 | 11,691 | 8,956 | 8,121 | 8,711 | 129,756 |
| SC 3 Total | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 1,566 | 1,480 | 1,429 | 1,372 | 1,126 | 10,394 | 989 | 1,155 | 1,138 | 1,429 | 1,372 | 1,149 | 24,597 |
| SC 4 Total | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 7,732 | 7,589 | 8,943 | 8,469 | 8,292 | 13,065 | 10,336 | 11,478 | 10,382 | 10,205 | 8,800 | 7,121 | 112,412 |
| SC 5/8 Total | 69 | 69 | 68 | 68 | 68 | 69 | 68 | 66 | 66 | 63 | 65 | 66 | 6,269 | 5,824 | 5,984 | 6,436 | 6,315 | 6,783 | 6,230 | 6,076 | 5,491 | 5,520 | 5,271 | 5,266 | 71,465 |
| SC 6 Total | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 4,492 | 2,865 | 4,207 | 4,435 | 5,178 | 6,839 | 6,354 | 6,616 | 6,171 | 6,554 | 3,031 | 3,367 | 60,109 |
| SM 1 1/2 Total | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 140 | 134 | 123 | 117 | 117 | 140 | 134 | 157 | 152 | 140 | 117 | 123 | 1,595 |
| SM 5/8 Total | 9 | 9 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 8 | 8 | 719 | 736 | 964 | 1,055 | 701 | 730 | 696 | 748 | 696 | 651 | 588 | 571 | 8,855 |
| SR 1 Total | 9 | 9 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 10 | 10 | 10 | 715 | 728 | 794 | 797 | 794 | 715 | 685 | 717 | 715 | 770 | 786 | 794 | 9,009 |
| SR 2 Total | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 163 | 1,951 |
| SR 3/4 Total | 8 | 8 | 7 | 8 | 6 | 6 | 7 | 8 | 7 | 7 | 7 | 8 | 514 | 514 | 473 | 514 | 386 | 386 | 446 | 493 | 450 | 450 | 450 | 491 | 5,566 |
| SR 5/8 Total | 1,785 | 1,779 | 1,796 | 1,803 | 1,796 | 1,766 | 1,760 | 1,776 | 1,759 | 1,764 | 1,777 | 1,776 | 100,586 | 100,266 | 101,228 | 101,640 | 101,204 | 99,532 | 99,184 | 100,067 | 99,130 | 99,415 | 100,163 | 100,073 | 1,202,487 |
| Grand Total | 1,953 | 1,947 | 1,963 | 1,971 | 1,962 | 1,932 | 1,925 | 1,938 | 1,920 | 1,923 | 1,939 | 1,939 | 141,269 | 137,668 | 143,751 | 146,101 | 145,493 | 158,163 | 141,124 | 144,642 | 142,965 | 140,218 | 134,916 | 133,495 | 1,709,805 |
| **Summary** | | | | | | | | | | | | | | | | | | | | | | | | | |
| Residential | 1,803 | 1,797 | 1,814 | 1,822 | 1,813 | 1,782 | 1,776 | 1,793 | 1,776 | 1,782 | 1,795 | 1,794 | 101,977 | 101,671 | 102,658 | 103,113 | 102,546 | 100,795 | 100,478 | 101,440 | 100,457 | 100,798 | 101,562 | 101,520 | 1,219,014 |
| Commercial | 140 | 140 | 138 | 138 | 139 | 140 | 139 | 136 | 135 | 132 | 135 | 136 | 38,433 | 35,127 | 40,005 | 41,816 | 42,128 | 56,498 | 39,816 | 42,297 | 41,660 | 38,629 | 32,649 | 31,262 | 480,341 |
| Multi-Family | 10 | 10 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 9 | 9 | 859 | 870 | 1,087 | 1,173 | 819 | 870 | 831 | 905 | 848 | 791 | 705 | 694 | 10,450 |

**Legend**
SR = Sewer Residential
SC = Sewer Commercial
SM = Sewer Multi-Family

EXHIBIT
stabler
R 4
ADMITTED

2008

# Algonquin Power Income Fund

## Annual Financial Results

Algonquin Power

ALGONQUIN POWER

## TABLE OF CONTENTS


2 MANAGEMENT'S DISCUSSION & ANALYSIS

51 AUDITORS' REPORT TO THE UNITHOLDERS

52 CONSOLIDATED BALANCE SHEETS

53 CONSOLIDATED STATEMENTS OF OPERATIONS

54 CONSOLIDATED STATEMENTS OF CASH FLOWS

55 CONSOLIDATED STATEMENTS OF DEFICIT

56 CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME/(LOSS) AND ACCUMULATED OTHER COMPREHENSIVE INCOME/(LOSS)

57 NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

93 CORPORATE INFORMATION

# MANAGEMENT'S DISCUSSION AND ANALYSIS

(All figures are in thousands of Canadian dollars, except per trust unit and convertible debenture values or where otherwise noted)

Algonquin Power Income Fund ("Algonquin" or the "Company") has prepared the following discussion and analysis to provide information to assist its unitholders' understanding of the financial results for the three and twelve months ended December 31, 2008. This discussion and analysis should be read in conjunction with Algonquin's audited consolidated financial statements for the years ended December 31, 2008 and 2007 and the notes thereto. This material is available on SEDAR at www.sedar.com and on the Algonquin website at www.AlgonquinPower.com. Additional information about the Company, including the Annual Information Form for the year ended December 31, 2008 can be found on SEDAR at www.sedar.com.

This Management's Discussion and Analysis ("MD&A") is based on information available to management as of March 5, 2009.

## Caution concerning forward looking statements and non-GAAP Measures

Certain statements included herein contain forward-looking information within the meaning of certain securities laws. These statements reflect the views of Algonquin and Algonquin Power Management Inc. ("APMI"), the entity which provides management services to Algonquin (including advice and consultation concerning business planning, support, guidance and policy making) with respect to future events, based upon assumptions relating to, among others, the performance of the Company's assets and the business, interest and exchange rates, commodity market prices, and the financial and regulatory climate in which it operates. These forward looking statements include, among others, statements with respect to the expected performance of the Company, its future plans and its distributions to unitholders. Statements containing expressions such as "outlook", "believes", "anticipates", "continues", "could", "expect", "may", "will", "project", "estimates", "intend", "plan" and similar expressions generally constitute forward-looking statements.

Since forward-looking statements relate to future events and conditions, by their very nature they require us to make assumptions and involve inherent risks and uncertainties. Algonquin and APMI caution that although we believe our assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that our actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include the continued volatility of world financial markets; the impact of movements in exchange rates and interest rates; the effects of changes in environmental and other laws and regulatory policy applicable to the energy and utilities sectors; decisions taken by regulators on monetary policy and the taxation of income funds; and the state of the Canadian and the United States ("U.S.") economy and accompanying business climate. Algonquin and APMI caution that this list is not exhaustive, and other factors could adversely affect our results. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. The Company reviews material forward-looking information it has presented, at a minimum, on a quarterly basis. Although Algonquin and APMI believe that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of the dates hereof. Algonquin and APMI are not obligated nor do either of them intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise, except as required by law.

The terms "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures", and "earnings before interest, taxes, depreciation and amortization" ("EBITDA") are used throughout this MD&A. The terms "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures" and EBITDA are not recognized measures under Canadian generally accepted accounting principles ("GAAP"). There is no standardized measure of "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures" and EBITDA, consequently Algonquin's method of calculating these measures may differ from methods used by other companies and therefore may not be comparable to similar measures presented by other companies. A calculation and analysis of "cash available for distribution", "cash available for distribution after growth and maintenance capital expenditures" and EBITDA can be found throughout this MD&A. EBITDA is a metric used by many investors to compare companies on the basis of ability to generate cash from operations. Algonquin uses these calculations to monitor the amount of cash generated by Algonquin as compared to the amount of cash distributed by Algonquin. Algonquin uses EBITDA to assess the operating performance of the Company without the effects of

depreciation and amortization expense which are derived from a number of non-operating factors, accounting methods and assumptions. APMI believes that presentation of this measure will enhance an investor's understanding of Algonquin's operating performance. EBITDA is not intended to be representative of cash provided by operating activities or results of operations determined in accordance with GAAP.

## Overview

Algonquin is a company that owns and has interests in a diverse portfolio of clean, renewable power generation and sustainable infrastructure assets across North America, including 42 renewable energy facilities, 11 thermal energy facilities, and 17 water distribution and waste-water facilities. Algonquin Power was established in 1997 and produces stable earnings through a diversified portfolio of renewable energy and utility assets.

Algonquin owns 41 hydroelectric facilities operating in Ontario, Québec, Newfoundland, Alberta, New York State, New Hampshire, Vermont and New Jersey with a combined generating capacity of 140 MW. The company also owns a 99 MW wind farm in Manitoba. The renewable energy facilities are generally facilities operating under power purchase agreements with major utilities that have an average remaining life of 18 years. The Company's 11 thermal energy facilities also operate under power purchase agreements with an average remaining contract length of 10 years with a combined generating capacity of 320 MW. The Company's Utility Services business unit owns 17 regulated utilities in the United States of America providing water and wastewater services in the states of Arizona, Texas, Missouri and Illinois. These utility operating companies are regulated investor-owned utilities subject to regulation, including rate regulation, by the public utility commissions of the states in which they operate.

## Business Strategy

Algonquin's business strategy is to maximize long term unitholder value by strengthening its position as a strong renewable energy and infrastructure company. The Company is focused on growth in cash flow and earnings in the business segments in which it operates. Algonquin currently makes monthly cash distributions to unitholders of $0.02 per trust unit per month or $0.24 per trust unit per annum. This sustainable level of cash distributions allows for both an immediate return on investment for unitholders and retention of sufficient cash to fund growth opportunities, fund anticipated tax liabilities when the new tax policies affecting income trusts are implemented, and mitigate the impact of volatility in foreign exchange.

Algonquin's operations are aligned into two major business units: *Power Generation & Development*, and *Utility Services*. The two business units reflect the Company's business strategy to be a leading provider of essential services and how Algonquin manages its business and classifies its operations for planning and measuring performance.

The Power Generation & Development business unit develops and operates a diversified portfolio of electrical energy generation facilities. Within this business unit there are three distinct divisions: Renewable Energy, Thermal Energy and Development. The Renewable Energy division operates the Company's hydro-electric and wind power facilities. The Thermal Energy division operates co-generation, energy from waste, steam production and other thermal facilities. The Development division develops Algonquin's greenfield power generation projects, pursues accretive acquisitions of electrical energy generation facilities as well as development of organic growth opportunities within Algonquin's existing portfolio of renewable energy and thermal energy facilities. The renewable power and thermal energy generation business of Algonquin is managed with an emphasis on growth through the development of green-field projects and opportunities within Algonquin's existing portfolio. This involves building on the Company's expertise in the origination of greenfield renewable energy projects, building upon the Company's existing portfolio of assets for further growth, and capitalizing on opportunities that may emerge in the current turbulence of the capital markets.

The Utility Services business unit provides safe, reliable transportation and delivery of water and waste-water treatment in its service area and pursues accretive water and waste-water utility acquisition opportunities. Building on its experience in the regulated water utility sector, Utility Services is also considering expanding its operations into other regulated essential utilities such as natural gas distribution and electricity distribution.

## 16. Related party transactions

In addition to the transaction described in note 3 (a) with APMI, the following related party transactions occurred:

APMI provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2008 and 2007, APMI was paid on a cost recovery basis for all costs incurred and charged $893 (2007 - $867). APMI is also entitled to an incentive fee of 25% on all distributable cash (as defined in the management agreement) generated in excess of $0.92 per trust unit. During 2008 $nil (2007 - $770) was earned by APMI as an incentive fee.

As part of the project to re-power the Sanger facility, the Fund entered into an agreement with APMI to undertake certain construction management services on the project. APMI is entitled to a development supervision fee plus a performance based contingency fee for its construction management role on the project. During 2008, APMI was paid $23 (2007 - $98) for development supervision. During 2008, the Fund accrued $674 as the final fee owed to APMI with respect to this project. This fee has been accrued and is included in accounts payable on the consolidated balance sheet.

The Fund has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2008 were $296 (2007 - $296).

On March 10, 2008, the Company advanced $225 to the Trustees for purposes of enabling the Trustees to purchase additional Units of the Company. The loans are subject to promissory notes issued in favour of the Company which are repayable upon demand, currently bear interest at 3% per annum, and are recorded as a reduction in Trust Units on the consolidated balance sheet. During 2008 a principal repayment of $8 was made. (2007 - $nil) (note 13)

The Fund utilizes chartered aircrafts, including the use of an aircraft owned by an affiliate of APMI, Airlink. In 2004, the Fund entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for the Fund's business use of the aircraft. Under the terms of this arrangement, the Fund will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft; such direct operating costs do not provide the affiliate with any profit or return on or of the capital committed to the aircraft. During the year, the Fund incurred costs in connection with the use of the aircraft of $332 (2007 - $422) and amortization expense related to the advance against expense reimbursements of $90 (2007 - $168). At December 31, 2008, the remaining amount of the advance was $818 (2007 - $908).

Up to August 1, 2008, the Company had project debt from Highground (previously Algonquin Power Venture Fund) in the amount of $3,000 related to the St. Leon facility. Highground advanced $1,600 at a rate of 11.25% as part of the initial financing of the St. Leon facility and advanced $1,400 at a rate of 9.25% during the first quarter of 2007. These amounts have now been eliminated on the Consolidated Balance Sheet of the Company due to the acquisition of Highground (Note 3 (a) and note 10).

Up to July 31, 2008, Highground was paid $150 (2007 - $150) in interest related to debt associated with the St. Leon facility. Some of the directors and shareholders of APMI were also directors, officers and shareholders of the manager of Highground.

In accordance with the construction services agreement related to the St. Leon facility GWAP, a company controlled by APMI, was paid a final payment of $134 (2007 - $845) in 2008 for construction services. In 2008, the Fund also paid $nil (2007 - $1,353) to GWAP on a cost recovery basis related to ongoing operating expenses of the project.

## 16. Related party transactions (continued)

Pursuant to the St. Leon Limited Partnership Agreement, in 2006, St. Leon Wind Energy LP ("St. Leon LP"), a subsidiary of Airsource and the legal owner of the St. Leon facility, was required to issue 100 Class B units to GWAP. The holders of the Class B Units are entitled to 2.5% of the income allocations and cash distributions from St. Leon LP for a 5 year period commencing after June 17, 2008, two years after the date the facility achieved commercial operations pursuant to the PPA. Such income allocations and cash distributions shall be increased by 2.5% for each successive 5 year period, to a maximum of 10.0%. In any particular period, cash distributions to the holders of the Class B Units are only to be made after distributions have been made to the other partners, in an aggregate amount, equal to the debt service on the outstanding debt in respect of such period. The holders of the Class B units are entitled to cash distributions of $288 for the year ended December 31, 2008 (2007 - $nil).

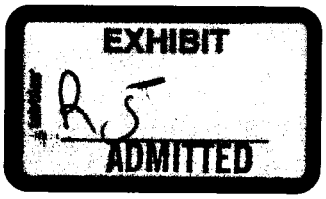
AirSource has agreed to reimburse AirSource Power Fund GP Inc (the "General Partner") of the AirSource Power Fund I LP for reasonable costs incurred by it in acting as registrar and transfer agent and in attending to the administration of the Partnership, as required in the Partnership Agreement. The general partner was paid $nil during the year ended December 31, 2008 (2007 - $11).

Pursuant to the agreement entered into on June 27, 2008 between the Company, Highground and CJIG (Note 3(a)), APMI is entitled to a fee of approximately $240 from the Company. This fee has been accrued and included in accounts payable on the consolidated balance sheet and is included in transaction costs of trust units issued.

APMI is entitled to 50% of the cash flow above 15% return on investment for the BCI project pursuant to its project management contract. During 2008, no amounts were paid under this agreement. However, APMI earned a construction supervision fee of $100 in relation to the development of this project.

**RIO RICO UTILITIES, INC.**
**DOCKET NO. WS-02676A-09-0257**
**RESPONSE TO STAFF'S FOURTH SET OF DATA REQUESTS**

November 20, 2009




Response provided by: Gerald Tremblay

Title: Director of Finance

Company Name: Algonquin Power Income Fund

Address: 2845 Bristol Circle
Oakville, Ontario Canada L6H 7H7

Company Response Number: GWB 4.2

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Q. The Company's responses to GB 3.2 and 3.10 indicate that provided amounts are based on the 2008 budget. Please provide a schedule that shows the corresponding actual amounts for the test year ended 12/31/08.

a. Please provide supporting documentation for the actual amounts expended and subject to allocation for the test year.

b. Please explain in specific detail the reasons that the amounts allocated were of benefit to the customers of Rio Rico.

c. For allocated depreciation expense, please provide a schedule of plant that is being depreciated, the corresponding depreciation rates, and depreciation expense by plant group.

d. Line 21 of the APT Cost Allocation tab indicates a conversion rate of 1.0 "Based on December 2007 Bank of Canada Average Rate". Please provide a schedule of the Bank of Canada Average rate for each month since the end of the test year to present and show supporting calculations of the rate for the month. Please provide any reasons that any subsequent changes in the Canadian dollar versus the US dollar should not be considered in the valuation of amounts allocated from Canada and ultimately reflected in the revenue requirements calculations.

e. Page 14 of the 2008 report for the Algonquin Power Income Fund indicates: At December 31, 2008, the Company had effectively hedged 100% of its expected 2009 U.S. dollar cash flow at $1.13. Please provide any reasons that a conversion rate of 1.13 should not be applied to any expenses approved in this proceeding for activity in Canada.

**OBJECTION: RRUI objects to this data request because it is overly burdensome. The Company believes it has submitted more than adequate information to support its allocation of a pro rata share of actual costs. The information requested by this data request would require the Company to produce thousands of pages of additional documentation from one or more third-parties. As a result RRUI proposes to provide invoices above $5000 for the build up of the corporate costs and a detailed GL listing of the total build up. If, thereafter, Staff would like to see any specific invoices under $5000, Staff may request those specific invoices and the Company will make a reasonable effort to promptly provide them.**

**Legal invoices are not being provided because they contain information that is subject to the attorney-client privilege. However, Staff may arrange to review the invoices by contacting the Company's legal counsel, Attn: Whitney Birk at 602-916-5720. The proposed manner of review of legal invoices is the same as used by Staff and Fennemore Craig in other rate cases. The Company reserves, and in no way intends to waive the attorney-client privilege with respect to the production of these documents, which are being made available for review to allow Staff to verify amounts incurred by the Company on matters that may be included in rate case expense and/or the Company's operating expenses.**

RESPONSE:

a. Please see the attachments for supporting invoices greater than $5,000. The Company notes that actual costs have exceeded budgeted costs by $1,319,182 and that an adjustment will be made to the amount allocated to Rio Rico's by $30,761 to adjust for actual amounts spent.

b.

i. Rent Expenses- these expenses account for corporate rent of APT staff at the offices located in Oakville, Ontario, Canada. These expenses benefit the rate payers of Rio Rico Utilities, as the staff provide accounting, operations, and strategic services to Liberty Water.

ii. Audit Fees – the rate payers of Rio Rico benefit from audit fees as the Company has increased financial rigor and controls surrounding its financial reporting and financial health. Further, it is a requirement of the parent of Rio Rico to have annual audits. Without these audits the Fund and, in turn, Rio Rico ratepayers, would have extremely limited access to capital. Further, the audits also ensure that rate case procedures can be expedited as Staff and Intervenors are able to rely on information provided.

iii. Tax Services – These fees are for tax provision calculations and tax return preparation, and are required in order for the Company to remain compliant. These are fees Rio Rico rate payers would likely pay (and likely pay more for) were it a standalone company.

iv. Legal Fees - Council for review of audited financial statements, annual information form, SEDAR filings, review of contracts with credit facility, BLAKES, listed in the annual report as prime legal council. As mentioned above, the Rio Rico rate payers benefit from these fees as they provide the Fund, and in turn, RRUI, access to capital and reliance on financial information that is produced.

v. Other Professional Services - These services mainly relate to maintenance of the ERP system, payroll system, 401k services, and Health and Benefit services. The allocated cost to RRUI is essential because RRUI must utilize the ERP system for proper record keeping as well as an upgraded payroll system to pay the operators. These services are essential to running a utility, and therefore provide benefit to the rate payers.

vi. Management Fees – The Rio Rico ratepayers receive the benefit of management services including strategic advice and consultation concerning business planning, support, guidance and policy making and general services. These expenses are critical to ensure the on going health and sustainability of RRUI.

vii. Unit Holder Communications - The Income Fund (RRUI's parent) is a publicly traded entity on the Toronto Stock Exchange. The Income Fund is obligated under securities law to report regularly on the Fund's financial condition to the unit holders. Communication costs are associated with the issuance of the quarterly and annual reporting, as well as the annual information form, the management discussion and analysis, and press releases. A publicly traded entity, the Income Fund must incur these costs in order to have access to the capital markets. RRUI benefits from this because it ensures that access to capital is available for its ongoing capital needs. The access to said capital would not be available without incurring these costs.

vii. Trustee Fees - The board of Trustees represents the unit holders. The board approves financial statements, provides corporate governance, is part of the audit committee, and oversees the strategic direction and overall health of the Income Fund. This board is required for publicly traded entities. As mentioned above, these

costs provide a direct benefit to the rate payers of RRUI as they ensure ongoing access to capital.

viii. Office Costs - These costs are associated with the day to day operating activities such as maintenance, development and purchasing for the computer systems, stationary materials, property maintenance, service awards, and other ad hoc costs. RRUI requires the use of corporate systems and support from the corporate office in order to operate.

ix. License Fees and Permits – These costs include TSE (Toronto Stock Exchange) listing fees, SEDAR Filing fees, Standard and Poors fees for rating, which are standard costs associated with Publicly traded entities. Some of these costs are related to donations and as a good corporate citizen. These costs benefit the rate payers of RRUI as they provide access to capital, and provide public relations benefits.

x. Escrow & Transfer Agent Fees – CIBC Trust Company is the agent that performs all distributions to the unit holders and convertible debenture holders. A publicly traded entity, the Income Fund must incur this cost in order to have access to the capital markets. RRUI benefits from the Fund's having access to the capital markets, which in turn ensures its health as a utility.

xi. Depreciation – These costs are for depreciation on equipment that is used to serve customers of Liberty Water utilities, including Rio Rico. Equipment includes: computer equipment, server equipment, software, shelving units, office furniture, office security system, all of which relates to the Oakville Office located in Canada.

c. Please see attachment 4.2.a, tab "Depreciation".

d. Please see attachment 4.2.d. Supporting calculations are not available since they are imputed by the Bank of Canada. The Company notes that the value of the Canadian dollar versus the US dollar fluctuates significantly. The Company is not opposed to using the most up to date rates, so long as Staff and the Commission acknowledge that rates will need to increase during periods where the Canadian dollar appreciates versus the US dollar.

e. The reference to the hedge on page 40 is only one part of the equation of offsetting fluctuations in exchange rates. As can be seen on page 41, Algonquin expects to have a loss on this currency transaction. Further, the loss can be minimized or increased by fluctuations in the currency. A hedge may be subject to gains or losses and should not be used as a single point of translation.

The Company would also like to point out the APIF hedging policy is to hedge on its net cash exposure and not on direct revenue or expenses.

Invoice

Remit To:
ALGONQUIN POWER SYSTEMS

2845 Bristol Circle

Oakville, ON L6H 7H7
(905) 465-4500 Ext. 0000

Bill To:
Algonquin Power Trust - CDN
Attn:
Mr. David Kerr
2845 Bristol Circle

Oakville, ON L6H 7H7

~~DD2A~~

Job Address:
2845 Bristol Circle

Oakville, ON L6H 7H7

//00APS-CDN

| Date | Invoice Number | Customer Order Number | Customer Number | Net Terms |
|---|---|---|---|---|
| 7/29/2008 | JC37171 | | 002APTCDN | Net 30 |

Description

Job Number: 002-999906-3217 Job Name: Wind Development

| Admin. | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| Telus Mob/MIKE/Burlington/POB 530 | 1.00 | 119.53<br>TELEPHONE & COMMUNICATION | 119.53 |
| Jocelyne Charron | 1.00 | 464.70<br>LICENSES AND FEES | 464.70 |
| Roger Ouellet | 1.00 | 553.08<br>LICENSES AND FEES | 553.08 |
| Philippe D'Astous | 1.00 | 540.76<br>LICENSES AND FEES | 540.76 |
| Eric D'Astous | 1.00 | 478.58<br>LICENSES AND FEES | 478.58 |
| Clement D'Astous | 1.00 | 435.40<br>LICENSES AND FEES | 435.40 |
| Claire Lavoie | 1.00 | 411.44<br>LICENSES AND FEES | 411.44 |
| Normand Dube | 1.00 | 394.00<br>LICENSES AND FEES | 394.00 |
| Ferme Sindamas Inc. (Herman Gendro | 1.00 | 691.24<br>LICENSES AND FEES | 691.24 |
| Le Group de Damabois a/s Martin La | 1.00 | 747.74<br>LICENSES AND FEES | 747.74 |
| Herman Caron | 1.00 | 604.46<br>LICENSES AND FEES | 604.46 |
| Dany Harrisson | 1.00 | 610.12<br>LICENSES AND FEES | 610.12 |
| Bernard Harrisson | 1.00 | 832.88<br>LICENSES AND FEES | 832.88 |
| Bernard Harrisson & Jeanne-Aimee S | 1.00 | 835.88<br>LICENSES AND FEES | 835.88 |
| Serge Tardif | 1.00 | 393.80<br>LICENSES AND FEES | 393.80 |
| Regis Pelletier | 1.00 | 590.14<br>LICENSES AND FEES | 590.14 |
| Roland Desrosiers | 1.00 | 585.52<br>LICENSES AND FEES | 585.52 |
| Carol Gauthier | 1.00 | 540.46<br>LICENSES AND FEES | 540.46 |
| Bernard Deschenes | 1.00 | 611.10<br>LICENSES AND FEES | 611.10 |
| Jean Yves Robitaille | | 385.75<br>LICENSES AND FEES | 385.75 |

| | | | | |
|---|---|---|---|---|
| | 1.00 | | 509.40 | 509.40 |
| Gilles Langlois | | LICENSES AND FEES | | |
| | 1.00 | | 523.60 | 523.60 |
| Jean Claude Berube | | LICENSES AND FEES | | |
| | 1.00 | | 517.04 | 517.04 |
| Roland Gauthier | | LICENSES AND FEES | | |
| | 1.00 | | 426.36 | 426.36 |
| Armand St-Louis | | LICENSES AND FEES | | |
| | 1.00 | | 730.58 | 730.58 |
| Emilien Simard | | LICENSES AND FEES | | |
| | 1.00 | | 379.98 | 379.98 |
| Gerard Savard | | LICENSES AND FEES | | |
| | 1.00 | | 560.00 | 560.00 |
| Dany Harrisson | | LICENSES AND FEES | | |

| | |
|---|---|
| Admin. Total: | 14,473.54 |
| Billing Amount: | $14,473.54 |
| Retention Withheld: | $0.00 |
| Retention Due: | $0.00 |
| Subtotal: | $14,473.54 |
| Misc: | 0.00 |
| Tax: | 1,863.48 |
| Pay This Amount: | $16,337.02 |

GST Number: 13248 7463 RC0001

| RECEIVED | VENDOR ID |
|---|---|
| | 1100 APS-CON |
| COMPANY | G/L CODE |
| APT | 1100-1-0000-~~50~~ 75-7430-0000 |
| APPROVED | JOB # |
| | 1100-9840-0069. |
| PAID | COST CODE |
| | 6-7200-0000-0000 |

$14,354.01

$ 119.53

Invoice

Remit To:
ALGONQUIN POWER SYSTEMS

2845 Bristol Circle

Oakville, ON L6H 7H7
(905) 465-4500 Ext. 0000

Bill To:
Algonquin Power Trust - CDN
Attn:
Mr. David Kerr
2845 Bristol Circle

Oakville, ON L6H 7H7

Job Address:
2845 Bristol Circle

Oakville, ON L6H 7H7

1100 APS-CDN

| Date | Invoice Number | Customer Order Number | Customer Number | Net Terms |
|---|---|---|---|---|
| 4/26/2008 | JC36162 | | 002APTCDN | Net 30 |

Description

Job Number: 002-999906-3217 Job Name: Wind Development

POSTED
-04- 29 2008
OAKVILLE

| Subcontractors | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| Marcel D'Auteuil | 1.00 | 560.00<br>DAM/PENSTOCK | 560.00 |
| | | Subcontractors Total: | 560.00 |

| Travel & Disbur | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| FEB1,08-MAR23,08 EXPENSE REPOR<br>April Meyer | 1.00 | 2.75<br>AIRFARE & OTHER TRANSPORT | 2.75 |
| MAR24,08 EXPENSE REPORT<br>Gaetan Mercier | 1.00 | 11.47<br>Vehicle Mileage | 11.47 |
| | | Travel & Disbur Total: | 14.22 |

| Admin. | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| SCADA<br>Telus Mob/MIKE/Burlington/POB 530 | 1.00 | 119.53<br>TELEPHONE & COMMUNICATION | 119.53 |

| | | | |
|---|---|---|---|
| TEL | 1.00 | 159.42 | 159.42 |
| Telus Mob/MIKE/Burlington/POB 530 | | TELEPHONE & COMMUNICATION | |
| CREDIT | -1.00 | 159.42 | -159.42 |
| TELUS Mob(QST)MIKE-Burling/5300 PO | | TELEPHONE & COMMUNICATION | |
| TEL | 1.00 | 185.68 | 185.68 |
| Telus Mob/MIKE/Burlington/POB 530 | | TELEPHONE & COMMUNICATION | |
| CREDIT | -1.00 | 185.68 | -185.68 |
| TELUS Mob(QST)MIKE-Burling/5300 PO | | TELEPHONE & COMMUNICATION | |
| TEL | 1.00 | 265.27 | 265.27 |
| Telebec Mobilite | | TELEPHONE & COMMUNICATION | |
| CREDIT | -1.00 | 265.27 | -265.27 |
| TELUS Mob(QST)MIKE-Burling/5300 PO | | TELEPHONE & COMMUNICATION | |
| FEE FOR HONI CONNECTION IMPACT | 1.00 | 5,250.00 | 5,250.00 |
| Hydro One Networks Inc. | | LICENSES AND FEES | |
| FEB1,08-MAR23,08 EXPENSE REPOR | 1.00 | 1,044.00 | 1,044.00 |
| April Meyer | | Training-Tech | |

| | |
|---|---|
| Admin. Total: | 6,413.53 |
| Billing Amount: | $6,987.75 |
| Retention Withheld: | $0.00 |
| Retention Due: | $0.00 |
| Subtotal: | $6,987.75 |
| Misc: | 0.00 |
| Tax: | 899.68 |
| Pay This Amount: | $7,887.43 |

GST Number: 13248 7463 RC0001

# CHEQUE REQUISITION FORM

**Date:** JAN 15/08 **Company:** GWAP

**Vendor (Payable To):** Algonquin Power (St Leon) Inc

**Vendor's Address:**

**Amount:** 80,114.55 **Cdn$ or US$**

**Description:** 60% of GWAP Mgmt Fee 133,524.25
Inv 2008-01-14

**Project:** **G/L Acct NO:** 3502.1.0000.75.7310.0000

**Requested By:**

**Approved By:**

Do not write below this line.

---

**Paid on :**

**Cheque No.:**

Invoice

Remit To:
ALGONQUIN POWER SYSTEMS

2845 Bristol Circle

Oakville, ON L6H 7H7
(905) 465-4500 Ext. 0000

Bill To:
Algonquin Power Trust - CDN
Attn:
Mr. David Kerr
2845 Bristol Circle

Oakville, ON L6H 7H7

Job Address:
2845 Bristol Circle

Oakville, ON L6H 7H7

| Date | Invoice Number | Customer Order Number | Customer Number | Net Terms |
|---|---|---|---|---|
| 5/31/2008 | JC36554 | | 002APTCDN | Net 30 |

Description

Job Number: 002-999908-3765 Job Name: APT-St.Leon Exp Pre-Con.Activ.

| Labor | | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|---|
| Homer | Lensink | 1.00 | 125.00 | 125.00 |
| | | | CDN-DIVISION MGR-CDN JOB- | |
| April | Meyer | 0.50 | 105.00 | 52.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 0.50 | 105.00 | 52.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 2.00 | 105.00 | 210.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 0.50 | 105.00 | 52.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 0.50 | 105.00 | 52.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 3.00 | 105.00 | 315.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.50 | 105.00 | 157.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 2.00 | 105.00 | 210.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 1.00 | 105.00 | 105.00 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 6.50 | 105.00 | 682.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |
| April | Meyer | 23.50 | 105.00 | 2,467.50 |
| | | | CDN-TECH LEADER-CDN JOB-T | |

| RECEIVED | VENDOR ID |
|---|---|
| 5/31/08 | 1100APSCDN |
| **COMPANY** | **G/L CODE** |
| APT 1100 | |
| **APPROVED** | **JOB #** |
| | 1100-9840-0082 |
| **PAID** | **COST CODE** |

| | | | | |
|---|---|---|---|---|
| April | Meyer | 1.00 | 105.00<br>CDN-TECH LEADER-CDN JOB-T | 105.00 |
| April | Meyer | 2.00 | 105.00<br>CDN-TECH LEADER-CDN JOB-T | 210.00 |
| April | Meyer | 2.00 | 105.00<br>CDN-TECH LEADER-CDN JOB-T | 210.00 |
| Rick | Harrop | 3.50 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 297.50 |
| Rick | Harrop | 2.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 170.00 |
| Rick | Harrop | 2.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 170.00 |
| Rick | Harrop | 4.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 340.00 |
| Rick | Harrop | 3.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 255.00 |
| Rick | Harrop | 3.50 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 297.50 |
| Rick | Harrop | 2.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 170.00 |
| Rick | Harrop | 3.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 255.00 |
| Rick | Harrop | 2.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 170.00 |
| Rick | Harrop | 2.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 170.00 |
| Rick | Harrop | 2.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 170.00 |
| Rick | Harrop | 3.00 | 85.00<br>CDN-SENIOR PM-CDN JOB-TEC | 255.00 |
| Doina | Tomescu | 2.50 | 37.50<br>CDN-ADMINISTRATION-CDN JO | 93.75 |
| Doina | Tomescu | 0.50 | 37.50<br>CDN-ADMINISTRATION-CDN JO | 18.75 |
| Mike | Griffin | 1.00 | 125.00<br>CDN-DIVISION MGR-CDN JOB- | 125.00 |
| Mike | Griffin | 1.00 | 125.00<br>CDN-DIVISION MGR-CDN JOB- | 125.00 |
| Mike | Griffin | 1.00 | 125.00<br>CDN-DIVISION MGR-CDN JOB- | 125.00 |
| Mike | Griffin | 1.00 | 125.00<br>CDN-DIVISION MGR-CDN JOB- | 125.00 |
| April | Meyer | 3.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 270.00 |
| Sean | Fairfield | 0.50 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 45.00 |
| Sean | Fairfield | 4.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 360.00 |
| Sean | Fairfield | 2.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 180.00 |
| Sean | Fairfield | 2.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 180.00 |
| Sean | Fairfield | 2.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 180.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 0.50 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 45.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 0.50 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 45.00 |
| Sean | Fairfield | 3.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 270.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 2.50 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 225.00 |
| Sean | Fairfield | 1.50 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 135.00 |

| | | | | |
|---|---|---|---|---|
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 2.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 180.00 |
| Sean | Fairfield | 2.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 180.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 2.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 180.00 |
| Sean | Fairfield | 3.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 270.00 |
| Sean | Fairfield | 3.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 270.00 |
| Sean | Fairfield | 3.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 270.00 |
| Sean | Fairfield | 7.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 630.00 |
| Sean | Fairfield | 17.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 1,530.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 0.50 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 45.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Sean | Fairfield | 1.00 | 90.00<br>CDN-TEAM LEADER-CDN JOB-M | 90.00 |
| Gaetan | Mercier | 0.50 | 70.00<br>CDN-PM-CDN JOB-MAINT | 35.00 |

3-7370-0000-0001

Labor Total: 15,695.00

| Subcontractors | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| Stantec Consulting Ltd (SCL) | 1.00 | 15,371.50<br>DAM/PENSTOCK | 15,371.50 |
| Phoenix Engineering | 1.00 | 125.00<br>POWER HOUSE/BUILDING | 125.00 |
| | | Subcontractors Total: | 15,496.50 |

3-7370-0000-0000

| Travel & Disbur | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| Sean Fairfield 5-7605-0000-0000 | 1.00 | 206.43<br>VEHICLE RENTAL | 206.43 |
| Sean Fairfield | 1.00 | 53.52<br>VEHICLE RENTAL | 53.52 |
| Sean Fairfield | 1.00 | 173.09<br>VEHICLE RENTAL | 173.09 |
| Sean Fairfield | 1.00 | 19.83<br>VEHICLE RENTAL | 19.83 |
| Sean Fairfield | 1.00 | 4.76<br>VEHICLE RENTAL | 4.76 |
| Sean Fairfield 5-7620-0000-0000 | 1.00 | 12.69<br>MEALS | 12.69 |
| Sean Fairfield | 1.00 | 3.69<br>MEALS | 3.69 |
| Sean Fairfield | 1.00 | 30.58<br>MEALS | 30.58 |
| Sean Fairfield | 1.00 | 1.29<br>MEALS | 1.29 |
| Sean Fairfield | 1.00 | 5.93<br>MEALS | 5.93 |
| Sean Fairfield | 1.00 | 6.42<br>MEALS | 6.42 |
| Sean Fairfield | 1.00 | 16.68<br>MEALS | 16.68 |
| Sean Fairfield 5-7610-0000-0000 | 1.00 | 211.86<br>ACCOMMODATIONS | 211.86 |

| | | | | |
|---|---|---|---|---|
| Sean Fairfield | 5-7610-0000-0000 | 1.00 | 121.79 | 121.79 |
| | | | ACCOMMODATIONS | |
| Sean Fairfield | | 1.00 | 31.24 | 31.24 |
| | | | Vehicle Mileage | |
| Sean Fairfield | 5-7640-0000-0000 | 1.00 | 15.62 | 15.62 |
| | | | Vehicle Mileage | |
| | | | Travel & Disbur Total: | 915.42 |

| Admin. | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| | 1.00 | 2,690.00 | 2,690.00 |
| Trade Commerce | | Office Supplies | |
| | 1.00 | 104.40 | 104.40 |
| Colette Labossiere | | REPRODUCTION | |
| | 1.00 | 58.00 | 58.00 |
| Colette Labossiere | | REPRODUCTION | |
| | 1.00 | 437.20 | 437.20 |
| Colette Labossiere | | REPRODUCTION | |
| | 1.00 | 140.00 | 140.00 |
| Colette Labossiere | | REPRODUCTION | |
| | 1.00 | 703.85 | 703.85 |
| The Times | | REPRODUCTION | |
| | 1.00 | 1,550.00 | 1,550.00 |
| Farm Business Communications | | REPRODUCTION | |
| | 1.00 | 1,550.00 | 1,550.00 |
| Farm Business Communications | | REPRODUCTION | |
| | 1.00 | 152.10 | 152.10 |
| La Liberte | | REPRODUCTION | |
| | 1.00 | 169.00 | 169.00 |
| La Liberte | | REPRODUCTION | |
| | 1.00 | 1,559.81 | 1,559.81 |
| Centiple Printing | | REPRODUCTION | |
| | 1.00 | 676.00 | 676.00 |
| The Western Canadian | | REPRODUCTION | |
| | | Admin. Total: | 9,790.36 |

2-7142-0000-0000

| | |
|---|---|
| Billing Amount: | $41,897.28 |
| Retention Withheld: | $0.00 |
| Retention Due: | $0.00 |
| Subtotal: | $41,897.28 |
| Misc: | 0.00 |
| Tax: | 2,094.87 |
| Pay This Amount: | $43,992.15 |

GST Number: 13248 7463 RC0001

# Cheque Requisition Form

1100 REG/EE

Date: July 14/08 **Company:** APT

Vendor(Payable to): Region of Peel

Vendor's Address:

Amount: 5000 - Cdn$ or US$

Description: Donation

Project: G/L Acct. No.: 1100.9860 OPS

**Your Signature:**

**Approval:**

Do not write below this line.

Paid on:

Cheque No.:

# Cheque Requisition Form

1100EMIKOL

Date: July 14/08 **Company:** APT

Vendor(Payable to): The Emil Kolb Hootenanny

Vendor's Address:

Amount: $7,800 - [redacted] Cdn$ or US$

Description: Donation

Project: G/L Acct. No.: 1100.& 9860-OPS

**Your Signature:**

**Approval:**

Do not write below this line.

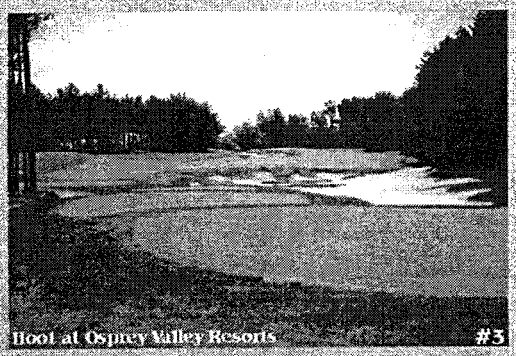
Paid on:

Cheque No.:

1100 TOWGAL

**Sponsorship Opportunities For Your Business**

| | |
|---|---|
| *Platinum* | *$5000* |
| *Gold -* | *$4000* |
| *Silver -* | *$3000* |
| *Ball Sponsor 2008* | *SOLD* |
| *Tournament Friend* | *$500* |
| *Hole Sponsor* | *$300* |
| *Virtual Golfer* | *$150* |
| *Virtual Foursome* | *$600* |



Hoot at Osprey Valley Resorts #3

**5th Annual CCCGT**

**Hosted by Osprey Valley Resorts**
18821 Main Street, Village of Alton

Town of Caledon
6311 Old Church Road
Caledon, Ontario, L7C 1J6

Tournament Coordinator -
Emma Rock
Phone 519 584 2272 ext 4102
E-mail: emma.rock@caledon.ca

pay to

***Platinum Sponsorship—$5000***
Each Platinum Opportunity includes:
Four complimentary players and dinner at the event
Exclusive Wine or Cocktail reception sponsorship or semi exclusive Sponsorship of Dinner .
Full page advertisement in program, banner opportunities and mention in all pre and post event media.

***Gold Sponsorship—$4000***
Each Gold Opportunity includes:
Four complimentary players and dinner at the event
Sponsorship of on Course game, Range or Golf Carts
1/2 page advertisement in program, hole signage and mention in all pre and post event advertising

***Silver Sponsorship—$3000***
Each Silver Opportunity includes:
Two complimentary players and dinner at the event
Sponsorship of beverage carts, event water, registration area, breakfast or silent auction
Company Logo in program and mention in all pre and post event advertising

***Ball Sponsor—Rogers Wireless Communications Inc.***
As Ball sponsor at the tournament your company logo will be printed on a sleeve of balls for every player.

RECEIVED
-07- 25 2008
OAKVILLE

***Friend of the Tournament—$500***
Signage at one hole and Logo in program

***Hole Sponsorship—$300***
Signage at one hole on course and listing in event program

***Virtual Golfers - $150 each***
This is a new concept.
If you are unable to play or unavailable for our tournament you can still be a part of our event !
By donating $150 per single, $300 for a twosome; $450 per threesome, and $600 per foursome.
Abbeyfield will issue a tax receipt to each Virtual Golfer for the full amount. Virtual Golfers will be listed on a program to be at each dinner setting. Virtual Golfers will be entered into draws and receive email updates on the net results of our tournament and who our prize winners were.

as per Chris Jarrett

1100-9840-OPS -development

Sales / Invoices SALES000000000290064

Private Companies
2845 Bristol Circle

Oakville ON L6H 7H7

Date 1/28/2008

Algonquin Power Trust
2845 Bristol Circle

Oakville ON L6H 7H7

| Purchase Order | Customer ID | Salesperson ID | Shipping Method | Payment Terms ID |
|---|---|---|---|---|
| | 003APT | | AR | |

| | |
|---|---|
| Management Fee - January 2008 | $72,406.42 |

| | |
|---|---|
| Subtotal | $72,406.42 |
| Misc | $0.00 |
| Tax | $5,068.45 |
| Freight | $0.00 |
| Trade Discount | $0.00 |
| Payment | $0.00 |
| Total Due | $77,474.87 |

ALGONQUIN POWER INCOME FUND
TRANSACTION INQUIRY REPORT
Payables Management



Vendor ID: 1100AMI Algonquin Power Management Inc

| Ranges: | From: | To: |
|---|---|---|
| Document Number | First | Last |
| Document Date | First | Last |
| Type | First | Last |

Sorted By: Document Date/Type Include: Open

* Voided

| Origin | Document Number | Type | Doc Date | Original Amount | Unapplied Amount |
|---|---|---|---|---|---|
| Voucher/Payment Number | | Due Date | Disc Date | Transaction Description | Currency ID |
| Open | 290-OCT08 | INV | 10/30/08 | $78,307.55 | $78,307.55 |
| 00000000000007449069 | | 11/29/08 | | Management Fee Oct08 | Z-C$ |
| Open | 290-NOV08 | INV | 11/30/08 | $78,307.55 | $78,307.55 |
| 00000000000007449070 | | 12/30/08 | | Management Fee Nov08 | Z-C$ |

Total Documents: 2

**Paul Dalglish**

233 Melrose Ave
Toronto, ON M5M 1Y9
Phone 416-540-3082

# INVOICE

INVOICE #**ALG-2008-01**
DATE: MARCH 5, 2008

**TO:**
Algonquin Power
2845 Bristol Circle
Oakville, ON L6H 7H7

**FOR:**
Consulting Services for **January 2008**

| PROJECT | DAYS | RATE | AMOUNT |
|---|---|---|---|
| 1100-9840-0075 - Algonquin Utilities Strategy | 1 | $1,000 | $1,000 |
| 1100-9840-0076 - Northern Utilities Acquisition | 19 | $1,000 | $19,000 |
| 1100-9840-0073 - PPL Acquisition | 3 | $1,000 | $3,000 |
| | | SUB-TOTAL | $23,000 |
| | | GST @ 5% | $1,150 |
| | | TOTAL | $24,150 |

| RECEIVED | VENDOR ID |
|---|---|
| | 1100PAUDAL |
| **COMPANY** | **G/L CODE** |
| APT | |
| **APPROVED** | **JOB #** |
| | 1100-9840-0073 1,000<br>1100-9840-0075 3,000<br>1100-9840-0076 19,000 |
| **PAID** | **COST CODE** |
| | 3-7370-0000-0000 |

See attached email

Make all checks payable to Paul Dalglish

GST #: 83178 6413 RT0001

RECEIVED
MAR 06 2008

# INVOICE

**Date:** 1-Nov-08

**Landlord:** Algonquin Power Property Limited Partnership

**Tenant:** Algonquin Power Trust

**Monthly Rent**

| | $ per Square Foot | Square Footage | Total |
|---|---|---|---|
| **Basic** | 19.75 | 14,981.32 | 24,656.76 |
| **Sub-Total** | | | **24,656.76** |
| **GST (#88208 3017 RT0002)** | | 5% | 1,232.84 |
| **Total** | | | **$ 25,889.59** |

| RECEIVED | VENDOR ID |
|---|---|
| 11/1/08 | 1100 APPROP |
| COMPANY | G/L CODE |
| 1100 | 1100.1.0000.10.1248.0000 |
| APPROVED | JOB # |
| PAID | COST CODE |

POSTED
NOV 3 1 2008
OAKVILLE

Grant Thornton

October 31, 2008

Mr. David Bronicheski
Chief Financial Officer
Algonquin Power Income Fund
2845 Bristol Circle
Oakville ON
L6H 7H7

Remit To: Grant Thornton LLP
350 Burnhamthorpe Road West
Suite 401
Mississauga, ON L5B 3J1

BN 12194 0282 RT0001

**CLIENT # 50000**

**TO PROFESSIONAL SERVICES**

**INVOICE # 223526**

| | | |
|---|---|---|
| Review of September 30, 2008 quarterly Canadian and US tax provisions. | | $8,110.00 |
| Administration Fees 3.5% | | 283.85 |
| | | $8,393.85 |
| | GST | 419.69 |
| | | $8,813.54 |

Chargeback
APT
APDT
APFL
APFA
AWRA
APEFW
St. Leon LP.
Mont Laurier

COMPANY
APIF
APPROVED
PAID

1000 GRATIO
ACCT
1000-1.000-20-2110-0000
A.B.
PO CODE

OK

**Billing Address**
Royal Bank Plaza
200 Bay St, Box 55
19th Floor South Tower
Toronto ON M5J 2P9
T 416-366-0100
F 416-360-4949
E Toronto@GrantThornton.ca
W www.GrantThornton.ca

***Make payment(s) payable to Grant Thornton LLP***

**Audit • Tax • Advisory**
Grant Thornton LLP. A Canadian Member of Grant Thornton International Ltd

All accounts outstanding over 30 days will be charged interest at the rate of 1 1/2% per month (18% per annum) until paid.

KPMG

June 26, 2008

**Invoice No. : 43139627**
Reference : CA001-11553398
Client : 60110711

KPMG LLP
Suite 3300 Commerce Court West
199 Bay Street
Toronto ON M5L 1B2

Telephone : (416) 777-8500
Telefax : (416) 777-8818

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact : John Krukowski
Telephone : 416-777-8579

**PRIVATE AND CONFIDENTIAL**
Algonquin Power Income Fund
2845 Bristol Circle
Oakville, ON L6H 7H7

Attention : Mr. David Bronicheski, Chief Financial Officer

For Canadian tax services rendered for the period ending January 31, 2008:

| | |
|---|---|
| OUR FEE | $ 7,700.00 |
| GST | 385.00 |
| **INVOICE AMOUNT** | **$ 8,085.00** |

POSTED
-07- 29 2008
OAKVILLE

2007 Tax Services

| RECEIVED | VENDOR ID |
|---|---|
| 7/29/08 | |
| COMPANY | G/L CODE |
| APIF 1000 | 1000.1.0000.20.2110.0000 |
| APPROVED | JOB # |
| | |
| PAID | COST CODE |
| | |

Payment is due upon receipt

accrued

**Algonquin Power Group**
**Canadian tax services billling details to January 31, 2008**

| Description of work | Amount | Billed to |
|---|---|---|
| Assistance provided with respect to the tax audit by CRA of APFC for the years from 2001 to 2005 including the following:<br>- Reading the information request from the CRA auditor, various discussions with APFC regarding the information requested and approach<br>- Various discussions and research regarding taxation years that are statute barred and CCPC status, request for signing of waiver by the CRA auditor<br>- Various discussions regarding settlement of Franklin Notes, research tax implications and prepared for appropriate reply to CRA auditor's questions, deductibility of legal fees<br>- Carrying out a review of management agreement, various discussions regarding allocation of management fees to US companies<br>- Read CRA auditor's letter regarding information required and issues raised, review of letter prepared by the Fund in response, several discussions, research and preparing response to CRA's letter<br>- Attendance at a meeting with CRA auditor to discuss the issuues raised by him and providing our comments thereon<br>- Review of schedule prepared by the Fund after incorporating CRA's proposed adjustments and claiming CCA to minimize tax impact in the taxation years subject to audit<br>- Review of notices of reassessments issued by CRA and discussions to compare with the adjustments proposed by the CRA auditor<br>- Review of notices of reassessments issued by Ontario in response to federal adjustments, research for filing of notice of objection, discussions with Luisa regarding missing notice of assessment, compared with CRA's adjustments | 42,900 | APFC |
| Services related to potential acquisitions of PPL Gas Utilities and Northern Utilities, Inc., including assistance with developing structuring alternatives, assistance with due dilligence and modelling issues, numerous emails, discussions and meeting thereon | 43,000 | Algonquin America AWEA |
| Preparation of revised steps memo for in-house loss utilization plan involving APEFW/APFC and providing revised analysis including results of research on affiliation rules, research for general anti-avoidance rules ("GAAR") and other related matters during the period | 18,300 | APFC |
| Assistance provided in reviewing draft T3 tax return and the information for CDS reporting purposes of Algonquin Airsource LP for the year ended December 31, 2006, including various discussions with Peter Kampian thereon | 3,500 | Airsource |
| Various follow up discussions and providing additional information as requested by the CRA for T1134s filed under the voluntary disclosure program for prior years, review of forms T1134s for the year 2005 for various entities and provided comments thereon. | 1,500 | APFC |
| Various discussions regarding transfer of power generating facility (the "Facility") by St. Leon Wind Energy GP Inc. to St. Leon LP including review of election (form T2059), read steps memo and other documents on transfer of the Facility and providing comments thereon. | 1,000 | St Leon LP |

| | | |
|---|---|---|
| Research legislation regarding energy rebate opportunity, manufactureres rebate and providing you with a letter summarizing the information requested, discussions and request with the Ontario authorities for clarifications on certain issues | 4,800 | APFC |
| Various discussions regarding implementation of SIFT tax due to its enactment, discussions regarding incorporating and developing new worksheets to calculate future tax relating to flow-through entities and implications on current and future tax calculations | 3,400 | APIF |
| Review of tax returns of APFC and APEFW for the year ended December 31, 2006 and providing our comments thereon. | 1,700 | APFC / APEFW |
| Review of information provided for Crossroad reorganization in the U.S. in 2007 and its implications for Canadian income tax purposes effecting surplus calculations | 2,500 | APFC |
| Attendance at meeting on October 4 to discuss tax issues and various matters relating to tax compliance | 3,600 | APFC |
| Preparation of update on various tax issues relating to the overall Canadian structure and December 18 meeting with trustees and management to provide update on tax matters and tax opportunities | 4,000 | APIF |
| Miscellelaneous questions raised from time to time, including information on functional foreign currency reporting, providing corporate income tax rates for tax provision purposes, discussions regarding creation of new company for administration of expeneses and payroll, etc. | 1,200 | APFC |
| Disbursements and administrative | 6,300 | Various |
| **Total fees** | **137,700** | |

| | |
|---|---|
| **Billed to:** | |
| Airsource | 3600 |
| St Leon LP | 1000 |
| APIF | 7700 |
| Algonquin America | 45100 |
| APFC | 80300 |
| | **137700** |

KPMG

June 26, 2008

**Invoice No. : C 43139839**
Reference : CA001-11668964
Client : 60110711

KPMG LLP
Suite 3300 Commerce Court West
199 Bay Street
Toronto ON M5L 1B2

Telephone : (416) 777-8500
Telefax : (416) 777-8818

GST/HST Number 12236 3153 RT0001
QST Registration 1023774310 TQ0001

Contact : John Krukowski
Telephone : 416-777-8579

**PRIVATE AND CONFIDENTIAL**
~~Algonquin Power~~ Fund (America) Inc. AWRA
c/o 2845 Bristol Circle
Oakville, ON L6H 7H7

Attention : Mr. David Bronicheski, Chief Financial Officer

For Canadian tax services rendered for the period ending January 31, 2008:

| | | |
|---|---|---|
| OUR FEE | POSTED | $ 45,100.00 |
| GST EXEMPT | -07- 29 2008 | .00 |
| **INVOICE AMOUNT** | OAKVILLE | **$ 45,100.00** CDN |
| | | **OR $ 45,100.00** US |

| RECEIVED | VENDOR ID |
|---|---|
| 7/29/08 | 8010KPMG |
| **COMPANY** AWRA 8010 | **G/L CODE** 8010.2.0000.75.7351.0000 |
| **APPROVED** | **JOB #** |
| **PAID** | **COST CODE** |

OK

Payment is due upon receipt

GrantThornton

February 29, 2008

Algonquin Power Income Fund
2845 Bristol Circle
Oakville ON L6H 7H7

Remit To: Grant Thornton LLP
350 Burnhamthorpe Road West
Suite 401
Mississauga, ON L5B 3J1
BN 12194 0282 RT0052

**CLIENT # 50000**

**TO PROFESSIONAL SERVICES**

**INVOICE # 218189**

Rendered in connection with review of the 2007 year end Canadian and US tax provisions; discussions regarding potential amendment of prior year US tax returns.

| | | |
|---|---|---|
| | | $12,000.00 |
| Disbursements | | 420.00 |
| | | $12,420.00 |
| | GST | 621.00 |
| | | $13,041.00 |

Payment Copy
Please Return With Cheque

**Billing Address**
Royal Bank Plaza
200 Bay St, Box 55
19th Floor South Tower
Toronto ON M5J 2P9
T 416-366-0100
F 416-360-4949

Invoice

Remit To:
ALGONQUIN POWER SYSTEMS

2845 Bristol Circle

Oakville, ON L6H 7H7
(905) 465-4500 Ext. 0000

Bill To:
Algonquin Power Trust - CDN
Attn:
Mr. David Kerr
2845 Bristol Circle

Oakville, ON L6H 7H7

Job Address:
2845 Bristol Circle

Oakville, ON L6H 7H7

| Date | Invoice Number | Customer Order Number | Customer Number | Net Terms |
|---|---|---|---|---|
| 9/30/2008 | JC37841 | | 002APTCDN | Net 30 |

Description

Job Number: 002-999907-3686 Job Name: APT-Ciel Pot.Acq -110098400061

| Admin. | Quantity | Unit Chg | Billable Amount |
|---|---|---|---|
| COMMUNICATION | 1.00 | 53.94 | 53.94 |
| Tele Communications de L'est | 1.00 | TELEPHONE & COMMUNICATION 686.40 | 686.40 |
| Ferme Castonguay Enr | 1.00 | LICENSES AND FEES 674.40 | 674.40 |
| Ferme RUISSOROCK S.E.N.C | 1.00 | LICENSES AND FEES 419.94 | 419.94 |
| Aime Durette | 1.00 | LICENSES AND FEES 642.45 | 642.45 |
| Jean-Yves Lavoie et Johanne Richar | 1.00 | LICENSES AND FEES 839.60 | 839.60 |
| Ranch Danclau inc. | 1.00 | LICENSES AND FEES 497.80 | 497.80 |
| Raymond Pelletier | 1.00 | LICENSES AND FEES 453.08 | 453.08 |
| Victor Labrie | 1.00 | LICENSES AND FEES 727.80 | 727.80 |
| Ferme J.M. Paquet & Fils Inc. | 1.00 | LICENSES AND FEES 360.00 | 360.00 |
| Claude Dube | | LICENSES AND FEES | |

| | |
|---|---|
| Admin. Total: | 5,355.41 |
| Billing Amount: | $5,355.41 |
| Retention Withheld: | $0.00 |
| Retention Due: | $0.00 |
| Subtotal: | $5,355.41 |
| Misc: | 0.00 |
| Tax: | 689.52 |
| Pay This Amount: | $6,044.93 |

| RECEIVED | VENDOR ID |
|---|---|
| | 1100APS-CDN |
| COMPANY | G/L CODE |
| APT | 1100-1-0000-75-7430-0000 |
| APPROVED | JOB # |
| | 1100-9840-0061 |
| GST Number: | 13248 7463 RC0001 |
| PAID | COST CODE |
| | 6-7200-0000-0000 |

$5,301.47

$53.94

Kendall
PRINTING COMPANY LIMITED

19 Belvia Road
Toronto, Ontario
M8W 3R2
Tel: 416 252 3174
Fax: 416 252 0068
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Invoice #:B3047

Date: 07 04 2008

Algonquin Power Income Fund
2020 Winston Park Drive
Suite 100
Oakville ON L6H 6X7

**Ship To:**

Broadridge
Perkins Mailing Services
Olympia Transfer Services

Printing costs for Highground Takeover material

| Description | Amount |
|---|---|
| 1,500 - proxy | |
| 5,000 - Offering memorndum 208 page + cover | |
| 5,000 - President/shareholder letter 2 side | |
| 100 - letter of transmittal 3 page - yellow stock | |
| total | $74,240.00 |

| RECEIVED | VENDOR ID |
|---|---|
| COMPANY AP LF 1000 | G/L CODE 1000.1.6000.20.2110.0000 |
| APPROVED | JOB # |
| PAID | COST CODE |

| | | | |
|---|---|---|---|
| Your Order #:Ian | Terms:Net 30 | Sub Total: | $74,240.00 |
| Tax ID Number: | | GST. | $3,712.00 |
| | | PST: | $5,939.20 |
| GST Registration #:102801842RT001 | | **Total Amount:** | **$83,891.20** |

***Detach and return this portion with payment***

Algonquin Power Income Fund
2020 Winston Park Drive
Suite 100
Oakville ON L6H 6X7

Invoice #: B3047
**$83,891.20**

RECEIVED
-07- 30 2008
OAKVILLE

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BEFORE THE ARIZONA CORPORATION C

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
NOV 19 2008
DOCKETED BY nr

EXHIBIT
R-7
ADMITTED

IN THE MATTER OF THE APPLICATION OF GOLD CANYON SEWER COMPANY FOR A DETERMINATION OF FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.

DOCKET NO. SW-02519A-06-0015

DECISION NO. 70624

**REHEARING OPINION AND ORDER**

DATES OF REHEARING: November 14, 2007; February 25, 2008; March 31, 2008

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: Mike Gleason, Chairman
William A. Mundell, Commissioner
Kristin K. Mayes, Commissioner
Gary Pierce, Commissioner

APPEARANCES: Mr. Jay L. Shapiro, FENNEMORE CRAIG, P.C., on behalf of Gold Canyon Sewer Company;

Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumers Office;

Mr. Mark Tucker, MARK TUCKER, P.C., on behalf of Cal-Am Properties, Inc.; and

Ms. Robin Mitchell, Mr. Keith Layton, and Ms. Nancy Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

**BY THE COMMISSION:**

On January 13, 2006, Gold Canyon Sewer Company ("Gold Canyon" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges for wastewater utility service provided to customers in the Company's certificated service area in Pinal

County, Arizona.

On June 28, 2007, the Commission issued Decision No. 69664, granting a rate increase to Gold Canyon.

On July 18, 2007, the Residential Utility Consumer Office ("RUCO") filed an Application for Rehearing on two issues raised by RUCO during the hearing: (1) an allegation of "excess capacity" in the Company's treatment plant and (2) the capital structure employed in the Commission's Order for purposes of determining the Company's cost of capital.

During an Open Staff Meeting held on August 1, 2007, the Commission granted rehearing to RUCO.

A procedural conference was held on September 5, 2007. During the procedural conference, the parties discussed, among other things, testimony filing dates and potential hearing dates.

By Procedural Order issued September 14, 2007, a hearing was scheduled to begin on November 13, 2007, Gold Canyon was directed to publish notice of the hearing, and testimony filing dates were established.

By Procedural Order issued October 15, 2007, a procedural conference was scheduled for October 22, 2007, to discuss a discovery dispute between the Company and the Commission's Utilities Division Staff ("Staff"). The Procedural Order also granted an extension of the testimony filing deadline.

The November 13, 2007, hearing was vacated due to unavailability of the hearing facility. The hearing commenced on November 14, 2007, but did not conclude that day. At the end of the hearing on November 14, 2007, the parties were directed to discuss scheduling of additional hearing days and to submit a proposed schedule.

On November 20, 2007, RUCO, Staff, and the Company filed a Joint Motion to Set Continued Rehearing Dates. The parties requested that additional hearing days be scheduled for January 17 and 18, 2008.

By Procedural Order issued November 29, 2007, the rehearing in this matter was scheduled to resume on January 17 and 18, 2008.

On December 11, 2007, RUCO requested that the rehearing be rescheduled to resume on

February 25, 2008, due to an out-of-state commitment by RUCO's counsel.

By Procedural Order issued December 12, 2007, the hearing was rescheduled to resume on February 25, 2008. An additional day of hearing was conducted, as scheduled, on February 25, 2008, but the hearing was not concluded on that day. The parties agreed to an additional hearing day on March 31, 2008.

On March 31, 2008, the hearing resumed with the cross-examination of Staff witnesses. The hearing did not conclude on that date, however, due to the unavailability of a RUCO witness.

On April 10, 2008, a teleconference was conducted with the parties. Due to the continuing unavailability of the RUCO witness for cross-examination, the parties agreed that portions of the RUCO witness's prior testimony would be stricken.[1] In addition, a briefing schedule was established.

Opening briefs were filed on May 5, 2008, by RUCO, Gold Canyon and Staff, and reply briefs were filed on May 22, 2008, by the same parties.

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

## FINDINGS OF FACT

1. In Decision No. 69664, the Commission granted Gold Canyon a revenue increase of approximately $1.8 million, resulting in an increase to residential sewer rates from $35.00 to $60.55 per month, or approximately 72 percent.

2. In its Application for Rehearing, RUCO argued that the rate increase is unfair to customers due to its magnitude. RUCO raised two specific issues as a basis for its rehearing request: (1) the Commission should have disallowed from rate base approximately $2.8 million to reflect what RUCO claims is "excess capacity" in Gold Canyon's wastewater treatment plant; and (2) the Commission should have adopted RUCO's proposed hypothetical capital structure of 60 percent equity and 40 percent debt, rather than the actual 100 percent equity capital structure used by the Commission, to calculate the Company's cost of capital.

[1] Under the parties' agreement, page 87, line 12 through page 92, line 9, and page 100, line 21 through page 101, line 15, of the verbal testimony of RUCO witness Marylee Diaz Cortez at the November 14, 2007, hearing was deleted from the evidentiary record.

3. During a Staff Meeting held on August 1, 2007, the Commission voted to grant RUCO's rehearing request and send the matter back for additional hearings on the issues raised by RUCO.

4. Hearings were held before an Administrative Law Judge, and additional testimony and exhibits were admitted into the evidentiary record. The record produced by the prior hearings in this docket was incorporated into the rehearing record of this case.

**Excess Capacity**

5. In Decision No. 69664, the Commission agreed with the Company and Staff that Gold Canyon's decision to increase the treatment plant's capacity from 1.0 million gallons per day ("gpd") to 1.9 million gpd was reasonable and should not result in a disallowance from rate base. As described in that Decision, the Commission disagreed with RUCO's proposed use of a mathematical disallowance, because of the evidence in the record that increasing the plant's capacity to 1.9 million gpd was a prudent decision based on peak flows and growth projections available to the Company at the time the decision was made.

6. As stated in Decision No. 69664, RUCO witness Rodney Moore conceded that Gold Canyon's decision to expand the treatment plant to 1.9 million gpd, rather than to 1.5 million gpd, was "reasonable" and "appropriate" and that the Company must consider *peak* flows in its analysis, as opposed to *average* daily flows, in making its plant expansion decisions. (Tr. 943, 951-54.) Despite these admissions, Mr. Moore advocated use of an average daily flow rate of 708,000 gpd for purposes of calculating RUCO's proposed $2.8 million disallowance. RUCO's proposal is based on its contention that approximately 28 percent of the plant is not "used and useful" from a "ratemaking perspective." (Decision No. 69664, at 6.)

7. As set forth in Decision No. 69664, Company witness Charles Hernandez, Gold Canyon's treatment plant operator, testified that Gold Canyon experienced a peak flow of almost 1.2 million gpd in February 2005. Based on growth projections at the time, Staff witness Marlin Scott, Jr., estimated that Gold Canyon would have a peak flow of more than 1.5 million gpd by mid-2007. As we stated in that Decision:

> not only did test year peak flows exceed the then-current capacity, but if the Company had expanded the plant to only 1.5 [million gpd], in order to avoid RUCO's proposed excess capacity disallowance, it would have needed to almost immediately begin planning to add another incremental amount of capacity to meet ongoing demand increases." (*Id.* at 7.)[2]

We also cited to testimony in the record that the additional 400,000 gpd of capacity was installed at a cost of approximately $1 million, whereas adding the same increment of capacity at a later date would have cost substantially more.[3]

RUCO's Position

8. In the rehearing phase of this proceeding, RUCO witness Moore continues to rely on the Company's average daily flows, rather than peak flows, for purposes of calculating RUCO's excess capacity adjustment. He also stated that RUCO's proposed disallowance is supported by the slower than anticipated growth that has occurred in the past two years (RUCO RH-1, at 2-5). In its post-hearing brief, RUCO states that "[w]hile no one has a crystal ball, given the actual growth that Gold Canyon has experienced since 2006, it is unlikely the Company will reach build-out by 2010" (RUCO Closing Brief at 2).

9. RUCO cites to several Commission decisions as precedent for its proposed excess capacity adjustment. RUCO cites Decision No. 50273 (*Litchfield Park Service Co.*, September 20, 1979), an accounting order in which the Commission excluded 50 percent of a new wastewater treatment plant because only 50 percent of the plant was being utilized. There was no hearing held in the case and, in the two-page accounting order, there was no discussion of the details of the plant's construction or whether LPSCO opposed the exclusion. When LPSCO sought inclusion of the remaining 50 percent of the plant in rate base approximately 10 years later, RUCO claims, Staff recommended disallowance, and LPSCO did not oppose that recommendation. (*See* Decision No. 56362, February 22, 1989, at 7).

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[2] Staff witness Marlin Scott explained that capacity requirements are evaluated over a five-year planning horizon and, under the Arizona Department of Environmental Quality's ("ADEQ's") "80 percent rule," sewer utilities are expected to have plans in place to increase capacity when demand reaches 80 percent of capacity and to have construction under way when demand reaches 90 percent of capacity *(Id.)*.

[3] Mr. Hernandez stated that adding 400,000 gpd of capacity at a later date would have cost the Company as much as $9 million. He also indicated that adding the additional capacity separately would have caused significant disruption to neighboring customers in the form of noises and odors that were experienced during the prior plant expansion (Rh. Tr. 246, 301-03).

10. RUCO also cites Decision No. 57395 (*Chaparral City Water Co.*, May 23, 1991, at 5) for the proposition that Chaparral City, not ratepayers, was required to bear the risk that anticipated growth would not occur. In that case, the Commission specifically did not exclude the Central Arizona Project ("CAP") facilities from rate base but, instead, adopted a rate design that allocated a portion of the recovery of some of the plant investment onto future customers through a hook-up fee. (*Id.* at 5-6.) However, Chaparral City's revenue requirement allowed for a return on the full cost of the plant. (*Id.*)

11. RUCO next argues that Decision No. 58743 (*Pima Utility Co.*, August 11, 1994, at 4-5) supports its claim that plant not serving customers is properly excluded from rate base because it is not used and useful. In that case, the Commission denied Pima Utility's request for inclusion of construction work in progress ("CWIP") in rate base and, according to RUCO, drew a distinction between the used and useful concept from a ratemaking and an engineering standpoint. In that Decision, the Commission found that, 15 months after the test year, the phase of the development to be served by the new plant was completely uninhabited, and therefore, the plant built to serve future customers was not used and useful and should be excluded from rate base. (*Id.*)

12. The final case cited by RUCO is Decision No. 56659 (*Tucson Electric Power Co.*, October 21, 1989, at 19-21), wherein the Commission excluded from rate base approximately $32.5 million related to TEP's investment in a mineable source of coal located in Gallo Wash, New Mexico, through an agreement that required TEP to make royalty payments whether or not any coal was actually mined. In making the disallowance, the Commission stated that there was no evidence any coal would ever be mined at the location and no railroad access to the mine that would enable transportation of the coal even if it were mined. As a result, the Commission found that the property was not used and useful and that "the investment is imprudent." (*Id.* at 20.)

Gold Canyon and Staff Positions

13. The Company and Staff argue that the cases cited by RUCO do not support its proposed excess capacity recommendation. Both point out that the *Chaparral City* case (Decision No. 57395) provided for recovery of the full costs of the CAP plant, despite the plant's capacity being greater than was needed to serve existing customers. With respect to the *LPSCO* matter, Gold

Canyon contends that the Commission's accounting order (Decision No. 50273) included virtually no discussion concerning the reason for the disallowance, and when the plant was still not being used to serve customers 10 years later, LPSCO did not challenge Staff's continued disallowance recommendation. (Decision No. 56362.) The Company claims that, in contrast to the LPSCO situation, Gold Canyon's plant was prudently built (by RUCO's admission), and the capacity is used and useful to serve customers over a five-year planning horizon.

14. Staff and the Company also argue that the *Pima Utility* case (Decision No. 58743) does not support RUCO's claims. Staff asserts that the case shows the Commission's reluctance to allow CWIP in rate base and, as such, has no bearing on the factual situation at issue in the Gold Canyon case. Staff pointed out that because the area intended to be served by the new Pima Utility plant was almost completely vacant well after the test year, inclusion in rate base would violate the ratemaking principle of matching revenues and expenses. The Company added that CWIP plant is entirely different from plant that is completed during the test year and is built to serve current customers and expected growth over a five-year horizon. Regarding the *TEP* case, Gold Canyon cited to the Commission's finding that TEP's investment was imprudent, because no coal was or could be delivered from the site, and the investment was therefore not used and useful. In contrast, the Company points out that RUCO has acknowledged that Gold Canyon's addition of the 400,000 gpd increment of capacity was prudent.

Resolution of Excess Capacity Issue

15. The Gold Canyon system was acquired in 2003 by Algonquin Water Resources of America ("Algonquin"). At that time, it had become apparent that the prior owner of the Company, a homebuilder, had constructed a treatment system that, by all accounts, contained insufficient treatment capacity for existing and expected customers. The inadequacy of the Gold Canyon system's facilities was evidenced by the issuance of several Arizona Department of Environmental Quality ("ADEQ") Notices of Violation to the Company due to raw sewage overflows into a wash adjacent to the treatment plant during periods of heavy rainfall. The Company had also received numerous complaints from area residents regarding odors and noise emanating from the original treatment facility. (*See* Decision No. 69664 at 30-35.)

16. The evidence indicates that almost immediately upon acquisition of Gold Canyon Sewer Company by Algonquin, the Company began planning to increase the plant's capacity and, based on growth and peak flow projections at the time, decided that expansion of the plant from 1.0 to 1.9 million gpd would provide adequate capacity over a five-year planning horizon, pursuant to ADEQ and Commission Staff guidelines, and would be the most cost-effective and least disruptive means of expanding the plant. The testimony also indicates that the treatment plant had been built in a less-than-ideal location adjacent to residential lots and a portion of a golf course. Following the acquisition, Gold Canyon moved quickly to invest significant capital (approximately $11 million) to upgrade and expand the plant in order to meet growth projections and respond to the many complaints registered by customers in the Gold Canyon community. (Tr. 678, 725-27.)

17. The record reflects that the guidelines employed by ADEQ and Commission Staff require wastewater utility companies to plan treatment capacity needs using a five-year planning horizon, based on peak flows. (Reh'g. Tr. at 512-14.) The ADEQ guidelines require companies to begin planning to add additional capacity when peak flows reach 80 percent of capacity, and to have construction underway when peak flows reach 90 percent of capacity. (Tr. at 305-06; Reh'g. Tr. at 523-34.) The plant's operator and Staff's engineer testified that Gold Canyon's treatment facility achieved a peak flow of 117 percent of then-current capacity in February 2005. (Tr. at 254; Ex. S-1, Attach. Ex. MSJ at 4.) In addition, it is undisputed that the smallest additional increment of capacity that could have been added at that time was 500,000 gpd and that peak flows were projected to exceed 1.5 million gpd by June 2007 (Tr. at 1066, Reh'g. Tr. at 257-58; Ex. S-1, Attach. Ex. MSJ at 4.) Under the facts known at the time, the Company had a choice. It could add the minimum 500,000 gpd of capacity and almost immediately begin construction of additional capacity to meet projected demand, or it could increase treatment capacity to the maximum permitted capacity of 1.9 million gpd all at one time. The testimony indicates that adding the additional 400,000 gpd increment of capacity at that time cost less than $1 million, saving at least several million dollars compared to increasing the capacity in phases. (Reh'g. Tr. at 257-58, 513.) The Company's decision also avoided additional disruptions to customers that would have been experienced if the plant had been built in phases.

18. We agree with RUCO that the Company had excess capacity at the Gold Canyon treatment plant during the test year and will disallow $1.0 million from the Company's rate base. The Commission is including in rate base all of the necessary plant capacity through 2008. Once the excess capacity becomes used and useful the Company will have the opportunity to earn a full rate of return on the entire plant. Until that time, the Company shall establish a deferred depreciation expense account to record the depreciation expenses on the disallowed plant. However, in the interim the Commission believes the Company's rate base should be decreased by $1.0 million.

**Hypothetical Capital Structure**

Decision No. 69664 Findings

19. In Decision No. 69664, we rejected RUCO's proposal to employ a hypothetical capital structure of 40 percent debt and 60 percent equity for purposes of establishing Gold Canyon's cost of capital. We agreed with Gold Canyon and Staff that the Company's actual 100 percent equity capital structure should be used. Because a 100 percent equity capital structure tends to minimize the overall financial risk for a company, we also adopted Staff's recommendation to employ a so-called "Hamada" adjustment of 100 basis points to the cost of equity calculated by Staff, thereby reducing Staff's Discounted Cash Flow ("DCF") and Capital Asset Pricing Model ("CAPM") average of 10.2 percent to 9.2 percent. (Decision No. 69664, at 24-29.) With the 100 basis point reduction to Staff's cost of equity determination, to account for Gold Canyon's risk being less than that of the sample companies' used in Staff's analysis, the 9.2 percent rate of return adopted in the Decision was found to be a reasonable reflection of the Company's weighted cost of capital in this proceeding. (*Id.* at 27-29.)

RUCO's Position

20. In the rehearing phase, RUCO continues to advocate for adoption of a hypothetical capital structure of 40 percent debt and 60 percent equity to account for Gold Canyon's lower level of financial risk, due to the absence of debt in the Company's capital structure. In its Application for Rehearing, as well as in the testimony of RUCO witness William Rigsby, RUCO agreed that the recognition of a lower level of financial risk could be accomplished by either adjusting DCF results downward or employing a hypothetical capital structure. (RUCO RH-4, Attach. 1, at 50-53.)

21. RUCO claims that its hypothetical capital proposal provides a more balanced result for ratepayers and shareholders and would reduce the current monthly bill of $60.55 to $53.84 (RUCO RH-1 at 6.) RUCO disputes the Company's assertion that RUCO is simply trying to lower customer bills by any means possible. RUCO contends that its proposed methodology is consistent with past Commission practices and takes into account the magnitude of the increase authorized by the underlying Decision. RUCO cites to Article 15, Section 3, of the Arizona Constitution, which requires the Commission to set "just and reasonable rates," and to language contained in a decision rendered by the Arizona Supreme Court in *Arizona Community Action Assoc. v. Arizona Corporation Comm'n*, 123 Ariz. 228, 231, 599 P.2d 184, 187 (1979), which provides: "A reasonable rate is not one ascertained solely from considering the bearing of facts upon the profits of the corporation. The effect of the rate upon persons to whom services are rendered is as deep a concern in the fixing thereof as is the effect upon the stockholders." RUCO argues that it is within the Commission's discretion to consider the magnitude of rate increases and the effects on customers in setting rates. RUCO asserts that the Commission should take into account ratepayer comments that have been received by the Commission through numerous letters and public comments.

22. RUCO also supports its hypothetical capital structure proposal with the claim that it was the Company's choice to capitalize with 100 percent equity rather than with a mix of lower cost debt. According to RUCO witness Rigsby, debt has the advantage of being able to reduce income taxes, and thus overall expenses, whereas dividend payments to equity holders do not offer a similar tax advantage. (RUCO RH-4, at 33.) RUCO argues that Gold Canyon should not be rewarded for its "imprudent and unbalanced capital structure." (RUCO Brief at 9.) RUCO also claims that the Company's capital structure should emulate the proxy group of companies used in the industry, which Mr. Rigsby stated had average capital structures of 51 percent debt and 49 percent equity (*Id.* at 13.)

23. RUCO contends that use of a hypothetical capital structure is preferable to Staff's Hamada adjustment. Mr. Rigsby asserts that the problem with Staff's use of the Hamada methodology is that Staff applied it to the average of its DCF and CAPM results instead of just the CAPM. Mr. Rigsby also criticizes the Hamada adjustment's failure to produce an appropriate

interest deduction to reflect debt in the capital structure. He stated that the additional cash flows associated with higher income tax expense benefits shareholders rather than ratepayers, whereas use of a hypothetical capital structure reflects a more balanced capital structure and results in a lower cost of capital for ratemaking purposes (*Id.* at 34.)

Staff's Position

24. Staff contends that RUCO has not offered any new testimony in the rehearing phase of this case that was not previously considered by the Commission. Staff claims that none of the prior Commission Decisions cited by RUCO in which the Commission adopted a hypothetical capital structure involved an increase in the debt component. Rather, Staff says, they increased the equity component as a means of enabling highly leveraged companies to earn their authorized rates of return.

25. Staff concedes that a balanced capital structure is preferable, but disagrees that a company that is capitalized with only equity has an imprudent capital structure. Staff claims that a number of prior Commission Decisions have adopted 100 percent equity capital structures for water and sewer companies. Staff also points out that the Commission has previously recognized the appropriateness of using a Hamada adjustment to address a company's unbalanced capital structure and has adopted Staff's Hamada recommendations in many prior cases.

26. Staff witness Steve Irvine testified that, contrary to RUCO's criticism, application of the Hamada adjustment to the average of the DCF and CAPM results is an appropriate method to adjust for financial risk. (Reh'g Tr. at 447-48.) Mr. Irvine conceded that using a hypothetical capital structure may be an appropriate alternative to the Hamada adjustment for purposes of adjusting an unbalanced capital structure, but he testified that Staff usually prefers the Hamada method because it is a less subjective methodology. (*Id.* at 446.) Staff argues that excessive debt increases financial risk and generally views excessive equity as less problematic than excessive debt. Staff also contends that use of the Hamada adjustment to recognize a company's financial risk, which in this case reduced Gold Canyon's cost of equity by 100 basis points, provides an incentive to the Company to maintain a reasonable level of debt in its capital structure or face reductions to its authorized return on equity.

Gold Canyon's Position

27. Gold Canyon contends that the Commission's Decision in the recent *Black Mountain Sewer Corporation,* case (Decision No. 69164, (December 5, 2006)), should be considered as controlling precedent in this proceeding because the stock of both Black Mountain and Gold Canyon is owned by Algonquin, both rate cases were filed in approximately the same time frame, and the Commission rejected RUCO's proposed hypothetical capital structure argument in *Black Mountain* and adopted Staff's 9.6 percent cost of equity recommendation. Staff's analysis in *Black Mountain* was based on an average of its DCF and CAPM calculations, but did not include a downward Hamada adjustment as was done in this case. (*Id.* at 23-27.)

28. The Company also cites a recent *Arizona-American Water Company (Paradise Valley)* case (Decision No. 68858 (July 28, 2006)), in which the Commission adopted Staff's recommended 10.4 percent cost of common equity, including a 50 basis point upward adjustment to reflect a higher financial risk associated with that company's high percentage of debt. (Decision No. 68858 at 28.) Gold Canyon claims that the *Paradise Valley* Decision properly reflects the Commission's use of an equity adjustment to recognize financial risk. The Company also points out that in a number of other recent cases involving both water and wastewater companies, the Commission has adopted Staff's recommended cost of equity, either with or without risk adjustments, but has not employed a hypothetical capital structure as a means of recognizing relative financial risk.[4]

29. Gold Canyon contends that the only two recent cases in which the Commission adopted a hypothetical capital structure involved Arizona-American's Mohave Water and Wastewater Districts and Southwest Gas Corporation.[5] The Company argues that in both of those cases, the Commission made only minor adjustments to the companies' *actual* capital structures in setting the cost of equity. In the *Arizona-American* case, the Commission increased the company's equity component from 37.2 percent to 40 percent; in *Southwest Gas*, the company's equity was

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[4] The Company cited *Far West Water and Sewer*, Decision No. 69335 (February 20, 2007); *Arizona Water Co. (Western Group)*, Decision No. 68302 (November 14, 2005); *Chaparral City Water Co.*, Decision No. 68176 (September 30, 2005); *Arizona Water Co. (Eastern Group)*, Decision No. 66849 (March 9, 2004); and *Rio Rico Utilities*, Decision No. 67279 (October 5, 2004).

[5] The Company cited *Arizona-American (Mohave)*, Decision No. 69440 (May 1, 2007); and *Southwest Gas Corp.*, Decision No. 68487 (February 23, 2006).

increased from 37 percent to 40 percent for purposes of establishing the cost of equity. Gold Canyon asserts that these minor hypothetical capital structure adjustments are the exception rather than the rule in Commission Orders and that they are significantly different from RUCO's proposal to reduce Gold Canyon's equity ratio of 100 percent to a hypothetical level of 60 percent.

30. The Company claims that RUCO's real motive in proposing a hypothetical capital structure is to lower Gold Canyon's operating expenses by creating a further hypothetical interest expense resulting from the hypothetical debt creation. According to the Company, after assuming Gold Canyon has hypothetical interest expense associated with the hypothetical debt, RUCO next uses the hypothetical interest to calculate the Company's federal and state income tax expenses, thereby calculating a hypothetical reduced income tax obligation, and ultimately fictionally reducing the Company's actual test year operating expenses. Gold Canyon points out that, without the additional hypothetical interest adjustment, simply applying RUCO's proposed hypothetical capital structure to the authorized rate base of $15,725,787 would actually increase the revenues authorized in Decision No. 69664 from $1,446,772 to $1,493,950, increasing the authorized return on rate base from 9.2 percent to 9.5 percent. Gold Canyon argues that it is only by recognizing RUCO's proposed hypothetical debt interest expense that the authorized revenue requirement would be reduced – by over $205,000. The Company contends that RUCO's recommendation would result in an approximate 10 percent reduction of its authorized revenues, thus reducing the Company's actual authorized return on rate base to 7.24 percent. (GC RH-8 at 16-17.) Gold Canyon claims that Staff's 100 basis point reduction to a 9.2 percent return on common equity is a more appropriate means of recognizing the Company's lower financial risk associated with its 100 percent equity capital structure.

31. Gold Canyon also argues that RUCO's analysis fails to recognize that a reduction in income taxes would be offset by payment of interest and principal to the lender of the debt. The Company claims that incurrence of debt would reduce its net income from operations and could limit its ability to invest in improvements and pay dividends. (GC RH-7 at 7.) Gold Canyon asserts that companies should not be required to have capital structures consisting primarily of debt as a means of providing a tax shield, especially in the case of smaller companies that may need to undertake

significant expenditures for plant additions and replacements. The Company therefore requests that RUCO's request to amend the prior Decision be denied.

Resolution of Hypothetical Capital Structure Issue

32. We agree with RUCO's hypothetical capital structure of 40 percent debt and 60 percent equity. A capital structure comprised of 100 percent equity would be viewed as having little to no financial risk. The proposed capital structure adopted by the Commission will bring the Company's capital structure and weighted cost of capital in line with the industry average and it will result in lower rates for the customers of the system. We therefore adopt a hypothetical capital structure of 40 percent debt and 60 percent equity.

33. We believe that RUCO's recommendation for a 8.60 percent cost of equity capital is appropriate, and will adopt it in this case. RUCO's expert witness relied on a DCF model and a CAPM analysis for calculating his cost of equity capital. We believe that adoption of RUCO's recommendations results in just and reasonable rates and charges for Gold Canyon based on the record of this proceeding. We therefore adopt a cost of equity of 8.60 percent, which also results in an overall weighted cost of capital of 8.54 percent.

Rate Case Expense

34. In Decision No. 69664, the Commission reduced Gold Canyon's request for recognition of rate case expenses in the amount of $160,000 to $70,000, amortized over four years, on the basis that the Company failed to provide to Staff and intervenors necessary documentation to support the request.

35. Although no party requested rehearing on the issue of rate case expense, during the Staff Meeting in which RUCO's request for rehearing was granted, the Commission also indicated an intent to reconsider the issue of rate case expense. (*See* Procedural Order issued August 23, 2007.)

36. Gold Canyon argues that, pursuant to the requirements of A.R.S. § 40-253, because no party raised the issue of rate case expense through a request for rehearing, the Commission may not now consider whether the $70,000 rate case expense allowance should be modified. However, the Company contends that the Commission may grant an allowance for rate case expenses incurred during the rehearing phase of this proceeding and requests that the Commission approve an additional

amount of $90,000 for rehearing rate case expense. Gold Canyon claims that Staff and RUCO were provided unredacted copies of the Company's rehearing expenses, but Staff declined to recommend granting recognition of such expenses, and RUCO took no position regarding the request.

37. We do not believe that the parties presented sufficient evidence on the issue of rehearing rate case expenses incurred by Gold Canyon to support the adjustment suggested by the Company. We therefore decline to adjust the amount for rate case expense authorized in Decision No. 69664.

## CONCLUSIONS OF LAW

1. Gold Canyon is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250, 40-251, 40-367, 40-202, 40-321, and 40-361.

2 The Commission has jurisdiction over Gold Canyon and the subject matter set forth in the Company's rate application and in RUCO's Application for Rehearing.

3. Pursuant to A.R.S. § 40-253, the Commission has considered the evidence and arguments presented by RUCO, Gold Canyon, and Staff pertaining to the Commission's grant of rehearing to RUCO on the issues of excess capacity and hypothetical capital structure, as discussed hereinabove.

## ORDER

IT IS THEREFORE ORDERED that Gold Canyon Sewer Company's rate base be reduced by $1.0 million as discussed herein and that Gold Canyon Sewer Company submit by November 30, 2008, for Commission approval, rates and charges revised per this rate base reduction. These revised rates and charges will be applied on a prospective basis and will not be applied retroactively.

IT IS FURTHER ORDERED that the revised rates and charges shall become effective the first day of the month after they are approved by the Commission.

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IT IS FURTHER ORDERED that the weighted cost of capital approved in this case shall be 8.54 percent and that Gold Canyon Sewer Company submit by November 30, 2008, rates and charges revised per this cost of capital. These revised rates and charges will be applied on a prospective basis and will not be applied retroactively.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

for William A. Mundell by KM Exo Dir

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 19th day of Nov., 2008.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT

DISSENT

SERVICE LIST FOR: GOLD CANYON SEWER COMPANY

DOCKET NO.: SW-02519A-06-0015

Jay L. Shapiro
Todd Wiley
Patrick J. Black
FENNEMORE CRAIG, P.C.
3003 North Central Avenue, Suite 2600
Phoenix, AZ 85012

Daniel Pozefsky, Chief Counsel
RESIDENTIAL UTILITY CONSUMER OFFICE
1110 West Washington Street, Suite 220
Phoenix, AZ 85007

Andy Kurtz
MOUNTAINBROOK VILLAGE
AT GOLD CANYON RANCH ASSOCIATION
5674 South Marble Drive
Gold Canyon, AZ 85218

Mark Tucker, P.C.
2650 East Southern Avenue
Mesa, AZ 85219
Attorney for Cal-Am Properties, Inc.

Janice Alward, Chief Counsel
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

Ernest G. Johnson, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
DOCKETED
DEC 23 2008
DOCKETED BY nr

EXHIBIT
R-8
ADMITTED

IN THE MATTER OF THE APPLICATION OF GOLD CANYON SEWER COMPANY FOR A DETERMINATION OF FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.

DOCKET NO. SW-02519A-06-0015

DECISION NO. 70662

**ORDER CLARIFYING DECISION NO. 70624**

Special Open Meeting
December 22, 2008
Phoenix, Arizona

**BY THE COMMISSION:**

* * * * * * * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

**FINDINGS OF FACT**

1. On January 13, 2006, Gold Canyon Sewer Company ("Gold Canyon" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a determination of the current fair value of its utility plant and property and for increases in its rates and charges for wastewater utility service provided to customers in the Company's certificated service area in Pinal County, Arizona.

2. On June 28, 2007, the Commission issued Decision No. 69664, granting a rate increase to Gold Canyon.

3. On July 18, 2007, the Residential Utility Consumer Office ("RUCO") filed an Application for Rehearing on two issues raised by RUCO during the hearing: (1) an allegation of "excess capacity" in the Company's treatment plant and (2) the capital structure employed in the Commission's Order for purposes of determining the Company's cost of capital.

4. During an Open Staff Meeting held on August 1, 2007, the Commission granted rehearing to RUCO.

5. Hearings were held before an Administrative Law Judge, and additional testimony and exhibits were admitted into the evidentiary record. The record produced by the prior hearings in this docket was incorporated into the rehearing record of this case.

6. On November 19, 2008, the Commission issued Decision No. 70624.

7. On November 28, 2008, Gold Canyon docketed its Notice of Filing which contained its revised rates and charges.

8. On December 3, 2008, RUCO filed its Response to Gold Canyon's Notice of Filing and Motion to Disapprove Gold Canyon's Proposed Revised Rates and Charges.

9. On December 5, 2008, Gold Canyon filed a Petition for Rehearing Pursuant to A.R.S. § 40-253.

10. On December 8, 2008, Chairman Gleason docketed a letter and Gold Canyon docketed its Filing Regarding RUCO's Response to Notice of Filing Revised Rates and Charges.

11. On December 10, 2008, the Commission's Utilities Division Staff ("Staff") docketed its Notice of Filing responding to Gold Canyon's November 28, 2008 filing of revised rates and charges.

12. On December 11, 2008, Gold Canyon filed its Reply to Response to RUCO's Motion to Disapprove Gold Canyon's Proposed Revised Rates and Charges.

13. On December 12, 2008, a Procedural Order was issued scheduling a procedural conference for December 22, 2008.

14. On December 19, 2008, notice of a December 22, 2008 Special Open Meeting was issued.

15. The Procedural Conference and Special Open Meeting were conducted as noticed on December 22, 2008.

## CONCLUSIONS OF LAW

1. Gold Canyon is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250, 40-251, 40-367, 40-202, 40-321, and 40-361.

2 The Commission has jurisdiction over Gold Canyon and the subject matter set forth in the Company's rate application and in RUCO's Application for Rehearing.

3. Pursuant to A.R.S. § 40-252 and/or § 40-253, the Commission has considered the evidence and arguments presented by RUCO, Gold Canyon, and Staff pertaining to the Commission's grant of rehearing to RUCO on the issues of excess capacity and hypothetical capital structure, and issues this Order to clarify the language and its intent in Decision No. 70624.

**ORDER**

IT IS THEREFORE ORDERED that Gold Canyon Sewer Company's plant in service (as reflected in Attachment 1) be reduced by $1.0 million as discussed herein and that Gold Canyon Sewer Company submit by December 29, 2008, in a form acceptable to Staff, rates and charges revised per this plant in service reduction. Depreciation on the plant removed from plant in service shall be deferred for recovery in a future rate case and the deferral account shall also include interest calculated using the Company's rate of return authorized in Decision No. 70624. These revised rates and charges will be applied on a prospective basis and will not be applied retroactively.

IT IS FURTHER ORDERED that the revised rates and charges shall become effective the first day of the month after they are filed in a form acceptable to Staff.

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IT IS FURTHER ORDERED that the weighted cost of capital approved in this case shall be 8.54 percent and that Gold Canyon Sewer Company shall submit by December 29, 2008, rates and charges revised per this cost of capital. Gold Canyon Sewer Company's weighted cost of debt is 3.38 percent and the Company's weighted cost of equity is 5.16 percent. The Company will use the weighted cost of debt of 3.38 percent in order to calculate Gold Canyon's test year adjusted level of income tax expense, using the interest synchronization method, to arrive at the revised level of operating revenue that will be generated by the revised rates and charges.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN | COMMISSIONER

COMMISSIONER | COMMISSIONER | COMMISSIONER

IN WITNESS WHEREOF, I, BRIAN C. McNEIL, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 23rd day of Dec., 2008.

BRIAN C. McNEIL
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

SERVICE LIST FOR: GOLD CANYON SEWER COMPANY

DOCKET NO.: SW-02519A-06-0015

Jay L. Shapiro
Todd Wiley
Patrick J. Black
FENNEMORE CRAIG, P.C.
3003 North Central Avenue, Suite 2600
Phoenix, AZ 85012

Daniel Pozefsky, Chief Counsel
RESIDENTIAL UTILITY CONSUMER OFFICE
1110 West Washington Street, Suite 220
Phoenix, AZ 85007

Andy Kurtz
MOUNTAINBROOK VILLAGE
AT GOLD CANYON RANCH ASSOCIATION
5674 South Marble Drive
Gold Canyon, AZ 85218

Mark Tucker, P.C.
2650 East Southern Avenue
Mesa, AZ 85219
Attorney for Cal-Am Properties, Inc.

Janice Alward, Chief Counsel
Legal Division
ARIZONA CORPORATION COMMISSION
1200 West Washington Street
Phoenix, AZ 85007

Ernest G. Johnson, Director
Utilities Division
ARIZONA CORPORATION COMMISSION
1200 West Washington
Phoenix, AZ 85007

# ATTACHMENT 1

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Computation of Increase in Gross Revenue
Requirements As Adjusted

Exhibit
Schedule A-1
Page 1
Witness: Bourassa

| Line No. | | |
|---|---|---|
| 1 | Fair Value Rate Base | $ 15,371,260 |
| 2 | | |
| 3 | Adjusted Operating Income | 562,633 |
| 4 | | |
| 5 | Current Rate of Return | 3.66% |
| 6 | | |
| 7 | Required Operating Income | $ 1,312,706 |
| 8 | | |
| 9 | Required Rate of Return on Fair Value Rate Base | 8.54% |
| 10 | | |
| 11 | Operating Income Deficiency | $ 750,072 |
| 12 | | |
| 13 | Gross Revenue Conversion Factor | 1.6286 |
| 14 | | |
| 15 | Increase in Gross Revenue | |
| 16 | Requirement | $ 1,221,593 |
| 17 | | |
| 18 | % Increase | 48.93% |
| 19 | | |
| 20 | | |

| 21 | Customer | Present | Proposed | Dollar | Percent |
|---|---|---|---|---|---|
| 22 | Classification | Rates | Rates | Increase | Increase |
| 23 | (Residential Commercial, Irrigation) | | | | |
| 24 | | | | | |
| 25 | Residential | $ 2,055,375 | $ 3,077,307 | $ 1,021,932 | 49.72% |
| 26 | Residential (<700 SF) per dwelling | 86,535 | 129,560 | 43,025 | 49.72% |
| 27 | Residential (Homeowner's Association) | 75,732 | 113,385 | 37,654 | 49.72% |
| 28 | Commercial | 178,185 | 266,778 | 88,593 | 49.72% |
| 29 | Effluent Sales | 31,699 | 47,460 | 15,761 | |
| 30 | | | | - | 0.00% |
| 31 | Revenue Annualization | 25,531 | 38,230 | 12,699 | 49.74% |
| 32 | **Subtotal** | $ 2,453,056 | $ 3,672,722 | $ 1,219,665 | 49.72% |
| 33 | | | | | |
| 34 | Other Wastewater Revenues | 44,804 | 44,804 | - | 0.00% |
| 35 | Reconciliation amount fo C-1 | (1,480) | 448 | 1,928 | -130.26% |
| 36 | | | | | |
| 37 | **Total of Water Revenues (a)** | $ 2,496,380 | $ 3,717,973 | $ 1,221,593 | 48.93% |

38
39
40
41
42
43
44 SUPPORTING SCHEDULES:
45 B-1
46 C-1
47 C-3
48 H-1
49
50

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Summary of Rate Base

Exhibit
Schedule B-1
Page 1
Witness: Bourassa

| Line No. | | Original Cost Rate base | Fair Value Rate Base |
|---|---|---|---|
| 1 | | | |
| 2 | Gross Utility Plant in Service | $ 20,033,564 | $ 20,033,564 |
| 3 | Less: Accumulated Depreciation | 1,244,431 | 1,244,431 |
| 4 | | | |
| 5 | Net Utility Plant in Service | $ 18,789,133 | $ 18,789,133 |
| 6 | | | |
| 7 | Less: | | |
| 8 | Advances in Aid of | | |
| 9 | Construction | 2,064,125 | 2,064,125 |
| 10 | Contributions in Aid of | | |
| 11 | Construction | 1,800,007 | 1,800,007 |
| 12 | Accumulated Amortization of CIAC | (138,100) | (138,100) |
| 13 | | | |
| 14 | Customer Meter Deposits | 30,769 | 30,769 |
| 15 | Deferred Income Taxes & Credits | (338,928) | (338,928) |
| 16 | Deferred Assets | - | - |
| 17 | | | |
| 18 | | | |
| 19 | Plus: | | |
| 20 | Unamortized Finance | | |
| 21 | Charges | - | - |
| 22 | Prepaids | - | - |
| 23 | Deferred Assets | - | - |
| 24 | Allowance for Working Capital | - | - |
| 25 | | | |
| 26 | | | |
| 27 | Total Rate Base | $ 15,371,260 | $ 15,371,260 |
| 28 | | | |
| 29 | | | |
| 30 | | | |
| 31 | SUPPORTING SCHEDULES: | | |
| 32 | B-2 | | |
| 33 | | | |
| 34 | | | |
| 35 | | | |
| 36 | | | |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Original Cost Rate Base Proforma Adjustments

Exhibit
Schedule B-2
Page 1
Witness: Bourassa

| Line No. | | Adjusted at End of Test Year | Adjustments | Rejoinder Adjusted at end of Test Year |
|---|---|---|---|---|
| 1 | Gross Utility | | | |
| 2 | Plant in Service | $ 21,033,564 | (1,000,000) | $ 20,033,564 |
| 3 | | | | |
| 4 | **Less:** | | | |
| 5 | Accumulated | | | |
| 6 | Depreciation | 1,269,431 | (25,000) | 1,244,431 |
| 7 | | | | |
| 8 | | | | |
| 9 | Net Utility Plant | | | |
| 10 | in Service | $ 19,764,133 | $ (975,000) | $ 18,789,133 |
| 11 | | | | |
| 12 | **Less:** | | | |
| 13 | Advances in Aid of | | | |
| 14 | Construction | 2,064,125 | - | 2,064,125 |
| 15 | | | | |
| 16 | Contributions in Aid of | | | |
| 17 | Construction (CIAC) | 1,827,557 | (27,550) | 1,800,007 |
| 18 | | | | |
| 19 | | | | |
| 20 | Accum. Amortization of CIAC | (138,788) | 689 | (138,100) |
| 21 | | | | |
| 22 | | | | |
| 23 | Customer Meter Deposits | 30,769 | - | 30,769 |
| 24 | Deferred Income Taxes | 254,681 | (593,609) | (338,928) |
| 25 | Investment Tax Credits | - | - | - |
| 26 | | | | |
| 27 | | | | |
| 28 | **Plus:** | | | |
| 29 | Unamortized Finance | | | |
| 30 | Charges | - | - | - |
| 31 | Prepaids | - | - | - |
| 32 | Allowance for Working Capital | - | - | - |
| 33 | | - | | - |
| 34 | | | | |
| 35 | Total | $ 15,725,789 | $ (354,530) | $ 15,371,260 |
| 36 | | | | |
| 37 | | | | |
| 38 | | | | |
| 39 | | | | |
| 40 | | | | |
| 41 | SUPPORTING SCHEDULES: | | | |
| 42 | B-2, pages 2-4 | | | |
| 43 | | | | |
| 44 | | | | |
| 45 | | | | |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Original Cost Rate Base Proforma Adjustments

Exhibit
Schedule B-2
Page 2
Witness: Bourassa

| Line No. | | ADJUSTMENT LABEL->> Decision 69664 Adjusted End of Test Year | 1 Capacity Adj. | 2 DIT | ROO Adjusted End of Test Year |
|---|---|---|---|---|---|
| 1 | Gross Utility | | | | |
| 2 | Plant in Service | $ 21,033,564 | (1,000,000) | | $ 20,033,564 |
| 3 | | | | | |
| 4 | **Less:** | | | | |
| 5 | Accumulated | | | | |
| 6 | Depreciation | 1,269,431 | (25,000) | | 1,244,431 |
| 7 | | | | | |
| 8 | | | | | |
| 9 | Net Utility Plant | | | | |
| 10 | in Service | $ 19,764,133 | $ (975,000) | $ - | $ 18,789,133 |
| 11 | | | | | |
| 12 | **Less:** | | | | |
| 13 | Advances in Aid of | | | | |
| 14 | Construction | 2,064,125 | | | 2,064,125 |
| 15 | | | | | |
| 16 | Contributions in Aid of | | | | |
| 17 | Construction (CIAC) | 1,827,557 | (27,550) | | 1,800,007 |
| 18 | | | | | |
| 19 | | | | | |
| 20 | Accum. Amortization of CIAC | (138,788) | 689 | | (138,100) |
| 21 | | | | | |
| 22 | | | | | |
| 23 | Customer Meter Deposits | 30,769 | | | 30,769 |
| 24 | Deferred Income Taxes | 254,681 | | (593,609) | (338,928) |
| 25 | Investment Tax Credits | - | | | - |
| 26 | | | | | |
| 27 | | | | | |
| 28 | **Plus:** | | | | |
| 29 | Unamortized Finance | | | | |
| 30 | Charges | - | | | - |
| 31 | Rounding | - | | | - |
| 32 | Allowance for Working Capital | - | | | - |
| 33 | | | | | |
| 34 | | | | | |
| 35 | Total | $ 15,725,789 | $ (948,139) | $ 593,609 | $ 15,371,260 |
| 36 | | | | | |
| 37 | | | | | |
| 38 | | | | | |
| 39 | | | | | |
| 40 | | | | | |
| 41 | SUPPORTING SCHEDULES: | | | | |
| 42 | B-2 | | | | |
| 43 | | | | | |
| 44 | | | | | |
| 45 | | | | | |

Gold Canyon Sewer Company Rehearing Decision
Test Year Ended October 31, 2005
Original Cost Rate Base Proforma Adjustments
Adjustment 1

Exhibit
Schedule B-2
Page 3.1
Witness: Bourassa

Line No.

1 Plant-in-Service

| Acct. | Description | RUCO's Proposed Adjustment | Factor | Adjustment per Rehearing Decision |
|---|---|---|---|---|
| 351 | Organization | | - | - |
| 352 | Franchises | | - | - |
| 353 | Land and Land Rights | | - | - |
| 354 | Structures and Improvements | (854,470) | 0.2945 | (294,482) |
| 355 | Power Generation Equipment | | - | - |
| 360 | Collection Sewers - Force | (1,883) | 0.0006 | (649) |
| 361 | Collection Sewers - Gravity | (5,637) | 0.0019 | (1,943) |
| 362 | Special Collecting Structures | | - | - |
| 363 | Services to Customers | | - | - |
| 364 | Flow Measuring Devices | | - | - |
| 365 | Flow Measuring Installations | | - | - |
| 370 | Receiving Wells | | - | - |
| 371 | Eff;uent Pumping Equipment | | - | - |
| 380 | Treatment and Disposal Equipment | (2,036,743) | 0.7019 | (701,937) |
| 381 | Plant Sewers | | - | - |
| 382 | Outfall Sewer Lines | | - | - |
| 389 | Other Plant and Misc. Equipment | | - | - |
| 390 | Office Furniture and Equipment | (2,872) | 0.0010 | (990) |
| 391 | Transportation Equipment | | - | - |
| 393 | Tools, Shop and Garage Equipment. | | - | - |
| 394 | Laboratory Equipment | | - | - |
| 395 | Power Operated Equipment | | - | - |
| 398 | Other TangiblePlant | | - | - |
| | | $ (2,901,605) | 1.00 | $ (1,000,000) |

DECISION NO. 70662

Gold Canyon Sewer Company Rehearing Decision
Test Year Ended October 31, 2005
Original Cost Rate Base Proforma Adjustments
Adjustment 1

Exhibit
Schedule B-2
Page 3.2
Witness: Bourassa

Line No.

1 Accumulated Depreciation

| Acct. | Description | Adjustment per Rehearing Decision | Dper. Rate (1/2 yr Conv.) | Adjustment per Rehearing Decision |
|---|---|---|---|---|
| 351 | Organization | - | 0.00% | - |
| 352 | Franchises | - | 0.00% | - |
| 353 | Land and Land Rights | - | 0.00% | - |
| 354 | Structures and Improvements | (294,482) | 2.50% | (7,362) |
| 355 | Power Generation Equipment | - | 2.50% | - |
| 360 | Collection Sewers - Force | (649) | 2.50% | (16) |
| 361 | Collection Sewers - Gravity | (1,943) | 2.50% | (49) |
| 362 | Special Collecting Structures | - | 2.50% | - |
| 363 | Services to Customers | - | 2.50% | - |
| 364 | Flow Measuring Devices | - | 2.50% | - |
| 365 | Flow Measuring Installations | - | 2.50% | - |
| 370 | Receiving Wells | - | 2.50% | - |
| 371 | Eff;uent Pumping Equipment | - | 2.50% | - |
| 380 | Treatment and Disposal Equipment | (701,937) | 2.50% | (17,548) |
| 381 | Plant Sewers | - | 2.50% | - |
| 382 | Outfall Sewer Lines | - | 2.50% | - |
| 389 | Other Plant and Misc. Equipment | - | 2.50% | - |
| 390 | Office Furniture and Equipment | (990) | 2.50% | (25) |
| 391 | Transportation Equipment | - | 2.50% | - |
| 393 | Tools, Shop and Garage Equipment. | - | 2.50% | - |
| 394 | Laboratory Equipment | - | 2.50% | - |
| 395 | Power Operated Equipment | - | 2.50% | - |
| 398 | Other TangiblePlant | - | 2.50% | - |
| | | $ (1,000,000) | | $ (25,000) |

Gold Canyon Sewer Company Rehearing Decision
Test Year Ended October 31, 2005
Original Cost Rate Base Proforma Adjustments
Adjustment 1

Exhibit
Schedule B-2
Page 3.3
Witness: Bourassa

| Line No. | | |
|---|---|---|
| 1 | Contributions-in-aid of Construction | |
| 2 | | |
| 3 | CIAC attributed to expansion | |
| 1 | | |
| 2 | Expansion Cost | $ 10,344,404 |
| 3 | Excess Capacity | 1,000,000 |
| 4 | % of Total Expansion | 10.0% |
| 5 | | |
| 6 | Total CIAC attributed to expansion (per RUCO) | $ 275,500 |
| 7 | | |
| 8 | CIAC attributed to excess capacity | $ 27,550 |
| 9 | | |
| 10 | | |
| 11 | Adjustment to CIAC | (27,550) |
| 12 | | |
| 13 | | |
| 14 | Amortization rate (1/2 year Conv.) | 2.50% |
| 15 | | |
| 16 | Amortization to be Removed | $ (689) |
| 17 | | |
| 18 | | |
| 19 | Adjustment to Accum. Amortization | 689 |
| 20 | | |
| 21 | | |
| 22 | | |
| 23 | | |
| 24 | | |
| 25 | | |
| 26 | | |
| 27 | | |
| 28 | | |

Gold Canyon Sewer Company Rehearing Decision
Test Year Ended October 31, 2005
Original Cost Rate Base Proforma Adjustments
Adjustment 2

Exhibit
Schedule B-2
Page 4
Witness: Bourassa

**CALCULATE ACCUMULATED DEFERRED INCOME TAX CREDIT ASSOCIATED WITH EXCESS CAPACITY**

| LINE NO. | DESCRIPTION | (A) COMPANY AS PER TAX BASIS | (B) COMPANY AS PER ACCOUNTING | (C) ADJM'T | (D) POST HEARING |
|---|---|---|---|---|---|
| 1 | Gross Utility Plant In Service | $ 17,205,559 | $ 20,033,564 | $ (1,000,000) | $ 19,033,564 |
| 2 | Accumulated Depreciation | (2,239,381) | (1,244,431) | 25,000 | (1,219,431) |
| 3 | Net Utility Plant In Service (L1 + L2) | $ 14,966,178 | $ 18,789,133 | $ (975,000) | $ 17,814,133 |
| 4 | Contribution In Aid Of Const. (from B-2) | $ - | $ (1,827,557) | $ 27,550 | $ (1,800,007) |
| 5 | Accumulated Amortization Of CIAC (from B-2) | - | 138,788 | (689) | $ 138,100 |
| 6 | NET CIAC (L4 + L5) | $ - | $ (1,688,769) | $ 26,861 | $ (1,661,907) |
| 7 | NET PLANT VALUES (Sum L's 3 & 6) | $ 14,966,178 | $ 17,100,364 | $ (948,139) | $ 16,152,226 |

CALCULATION OF ACCUMULATED DEFERRED INCOME TAX

| | | | |
|---|---|---|---|
| | FIXED ASSETS | | |
| 8 | Accounting Basis | Column (D), Line 7 | $ 16,152,226 |
| 9 | Tax Basis | Column (A), Line 7 | $ 14,966,178 |
| 10 | Timing Difference | Line 8 - Line 9 | $ 1,186,048 |
| 11 | Tax Rate | From C-3 | 38.60% |
| 12 | DEFERRED TAX LIABILITY - FIXED ASSETS | Line 10 X Line 11 | $ 457,801 |
| | AIAC | | |
| 13 | Accounting Basis | From B-2 | $ (2,064,125) |
| 14 | Tax Basis | AIAC Does Not Exist For Tax Purposes (See CSB 2.42 (a) | $ - |
| 15 | Timing Difference | Line 13 - Line 14 | $ (2,064,125) |
| 16 | Tax Rate | From C-3 | 38.60% |
| 17 | DEFERRED TAX ASSET - AIAC | Line 15 X Line 16 | $ (796,729) |
| 18 | NET FUTURE TAX LIABILITY (ASSET) | Line17 - Line 12 | $ (338,928) |
| 19 | Accumulated Deferred Income Tax per Decision 69664 | Schedule B-2, Page 2 | $ 254,681 |
| 20 | Adjustment To Accumulated Deferred Income Tax | Line19 - Line 18 | $ (593,609) |
| 19 | Adjustment | Line 18 | $ (593,609) |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Income Statement

Exhibit
Schedule C-1
Page 1
Witness: Bourassa

| Line No. | | Adjusted Book Results | Adjustments | Rejoinder Adjusted Results | Proposed Rate Increase | Adjusted with Rate Increase |
|---|---|---|---|---|---|---|
| 1 | **Revenues** | | | | | |
| 2 | Flat Rate Revenues | $ 2,451,576 | $ - | $ 2,451,576 | $ 1,221,593 | $ 3,673,169 |
| 3 | Measured Revenues | - | - | - | | - |
| 4 | Other Wastewater Revenues | 44,804 | - | 44,804 | | 44,804 |
| 5 | | $ 2,496,380 | $ - | $ 2,496,380 | $ 1,221,593 | $ 3,717,973 |
| 6 | **Operating Expenses** | | | | | |
| 7 | Salaries and Wages | $ - | - | $ - | | $ - |
| 8 | Purchased Wastewater Treatment | 6,159 | - | 6,159 | | 6,159 |
| 9 | Sludge Removal Expense | 44,737 | - | 44,737 | | 44,737 |
| 10 | Purchased Power | 107,040 | - | 107,040 | | 107,040 |
| 11 | Fuel for Power Production | - | - | - | | - |
| 12 | Chemicals | 63,590 | - | 63,590 | | 63,590 |
| 13 | Materials and Supplies | 11,394 | - | 11,394 | | 11,394 |
| 14 | Contractual Services - Professional | 22,068 | - | 22,068 | | 22,068 |
| 15 | Contractual Services - Testing | 11,655 | - | 11,655 | | 11,655 |
| 16 | Contractual Services - Other | 441,702 | - | 441,702 | | 441,702 |
| 17 | Rents | - | - | - | | - |
| 18 | Transportation Expenses | 35,925 | - | 35,925 | | 35,925 |
| 19 | Insurance - General Liability | 6,293 | - | 6,293 | | 6,293 |
| 20 | Regulatory Commission Expense | 18,680 | - | 18,680 | | 18,680 |
| 21 | Miscellaneous Expense | 17,500 | - | 17,500 | | 17,500 |
| 22 | Scottsdale Capacity- Lease | 35,325 | - | 35,325 | | 35,325 |
| 23 | Depreciation | 901,223 | (43,693) | 857,530 | | 857,530 |
| 24 | Taxes Other Than Income | - | - | - | | - |
| 25 | Property Taxes | 248,055 | (20,991) | 227,064 | | 227,064 |
| 26 | Income Tax | 182,867 | (155,782) | 27,085 | 471,521 | 498,606 |
| 27 | | | | | | |
| 28 | **Total Operating Expenses** | $ 2,154,213 | $ (220,466) | $ 1,933,746 | $ 471,521 | $ 2,405,268 |
| 29 | **Operating Income** | $ 342,167 | $ 220,466 | $ 562,633 | $ 750,072 | $ 1,312,706 |
| 30 | **Other Income (Expense)** | | | | | |
| 31 | Interest Income | - | | - | | - |
| 32 | Other income | - | | - | | - |
| 33 | Interest Expense | - | (519,549) | (519,549) | | (519,549) |
| 34 | Other Expense | - | | - | | - |
| 35 | | | | | | |
| 36 | **Total Other Income (Expense)** | $ - | $ (519,549) | $ (519,549) | $ - | $ (519,549) |
| 37 | **Net Profit (Loss)** | $ 342,167 | $ (299,082) | $ 43,085 | $ 750,072 | $ 793,157 |
| 38 | | | | | | |
| 39 | | | | | | |
| 40 | | | | | | |
| 41 | SUPPORTING SCHEDULES: | | | | RECAP SCHEDULES: | |
| 42 | C-1, Page 2 | | | | A-1 | |
| 43 | C-2 | | | | | |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Income Statement

Exhibit
Schedule C-1
Page 2
Witness: Bourassa

| Line No. | | ADJUSTMENT LABEL->> Decision 69664 Adjusted Results | 1 Property Taxes | 2 Depr. | 3 Interest Synchronization | 3 Income Tax | Rehearing Decision Adjusted Results | Proposed Rate Increase | Rehearing Decision with Rate Increase |
|---|---|---|---|---|---|---|---|---|---|
| 1 | **Revenues** | | | | | | | | |
| 2 | Flat Rate Revenues | $ 2,451,576 | | | | | $ 2,451,576 | $ 1,221,593 | $ 3,673,169 |
| 3 | Measured Revenues | - | | | | | - | | - |
| 4 | Other Wastewater Revenues | 44,804 | | | | | 44,804 | | 44,804 |
| 5 | | $ 2,496,380 | $ - | $ - | $ - | $ - | $ 2,496,380 | $ 1,221,593 | $ 3,717,973 |
| 6 | **Operating Expenses** | | | | | | | | |
| 7 | Salaries and Wages | $ - | | | | | $ - | | $ - |
| 8 | Purchased Wastewater Treatment | 6,159 | | | | | 6,159 | | 6,159 |
| 9 | Sludge Removal Expense | 44,737 | | | | | 44,737 | | 44,737 |
| 10 | Purchased Power | 107,040 | | | | | 107,040 | | 107,040 |
| 11 | Fuel for Power Production | - | | | | | - | | - |
| 12 | Chemicals | 63,590 | | | | | 63,590 | | 63,590 |
| 13 | Materials and Supplies | 11,394 | | | | | 11,394 | | 11,394 |
| 14 | Contractual Services - Professional | 22,068 | | | | | 22,068 | | 22,068 |
| 15 | Contractual Services - Testing | 11,655 | | | | | 11,655 | | 11,655 |
| 16 | Contractual Services - Other | 441,702 | | | | | 441,702 | | 441,702 |
| 17 | Repairs and Maintenance | - | | | | | - | | - |
| 18 | Rents | 35,925 | | | | | 35,925 | | 35,925 |
| 19 | Transportation Expenses | 6,293 | | | | | 6,293 | | 6,293 |
| 20 | Insurance | 18,680 | | | | | 18,680 | | 18,680 |
| 21 | Regulatory Commission Expense - Rate Case | 17,500 | | | | | 17,500 | | 17,500 |
| 22 | Miscellaneous Expense | 35,325 | | | | | 35,325 | | 35,325 |
| 23 | Depreciation Expense | 901,223 | | (43,693) | | | 857,530 | | 857,530 |
| 24 | Taxes Other Than Income | - | | | | | - | | - |
| 25 | Property Taxes | 248,055 | (20,991) | | | | 227,064 | | 227,064 |
| 26 | Income Tax | 182,867 | | | | (155,782) | 27,085 | 471,521 | 498,606 |
| 27 | Unidentified | | | | | | - | | - |
| 28 | **Total Operating Expenses** | $ 2,154,213 | $ (20,991) | $ (43,693) | $ - | $ (155,782) | $ 1,933,746 | $ 471,521 | $ 2,405,268 |
| 29 | **Operating Income** | $ 342,167 | $ 20,991 | $ 43,693 | $ - | $ 155,782 | $ 562,633 | $ 750,072 | $ 1,312,706 |
| 30 | **Other Income (Expense)** | | | | | | | | |
| 31 | Interest Income | - | | | | | - | | - |
| 32 | Other Income | - | | | | | - | | - |
| 33 | Interest Expense | - | | | (519,549) | | (519,549) | | (519,549) |
| 34 | Other Expense | - | | | | | - | | - |
| 35 | | - | | | | | - | | - |
| 36 | **Total Other Income (Expense)** | $ - | $ - | $ - | $ (519,549) | $ - | $ (519,549) | $ - | $ (519,549) |
| 37 | **Net Profit (Loss)** | $ 342,167 | $ 20,991 | $ 43,693 | $ (519,549) | $ 155,782 | $ 43,085 | $ 750,072 | $ 793,157 |
| 38 | | | | | | | | | |
| 39 | | | | | | | | | |
| 40 | | | | | | | | | |
| 41 | SUPPORTING SCHEDULES: | | | | | | RECAP SCHEDULES: | | |
| 42 | C-2 | | | | | | A-1 | | |
| 43 | | | | | | | | | |

DECISION NO. 70662

DOCKET NO. SW-02519A-06-0015

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Adjustment to Revenues and Expenses
Adjustment Number 1

Exhibit
Schedule C-2
Page 1
Witness: Bourassa

| Line No. | | | |
|---|---|---|---|
| 1 | Adjust Property Taxes to Reflect Proposed Revenues: | | |
| 2 | | | |
| 3 | Adjusted Revenues in year ended 10/31/05 | $ | 2,496,380 |
| 4 | Adjusted Revenues in year ended 10/31/05 | | 2,496,380 |
| 5 | Proposed Revenues | | 3,717,973 |
| 6 | Average of three year's of revenue | $ | 2,903,578 |
| 7 | Average of three year's of revenue, times 2 | $ | 5,807,156 |
| 8 | Add: | | |
| 9 | Construction Work in Progess at 10% | $ | - |
| 10 | Deduct: | | |
| 11 | Book Value of Transportation Equipment | | - |
| 12 | | | |
| 13 | Full Cash Value | $ | 5,807,156 |
| 14 | Assessment Ratio | | 24% |
| 15 | Assessed Value | | 1,393,717 |
| 16 | Property Tax Rate | | 16.2920% |
| 17 | | | |
| 18 | Property Tax | | 227,064 |
| 19 | Tax on Parcels | | - |
| 20 | | | |
| 21 | Total Property Tax at Proposed Rates | $ | 227,064 |
| 22 | Property Taxes per Decision 69664 | | 248,055 |
| 23 | Change in Property Taxes | $ | (20,991) |
| 24 | | | |
| 25 | | | |
| 26 | Adjustment to Revenues and/or Expenses | $ | (20,991) |
| 27 | | | |
| 28 | | | |

Gold Canyon Sewer Company Rehearing Decision
Test Year Ended October 31, 2005
Adjustments to Revenues and Expenses
Adjustment 2

Exhibit
Schedule C-2
Page 2
Witness: Bourassa

Depreciation Expense

| Account No. | Description | Decision 69664 Adjusted Original Cost | Rehearing Plant Adjustment | Rehearing Adjusted Original Cost | Depr. Rates | Rehearing Depreciation Expense |
|---|---|---|---|---|---|---|
| 351 | Organization | 25,000 | - | 25,000 | 0.00% | - |
| 352 | Franchises | 25,000 | - | 25,000 | 0.00% | - |
| 353 | Land and Land Rights | - | - | - | 0.00% | - |
| 354 | Structures and Improvements | 4,942,333 | (294,482) | 4,647,851 | 3.33% | 154,773 |
| 355 | Power Generation Equipment | (92) | - | (92) | 5.00% | (5) |
| 360 | Collection Sewers - Force | 78,718 | (649) | 78,069 | 2.00% | 1,561 |
| 361 | Collection Sewers - Gravity | 1,570,222 | (1,943) | 1,568,279 | 2.00% | 31,366 |
| 362 | Special Collecting Structures | 18,595 | - | 18,595 | 2.00% | 372 |
| 363 | Services to Customers | 21,498 | - | 21,498 | 2.00% | 430 |
| 364 | Flow Measuring Devices | 3,231 | - | 3,231 | 10.00% | 323 |
| 365 | Flow Measuring Installations | 159,362 | - | 159,362 | 10.00% | 15,936 |
| 370 | Receiving Wells | - | - | - | 3.33% | - |
| 371 | Effluent Pumping Equipment | 66,132 | - | 66,132 | 12.50% | 8,267 |
| 380 | Treatment and Disposal Equipment | 10,675,637 | (701,937) | 9,973,700 | 5.00% | 498,685 |
| 381 | Plant Sewers | 883 | - | 883 | 5.00% | 44 |
| 382 | Outfall Sewer Lines | - | - | - | 3.33% | - |
| 389 | Other Plant and Misc. Equipment | 3,393,045 | - | 3,393,045 | 6.67% | 226,316 |
| 390 | Office Furniture and Equipment | 36,587 | (990) | 35,597 | 6.67% | 2,374 |
| 391 | Transportation Equipment | - | - | - | 20.00% | - |
| 393 | Tools, Shop and Garage Equipment. | - | - | - | 5.00% | - |
| 394 | Laboratory Equipment | 17,413 | - | 17,413 | 10.00% | 1,741 |
| 395 | Power Operated Equipment | - | - | - | 5.00% | - |
| 398 | Other TangiblePlant | - | - | - | 10.00% | - |
| | TOTALS | $ 21,033,564 | $ (1,000,000) | $ 20,033,564 | | $ 942,184 |
| | Less: Amortization of Contributions - Balance End of TY ( | $ 1,827,557 | $ (27,550) | $ 1,800,007 | 4.703% | $ (84,655) |
| | Total Depreciation Expense | | | | | $ 857,530 |
| | Adjusted Test Year Depreciation Expense per Decision 69664 | | | | | 901,223 |
| | Increase (decrease) in Depreciation Expense | | | | | (43,693) |
| | Adjustment to Revenues and/or Expenses | | | | | $ (43,693) |

DOCKET NO. SW-02519A-06-0015

DECISION NO. 70662

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Adjustment to Revenues and Expenses
Adjustment Number 3

Exhibit
Schedule C-2
Page 1
Witness: Bourassa

| Line No. | | |
|---|---|---|
| 1 | Interest Synchronization | |
| 2 | | |
| 3 | Fair Value Rate Base (from B-1) | $ 15,371,260 |
| 4 | Weighted Cost of Debt (from D-1) | 3.38% |
| 5 | Computed Interest Expense | $ 519,549 |
| 6 | | |
| 7 | Interest Expense Per Decision 69664 | $ - |
| 8 | | |
| 9 | Increase in Interest Expense | $ 519,549 |
| 10 | | |
| 11 | Adjustment to Interest Expense | $ (519,549) |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | | |
| 16 | | |
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| 30 | | |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Adjustment to Revenues and Expenses
Income Tax Calculation
Adjustment 4

Exhibit
Schedule C-2
Page 4
Witness: Bourassa

| Line No. | | Test Year Book Results | | Test Year Adjusted Results | | Adjusted with Rate Increase | |
|---|---|---|---|---|---|---|---|
| 1 | | | | | | | |
| 2 | | | | | | | |
| 3 | | | | | | | |
| 4 | | | | | | | |
| 5 | Net Income | $ - | | $ 43,085 | | $ 793,157 | |
| 6 | **Plus:** | | | | | | |
| 7 | Income Taxes | $ 182,867 | | $ 27,085 | | $ 498,606 | |
| 8 | Interest Synchronization | | | | | | |
| 9 | | | | | | | |
| 10 | Taxable Income | 182,867 | | 70,170 | | 1,291,763 | |
| 11 | | | | | | | |
| 12 | | | | | | | |
| 13 | | | | | | | |
| 14 | Income Before Taxes | 182,867 | | 70,170 | | 1,291,763 | |
| 15 | Arizona Income Before Taxes | 182,867 | | 70,170 | | 1,291,763 | |
| 16 | | | | | | | |
| 17 | Less Arizona Income Tax | 12,742 | | 4,889 | | 90,010 | |
| 18 | Rate 6.97% | | | | | | |
| 19 | | | | | | | |
| 20 | Arizona Taxable Income | 170,125 | | 65,280 | | 1,201,753 | |
| 21 | Arizona Income Taxes | 12,742 | | 4,889 | | 90,010 | |
| 22 | | | | | | | |
| 23 | Federal Income Before Taxes | 182,867 | | 70,170 | | 1,291,763 | |
| 24 | | | | | | | |
| 25 | Less Arizona Income Taxes | 12,742 | | 4,889 | | 90,010 | |
| 26 | | | | | | | |
| 27 | Federal Taxable Income | 170,125 | | 65,280 | | 1,201,753 | |
| 28 | | | | | | | |
| 29 | | | | | | | |
| 30 | | | | | | | |
| 31 | FEDERAL INCOME TAXES: | | | | | | |
| 32 | 15% BRACKET | 7,500 | | 7,500 | | 7,500 | |
| 33 | 25% BRACKET | 6,250 | | 3,820 | | 6,250 | |
| 34 | 34% BRACKET | 8,500 | Federal | - | Federal | 8,500 | Federal |
| 35 | 39% BRACKET | 27,349 | Effective | - | Effective | 91,650 | Effective |
| 36 | 34% BRACKET | - | Tax | - | Tax | 294,696 | Tax |
| 37 | | | Rate | | Rate | | Rate |
| 38 | Federal Income Taxes | 49,599 | 27.12% | 11,320 | 16.13% | 408,596 | 31.63% |
| 39 | | | | | | | |
| 40 | | | | | | | |
| 41 | Total Income Tax | 62,341 | | 16,209 | | 498,606 | |
| 42 | | | | | | | |
| 43 | Overall Tax Rate | 34.09% | | 23.10% | | 38.60% | |
| 44 | | | | | | | |
| 45 | Income Tax at Proposed Rates Effective Rate | | | $ 27,085 | | | |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Computation of Gross Revenue Conversion Factor

Exhibit
Schedule C-3
Page 1
Witness: Bourassa

| Line No. | Description | Percentage of Incremental Gross Revenues |
|---|---|---|
| 1 | Federal Income Taxes | 31.63% |
| 2 | | |
| 3 | State Income Taxes | 6.97% |
| 4 | | |
| 5 | Other Taxes and Expenses | 0.00% |
| 6 | | |
| 7 | | |
| 8 | Total Tax Percentage | 38.60% |
| 9 | | |
| 10 | Operating Income % = 100% - Tax Percentage | 61.40% |
| 11 | | |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | 1 = Gross Revenue Conversion Factor | |
| 16 | Operating Income % | 1.6286 |
| 17 | | |
| 18 | SUPPORTING SCHEDULES: | RECAP SCHEDULES: |
| 19 | | Rejoinder A-1 |
| 20 | | |

**Gold Canyon Sewer Company Rehearing Decision**
Test Year Ended October 31, 2005
Summary of Cost of Capital

Exhibit
Schedule D-1
Page 1
Witness: Bourassa

| Line No. | Item of Capital | Percent of Total | (e) Cost Rate | Weighted Cost |
|---|---|---|---|---|
| 1 | Long-Term Debt | 40.00% | 8.45% | 3.38% |
| 2 | | | | |
| 3 | Stockholder's Equity | 60.00% | 8.60% | 5.16% |
| 4 | | | | |
| 5 | Totals | 100.00% | | 8.54% |
| 6 | | | | |
| 7 | | | | |
| 8 | | | | |
| 9 | | | | |
| 10 | | | | |
| 11 | | | | |
| 12 | SUPPORTING SCHEDULES: | | | |
| 13 | | | | |
| 14 | | | | |
| 15 | | | | |
| 16 | | | | |
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| 18 | | | | |
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| 30 | | | | |

**Gold Canyon Sewer Company - Rehearing Decision**
Revenue Summary
With Annualized Revenues to Year End Number of Customers
And Estimated Customer Growth
Test Year Ended October 31, 2005

Exhibit
Schedule H1
Witness: Bourassa

| Line No. | Customer Classification and/or Meter Size | Present Revenues | Proposed Revenues | Dollar Change | Percent Change | Percent of Present Sewer Revenues | Percent of Proposed Sewer Revenues |
|---|---|---|---|---|---|---|---|
| 1 | Residential | $ 2,055,375 | $ 3,077,307 | $ 1,021,932 | 49.72% | 83.79% | 83.79% |
| 2 | Residential (<700 SF) per dwelling | 86,535 | 129,560 | 43,025 | 49.72% | 3.53% | 3.53% |
| 3 | Residential (Homeowner's Association) | 75,732 | 113,385 | 37,654 | 49.72% | 3.09% | 3.09% |
| 4 | Commercial | 178,185 | 266,778 | 88,593 | 49.72% | 7.26% | 7.26% |
| 5 | Effluent Sales | 31,699 | 47,460 | 15,761 | 49.72% | 1.29% | 1.29% |
| 6 | Subtotal | $ 2,427,526 | $ 3,634,491 | $ 1,206,966 | 49.72% | 98.96% | 98.96% |
| 7 | | | | | | | |
| 8 | ***Residential customer revenue*** | | | | | | |
| 9 | ***annualized to end of year, based on*** | | | | | | |
| 10 | ***year end number of customers*** | | | | | | |
| 11 | **Residential** | 51,345 | 76,874 | 25,529 | 49.72% | 2.09% | 2.09% |
| 12 | **Residential (<700 SF) per dwelling** | (27,203) | (40,729) | (13,525) | 49.72% | -1.11% | -1.11% |
| 13 | **Residential (Homeowner's Association)** | 1,400 | 2,096 | 696 | 49.72% | 0.06% | 0.06% |
| 14 | **Commercial** | (11) | (11) | - | 0.00% | 0.00% | 0.00% |
| 15 | Subtotal | $ 25,531 | $ 38,230 | $ 12,699 | 49.74% | 1.04% | 1.04% |
| 16 | | | | | | | |
| 17 | Subtotal Revenues from Bill Count | 2,453,056 | 3,672,722 | 1,219,665 | 49.72% | 200.00% | 200.00% |
| 18 | Misc Revenues | 44,804 | 44,804 | 0 | 0.00% | 0.00% | 0.00% |
| 19 | Reconcilation amount to C-1 | (1,480) | 448 | 1,928 | -130.26% | 0.00% | 0.00% |
| 20 | Totals | $ 2,496,380 | $ 3,717,973 | $ 1,221,593 | 48.93% | 200.00% | 200.00% |

DECISION NO. 70662

DOCKET NO. SW-02519A-06-0015

**Gold Canyon Sewer Company - Rehearing Decision**
Test Year Ended October 31, 2005
Analysis of Revenue by Detailed Class

Schedule H-2
Page 1
Witness: Bourassa

| Line No. | Customer Classification | Average Number of Customers at 10/31/2005 | Average Effluent | Average Bill Present Rates | Average Bill Proposed Rates | Proposed Increase Dollar Amount | Proposed Increase Percent Amount |
|---|---|---|---|---|---|---|---|
| 1 | Residential | 5,016 | N/A | $ 35.00 | $ 52.40 | $ 17.40 | 49.72% |
| 2 | Residential (<700 S.F.) | 259 | N/A | 19.09 | 28.58 | 9.49 | 49.72% |
| 3 | Residential (Homeowners Association)* | 1 | N/A | 31.82 | 47.64 | 15.82 | 49.72% |
| 4 | Commercial | 20 | N/A | 0.18 | 0.26 | 0.09 | 49.72% |
| 5 | Effluent | 3 | 2,382,750 | 0.39 | 0.59 | 0.19 | 49.72% |
| 6 | | | | | | | |
| 7 | Total | 5,299 | | | | | |
| 8 | | | | | | | |
| 9 | | | | | | | |
| 10 | * Shown on H5 schedule as number of occupied units billed, but only one customer is billed. | | | | | | |
| 11 | | | | | | | |

DOCKET NO. SW-02519A-06-0015

DECISION NO. 70662

**Gold Canyon Sewer Company - Rehearing Decision**
Present and Proposed Rates
Test Year Ended October 31, 2005

Exhibit
Schedule H3
Page 1
Witness: Bourassa

| Line No. | Customer Classification and Meter Size | Present Rates | Proposed Rates | Percent Change |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | | | | |
| 4 | | | | |
| 5 | **Monthly Charge for:** | | | |
| 6 | Residential | $ 35.00 | $ 52.40 | 49.7200% |
| 7 | Commercial, per gallon per day | 0.175 | 0.262 | 49.7200% |
| 8 | Effluent Sales (per 1,000 gallons) | 0.391 | 0.586 | 49.7200% |
| 9 | Residential charge for dwelling less than 700 SF | 19.09 | 28.58 | 49.7200% |
| 10 | Homeowner's Associations, per dwelling | 31.82 | 47.64 | 49.7200% |
| 11 | Recalimed non-pottable water per A.F. (See Effluent Sales per 1,000 gallons) | 127.50 | 190.89 | 49.7200% |

DOCKET NO. SW-02519A-06-0015

DECISION NO. 70662

EXHIBIT
R-9
ADMITTED

RIO RICO UTILITIES, INC.

DOCKET NO. WS-02676A-09-0257

# DIRECT TESTIMONY
# (REQUIRED REVENUE)

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 23, 2009

1 **TABLE OF CONTENTS**

2 INTRODUCTION ..... 1

3 BACKGROUND ..... 2

4 SUMMARY OF ADJUSTMENTS ..... 3

5 Rate Base ..... 3
6 Operating Income ..... 4
7 Other Issues ..... 6

8 REVENUE REQUIREMENTS ..... 7

9 RATE BASE ADJUSTMENTS ..... 8

10 Rate Base Adj. #1 – Plant and Accumulated Depreciation ..... 8
11 Rate Base Adj. #2 – Accumulated Deferred Income Taxes ..... 10
12 Rate Base Adj. #3 – Advances and Contributions ..... 32

13 OPERATING INCOME ADJUSTMENTS ..... 33

14 Operating Income Adj. #1 – Revenue Annualization ..... 33
15 Operating Income Adj. #2 – Purchased Power Expense Annualization ..... 39
16 Operating Income Adj. #3 – Depreciation Expense ..... 40
17 Operating Income Adj. #4 – Property Tax Expense ..... 41
18 Operating Income Adj. #5 – Rate Case Expense ..... 42
19 Operating Income Adj. #6 – Misc. Expense ..... 44
20 Operating Income Adj. #7 – Purchased Power Expense ..... 44
21 Operating Income Adj. #8 – Corporate Allocations ..... 45
22 Operating Income Adj. #9 – Bad Debt Expense ..... 51
23 Operating Income Adj. #10 – Income Tax Expense ..... 52

24 OTHER ISSUES ..... 52

25 Low Income Tariff Program ..... 52
26 Hook Up Fee ..... 53
27 Other Tariff Changes ..... 56
28 Late Payment Finance Charge ..... 56

29 APPENDIX I

30 RUCO EXHIBITS 1 - 6

31 SCHEDULES TJC-1 thru TJC-17

## INTRODUCTION

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

A. My Name is Timothy J. Coley. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate cases and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Rio Rico Utilities, Inc.'s ("RRUI" or "Company") application for a determination of the current fair value of both its Water and Wastewater utility plant and property and for a permanent increase in its rates and charges based thereon for utility service. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended December 31, 2008.

**BACKGROUND**

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to operating income, rate base, and the Company's overall revenue requirement. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of several sets of data requests, the review and analysis of the Company's responses to Commission Staff data requests, and review of prior ACC dockets related to RRUI.

RUCO's participation in this proceeding is the cumulative effort of me (Timothy J. Coley) and William A. Rigsby. I performed the revenue requirement analysis on the Company's rate base and operating income. Mr. Rigsby will provide an analysis of the cost of capital. I will also subsequently file RUCO's recommended rate design on January 4, 2010. RUCO analyzed each division (Water and Wastewater Divisions) on a stand-alone basis.

Q. Please identify the Schedules and Exhibits you are sponsoring.

A. I am sponsoring schedules for both the Water and Wastewater Divisions of RRUI that are numbered TJC-1 through TJC-17 and RUCO Exhibits 1 through 6.

**SUMMARY OF ADJUSTMENTS**

Q. Please summarize RUCO's adjustments to the rate base and operating income contained in your testimony.

A. My testimony addresses the following issues and is common to both the Water and Wastewater Divisions unless otherwise noted:

**Rate Base**

RUCO Rate Base Adjustment #1 – Accumulated Depreciation – This adjustment reflects RUCO's recommended Accumulated Depreciation balances since the last rate case for each Division. I started with the last Commission approved Utility Plant in Service ("UPIS") and Accumulated Depreciation balances and reconstructed all plant additions, retirements, and adjustments at the approved depreciation rates.

RUCO Rate Base Adjustment #2 – Accumulated Deferred Income Taxes ("ADIT") – This adjustment recalculates the Company's ADIT balances.

RUCO Rate Base Adjustment #3 – Advances in Aid of Construction ("AIAC") and Contributions in Aid of Construction ("CIAC") – This is a conforming adjustment to the AIAC and CIAC balances the Company identified in its data response to RUCO data request 1.08.

**Operating Income**

RUCO Operating Income Adjustment #1 – Revenue Annualization – This adjustment annualizes the revenues for the 5/8" residential customer based on the average test-year customer count.

RUCO Operating Income Adjustment #2 – Purchased Power Expense Annualization – This is a corresponding adjustment to account for the additional purchased power expense related to RUCO's Operating Adjustment #1 – Revenue Annualization.

RUCO Operating Income Adjustment #3 – Depreciation Expense – This adjustment reflects RUCO's recommended level of depreciation expense.

RUCO Operating Income Adjustment #4 – Property Tax Expense – This adjustment reflects RUCO's recommended level of an increase to gross revenues.

RUCO Operating Income Adjustment #5 – Rate Case Expense – This adjustment reflects RUCO's recommended five-year normalization rather than the Company's three-year proposed normalization period.

RUCO Operating Income Adjustment #6 – Miscellaneous Expense – This adjustment pertains to the Water Division only. It removes unnecessary expenses that are unwarranted for the provision of water service.

RUCO Operating Income Adjustment #7 – Purchased Power Expense – This is a conforming adjustment to purchased power expense that transfers $48,005 from the Water Division to the Wastewater Division. It was improperly booked to the Water Division as identified by the Company's data response to Staff data request GB 3.8.

RUCO Operating Income Adjustment #8 – Corporate Allocations – This adjustment removes some corporate allocations that RUCO finds as unnecessary in the provisioning of water and wastewater service.

RUCO Operating Income Adjustment #9 – Bad Debt Expense – This adjustment normalizes bad debt expense.

RUCO Operating Income Adjustment #10 – Income Taxes – This adjustment reflects RUCO's level of income taxes on its recommended taxable operating income.

**Other Issues**

Low Income Tariff Program – The Company has proposed a new Low Income Tariff Program for RRUI in its rate application for this case. RUCO will provide its position on the Company's proposal later in this testimony.

Hook Up Fee – The Company is proposing a new Hook Up Fee to address part of the costs for off-site facilities for new service connections. RUCO will address this matter later in its testimony.

Other Tariff Changes – The Company also proposes a change in the cost of new service lines. RRUI has proposed that all service line installation charges be at "cost" rather than current stated tariff rates. This matter will be addressed later in RUCO's testimony.

Late Payment Finance Charge – The Company is proposing the Commission to approve at 1.5 percent finance charge for customers that are delinquent on their accounts. RUCO will discuss this proposal later in its testimony.

**REVENUE REQUIREMENTS**

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. RUCO's analysis found many of the Company's financial statements (i.e. balance sheets) filed with the application and invoices provided in data responses to the various intervenors in the Algonquin related cases unreliable and without sufficient detail.

RUCO's recommended fair value rate base is $7,045,555 for the Water Division and $2,937,595 for the Wastewater Division. Mr. Rigsby recommends a 9 percent return on common equity and an overall rate of return on fair value rate base of 7.90 percent.

RUCO's recommended revenue requirements increase gross revenues by $936,172 for the Water Division and decrease gross revenues in the amount of $549,328 for the Wastewater Division. RUCO's recommended increase (decrease) in gross revenues represents a 49.95 percent increase and a (29.69) percent decrease in the Water and Wastewater Divisions respectively. The details are shown on Schedules TJC-1 and TJC-17.

## RATE BASE ADJUSTMENTS

Q. Is RUCO recommending any changes to the Company's proposed rate base?

A. Yes. RUCO analyzed the Company's rate base adjustments to its historical test-year elements of rate base and made adjustments to the rate base as filed by the Company. The details of RUCO's adjustments are explained individually below.

### Rate Base Adj. #1 – Plant and Accumulated Depreciation

Q. Please explain any adjustments that RUCO made to the Company's utility plant in service ("UPIS") and Accumulated Depreciation balances.

A. All of RUCO's adjustments are common to both the Water and Wastewater Divisions unless otherwise noted. Each division is comprised of its UPIS and Accumulated Depreciation. RUCO reconstructed the UPIS additions, adjustments, and retirements since the last rate case, as did the Company, to determine the proper UPIS and Accumulated Depreciation balances for the test year in this case.

Q. Does RUCO accept the Company's balances of UPIS and Accumulated Depreciation balances authorized in the previous case for a starting point?

A. Yes.

Q. Did RUCO make any adjustments to Company's adjusted test-year UPIS or Accumulated Depreciation balances to the divisions?

A. RUCO agrees with the Company's adjusted test-year end UPIS balances for both the Water and Wastewater Divisions. However, RUCO made adjustments to the Accumulated Depreciation balances for both divisions.

Q. What led RUCO to make those adjustments for Accumulated Depreciation?

A. Apparently, the Company's Water Division Schedule B-2, pages 3.1 – 3.6, contains an error in the depreciation expense formula for Account 341 – Transportation Equipment for years 2003 - 2007. The Company's 2008 depreciation expense for Account 341 is calculating properly. This is not the only mistake I identified but the most significant.

The same problem exists in the Company's Wastewater Division Schedule B-2's with the exception of year 2004. For year 2003, there is a slight error in Accounts 360 and 361 depreciation expense calculation. Account 390.1 – Computers and Software has a marginal mistake for year 2005. For years 2006 through 2008, the same computational error occurs in Accounts 390.1 and 396.

...

Q. What adjustments did RUCO make to the Accumulated Depreciation balances?

A. RUCO's adjustments increased the Accumulated Depreciation balances by $130,701 for the Water Division and $45,969 for the Wastewater Division. Those adjustments are on Schedules TJC-2 with the supporting detail on Schedules TJC-3.

**Rate Base Adj. #2 – Accumulated Deferred Income Taxes**

Q. Did the Company make a proforma adjustment in its rate application that created an adjusted test-year end Accumulated Deferred Income Tax ("ADIT") Assets for both the Water and Wastewater Divisions?

A. Yes.

Q. What are ADIT's?

A. ADIT is a balance sheet item that is derived through the normalization of income tax expense on the income statement. ADIT's can be classified as either ADIT Liabilities ("ADTL") or ADIT Assets ("ADTA"). An accounting department may manage deferred tax liabilities and assets in a way that helps maximize a company's net income for external financial accounting reporting purposes. On the other hand, an accountant may seek to minimize the company's net income for purposes of the Internal Revenue Service ("IRS") tax liability reporting purposes in a given fiscal tax year.

ADIT's are created by temporary inter-period timing differences between the book and taxable income treatment of certain accounting events and transactions. These differences typically originate in one period and reverse in one or more subsequent periods. For utilities, the largest such timing difference is the extent to which accelerated tax depreciation generally exceeds straight-line book depreciation during the early years of an asset's service life.[1] ADIT represents the cumulative net deferred tax amounts as shown in the table 1 on the next page:

...

[1] South Dakota Public Utilities Commission, Testimony of Witness Kyle Sem, Docket EL08-030, page 47.

**Table 1**[2]

**Utility Company**
**Accounting for Deferred Income Taxes**

| | | Tax Deductions | | | | |
|---|---|---|---|---|---|---|
| Year | Books Straight-line Depreciation | Tax Accelerated Depreciation | Cost of Removal | Net Timing Difference | Deferred Income Taxes | Accumulated Deferred Income Taxes |
| 1 | $ 102,000 | $ 400,000 | | $ 298,000 | $ 119,200 | $ 119,200 |
| 2 | 102,000 | 240,000 | | 138,000 | 55,200 | 174,400 |
| 3 | 102,000 | 144,000 | | 42,000 | 16,800 | 191,200 |
| 4 | 102,000 | 108,000 | | 6,000 | 2,400 | 193,600 |
| 5 | 102,000 | 108,000 | | 6,000 | 2,400 | 196,000 |
| 6 | 102,000 | | | (102,000) | (40,800) | 155,200 |
| 7 | 102,000 | | | (102,000) | (40,800) | 114,400 |
| 8 | 102,000 | | | (102,000) | (40,800) | 73,600 |
| 9 | 102,000 | | | (102,000) | (40,800) | 32,800 |
| 10 | 102,000 | | 20,000 | (82,000) | (32,800) | |
| | $ 1,020,000 | $ 1,000,000 | $ 20,000 | | | |

**Assumptions:**

| | |
|---|---|
| Asset Cost | $ 1,000,000 |
| Income Tax Rate | 40% |
| Cost of Removal | $ 20,000 |

**Depreciation -**

Book – 10-years; Straight-line

Tax - 5 years; DDB with Switch to SL

**Note:** The Deferred Income Tax amount in Year 1 is derived from multiplying the Net Timing Difference of $298,000 by the assumed Income Tax Rate of 40 percent = Deferred Income Tax of $119,200. The Accumulated Deferred Income Taxes are the accumulation of each year's Deferred Income Tax amount.

...

[2] Carl W. Dabelstein, CPA, Income Taxes in Ratemaking, Exhibit No. 8.

The illustrative example shown in Table 1 assumes a single asset with no further ongoing investment in capital assets. Using that example, one can see how the reversal of the ADTL reverses itself in the later years of its useful life and to zero in the last year.

Q. Are utilities a capital intensive industry that requires continuous investments in new plant assets?

A. Yes.

Q. Does RUCO believe that a utility company that is making ongoing capital investments in plant that it is conceivable and logical that a deferred tax liability, a reduction to rate base could exist on a company's books indefinitely?

A. Yes. RRUI should be reflecting a deferred tax liability, which is a reduction to rate base rather than an asset that increases rate base. Utilities are constantly adding and repairing new and old infrastructure all the time. This requires additional investment on behalf of the utility year after year. When a utility's asset (rate) base continues to grow each year, the total accelerated depreciation will continue to exceed book depreciation, but for individual assets, at some point book depreciation will be larger.[3] Another source that I researched stated the following:

[3] E. Busch and J. Johnson, "Treatment of Income Taxes In Utility Ratemaking," A White Paper Prepared for The Oregon Legislative Assembly By Public Utility Commission of Oregon Staff; February 2005, page 7 of 17.

> New investments that cause the level of depreciable assets to at least remain constant over time can effectively delay that deferred tax liability indefinitely.[4]

RUCO's analysis determined that RRUI has continually added plant since its last rate case Decision No. 67279. RUCO believes it is improper for the Company to claim an ADTA on its B-2 Schedules when no such designation appears on its Schedule E's balance sheet.

Q. Did RUCO inquire as to why the Company's Schedule E's balance sheets reported no ADIT amounts?

A. Yes.

Q. What response did the Company provide regarding it not reporting any ADIT on its balance sheet?

A. The Company responded by saying that its ADIT balances are maintained on the parent level, Algonquin Power Trust Fund ("APTF"), books.

Q. Did RUCO review the parent, APFT, balance sheet provided in its 2008 Annual Report to assess the amount of ADIT reported there?

A. Yes. APFT reported a net ADIT Liability in the amount of $83,951,000, as shown in RUCO Exhibit 1. When that amount is allocated down to APFT

[4] Source: http:www.utdallas.edu, Accounting Text, Chapter 16, Accounting for Income Taxes, page 3 of 20.

affiliates in some logical, rationale, and/or systematic[5] manner would amount to a reduction to rate base rather than an addition to rate base as the Company's rate application reports.

Q. Did APTF 2008 Annual Report balance sheet actually balance properly (i.e., Assets = Liabilities + Equity)?

A. Yes.

Q. If RRUI had reported its claimed ADIT Assets of $778,203 and $323,602 on its balance sheets for the Water and Wastewater Divisions respectively, would RRUI Schedule E balance sheets balance properly?

A. No.

Q. Did RRUI claim any ADIT's in the Company's Annual Reports financial statements, filed with the Commission annually, since the last rate case authorized in Decision No. 67279.

A. Yes. RRUI filed three annual reports for the Water Division that showed both ADIT Asset and Liability amounts in years 2006, 2007, and 2008.

...

[5] As prescribed in Statement of Financial Standards No. 109, Section 40, page 19.

Q. Did RUCO ask the Company about the ADIT amounts claimed in the Annual Reports filed with the Commission for those three-years?

A. Yes. RUCO asked the Company about the ADIT Liability amount of $72,985 for the Water Division reported in the 2008 Annual Report filed with the Commission. The Company responded that the amount was not an ADIT Liability in actuality but was a deferred rate case expense that was misclassified as shown in RUCO Exhibit 2.

Q. Did Commission Decision No. 67279 in RRUI's last rate case authorize any ADIT balance?

A. No. Albeit, the Company firmly denied that fact in its response to RUCO data request number 3.03. First, the Company denied the fact that no ADIT were granted in that decision and then, responded that "The decision speaks for itself," as shown in RUCO Exhibit 3.

Q. What is an Accumulated Deferred Tax Asset ("ADTA")?

A. An ADTA is listed on a company's balance sheet to document or record an event/situation where the Company will likely realize a reduction in future income taxes due to an asset. In other words, an ADTA is a future tax benefit. In order for the company to benefit from a deferred tax asset, a company first deducts the expense on its accounting books. Tax breaks are then provided at a later date. Warranties and Net Operating Losses ("NOL") are good examples of ADTA. Generally Accepted Accounting

Principles ("GAAP") allows a company to make estimates on their future warranty expense based on how many returns they think they will get and records the estimated expense on its books. However, the IRS will not allow the recognition of the estimated warranty expense until the actual event occurs, and as a result, shareholder income is lower than taxable income. An ADTA is similar to a prepaid tax. Here is an example that contains numbers; a company may have an ADTA of $10,000 listed on its books. If the company earns $50,000 in income prior to taxes, the company can deduct the $10,000 ADTA from the total taxable income. As a result, the company is only required to pay taxes on the $40,000.

Q. What is an Accumulated Deferred Tax Liability ("ADTL")?

A. The Rate Case and Audit Manual prepared by the National Association of Regulatory Utility Commissioners ("NARUC") Staff Subcommittee on Accounting and Finance in the summer of 2003 reported the following:

> Deferred income taxes (DIT) arise when income tax amounts provided for book purposes differ from the amount of taxes currently due and payable. The **primary** [emphasis added] cause of the tax differences is the straight-line depreciation rates used for rate making purposes versus the accelerated depreciation rates used for federal and state income tax purposes. Under this method, there is higher depreciation expense for tax purposes than for regulatory book purposes, causing the taxes computed for regulatory books (and thus, included in revenue requirement) to be more than the taxes actually payable to the Internal Revenue Service and state

taxing entities, in the early years of the asset's life. In later years, the situation reverses itself, such that the revenue requirement will reflect a lesser amount of income tax than that which is actually due and payable. This difference then becomes a source of interest-free funds, provided by ratepayers and not investors. This accumulated balance of interest-free funds (ADIT) is available to the utility to further invest until it is then needed to fund the taxes due and payable in the later years.

These differences are generally caused by both differences between IRS/State and regulatory allowed asset depreciation lives, and differences in the depreciation method (e.g., straight line versus accelerated)...

The timing differences related to life and method differences are required by the federal tax code to be *normalized*. Pursuant to normalization, the timing differences are accumulated in the DIT account and used to spread the benefits of the IRS tax policies over the economic life of the asset. This will be the **bulk** [emphasis added] of the dollars involved in DIT. The remaining items, related to basis differences, may be either normalized or *flowed-through* to customers. Under the flow-through method, income tax savings resulting from IRS tax methods are immediately used to reduce rate (i.e., revenue requirements) instead of recording the difference as a liability in the deferred tax accounts.

In looking at accumulated DIT, the auditor should look at the Schedule M of the federal (and possibly state) tax return, to

> determine the types of items the IRS/State computed taxes and taxes computed for regulatory purposes…
>
> There are two ways of treating DIT in the revenue requirement computation. In the first, the accumulated DIT is deducted from rate base. This appropriately recognizes that these are interest free funds upon which the utility should not earn a return. In the second, the accumulated DIT is not deducted from rate base, but instead, is treated as zero cost element of the capital structure. In doing so, a lower average authorized rate of return is applied to a higher rate base. In concept, the methods should derive similar results. The auditor should become familiar with the jurisdiction's policy and practice on this matter, so it is properly reflected in the rate computation.[6]

Q. The above referenced source addressed two methods of addressing Accumulated Deferred Income Taxes. Which method does Arizona utilize in revenue requirement computation?

A. Arizona utilizes the normalization method that spreads the DIT benefits of the IRS tax policies over the economic life of the asset, which is a reduction to rate base.

…

[6] Rate Case and Audit Manual prepared by the National Association of Regulatory Utility Commissioners ("NARUC") Staff Subcommittee on Accounting and Finance in the Summer of 2003, pages 24-26.

Q. Does RUCO have another source that supports its position regarding the ADIT issue to which the Company claims?

A. Yes. A paper[7] prepared for the Public Service Commission of Utah cited the following:

> Deferred income taxes are created when components of income or expense are recognized in different time periods for financial reporting purposes than for income tax purposes. The Federal income tax laws necessarily require some items to be reflected differently for income tax reporting purposes. Some of these differences are the result of efforts to protect the federal government from abuse by tax payers. Other differences are the result of legislative efforts to stimulate economic activity. These efforts often take the form of accelerated depreciation or an immediate write-off of investments in fixed assets. When these assets are deducted more quickly on income tax returns than for financial reporting purposes the current burden of income tax payments are reduced. These accelerated write-offs will eventually be exhausted and the company's taxable income will increase to a level that is above book income relative to those specific items...
>
> The income tax issues related to the establishment of utility rates can be complicated. Regulatory agencies sometimes require that advantageous tax provisions be flowed-through to ratepayers by including those adjustments in the calculation of the income tax component of the revenue requirement. However, Congress has restricted this practice so that temporary differences related to accelerated

[7] Edwin C. Farrar, CPA for the Garrett Group, LLC; Normalization of Deferred Income Taxes for Rocky Mountain Power; May 28, 2009, pages 1-2.

> depreciation cannot be used to directly benefit ratepayers. Instead, regulatory bodies must use the same depreciation rates for both the revenue requirement calculation and for the income tax calculation contained in the revenue requirement. The regulator is then permitted to use the accumulated balance of deferred income taxes that results from this treatment as a reduction to the rate base. This requirement results in an interperiod tax allocation because income tax deductions are recognized when the asset is depreciated for ratemaking purposes instead of when the deduction is actually taken on the tax return. The use of the interperiod tax allocation to calculate components of the revenue requirement and to calculate income tax expense and the deduction of the accumulated deferred income tax balance from the rate base is known as income tax normalization... With normalization, the balance of accumulated deferred income taxes may be deducted from rate base as a source of cost free capital. The ratepayer will realize a reduction in rates under full normalization equal to the Commission authorized pretax return on the balance of accumulated deferred income taxes...

Q. Besides Modified Accelerated Cost Recovery System ("MACRS"), what other tax laws exist within the Internal Revenue Code ("IRC") that allows a company to write-off capital investments and plant more quickly on its income tax returns than for financial / ratemaking purposes?

A. Two other tax laws come to mind that allow a company to immediately write-off investments in fixed assets. The first is the IRC Section 179 Expense, which allows a company to deduct up to $250,000 in the first

year of the asset's cost for qualified property. The second IRC option for a company is the 2008 bonus depreciation, which allows a company to immediately write-off 50 percent of the cost in the fixed asset the first year it is placed in service. Both of those options are the result of legislative efforts to stimulate economic activity. When these assets are depreciated more quickly on income tax returns than for financial reporting purposes, the company's current burden of income tax payments is reduced. Thus, ratepayers are paying more income taxes through their rates than the company is actually paying the IRS from the greater depreciation income tax deductions. The reason that the ratepayers are contributing more income tax expense through rates than the company is actually paying the IRS is primarily because the ratemaking process is prohibited from using the greater accelerated depreciation method deduction when setting the income tax expense levels for rates. The difference between 1) the higher income tax expense authorized by the Commission in setting rates and 2) the lower income tax the company actually pays to the IRS is 3) the deferred income tax liability, which is a *reduction* to rate base.

Q. Please provide a hypothetical scenario illustrating how the special depreciation deductions affect depreciation expense and thus, taxable income.

A. Assume a company completed its second full year of operations ending on December 31, 2008 and has a rate base of $12,000,000. It added

$2,500,000 of plant additions during 2008, which are included in the $12,000,000 rate base. The new plant additions have a useful life of 10 years, which qualify for MACRS tax depreciation of 150 percent declining balance ("DB") method using the half-year ("HY") convention.

The Commission predetermined just and reasonable rates prior to the company's first year of operations based on the company's rate base, estimated allowable expense levels, and its cost of capital. The Commission estimated an allowable depreciation expense of $1,200,000, calculated using straight-line depreciation, to be recovered annually through the company's ratepayers' rates. The Commission also authorized an annual income tax expense of $406,182 to be collected in rates paid by the utility's customers.

The company elected not to recover any part of the cost of the new plant additions under IRC Section 179 Deduction[8] but did choose to claim the Special Depreciation Allowance or Bonus Depreciation, as RRUI refers to it.

The company can take a special deduction allowance to recover part of the cost of qualified property, placed in service during the 2008 tax year. The allowance applies only for the first year you place the property in

[8] IRS Publication 946: The total amount you can elect to deduct under section 179 for most property placed in service in 2008 generally cannot be more than $250,000.

service. The company claims an additional 50 percent special allowance after electing or not electing to take the section 179 deduction. The allowance is an additional deduction that can be taken after any section 179 deduction and before the calculation of regular MACRS depreciation.

The order of the depreciation election process is 1) first, elect to take or not take the section 179 deduction, 2) claim or not claim the special 50 percent deduction allowance, and then 3) figure the regular MACR's depreciation on the new tax basis from the adjustments from the elections and claims in one and two above.

Q. Please take us through the process of calculating the tax depreciation deductions for these special IRS allowances for the $2,500,000 of new plant additions.

A. The company would first choose to either elect or not elect the section 179 deduction, which is up to $250,000. In this hypothetical scenario, the company chose <u>not</u> to elect the section 179 deduction. The company did choose to claim the special depreciation allowance of 50 percent of the $2,500,000 new 2008 plant additions. The Company deducts half of the plant additions for a total tax deduction of $1,250,000. The remaining $1,250,000 is the company's new tax basis in the assets. The company's book basis in the plant additions is still $2,500,000. The difference of $1,250,000 in the tax versus book basis is due solely to the company

claiming the special depreciation allowance. Hence, the special deduction has lowered the taxable operating income by an additional $1,250,000 over financial book reporting. Thus, the actual income tax payable to the IRS is lower than that reported in the company's books. The company can now figure its regular MACRS depreciation for tax purposes on the new plant additions.

Using the MACRS 150 percent DB tax depreciation method and the HY convention, the company is allowed to deduct 7.5 percent tax depreciation on its adjusted $1,250,000 tax basis on the new plant additions or $93,750 ($1,250,000 X 7.5%). Under straight-line book depreciation method using the HY convention, the company is allowed a 5 percent depreciation expense deduction for the first year the plant is placed in service or $125,000 ($2,500,000 X (10% / 2)). For tax purposes, the company is allowed to deduct the additional special depreciation allowance of $1,250,000 plus the $93,750 for the regular MACRS depreciation calculation for a total depreciation deduction of $1,343,750 ($1,250,000 + $93,750). For book and ratemaking purposes, GAAP allows only a straight-line depreciation deduction of $125,000 ($2,500,000 X (10% / 2)) in the first year that the plant is placed in service. Thus, taxable income is lower for tax purposes than book purposes because of the greater tax depreciation deduction generated by claiming the special depreciation deduction allowance.

The deferred tax calculation for the hypothetical DIT scenario[9] is shown in the table below:

| Plant Additions | Book Depreciation | 1st Year Tax Depreciation Rate | Tax Depreciation | Difference | Tax Rate | Deferred Tax |
|---|---|---|---|---|---|---|
| 2,500,000 | 125,000 | 53.75% | 1,343,750 | 1,218,750 | 38.60% | (470,438) |

As shown in the last column of the table above, the deferred income tax related to the bonus depreciation that the company claimed is a liability of $470,438, which is a *reduction* to rate base for the interest free funds the company over collected from the ratepayers for income taxes.

Q. Did RUCO ask RRUI about its bonus depreciation it is claiming in this case that creates a deferred income tax liability?

A. Yes. RUCO issued data request number 3.10 that inquired about the bonus depreciation and the Company's response was as follows:

> Q. Accumulated Deferred Income Tax (ADIT) – Admit that the bonus depreciation (50%) taken by the Company that led to the Company's net operating loss (NOL) shown on Company Schedules B-2, page 5 – line 11, would create a book ADIT liability for that year. If denied, please explain why.
>
> RESPONSE: Deny. The tax net operating loss was caused, in part, by the bonus depreciation. However, the bonus depreciation is already contained in the tax basis value of plant and equipment of $13,584,404 shown on Schedule B-2, page 5. The inclusion of the bonus depreciation contributed to lowering the tax basis and ultimately the book-tax timing difference. However, the adjusted net

[9] The numbers and amounts used in this hypothetical are not exact amounts as shown in RRUI's rate application but are relatively comparable in size.

book basis of assets remains greater than the tax basis of assets and creates a deferred tax asset. [emphasis added] The tax net operating loss carry forward is a distinct book-tax timing difference which by itself creates a deferred tax asset.

Q. Does RUCO agree with the Company's response and if no, why?

A. There are two primary reasons why RUCO disagrees with the Company's response. First, the table on the previous page clearly demonstrates that bonus depreciation creates a deferred tax liability in and of itself. Secondly, the part of the Company's response that is underlined with emphasis added is wrong and backwards.

Q. Please explain why RUCO believes that portion of the Company's response is wrong and backwards.

A. It is wrong and backwards for the same reason. Deferred tax assets are created when the tax basis of an asset is greater than book basis (See RUCO Exhibit 4). This exhibit is an excerpt from a Chapter titled Corporate Income Tax from a 2008 Prentice Hall publication text book slide show presentation. The conclusions displayed in RUCO Exhibit 4 are the exact opposite of what the Company claims in its response. Maybe that is why the Company has proposed an ADIT asset to increase rate base in the instant case. A deferred tax liability, which is a reduction to rate base, occurs when the tax basis of an asset is less than the book basis. When the tax basis is less than the book basis, this means that more depreciation through accelerated methods has been taken than on

the book basis, which must use the straight-line depreciation method that results in less depreciation in the early years of an asset's life. As RUCO has shown throughout its testimony that is what creates the **bulk** of a utilities ADIT.

In a case involving Hope Gas, Inc., Case No. 05-0304-G-42T, Mr.Hugh Larkin,[10] Jr. testified on behalf of the Consumer Advocate Division of the Public Service Commission of West Virginia and summed up ADIT in a much more concise way than I have here as follows:

> In Adjustment 59A the Company reduced accumulated deferred income taxes and increased rate base. It appears that this adjustment was made incorrectly by the Company and should have increased deferred income taxes and not decreased them.

Q. Does RUCO agree with the Company's proforma adjustment to RRUI that establishes an ADTA?

A. No.

Q. What other reason(s) does RUCO provide in opposing the Company's proforma adjustment that claims an existence of an ADTA?

A. RUCO takes issue with the creation of the ADTA on several grounds beyond what RUCO has already discussed in this testimony.

[10] Mr. Larkin is a CPA and senior partner in the firm of Larkin & Associates, PLLC. RUCO and the Commission has obtained Larkin & Associates for its services as outside consultants in a number of Arizona regulatory cases and matters.

Q. Please expound further on the issues of why RUCO opposes the Company's proforma adjustment that gives rise to the ADTA.

A. RUCO has reviewed all interveners data requests and responses to APTF's utility affiliates in Black Mountain Sewer, Litchfield Park Water and Sewer, and RRUI Water and Sewer Divisions rate cases. All interveners that analyzed the ADIT issue have grave concerns in regards to the Company's claim of an ADTA.

Q. Does the Company's calculation of its ADIT Asset include Advances in Aid of Construction ("AIAC")?

A. Yes.

Q. What is RUCO's position regarding the Company's inclusion of AIAC in its ADIT computation?

A. RUCO's position on the Company's inclusion of AIAC in the computation of ADIT is its erroneous. The Company does not have any book neither tax basis in plant that was funded through non-investor capital other than the amount previously refunded. The Company is already earning a return of the AIAC balances through depreciation expense and is entitled to no more or less.

...

Q. What is RUCO's recommendation regarding the ADIT?

A. RUCO recommends that the Commission follow the guidelines set forth in the Statement of Financial Accounting Standards ("SFAS") No. 109 that was issued in February 1992 and specifically for companies that file consolidated tax returns as APTF does with its affiliate RRUI.

Q. Please state what those guidelines are in SFAS No. 109.

A. Section 40, page 19, of SFAS No. 109 states the following guidelines whenever "The consolidated amount of current and deferred tax expense for a group that files a consolidated tax return shall be allocated among the members of the group when those members issue separate financial statements" as is the case with RRUI for this rate proceeding. SFAS No. 109 further states the following:

> **Separate Financial Statements of a Subsidiary**
>
> 40. This Statement does not require a single allocation method. The method adopted, however, shall be systematic, rationale, and consistent with the broad principles established by this Statement. A method that allocates current and deferred taxes to members of the group by applying this Statement to each member as if it were a separate taxpayer meets those criteria…

The excerpt of SFAS No. 109 is provided in this testimony as RUCO Exhibit 5.

…

Q. How has RUCO allocated, as set forth in Section 40 of SFAS No. 109, the parent Company's net deferred income tax liabilities that are reported on APTF 2008 Annual Report balance sheet?

A. RUCO adopted the prescribed SFAS 109 method to allocate APTF's net deferred income tax liabilities. RUCO's allocation factor is based on RRUI total asset cost ($8.8 million) divided by Algonquin Power Trust Fund's total assets ($978.1 million) to arrive at RRUI asset ratio, as reported on its 2008 Annual Report. RUCO's allocation method adopted is systematic, rationale, and consistent with the broad principles established by Section 40 of SFAS No. 109. It allocates current and deferred taxes to members of the group by applying SFAS No. 109 to each member as if it were a separate taxpayer and meets the criteria established therein. These deferred income tax liabilities are attributable to all APTF's affiliates. The ratepayers of RRUI are entitled to those tax benefits that it contributed towards.

Q. What is RUCO's recommendation for RRUI ADIT balance for the Water and Wastewater Divisions?

A. RUCO recommends an ADIT Liability balance of $501,057 for the Water Division and $208,912 for the Wastewater Division to properly reflect SFAS No. 109 criteria of allocating the tax benefits that the ratepayers are entitled, which reduces rate base accordingly. Those adjustments are on

Schedules TJC-2 with the supporting detail on Schedules TJC-3 and TJC-5.

**Rate Base Adj. #3 – Advances and Contributions**

Q. Please discuss RUCO's adjustment to advances-in-aid-of-construction ("AIAC") and contributions-in-aid-of-construction ("CIAC").

A. This is a conforming adjustment to AIAC and CIAC that arose through RUCO data request 1.08. RUCO inquired about the balances in the respective AIAC and CIAC accounts. The Company's response was after closer investigation it determined that the amounts filed in the application was not correct. RUCO made the necessary adjustments to conform with the Company's updated AIAC and CIAC balances.

Q. What adjustment was necessary to conform to the Company's updated AIAC and CIAC balances?

A. It was necessary to increase the AIAC balance by $48,724 and a corresponding adjustment to decrease the CIAC by the same $48,724 for the Water Division. The Company's data response indicated an adjustment was needed to increase AIAC by $238,783 and a corresponding adjustment to decrease CIAC by the same $238,783 for the Wastewater Division. Those adjustments are on Schedules TJC-2 with the supporting detail on Schedules TJC-3.

## OPERATING INCOME ADJUSTMENTS

### Operating Income Adj. #1 – Revenue Annualization

Q. Please explain RUCO's Operating Income Adjustment #1.

A. This adjustment annualizes the Company's revenues of the 5/8 inch average test-year customer count for the Water Division. The same calculation applies to the 5/8 inch residential Wastewater customers.

Q. Did the Company make a revenue annualization adjustment to the test-year end revenue balances?

A. Yes. The Company annualized revenues to the test-year end customer counts. RRUI's revenue annualization decreased revenues by $4,794 and $4,505 for the Water and Wastewater Divisions respectively.

Q. Doesn't RUCO normally annualize revenues to the test-year end customer count rather than averaging the test-year customer count?

A. Yes. RUCO normally annualizes the revenues to the test-year end customer count.

Q. Why did RUCO deviate from annualizing revenues to the test-year end customer count to averaging the customer count in the test-year?

A. RUCO did annualize revenues to the test-year end customer count for all customer classifications with the exception of the 5/8 inch residential customer.

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

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

Q. Why does RUCO believe that averaging the test-year customer count is more appropriate in this case for the 5/8 inch residential customers?

A. The Company's method of annualizing revenue is similar to the one used in its last rate case. However, the use of such a method in this case is decreasing test-year revenues. RUCO's analysis of the 5/8 inch residential bill counts determined that the Company's decrease to revenues were not attributable to a permanent decline in customer count during the test-year but more attributable to the *seasonality* of the monthly customer counts.

...

Q. Has RUCO recommended averaging the test-year customer count in prior rate cases to annualize revenue?

A. Yes. Mr. Ralph Smith, RUCO's outside consultant, recommended a similar approach to averaging the customer count when annualizing revenues in the last Unisource Gas ("UNS Gas") rate case – Docket No. G-04204A-08-0571. RUCO recommends averaging the customer count in RRUI for the same reasons Mr. Smith gave in the UNS Gas case. Mr. Smith stated the following:

> Moreover, the decrease in revenue produced by the Company's calculation appears to be related to customer seasonality rather than a permanent decline in customer count during the test year, and therefore should not be adopted because it would understate test year and going-forward revenues.
>
> I conclude that UNS Gas has added, on average, both residential and commercial customers in each and every year, including the test year. Consequently, an adjustment to decrease test year revenue would understate test year and going-forward revenues and be inappropriate and should be rejected. Test year revenue of $516,000 should not be removed as proposed by UNSG…

…

Q. In performing RUCO analysis of the monthly customer counts that led it to the determination that the low test-year end customer count for the 5/8 inch residential customers is caused more by the seasonality of the customers rather than a permanent decline in customer counts, what did the data disclose?

A. After analyzing the Company's Annual Reports filed with the Commission, the "Water Use Data Sheet By Month" for calendar years 2005 – 2008 showed an increase in customers for each month, with the exception of one-month of the 48 months analyzed, during that four-year time period. That analysis determined that to annualize revenues to test-year end customer count was a proper methodology to utilize.

However, RUCO's examination of the Company's H-5 Schedules discovered that the test-year end customer count was less than all other months in the test-year, with the exception of the month of October. In fact, the month of June had 331 more customers than the test-year end month of December. This analysis shows that to annualize to the test-year end customer count would skew the results of the annualization to the detriment of the ratepayers. Thus, a more proper methodology to utilize in this particular instance would be to average the number of customers in the test-year for a basis of the annualization. This approach normalizes the customer count over the test-year period and eliminates the outliers, which produces more reasonable results.

Q. Has RRUI experienced growth to both plant and customer count since its last rate case?

A. Yes. Using the average test-year customer count for the 5/8 inch residential customers better matches the revenue to the plant added to serve the new customers. For years 2006 through 2008, new plant investments were as follows:

**Water Division**

| Period | Total Plant in Service | Change |
|---|---|---|
| 2006 | $ 30,269,691 | |
| 2007 | 31,033,505 | $ 763,814 |
| 2008 | 34,023,226 | 2,989,721 |

**Wastewater Division**

| Period | Total Plant in Service | Change |
|---|---|---|
| 2006 | $ 11,626,019 | |
| 2007 | 11,673,445 | $ 47,426 |
| 2008 | 11,833,279 | 159,834 |

Q. What year-over-year increases has RRUI experienced for total average customers?

A. The year-over-year increases that RRUI has experienced for total average customers are summarized in the following tables:

**Water Division**

| Period | Average Customers | Change |
|---|---|---|
| 2006 | 5,725 | |
| 2007 | 6,147 | 422 |
| 2008 | 6,506 | 359 |

**Wastewater Division**

| Period | Average Customers | Change |
|---|---|---|
| 2006 | 1,929 | |
| 2007 | 2,060 | 131 |
| 2008 | 2,170 | 110 |

Q. What adjustment does RUCO recommend to annualize revenues to the average test-year customer count to better match revenues to the plant additions and to account for the seasonality of the customer base?

A. RUCO recommends increasing gross revenues by $26,801 for the Water Division and increasing the Wastewater Division's gross revenues by $20,125. This mitigates the seasonality of RRUI customer base. Those adjustments are on Schedules TJC-6 with the supporting detail on Schedules TJC-7 and TJC-8, pages 1-16.

**Operating Income Adj. #2 – Purchased Power Expense Annualization**

Q. Please explain RUCO's adjustment to Purchased Power Expense.

A. RUCO's adjustment to Purchased Power Expense Annualization is a direct result of RUCO's adjustment #1 to Revenue Annualization. Since RUCO recommends additional revenue, it is also necessary to account for the additional gallons of water to be pumped and sewage to be transported and treated.

Q. Are there any other adjustments that RUCO made to the Purchased Power Expense Annualization that you would like to discuss?

A. Yes. When annualizing the related expenses (purchased power and chemicals), it was determined the Company miscalculated the purchased power expense. The Company's calculation (Adjustment #6) fails to include the purchased power adjustment #5 that relates to the estimated APS rate increase. RUCO has properly accounted for that adjustment when annualizing its purchased power expense. That correction slightly increases the purchased power expense in the annualization of the expense.

...

Q. What adjustments are necessary to properly reflect the additional expenses to account for RUCO's increased levels of revenue because of its' Revenue Annualization recommendation?

A. Adjustments to increase Purchased Power by $9,081 for the Water Division and by $1,694 for the Wastewater Division are necessary to account for the additional flows. Those adjustments are on Schedules TJC-6 with the supporting detail on Schedules TJC-7 and TJC-9.

**Operating Income Adj. #3 – Depreciation Expense**

Q. Have you recalculated Test Year Depreciation and Amortization expense?

A. Yes. Based on RUCO's adjusted test-year plant and CIAC balances, I have recalculated Depreciation and Amortization Expense on a going-forward basis. The adjustment is exhibited in Schedule TJC-10 for both the Water and Wastewater Divisions.

Q. What was RUCO's reason for adjusting the Company's Depreciation Expense?

A. The primary reason that led to the adjustments was due to differences between the Company's and RUCO's CIAC balances.

...

Q. What adjustments are necessary to reflect RUCO's recommended levels of depreciation expense?

A. RUCO's adjustments increase the Company's Depreciation and Amortization Expense by $1,687 and $9,361 for the Water and Wastewater Divisions respectively.

**Operating Income Adj. #4 – Property Tax Expense**

Q. Has RUCO made an adjustment to the Company-proposed level of Property Tax Expense?

A. Yes.

Q. Has RUCO calculated Property Tax Expense using a methodology that has been adopted by the ACC in prior rate cases?

A. Yes. RUCO has used a modified version of the ADOR formula that has been adopted by the Commission in a number of prior rate cases. RUCO's calculation of Property Tax Expense uses two years of adjusted gross revenues and one year of RUCO's recommended level of gross revenues to arrive at a three-year average of gross revenues that is subject to property tax. The calculation of Property Tax Expense can be viewed in Schedules TJC-11 for both the Water and Wastewater Divisions.

...

Q. Are there any differences between RUCO's calculation of Property Tax Expense and the Company's calculation?

A. Yes. There are three differences. First, RUCO's adjusted test-year gross revenues are not the same as the Company due to an adjustment for Revenue Annualization nor is the proposed level of gross revenues the same because RUCO recommends a lower amount of an increase in rates. Second, RUCO's calculation includes an addition of 10 percent of the amount of Construction Work in Progress ("CWIP") that was booked during the test-year. Finally, RUCO has deducted a different amount of test-year net book value (See Schedule TJC-4, page 7) of the Company's vehicles.

Q. What adjustments were necessary to reflect RUCO's differences in calculating the Property Tax Expense?

A. RUCO's adjustments decrease the Company's Property Tax Expense by $30,780 and $12,434 for the Water and Wastewater Divisions respectively.

**Operating Income Adj. #5 – Rate Case Expense**

Q. What level of Rate Case Expense is RRUI estimating in this case?

A. RRUI is estimating its Rate Case Expense to be $210,000 for the Water Division and $125,000 for the Wastewater Division. The Company

proposes that the Rate Case Expense be recovered over a three-year period.

Q. What level of rate case expense is RUCO recommending?

A. The last updated amount of invoiced Rate Case Expense that RUCO is aware of was $41,307 through October 2009. That is approximately 12 percent of the total $335,000 estimated by the Company. At this time, RUCO has made an adjustment of 25 percent to the Company's total estimated Rate Case Expense for both the Water and Wastewater Divisions. RUCO is reserving its right to make further adjustments to the Company's estimates in surrebuttal testimony and final schedules. I will review the final rate case invoices and make a reasonable adjustment as this case proceeds.

Q. What adjustments are necessary to reflect RUCO's reasonable Rate Case Expense recommendations?

A. RUCO recommended five-year normalization of Rate Case Expense decreases the annual recovery by $17,500 for the Water Division and $10,417 for the Wastewater Division. The adjustments can be seen on Schedules TJC-12 for both the Water and Wastewater Divisions.

**Operating Income Adj. #6 – Misc. Expense**

Q. Please explain the adjustment RUCO makes to Miscellaneous Expense.

A. This adjustment to Miscellaneous Expense affects the Water Division only. It removes unnecessary expenses associated with the provision in the provisioning of utility services such as public relations and charitable contributions in the amount of $1,363 for the Water Division. This adjustment is shown on Schedule TJC-6 and TJC-7. The details are shown in RUCO's work papers.

**Operating Income Adj. #7 – Purchased Power Expense**

Q. Please discuss RUCO's adjustment to Purchased Power Expense.

A. This adjustment is the result of Staff data request GB 3.8. The data request inquired about the abnormally low amount of Purchased Power Expense for the Wastewater Division. The Company's response stated the following:

> First, there was about $52k of sewer power costs erroneously coded to water power costs in 2007, and 48k in 2008 (see the attached file). The Company would not oppose a recommendation by Staff to transfer this cost from water to sewer, where it belongs.

...

Q. What adjustment was necessary to properly charge the power costs to the appropriate division?

A. RUCO decreased the Water Division's Purchased Power Expense by $48,005 and increased the Wastewater Division's Purchased Power Expense by $48,005.

**Operating Income Adj. #8 – Corporate Allocations**

Q. Did RUCO make any adjustments to the Company's Corporate Expense Allocation?

A. Yes.

Q. What is RUCO's rationale for making the adjustments to the Corporate Expense Allocation?

A. First, RUCO believes that most of the expenses being allocated to the Arizona Utility Infrastructure regulated affiliates, including RRUI, are unnecessary and not directly attributable in the provisioning of water and wastewater services. Second, the unregulated parent Company, Algonquin Power Income Fund ("APIF" or "Fund"), allocated the costs down to Algonquin Power Trust ("APT"), which the Company claims is another unregulated affiliate. RUCO reviewed the Fund's organizational chart of all its affiliates and could not ascertain if APT is even an affiliate because APT is not on the organizational chart. Third, the Fund allocated costs down to APT, which are later allocated to RRUI that included Super

Bowl tickets, hockey tickets, basketball tickets, gold watches etc. and other licenses, fees, and permits that, should be totally disallowed for ratemaking purposes. Fourth, RUCO does not agree with the allocation factors utilized by APIF. Finally, RUCO has concerns with the allocation and documentation methods between an unregulated parent, the Fund, and regulated affiliates such as RRUI. The NARUC Guidelines for Cost Allocations and Affiliate Transactions, attached as RUCO Exhibit 6, states that, "The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities…" The Guidelines also suggest that "to the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

Q. What is the definition of direct costs and indirect costs?

A. *Direct costs* are those costs that can be traced easily and accurately to a cost object. The more costs that can be traced to the object, the greater the accuracy of the cost assignments. Establishing traceability is a key element in building accurate cost assignments. Tracing costs to cost objects can occur in one of two ways: (1) direct tracing and (2) driver tracing. Ideally, all costs should be charged to cost objects using direct tracing. *Indirect costs* cannot be traced to cost objects. At the very least, direct and indirect cost assignments should be reported separately.

Q. Have any of APT allocated costs been reported separately as either a direct cost or indirect cost?

A. No. All the costs have been pooled into one grouping that I would classify as all indirect costs and allocated accordingly.

Q. Please describe the Company's process of allocating the pooled APT costs.

A. APT pools costs from twelve distinct areas, such as audit, tax services, unit holder communications, trustee fees, and escrow/transfer fees etc. The total amount of these costs is $3,950,800. Next, the Company arrives at an allocation factor of 26.98 percent to be allocated to the seventeen utilities that the Fund owns. The 26.98 percent allocation factor is derived by dividing the seventeen utility companies by the 63 total companies to which it claims to own. RUCO does not agree that the Company has just 63 total companies but rather 70 as indicated in its 2008 APIF Annual Report. Then, APT takes the total cost of $3,950,800 and multiplies it by the 26.98 percent allocation factor that it claims the seventeen utility companies are attributable to arrive at $1,066,089, which RUCO also disagrees. Finally, the $1,066,089 is allocated to each of the seventeen utility companies based on each utility's customer count. In RRUI's case, the customer count represents approximately 12.92 percent of the total 64,094 customers in the seventeen utility companies. The Company's ultimately allocates 12.92 percent of the $1,066,089 to RRUI, which is

$137,706. That amount is allocated to RRUI Water and Wastewater Divisions based on its rate base to RRUI total combined rate base.

Q. If RUCO does not agree with the first allocation factor of 26.98 percent, what does RUCO recommend that allocation factor be?

A. RUCO has no problem with the Company's method of computing the allocation factor of 26.98 percent (17 / 63). RUCO disagrees with the variable of 63 being used. The 2008 Annual Report identifies 70 total companies to which the Fund owns. A more accurate allocation factor for the seventeen utility companies would be 24.29 percent (17 / 70).

Q. Does RUCO agree with the Company's total allocated cost of $1,066,089 to be shared (based on customer count) among the seventeen utility companies that the Fund owns?

A. No. This disagreement with the Company is nearly the entire amount of RUCO's recommended adjustment.

Q. What is RUCO's position regarding the allocated APT costs of $1,066,089 to be shared (based on customer count) among the seventeen utility companies that the Fund owns?

A. For all the reasons previously stated by RUCO, only a very small portion of the $1,066,089 is attributable to RRUI. RUCO cannot directly trace any of those costs to RRUI. The invoices essentially contain no detail. At the

very most, only a fraction of the costs would appear to be attributable to a relatively small sewer company of roughly 2,100 customers such as RRUI.

Q. What APT expenses does RUCO believe could be attributable to RRUI?

A. RUCO's analysis and review determined that the audit, tax services, legal – general, and depreciation expenses could possibly benefit the ratepayers of RRUI to some minor extent.

Q. What amount of those expenses does RUCO believe could possibly benefit RRUI in the provision of utility service?

A. RUCO recommends the Commission allow no more than 25 percent of the APT audit, tax services, legal – general, and depreciation expenses and disallow 100 percent of the other APT expense as being much more attributable to the Fund's operating activities.

Q. Does RUCO agree with the Company's methodology in allocating RUCO's recommended level of APT costs to RRUI by customer count?

A. RUCO is in general agreement to allocate RUCO's recommended level of APT expenses to RRUI by customer count. However, other methods could be appropriate too. RUCO did recommend correcting the Company's 26.98 percent allocation factor to 24.29 percent. It is not so much the Company's allocation methodology that RUCO takes issue with,

but rather the inappropriate and unnecessary nature of the expenses in the provision of utility service.

Q. Does RUCO believe RRUI would incur the APT type of expenses if it were a stand-alone utility and not multi-layered with corporate allocations by the non-regulated parent and affiliates?

A. RUCO believes that RRUI would incur some of the types of expenses (e.g., audit, tax services, and legal–general expenses) that APT was allocating down to its affiliates but certainly not the majority of the type of expenses being allocated by APT. RUCO will provide further analysis in surrebuttal testimony comparing stand-alone companies to companies structured as RRUI.

Q. Is RUCO aware that the Company claimed an additional $200,000 to $300,000 of APT expenses in the Litchfield Park rate case during discovery?

A. Yes. RUCO will make a further adjustment to the APT expenses in surrebuttal testimony after the Company files the additional expense.

...

Q. What adjustments did RUCO make to Outside Services in direct testimony to remove the majority of the APT related costs?

A. RUCO's adjustments remove $96,681 and $31,637 from Outside Services for the Water and Wastewater Divisions respectively. These adjustments are shown on Schedules TJC-14.

**Operating Income Adj. #9 – Bad Debt Expense**

Q. Please explain RUCO's adjustment to Bad Debt Expense.

A. This adjustment normalizes the Bad Debt Expense over three-years to obtain a more realistic and normal expense level than the amount recorded in test-year. This was especially true for the Wastewater Division where the test-year 2008 Bad Debt Expense was greater than 700 percent than that reported in 2006. The test-year Bad Debt Expense was more than 200 percent higher when compared to 2007. These wide fluctuations are mitigated by normalizing any extenuating circumstances leading to the abnormally high test-year expense levels. The Water Division did not experience the same wide fluctuations from year to year. RUCO did normalize the Water Division Bad debt Expense for the sake of consistency and fairness.

...

Q. What adjustments were necessary to smooth out the wide fluctuations reported in the Wastewater Division and to normalize the Water Division's Bad Debt Expense?

A. RUCO decreased the Wastewater Bad Debt Expense by $30,315 and increased the Water Division's Bad Debt Expense by $799. These adjustments are shown on Schedules TJC-15.

**Operating Income Adj. #10 – Income Tax Expense**

Q. Have you calculated the Income Tax Expenses based on RUCO's recommended adjusted operating incomes?

A. Yes. These adjustments are shown on Schedules TJC-16 for both the Water and Wastewater Divisions.

**OTHER ISSUES**

**Low Income Tariff Program**

Q. What is RUCO's position on the Company's proposed new HUF tariff?

A. RUCO is in general agreement with most HUF tariffs that are intended to fund new infrastructure created by growth and assists in equitably apportioning the cost of off-site facilities. However, RUCO does <u>not</u> support the Company's proposed HUF tariff as filed.

**Hook Up Fee**

Q. Why doesn't RUCO support the Company's proposed hook up fee ("HUF") tariff?

A. RUCO does not support the Company's HUF tariff because of certain language contained in the tariff and the Wastewater tariff is inconsistent with the amount of the HUF in the Company's testimony.

Q. What language in the HUF tariff is RUCO opposed?

A. Both the Water and Wastewater Divisions tariff state, "The Company shall not record amounts collected under this tariff as CIAC until such amounts have been expended for plant."

Q. Please give RUCO's reasoning for which it is in opposition to that particular language.

A. CIAC is non-investor funded capital. From the day the Company collects the CIAC from the developer or customer, the Company has use of those funds to expend them as it wishes. CIAC also frees up the investor supplied capital to be expended on other investments. The CIAC balance at any given point in time is the amount that has been collected up to that point in time. Arizona ratemaking does not defer CIAC to be recorded at a later time in the future.

...

Q. Hasn't the Commission granted accounting orders that allowed a Company to not record CIAC until a particular item of plant that the CIAC is funding is fully constructed, operational, and in gross utility plant in service?

A. Yes. The Commission has approved accounting orders that allowed a company to not record CIAC until a "specific" piece of plant is fully constructed, operational, and in gross utility plant in service. Normally, the Commission approves such an accounting order only in extraordinary circumstances. RRUI's request is far from an extraordinary circumstance. In fact, the Company's request for this special treatment of CIAC is for quite ordinary purposes.

Q. When did the Commission approve an accounting order that delayed the recording of collecting CIAC from non-investors?

A. A case that comes to mind is an Arizona-American Water Company's ("Arizona-American" or "AZ-AM") proceeding that involved construction of the White Tank Regional Treatment Plant?

Q. What was the parties' positions regarding delaying the recording of CIAC until the plant was fully constructed, operational, and in gross utility plant in service?

A. Arizona-American requested an accounting order to delay the recording of CIAC associated only with the White Tank Water Treatment Plant, which

was estimated to cost approximately $74.8 Million and originally to be funded predominantly with CIAC. AZ-AM had planned on filing a rate case several years before the completion of the White Tank Plant that included the White Tank System. If the CIAC associated with the White Tank Plant had been recorded when collected, it would distort White Tanks' rate base because of the magnitude of the CIAC balance related to the specific plant item in question. The Commission granted approval of the accounting order, which delayed the recording of the associated CIAC, based primarily on the fact that it was indeed an extraordinary circumstance. RUCO was in support of the Company's request in that extraordinary instance.

Q. Then, is it RUCO's position that without some extraordinary circumstance, which does not exist in RRUI's situation, the Commission should reject the Company's request to not record CIAC on its books until the CIAC has been expended for some generic plant?

A. Yes.

Q. If RRUI were to strike that sentence from its proposed HUF tariff, would RUCO be in support of the Company's HUF to be treated as CIAC?

A. Yes, with one clarification. The Company's proposed HUF tariffs for both the Water and Wastewater Divisions show the HUF to be $1,800 for a 5/8 inch meter. However, Mr. Sorensen's testimony indicates the Wastewater

HUF to be $2,000 on page 10, line 23 of his testimony. RUCO would like the Company to clarify if it is $1,800 or $2,000.

**Other Tariff Changes**

Q. What changes to new service line installations charges has RRUI proposed?

A. The Company proposed a change in the cost of new service lines. RRUI has proposed that all service line installation charges be at "cost" rather than the current stated tariff rates.

Q. What is RUCO's position regarding that all service line installation charges be at "cost" rather than current stated tariff rates.

A. RUCO prefers that the current rates in the tariff be maintained. RUCO will defer this issue to Commission Staff engineers.

**Late Payment Finance Charge**

Q. Has the Company proposed a 1.5 percent late payment charge to be included in its tariff?

A. Yes.

Q. Is RUCO in support of the Company's proposed 1.5 percent late payment charge?

A. Yes. This is a common charge found in many utility bills.

Q. Does this conclude your testimony?

A. Yes, it does.

# APPENDIX 1

## Qualifications of Timothy J. Coley

## WORK HISTORY

July 2000 – Present: **RESIDENTIAL UTILITY CONSUMER OFFICE,** Phoenix, Arizona
**Public Utilities Analyst V.** The Residential Utility Consumer Office (RUCO) is a consumer advocate group providing residential consumers a voice in utility regulation and backed by a professional staff with legal and financial expertise. Responsibilities include: audited, reviewed and analyzed public utility companies various filings; prepared written testimony, schedules, financial statements, and spreadsheet models and analyses. Testified and stand cross-examination before the Arizona Corporation Commission.

January 2000 - April 2000: **JACKSON HEWITT TAX SERVICE,** Phoenix, Arizona
**Tax Preparer.** Interviewed clients, determined tax situation, and explained how the tax laws benefited them in their specific situation. Ensured that each customer received every deduction that they were entitled. Prepared individual and business income tax returns, which best utilized each specific situation that minimized their tax obligations.

May 1998 - November 1999: **BENEFITS CONSULTING,** Cypress, Texas
**Consultant Assistant.** The consulting firm specialized in alleged medical claim charges brought against the government of Harris County in Houston, Texas. Assisted in the review, examination, and analysis of the attested charges. Determined if the purported medical claim charges were prudent, customary, and reasonable for the alleged sustained injuries. The firm analyzed cases for both the County's Risk Department and Attorneys Office.

January 1992 - April 1998: **PHOENIX SERVICES,** Villa Rica, Georgia
**Owner.** Provided landscaping services primarily in a high growth gated community where the Property Owners' Association approved mandated ordinances to be strictly adhered and abided by. Coordinated and supervised all aspects of projects from inception to completion, from master planning to site design to installation.

May 1989 - October 1991: **GEORGIA PUBLIC SERVICE COMMISSION,** Atlanta, GA
**Senior Auditor.** The Public Service Commission (PSC) was responsible for regulating many intrastate telecommunications, electric, and gas utility industries operating in Georgia. It was the PSC's job to ensure that consumers received adequate and reliable service at reasonable rates. It must also assure the utility companies and investors an opportunity to earn a fair rate of return on prudent investments. The Commission participated significantly in Georgia's economic health and growth. I was promoted to the PSC's Electric/Gas Division where I examined, verified, and analyzed various financial documents, accounting records, reports, ledgers, and statements. In addition, I was assigned to automate the PSC's Electric Division where I utilized a computer application process that I had developed earlier while with the (PSC) Telecommunication Division. I was later ascribed to work in conjunction with the Engineering Department and established a procedure to track and compare costs of operation and maintenance (O&M) expenses of nuclear electric generating plants. This effort determined a comparative price per kilowatt-hour produced that influenced the awareness for the company to control the O&M costs, which benefited the consumer through lower prices.

- Developed computer application system that streamlined audit procedures by 30 – 40%.
- Various other schedules were implemented to track, maintain, and control costs.

## GEORGIA PUBLIC SERVICE COMMISSION (continued)

November 1986 - April 1989: **Georgia Public Service Commission,** Atlanta, Georgia
**Auditor.** Regulated telecommunications and also oversaw the deregulation process that was currently under way in that industry. Examined and analyzed accounting records to determine financial status of companies and prepared financial reports concerning audit findings. Reviewed data including payroll, time sheets, purchase vouchers, cash receipt ledgers, financial reports, and disbursements. Verified statewide telephone company transaction classifications and documentation.

- Developed computer application utilizing Lotus to completely automate and streamline the entire telecommunication audit process. The results saved 25% in field audit time and produced a product of professional appearance.
- Created, coordinated, and implemented "Operational Project Training" automated procedure-training program. Trained and supervised staff of five auditors.
- Computerized "Desk Audit Analysis" program that identified 11 independent telephone companies in the state of over-earning and resulted in $4.1M annual savings to the Georgia ratepayers affected.

October 1985 - October 1986: **Georgia Public Service Commission,** Atlanta, Georgia
**Junior Auditor.** Assisted in planning and performing telecommunication audit engagements. Examined financial records, internal management control, correspondence, bills, and records of services delivered in order to verify or recommend compliance with company specifications contained in contracts, agreements, regulations, and/or laws.

- As a special project, I was assigned to analyze the results of a survey designed to evaluate "Interest in Organizing a Multi-State Nuclear Management Review Group" by the Director of Utilities. Wrote the draft and findings for the speech that was presented to all participatory commissions.

## PROFESSIONAL MEMBERSHIPS

- Elected Member of the National Honor Society for Public Affairs and Administration.
- Active Member of Delta Sigma Pi - Professional Business Fraternity.

## SPECIAL TRAINING AND CERTIFICATES

- The Graduate School of Business Administration - Michigan State University; completed the Annual Regulatory Studies Program of the National Association of Regulatory Utility Commissioners.
- Completed Graduate Exit Paper on "Deregulation of the Electric Industry".
- Attended Eastern Utility Rate School in 2000 and 2005.

## EDUCATION

- Currently enrolled at Arizona State University - West in the Post Baccalaureate Graduate Certificate Program in Accountancy with two courses remaining.
- Master of Public Administration, State University of West Georgia, 1997, GPA 3.5.
- BS Business Management & Administration, Minor in Economics, Sorrel School of Business, Troy State University, 1985.
- AA Business Administration, Miles Community College, 1981.

## RESUME OF PUBLIC UTILITY RATE CASES & AUDITS PARTICIPATION

**Residential Utility Consumer Office For Years 2000 To Present**

Arizona-American Water Company – Docket No. WS-01303A-05-0405

Arizona Public Service Co. – Docket No. E-01345A-03-0437

Tucson Electric Power Company – Docket No. E-01933A-04-0408

UniSource Merger – Docket No. E-04230A-03-0933

Arizona-American Water Company – Docket No. WS-01303A-02-0867

Arizona Water Company (Eastern Group) – Docket No. W01445A-02-0619

Litchfield Park Service Company – Docket Nos. W-01427A-01-0487 &
SW-01428A-01-0487

Arizona Water Company (Northern Group) – Docket No. W-01445A-00-0962

Rio Verde Utilities, Inc. – Docket Nos. W-02156A-00-0321 &
SW-02156A-00-0323

Arizona-American Water Company (Paradise Valley) –
Docket Nos. W-01303A-05-0405 &
W-01303A-05-0910

Arizona-American Water Company (Mohave District) –
Docket No. WS-01303A-06-0014

Arizona-American Water Company (Sun City & Sun Cit West Wastewater) –
Docket No. WS-01303A-06-0491

Arizona-American Water Company - Docket No. W-01303A-07-0209

Chaparral City Water Company – Docket No. W-02113A-07-0551

Arizona-American Water Company - Docket No. W-01303A-08-0227

Arizona Water Company - Docket No. W-01445A-08-0440

**Georgia Public Service Commission For Years 1985 – 1991**

Atlanta Gas Light Company

Georgia Power Company

Atlanta Gas Light Company (Management Audit)

Georgia Power Company

Trenton Telephone Company

Fairmount Telephone Company

Ellijay Telephone Company

GTE, Inc.

ALL-TEL Telephone Company

Citizens Utilities Co.

Ball Ground Telephone Company

Lanett Telephone Company

Brantley Telephone Company

Blue Ridge Telephone Company

Waverly Hall Telephone Company

St. Marys Telephone Company

Darien Telephone Company

Statesboro Telephone Company

Statesboro Telephone Co-op

Wilkes Telephone Company

# EXHIBIT 1

2008

# Algonquin Power Income Fund

## Annual Financial Results

Algonquin Power

# Consolidated Balance Sheets

**December 31, 2008 and 2007**

*(thousands of Canadian dollars)*

| | 2008 | 2007 |
|---|---|---|
| **ASSETS** | | |
| Current assets: | | |
| Cash | $ 5,902 | $ 10,361 |
| Accounts receivable | 28,138 | 26,597 |
| Prepaid expenses | 2,832 | 3,052 |
| Current portion of notes receivable (note 5) | 485 | 421 |
| Current portion of derivative assets | - | 7,857 |
| | 37,357 | 48,288 |
| Long-term investments and notes receivable (note 5) | 27,134 | 30,047 |
| Future non-current income tax asset | 2,894 | 2,416 |
| Property, plant and equipment (note 6) | 804,965 | 760,677 |
| Intangible assets (note 7) | 97,398 | 99,529 |
| Restricted cash | 5,295 | 6,105 |
| Deferred costs | 243 | 80 |
| Other assets (note 4) | 2,844 | 2,737 |
| Derivative assets | - | 4,188 |
| | $ 978,130 | $ 954,067 |
| **LIABILITIES AND UNITHOLDERS' EQUITY** | | |
| Current liabilities: | | |
| Accounts payable and accrued liabilities | $ 34,074 | $ 27,007 |
| Distributions payable | 1,587 | 11,649 |
| Current portion of long-term liabilities (notes 10 and 12) | 4,236 | 1,915 |
| Current portion of derivative liabilities (note 8) | 8,438 | - |
| Current income tax liability (note 14) | 541 | 669 |
| Future income tax liability | 1,191 | 756 |
| | 50,067 | 41,996 |
| Long-term liabilities (notes 9 and 10) | 293,590 | 281,725 |
| Convertible debentures (note 11) | 140,427 | 139,587 |
| Other long-term liabilities (note 12) | 28,859 | 23,771 |
| Future non-current income tax liability (note 14) | 85,654 | 80,785 |
| Derivative liabilities (note 8) | 25,116 | - |
| Non controlling interest | 12,548 | 21,700 |
| Unitholders' equity: | | |
| Trust units (note 13) | 722,215 | 692,213 |
| Deficit | (358,904) | (283,820) |
| Accumulated other comprehensive income | (21,442) | (43,890) |
| | 341,869 | 364,503 |
| Commitments and contigencies (note 18) | | |
| | $ 978,130 | $ 954,067 |

See accompanying notes to consolidated financial statements

Approved bv the Trustees

Ken Moore

George Steeves

## 1. Significant accounting policies: (continued)

(k) Foreign currency translation: (continued)

The ongoing review of the economic factors to be considered in determining whether foreign operations are integrated or self-sustaining has resulted in the determination that the Fund's operating entities in the Utility Services Division have changed to self-sustaining. This change was made as a result of the Utility Services Division entities' increasing proportion of operating, financing and investing transactions that are denominated in currencies other than the Canadian dollar. This change in method was effective at October 1, 2007 and was applied prospectively. These self-sustaining operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the operations of self-sustaining operations are reported as a component of Other Comprehensive Income in the Consolidated Statement of Comprehensive Income.

The Fund's remaining United States subsidiaries and partnership interests continue to be considered as functionally integrated with the Canadian operations and accounted for as integrated foreign operations.

(l) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and are included in amortization expense on the Consolidated Statements of Operations. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the Consolidated Statements of Operations. Actual expenditures incurred are charged against the accumulated obligation. Based on the Fund's assessments the Company does not have any significant asset retirement obligations and therefore no provision for retirement obligations has been recorded in 2008 and 2007.

(m) Income taxes:

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment or substantive enactment.

A valuation allowance is recorded against future tax assets to the extent that it is considered more likely than not that the future tax asset will not be realized.

## 14. Income taxes (continued)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2008 and 2007 are presented below:

| | 2008 | 2007 |
|---|---|---|
| Future tax assets: | | |
| Non-capital loss, debt restructuring charges and currently non-deductible interest carry forwards | $ 25,355 | $ 19,561 |
| Unrealized foreign exchange differences on US entity debt | 11,674 | 30,003 |
| Customer advances in aid of construction | 6,768 | 4,414 |
| Foreign exchange hedges and interest rate swaps | 3,940 | - |
| Total future tax assets | 47,737 | 53,978 |
| Less: Valuation allowance | (24,705) | (42,996) |
| Total future tax assets | 23,032 | 10,982 |
| Future tax liabilities: | | |
| Property, plant and equipment | (95,007) | (81,567) |
| Intangible assets | (9,861) | (8,174) |
| Other | (2,115) | (366) |
| Total future tax liabilities | (106,983) | (90,107) |
| Net future tax liability | $ (83,951) | $ (79,125) |

Classified in the financial statements as:

| | 2008 | 2007 |
|---|---|---|
| Future non-current income tax asset | $ 2,894 | $ 2,416 |
| Future current income tax liability | (1,191) | (756) |
| Future non-current income tax liability | (85,654) | (80,785) |
| | $ (83,951) | $ (79,125) |

Current income tax recoverable of $1,538 (2007 - $nil) is included as part of accounts receivable on the financial statements.

On June 22, 2007 legislation ("the SIFT Rules") relating to the federal income taxation of publicly-traded trusts and partnerships received royal assent. Under transitional relief the SIFT Rules will not apply to a publicly-traded trust or partnership that is a "specified investment flow through entity" (a "SIFT") which was listed before November 1, 2006 ("Existing Trust") until taxation years ending in or after 2011. The SIFT Rules do not affect the current and future tax amounts of the Fund's corporate subsidiaries.

Under the SIFT Rules, distributions of certain income by a SIFT will not be deductible in computing the SIFT's taxable income, and the SIFT will be subject to tax on such income at a rate that is substantially equivalent to the general tax rate applicable to Canadian corporations. A SIFT's income that is dividends or income received directly from foreign sources will continue to be taxed to unitholders under the existing rules and distributions paid by a SIFT as returns of capital will not be subject to this tax. An Existing Trust may lose its transitional relief where its equity capital grows beyond certain dollar limits measured by reference to the Existing Trust's market capitalization at the close of trading on October 31, 2006 in which case application of this tax to an Existing Trust may commence before 2011.

# EXHIBIT 2

# ARIZONA CORPORATION COMMISSION
# UTILITIES DIVISION

ANNUAL REPORT MAILING LABEL – MAKE CHANGES AS NECESSARY

**WS-02676A**
**Rio Rico Utilities Inc.**
**12725 W. Indian School Rd. Suite D101**
**Avondale, AZ 85392**

# ANNUAL REPORT

## FOR YEAR ENDING

| 12 | 31 | 2008 |
|---|---|---|

FOR COMMISSION USE

| ANN06 | 07 |
|---|---|

| COMPANY NAME |
|---|
| Rio Rico Utilities, Inc (Water) |

## BALANCE SHEET

| Acct. No. | ASSETS | BALANCE AT BEGINNING OF YEAR | BALANCE AT END OF YEAR |
|---|---|---|---|
| | | | |
| | **CURRENT AND ACCRUED ASSETS** | | |
| 131 | Cash | $ 75,786 | $ 78,710 |
| 134 | Working Funds | | |
| 135 | Temporary Cash Investments | | |
| 141 | Customer Accounts Receivable | (19,893) | 292,048 |
| 146 | Notes/Receivables from Associated Companies | | |
| 151 | Plant Material and Supplies | | |
| 162 | Prepayments | 16,846 | 9,603 |
| 174 | Miscellaneous Current and Accrued Assets | 1,715,216 | 1,929,391 |
| | **TOTAL CURRENT AND ACCRUED ASSETS** | **$ 1,787,955** | **$ 2,309,751** |
| | | | |
| | **FIXED ASSETS** | | |
| 101 | Utility Plant in Service | $ 30,312,040 | $ 32,844,626 |
| 103 | Property Held for Future Use | | |
| 105 | Construction Work in Progress | 1,368,681 | 813,309 |
| 108 | Accumulated Depreciation - Utility Plant | 10,312,729 | 10,986,265 |
| 121 | Non-Utility Property | | |
| 122 | Accumulated Depreciation - Non Utility | | |
| | **TOTAL FIXED ASSETS** | $ 21,367,992 | $ 22,671,670 |
| | | | |
| | **TOTAL ASSETS** | **$ 23,155,947** | **$ 24,981,422** |

NOTE: The Assets on this page should be equal to Total Liabilities and Capital on the following page.

| COMPANY NAME |
|---|
| Rio Rico Utilities, Inc (Water) |

## BALANCE SHEET (CONTINUED)

| Acct. No. | LIABILITIES | BALANCE AT BEGINNING OF YEAR | BALANCE AT END OF YEAR |
|---|---|---|---|
| | | | |
| | **CURRENT LIABILITES** | | |
| 231 | Accounts Payable | $ 19,634 | $ 16,001 |
| 232 | Notes Payable (Current Portion) | | |
| 234 | Notes/Accounts Payable to Associated Companies | (160,429) | 543,237 |
| 235 | Customer Deposits | 110,138 | 103,380 |
| 236 | Accrued Taxes | 61,275 | 74,300 |
| 237 | Accrued Interest | 2,705 | 2,605 |
| 241 | Miscellaneous Current and Accrued Liabilities | 1,310,800 | 1,603,737 |
| | **TOTAL CURRENT LIABILITIES** | $ 1,344,124 | $ 2,343,261 |
| | | | |
| | **LONG-TERM DEBT (Over 12 Months)** | | |
| 224 | Long-Term Notes and Bonds | | |
| | | | |
| | **DEFERRED CREDITS** | | |
| 251 | Unamortized Premium on Debt | | |
| 252 | Advances in Aid of Construction | 208,128 | 275,455 |
| 255 | Accumulated Deferred Investment Tax Credits | | |
| 271 | Contributions in Aid of Construction | 20,324,408 | 20,262,569 |
| 272 | Less: Amortization of Contributions | 6,136,557 | 6,676,552 |
| 281 | Accumulated Deferred Income Tax | (104,031) | 72,985 |
| | **TOTAL DEFERRED CREDITS** | $ 14,291,947 | $ 13,934,457 |
| | | | |
| | **TOTAL LIABILITIES** | $ 15,636,072 | $ 16,277,717 |
| | | | |
| | **CAPITAL ACCOUNTS** | | |
| 201 | Common Stock Issued | $ 1 | $ 1 |
| 211 | Paid in Capital in Excess of Par Value | 7,130,561 | 7,130,561 |
| 215 | Retained Earnings | 389,313 | 1,573,143 |
| 218 | Proprietary Capital (Sole Props and Partnerships) | | |
| | **TOTAL CAPITAL** | $ 7,519,875 | $ 8,703,705 |
| | | | |
| | **TOTAL LIABILITIES AND CAPITAL** | **$ 23,155,947** | **$ 24,981,422** |

# EXHIBIT 3

**RIO RICO UTILITIES, INC.**
**DOCKET NO. WS-02676A-09-0257**
**RESPONSE TO RUCO'S THIRD SET OF DATA REQUESTS**

November 16, 2009

Response provided by: Rio Rico Utilities, Inc.

Address: 12725 W Indian School Rd Suite D-101
Avondale, AZ 85392

Company Response Number: 3.03

---

Q. Accumulated Deferred Income Tax (ADIT) – Admit that the Commission did not authorize any ADIT in the last Decision No. 67279. If denied, please explain why.

RESPONSE: Deny. The decision speaks for itself.

**Rio Rico Utilities, Inc. / Water**
Test Year Ended December 31, 2002
Summary of Rate Base

Exhibit
Schedule B-1
Page 1
Witness: Kozoman

| Line No. | | |
|---|---|---|
| 1 | Gross Utility Plant in Service | $ 25,375,732 |
| 2 | Less: Accumulated Depreciation | 8,160,455 |
| 3 | | |
| 4 | Net Utility Plant in Service | $ 17,215,277 |
| 5 | | |
| 6 | Less: | |
| 7 | Advances in Aid of | |
| 8 | Construction | 88,934 |
| 9 | Contributions in Aid of | |
| 10 | Construction - Net of amortization | 14,955,477 |
| 11 | Customer Meter Deposits | 80,898 |
| 12 | | |
| 13 | Plus: | |
| 14 | Allowance for Working Capital | 119,316 |
| 15 | | |
| 16 | | |
| 17 | Total Rate Base | $ 2,209,283 |
| 18 | | |
| 19 | | |
| 20 | SUPPORTING SCHEDULES: | |
| 21 | (a) B-2 | |
| 22 | (b) B-3 | |

# EXHIBIT 4

# Chapter 3
# The
# Corporate Income Tax

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# *Temporary Differences*
*(1 of 2)*

- Deferred tax liabilities occur when
  - Rev/gains recognized earlier for book than tax
  - Exp/losses deducted earlier for tax than book
  - Tax basis of asset < book basis
  - Tax basis of liability > book basis

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# *Temporary Differences*
## *(2 of 2)*

- Deferred tax assets occur when
  - Rev/gains recognized earlier for tax than book
  - Exp/losses deducted earlier for book than tax
  - Tax basis of asset > book basis
  - Tax basis of liability < book basis
  - Loss/credit carryforwards exist

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# End
# Chapter 3

Comments or questions about PowerPoint Slides?
Contact Dr. Richard Newmark at
University of Northern Colorado's
Kenneth W. Monfort College of Business
richard.newmark@PhDuh.com

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# EXHIBIT 5

# Statement of Financial Accounting Standards No. 109

FAS109 Status Page
FAS109 Summary

## Accounting for Income Taxes

February 1992

Financial Accounting Standards Board
of the Financial Accounting Foundation
401 MERRITT 7, P.O. BOX 5116, NORWALK, CONNECTICUT 06856-5116

those circumstances, the procedures to allocate the remaining amount to items other than continuing operations are as follows:

a. Determine the effect on income tax expense or benefit for the year of the total net loss for all net loss items
b. Apportion the tax benefit determined in (a) ratably to each net loss item
c. Determine the amount that remains, that is, the difference between (1) the amount to be allocated to all items other than continuing operations and (2) the amount allocated to all net loss items
d. Apportion the tax expense determined in (c) ratably to each net gain item.

Refer to paragraphs 273-276 for additional guidance.

**Certain Quasi Reorganizations**

39. The tax benefits of deductible temporary differences and carryforwards as of the date of a quasi reorganization as defined and contemplated in ARB No. 43, Chapter 7, "Capital Accounts," ordinarily are reported as a direct addition to contributed capital if the tax benefits are recognized in subsequent years. The only exception is for enterprises that have previously both adopted Statement 96 and effected a quasi reorganization that involves only the elimination of a deficit in retained earnings by a concurrent reduction in contributed capital prior to adopting this Statement. For those enterprises, subsequent recognition of the tax benefit of prior deductible temporary differences and carryforwards is included in income and reported as required by paragraph 37 (without regard to the referenced exceptions) and then reclassified from retained earnings to contributed capital. Those enterprises should disclose (a) the date of the quasi reorganization, (b) the manner of reporting the tax benefits and that it differs from present accounting requirements for other enterprises and (c) the effect of those tax benefits on income from continuing operations, income before extraordinary items, and on net income (and on related per share amounts).

**Separate Financial Statements of a Subsidiary**

40. The consolidated amount of current and deferred tax expense for a group that files a consolidated tax return shall be allocated among the members of the group when those members issue separate financial statements. This Statement does not require a single allocation method. The method adopted, however, shall be systematic, rational, and consistent with the broad principles established by this Statement. A method that allocates current and deferred taxes to members of the group by applying this Statement to each member as if it were a separate taxpayer [10] meets those criteria. Examples of methods that are not consistent with the broad principles established by this Statement include:

a. A method that allocates only current taxes payable to a member of the group that has taxable temporary differences

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b. A method that allocates deferred taxes to a member of the group using a method fundamentally different from the asset and liability method described in this Statement (for example, the Opinion 11 deferred method)
c. A method that allocates no current or deferred tax expense to a member of the group that has taxable income because the consolidated group has no current or deferred tax expense.

Certain disclosures are also required (paragraph 49).

**Financial Statement Presentation**

41. In a classified statement of financial position, an enterprise shall separate deferred tax liabilities and assets into a current amount and a noncurrent amount. Deferred tax liabilities and assets shall be classified as current or noncurrent based on the classification of the related asset or liability for financial reporting. A deferred tax liability or asset that is not related to an asset or liability for financial reporting (paragraph 15), including deferred tax assets related to carryforwards, shall be classified according to the expected reversal date of the temporary difference pursuant to FASB Statement No. 37, *Balance Sheet Classification of Deferred Income Taxes.* The valuation allowance for a particular tax jurisdiction shall be allocated between current and noncurrent deferred tax assets for that tax jurisdiction on a pro rata basis.

42. For a particular tax-paying component of an enterprise and within a particular tax jurisdiction, (a) all current deferred tax liabilities and assets shall be offset and presented as a single amount and (b) all noncurrent deferred tax liabilities and assets shall be offset and presented as a single amount. However, an enterprise shall not offset deferred tax liabilities and assets attributable to different tax-paying components of the enterprise or to different tax jurisdictions.

**Financial Statement Disclosure**

43. The components of the net deferred tax liability or asset recognized in an enterprise's statement of financial position shall be disclosed as follows:

a. The total of all deferred tax liabilities measured in procedure (b) of paragraph 17
b. The total of all deferred tax assets measured in procedures (c) and (d) of paragraph 17
c. The total valuation allowance recognized for deferred tax assets determined in procedure (e) of paragraph 17.

The net change during the year in the total valuation allowance also shall be disclosed. A **public enterprise** shall disclose the approximate tax effect of each type of temporary difference and carryforward that gives rise to a significant portion of deferred tax liabilities and deferred tax assets (before allocation of valuation allowances). A **nonpublic enterprise** shall disclose the types of significant temporary differences and carryforwards but may omit disclosure of the tax effects of each type. A public enterprise that is not subject to income taxes because its income is

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taxed directly to its owners shall disclose that fact and the net difference between the tax bases and the reported amounts of the enterprise's assets and liabilities.

44. The following information shall be disclosed whenever a deferred tax liability is not recognized because of the exceptions to comprehensive recognition of deferred taxes for any of the areas addressed by Opinion 23 (as amended by this Statement) or for deposits in statutory reserve funds by U.S. steamship enterprises:

a. A description of the types of temporary differences for which a deferred tax liability has not been recognized and the types of events that would cause those temporary differences to become taxable
b. The cumulative amount of each type of temporary difference
c. The amount of the unrecognized deferred tax liability for temporary differences related to investments in foreign subsidiaries and foreign corporate joint ventures that are essentially permanent in duration if determination of that liability is practicable or a statement that determination is not practicable
d. The amount of the deferred tax liability for temporary differences other than those in (c) above (that is, undistributed domestic earnings, the bad-debt reserve for tax purposes of a U.S. savings and loan association or other qualified thrift lender, the policyholders' surplus of a life insurance enterprise, and the statutory reserve funds of a U.S. steamship enterprise) that is not recognized in accordance with the provisions of paragraphs 31 and 32.

45. The significant components of income tax expense attributable to continuing operations for each year presented shall be disclosed in the financial statements or notes thereto. Those components would include, for example:

a. **Current tax expense or benefit**
b. Deferred tax expense or benefit (exclusive of the effects of other components listed below)
c. Investment tax credits
d. Government grants (to the extent recognized as a reduction of income tax expense)
e. The benefits of operating loss carryforwards
f. Tax expense that results from allocating certain tax benefits either directly to contributed capital or to reduce goodwill or other noncurrent intangible assets of an acquired entity
g. Adjustments of a deferred tax liability or asset for enacted changes in tax laws or rates or a change in the tax status of the enterprise
h. Adjustments of the beginning-of-the-year balance of a valuation allowance because of a change in circumstances that causes a change in judgment about the realizability of the related deferred tax asset in future years.

46. The amount of income tax expense or benefit allocated to continuing operations and the amounts separately allocated to other items (in accordance with the provisions of paragraphs 35-39) shall be disclosed for each year for which those items are presented.

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47. A public enterprise shall disclose a reconciliation using percentages or dollar amounts of (a) the reported amount of income tax expense attributable to continuing operations for the year to (b) the amount of income tax expense that would result from applying domestic federal statutory tax rates to pretax income from continuing operations. The "statutory" tax rates shall be the regular tax rates if there are alternative tax systems. The estimated amount and the nature of each significant reconciling item shall be disclosed. A nonpublic enterprise shall disclose the nature of significant reconciling items but may omit a numerical reconciliation. If not otherwise evident from the disclosures required by this paragraph and paragraphs 43-46, all enterprises shall disclose the nature and effect of any other significant matters affecting comparability of information for all periods presented.

48. An enterprise shall disclose (a) the amounts and expiration dates of operating loss and tax credit carryforwards for tax purposes and (b) any portion of the valuation allowance for deferred tax assets for which subsequently recognized tax benefits will be allocated to reduce goodwill or other noncurrent intangible assets of an acquired entity or directly to contributed capital (paragraphs 30 and 36).

49. An entity that is a member of a group that files a consolidated tax return shall disclose in its separately issued financial statements:

a. The aggregate amount of current and deferred tax expense for each statement of earnings presented and the amount of any tax-related balances due to or from affiliates as of the date of each statement of financial position presented
b. The principal provisions of the method by which the consolidated amount of current and deferred tax expense is allocated to members of the group and the nature and effect of any changes in that method (and in determining related balances to or from affiliates) during the years for which the disclosures in (a) above are presented.

**Effective Date and Transition**

50. This Statement shall be effective for fiscal years beginning after December 15, 1992. Earlier application is encouraged. Financial statements for any number of consecutive fiscal years before the effective date may be restated to conform to the provisions of this Statement. Initial application of this Statement shall be as of the beginning of an enterprise's fiscal year (that is, if the Statement is adopted prior to the effective date and during an interim period other than the first interim period, all prior interim periods of that fiscal year shall be restated). Application of the requirements for recognition of a deferred tax liability or asset for a restated interim or annual period shall be based on the facts and circumstances as they existed at that prior date and without the benefit of hindsight.

51. The effect of initially applying this Statement shall be reported as the effect of a change in accounting principle in a manner similar to the cumulative effect of a change in accounting principle (APB Opinion No. 20, *Accounting Changes,* paragraph 20) except for initially

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# EXHIBIT 6

**Guidelines for Cost Allocations and Affiliate Transactions:**

The following Guidelines for Cost Allocations and Affiliate Transactions (Guidelines) are intended to provide guidance to jurisdictional regulatory authorities and regulated utilities and their affiliates in the development of procedures and recording of transactions for services and products between a regulated entity and affiliates. The prevailing premise of these Guidelines is that allocation methods should not result in subsidization of non-regulated services or products by regulated entities unless authorized by the jurisdictional regulatory authority. These Guidelines are not intended to be rules or regulations prescribing how cost allocations and affiliate transactions are to be handled. They are intended to provide a framework for regulated entities and regulatory authorities in the development of their own policies and procedures for cost allocations and affiliated transactions. Variation in regulatory environment may justify different cost allocation methods than those embodied in the Guidelines.

The Guidelines acknowledge and reference the use of several different practices and methods. It is intended that there be latitude in the application of these guidelines, subject to regulatory oversight. The implementation and compliance with these cost allocations and affiliate transaction guidelines, by regulated utilities under the authority of jurisdictional regulatory commissions, is subject to Federal and state law. Each state or Federal regulatory commission may have unique situations and circumstances that govern affiliate transactions, cost allocations, and/or service or product pricing standards. For example, The Public Utility Holding Company Act of 1935 requires registered holding company systems to price "at cost" the sale of goods and services and the undertaking of construction contracts between affiliate companies.

The Guidelines were developed by the NARUC Staff Subcommittee on Accounts in compliance with the Resolution passed on March 3, 1998 entitled "Resolution Regarding Cost Allocation for the Energy Industry" which directed the Staff Subcommittee on Accounts together with the Staff Subcommittees on Strategic Issues and Gas to prepare for NARUC's consideration, "Guidelines for Energy Cost Allocations." In addition, input was requested from other industry parties. Various levels of input were obtained in the development of the Guidelines from the Edison Electric Institute, American Gas Association, Securities and Exchange Commission, the Federal Energy Regulatory Commission, Rural Utilities Service and the National Rural Electric Cooperatives Association as well as staff of various state public utility commissions.

In some instances, non-structural safeguards as contained in these guidelines may not be sufficient to prevent market power problems in strategic markets such as the generation market. Problems arise when a firm has the ability to raise prices above market for a sustained period and/or impede output of a product or service. Such concerns have led some states to develop codes of conduct to govern relationships between the regulated utility and its non-regulated affiliates. Consideration should be given to any "unique" advantages an incumbent utility would have over competitors in an emerging market such as the retail energy market. A code of conduct should be used in conjunction with guidelines on cost allocations and affiliate transactions.

A. DEFINITIONS

1. Affiliates - companies that are related to each other due to common ownership or control.

2. Attestation Engagement - one in which a certified public accountant who is in the practice of public accounting is contracted to issue a written communication that expresses a conclusion about the reliability of a written assertion that is the responsibility of another party.

3. Cost Allocation Manual (CAM) - an indexed compilation and documentation of a company's cost allocation policies and related procedures.

4. Cost Allocations - the methods or ratios used to apportion costs. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).

5. Common Costs - costs associated with services or products that are of joint benefit between regulated and non-regulated business units.

6. Cost Driver - a measurable event or quantity which influences the level of costs incurred and which can be directly traced to the origin of the costs themselves.

7. Direct Costs - costs which can be specifically identified with a particular service or product.

8. Fully Allocated costs - the sum of the direct costs plus an appropriate share of indirect costs.

9. Incremental pricing - pricing services or products on a basis of only the additional costs added by their operations while one or more pre-existing services or products support the fixed costs.

10. Indirect Costs - costs that cannot be identified with a particular service or product. This includes but not limited to overhead costs, administrative and general, and taxes.

11. Non-regulated - that which is not subject to regulation by regulatory authorities.

12. Prevailing Market Pricing - a generally accepted market value that can be substantiated by clearly comparable transactions, auction or appraisal.

13. Regulated - that which is subject to regulation by regulatory authorities.

14. Subsidization - the recovery of costs from one class of customers or business unit that are attributable to another.

B. COST ALLOCATION PRINCIPLES

The following allocation principles should be used whenever products or services are provided between a regulated utility and its non-regulated affiliate or division.

1. To the maximum extent practicable, in consideration of administrative costs, costs should be collected and classified on a direct basis for each asset, service or product provided.

2. The general method for charging indirect costs should be on a fully allocated cost basis. Under appropriate circumstances, regulatory authorities may consider incremental cost, prevailing market pricing or other methods for allocating costs and pricing transactions among affiliates.

3. To the extent possible, all direct and allocated costs between regulated and non-regulated services and products should be traceable on the books of the applicable regulated utility to the applicable Uniform System of Accounts. Documentation should be made available to the appropriate regulatory authority upon request regarding transactions between the regulated utility and its affiliates.

4. The allocation methods should apply to the regulated entity's affiliates in order to prevent

subsidization from, and ensure equitable cost sharing among the regulated entity and its affiliates, and vice versa.

5. All costs should be classified to services or products which, by their very nature, are either regulated, non-regulated, or common to both.

6. The primary cost driver of common costs, or a relevant proxy in the absence of a primary cost driver, should be identified and used to allocate the cost between regulated and non-regulated services or products.

7. The indirect costs of each business unit, including the allocated costs of shared services, should be spread to the services or products to which they relate using relevant cost allocators.

## C. COST ALLOCATION MANUAL (NOT TARIFFED)

Each entity that provides both regulated and non-regulated services or products should maintain a cost allocation manual (CAM) or its equivalent and notify the jurisdictional regulatory authorities of the CAM's existence. The determination of what, if any, information should be held confidential should be based on the statutes and rules of the regulatory agency that requires the information. Any entity required to provide notification of a CAM(s) should make arrangements as necessary and appropriate to ensure competitively sensitive information derived therefrom be kept confidential by the regulator. At a minimum, the CAM should contain the following:

1. An organization chart of the holding company, depicting all affiliates, and regulated entities.

2. A description of all assets, services and products provided to and from the regulated entity and each of its affiliates.

3. A description of all assets, services and products provided by the regulated entity to non-affiliates.

4. A description of the cost allocators and methods used by the regulated entity and the cost allocators and methods used by its affiliates related to the regulated services and products provided to the regulated entity.

## D. AFFILIATE TRANSACTIONS (NOT TARIFFED)

The affiliate transactions pricing guidelines are based on two assumptions. First, affiliate transactions raise the concern of self-dealing where market forces do not necessarily drive prices. Second, utilities have a natural business incentive to shift costs from non-regulated competitive operations to regulated monopoly operations since recovery is more certain with captive ratepayers. Too much flexibility will lead to subsidization. However, if the affiliate transaction pricing guidelines are too rigid, economic transactions may be discouraged.

The objective of the affiliate transactions' guidelines is to lessen the possibility of subsidization in order to protect monopoly ratepayers and to help establish and preserve competition in the electric generation and the electric and gas supply markets. It provides ample flexibility to accommodate exceptions where the outcome is in the best interest of the utility, its ratepayers and competition. As with any transactions, the burden of proof for any exception from

the general rule rests with the proponent of the exception.

1. Generally, the price for services, products and the use of assets provided by a regulated entity to its non-regulated affiliates should be at the higher of fully allocated costs or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

2. Generally, the price for services, products and the use of assets provided by a non-regulated affiliate to a regulated affiliate should be at the lower of fully allocated cost or prevailing market prices. Under appropriate circumstances, prices could be based on incremental cost, or other pricing mechanisms as determined by the regulator.

3. Generally, transfer of a capital asset from the utility to its non-regulated affiliate should be at the greater of prevailing market price or net book value, except as otherwise required by law or regulation. Generally, transfer of assets from an affiliate to the utility should be at the lower of prevailing market price or net book value, except as otherwise required by law or regulation. To determine prevailing market value, an appraisal should be required at certain value thresholds as determined by regulators.

4. Entities should maintain all information underlying affiliate transactions with the affiliated utility for a minimum of three years, or as required by law or regulation.

E. AUDIT REQUIREMENTS

1. An audit trail should exist with respect to all transactions between the regulated entity and its affiliates that relate to regulated services and products. The regulator should have complete access to all affiliate records necessary to ensure that cost allocations and affiliate transactions are conducted in accordance with the guidelines. Regulators should have complete access to affiliate records, consistent with state statutes, to ensure that the regulator has access to all relevant information necessary to evaluate whether subsidization exists. The auditors, not the audited utilities, should determine what information is relevant for a particular audit objective. Limitations on access would compromise the audit process and impair audit independence.

2. Each regulated entity's cost allocation documentation should be made available to the company's internal auditors for periodic review of the allocation policy and process and to any jurisdictional regulatory authority when appropriate and upon request.

3. Any jurisdictional regulatory authority may request an independent attestation engagement of the CAM. The cost of any independent attestation engagement associated with the CAM, should be shared between regulated and non-regulated operations consistent with the allocation of similar common costs.

4. Any audit of the CAM should not otherwise limit or restrict the authority of state regulatory authorities to have access to the books and records of and audit the operations of jurisdictional utilities.

5. Any entity required to provide access to its books and records should make arrangements as necessary and appropriate to ensure that competitively sensitive information derived therefrom be kept confidential by the regulator.

F. REPORTING REQUIREMENTS

1. The regulated entity should report annually the dollar amount of non-tariffed transactions

associated with the provision of each service or product and the use or sale of each asset for the following:

a. Those provided to each non-regulated affiliate.

b. Those received from each non-regulated affiliate.

c. Those provided to non-affiliated entities.

2. Any additional information needed to assure compliance with these Guidelines, such as cost of service data necessary to evaluate subsidization issues, should be provided.

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Water Division

## TABLE OF CONTENTS TO TJC SCHEDULES


| SCHEDULE NO. | PAGE NO. | TITLE |
|---|---|---|
| TJC-1 | 1 & 2 | REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR |
| TJC-2 | 1 | RATE BASE |
| TJC-3 | 1 | SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS |
| TJC-4 DIRECT PLANT | 1 TO 7 | RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT |
| TJC-5 | 1 | RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEFERRED INCOME TAXES |
| TESTIMONY | | RATE BASE ADJUSTMENT NO. 3 - AIAC & CIAC BALANCES PER RUCO DR 1.08 & 1.09 |
| | | RATE BASE ADJUSTMENT NO. 4 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 5 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 6 - INTENTIONALLY LEFT BLANK |
| TJC-6 | 1 | OPERATING INCOME |
| TJC-7 | 1 | SUMMARY OF OPERATING INCOME ADJUSTMENTS |
| TJC-8 | 1 OF 16 | OPERATING INCOME ADJUSTMENT NO. 1 - REVENUE ANNUALIZATION |
| TJC-9 | 1 | OPERATING INCOME ADJUSTMENT NO. 2 - PURCHASED POWER INCREASE & EXPENSE ANNUALIZATION |
| TJC-10 | 1 | OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE |
| TJC-11 | 1 | OPERATING INCOME ADJUSTMENT NO. 4 - PROPERTY TAX EXPENSE |
| TJC-12 | 1 | OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSE |
| TJC-13 | 1 | OPERATING INCOME ADJUSTMENT NO. 6 - MISCELLANEOUS EXPENSE |
| TESTIMONY | | OPERATING INCOME ADJUSTMENT NO. 7 - PURCHASED POWER EXPENSE ADJUSTMENT |
| TJC-14 | 1 | OPERATING INCOME ADJUSTMENT NO. 8 - CORPORATE ALLOCATIONS |
| TJC-15 | 1 | OPERATING INCOME ADJUSTMENT NO. 9 - NORMALIZE BAD DEBT EXPENSE |
| TJC-16 | 1 | OPERATING INCOME ADJUSTMENT NO. 10 - INCOME TAX EXPENSE |
| TJC-17 & WAR TESTIMONY | 1 | COST OF CAPITAL |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**REVENUE REQUIREMENT**

| LINE NO. | DESCRIPTION | (A) COMPANY OCRB/FVRB COST | (B) RUCO OCRB/FVRB COST |
|---|---|---|---|
| 1 | Adjusted Original Cost/Fair Value Rate Base | $ 8,455,517 | $ 7,045,555 |
| 2 | Adjusted Operating Income (Loss) | $ (214,606) | $ (17,940) |
| 3 | Current Rate of Return (L2 / L1) | -2.54% | -0.25% |
| 4 | Required Operating Income (L5 X L1) | $ 1,048,484 | $ 556,881 |
| 5 | Required Rate of Return on Fair Value Rate Base | 12.40% | 7.90% |
| 6 | Operating Income Deficiency (L4 - L2) | $ 1,263,090 | $ 574,820 |
| 7 | Gross Revenue Conversion Factor (TJC-1, Page 2) | 1.6286 | 1.6286 |
| 8 | Required Increase in Gross Revenue Requirement (L7 X L6) | $ 2,057,112 | $ 936,172 |
| 9 | Adjusted Test Year Revenue | $ 1,847,256 | $ 1,874,057 |
| 10 | Proposed Annual Revenue (L8 + L9) | $ 3,904,369 | $ 2,810,229 |
| 15 | Required Percentage Increase in Revenue (L8 / L9) | 111.36% | 49.95% |
| 16 | Rate of Return on Common Equity | 12.40% | 9.00% |

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-6, and TJC-17

## GROSS REVENUE CONVERSION FACTOR

| LINE NO. | DESCRIPTION | (A) | (B) | (C) | (D) |
|---|---|---|---|---|---|
| | CALCULATION OF GROSS REVENUE CONVERSION FACTOR: | | | | |
| 1 | Revenue | 1.0000 | | | |
| 2 | Combined Federal And State Tax Rate (L10) | 0.3860 | | | |
| 3 | Subtotal (L1 - L2) | 0.6140 | | | |
| 4 | **Revenue Conversion Factor** (L1 / L3) | **1.6286** | | | |
| | CALCULATION OF EFFECTIVE TAX RATE: | | | | |
| 5 | Operating Income Before Taxes (Arizona Taxable Income) | 100.0000% | | | |
| 6 | Arizona State Income Tax Rate | 6.9680% | | | |
| 7 | Federal Taxable Income (L5 - L6) | 93.0320% | | | |
| 8 | Applicable Federal Income Tax Rate (Col. (D), L34) | 34.0000% | | | |
| 9 | Effective Federal Income Tax Rate (L7 X L8) | 31.6309% | | | |
| 10 | Combined Federal And State Income Tax Rate (L6 + L9) | 38.5989% | | | |
| 11 | Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4) | $ 556,881 | | | |
| 12 | Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2) | (17,940) | | | |
| 13 | Required Increase In Operating Income (L11 - L12) | | $ 574,820 | | |
| 14 | Income Taxes On Recommended Revenue (Col. (D), L31) | $ 239,170 | | | |
| 15 | Income Taxes On Test Year Revenue (Col. (D), L32) | (122,182) | | | |
| 16 | Required Increase In Revenue To Provide For Income Taxes (L14 - L15) | | $ 361,352 | | |
| 17 | Total Required Increase In Revenue (L13 + L16) | | $ 936,172 | | |
| | CALCULATION OF INCOME TAX: | | | RUCO Recommended | |
| 18 | Revenue (Sch. TJC-1, Pg 1, Col. (B), L12) | | | $ 2,810,229 | |
| 19 | Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23) | | | 2,014,178 | |
| 20 | Synchronized Interest (Col. (C), L37) | | | 176,421 | |
| 21 | Arizona Taxable Income (L18 - L19 - L20) | | | $ 619,630 | |
| 22 | Arizona State Income Tax Rate | | | 6.9680% | |
| 23 | Arizona Income Tax (L21 X L22) | | | | $ 43,176 |
| 24 | Fed. Taxable Income (L21 - L23) | | | $ 576,455 | |
| 25 | Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15% | | | $ 7,500 | |
| 26 | Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25% | | | $ 6,250 | |
| 27 | Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34% | | | $ 8,500 | |
| 28 | Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39% | | | $ 91,650 | |
| 29 | Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34% | | | $ 82,095 | |
| 30 | Total Federal Income Tax (L25 + L26 + L27 + L28 + L29) | | | | $ 195,995 |
| 31 | Combined Federal and State Income Tax (L23 + L30) | | | | $ 239,170 |
| 32 | Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23) | | | | $ (122,182) |
| 33 | RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23) | | | | $ 361,352 |
| 34 | Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24) | | | | 34.00% |
| | CALCULATION OF INTEREST SYNCHRONIZATION: | | | | |
| 35 | Rate Base (Sch. TJC-2, Col. (C), L17) | | | $ 7,045,555 | |
| | | | | 2.50% | |
| | | | | $ 176,421 | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Water Division
Schedule TJC-2
Page 1 of 1

## RATE BASE - ORIGINAL COST

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) RUCO OCRB/FVRB ADJUSTMENTS | (C) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 34,059,801 | $ - | $ 34,059,801 |
| 2 | Less: Accumulated Depreciation | (12,472,661) | (130,701) | (12,603,362) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 21,587,140 | $ (130,701) | $ 21,456,439 |
| | Less: | | | |
| 4 | Advances in Aid of Construction | (73,648) | (48,724) | (122,372) |
| 5 | Contribution in Aid of Construction | (20,188,921) | 48,724 | (20,140,197) |
| 6 | Accumulated Amortization of CIAC | 6,628,197 | - | 6,628,197 |
| 7 | NET CIAC (L5 + L6) | $ (13,560,724) | $ 48,724 | $ (13,512,000) |
| 8 | Customer Meter Deposits | (275,455) | - | (275,455) |
| 9 | Deferred Income Taxes & Credits | 778,203 | (1,279,260) | (501,057) |
| | Plus: | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - |
| 12 | Allowance For Working Capital | - | - | - |
| 13 | Rounding | 1 | - | 1 |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 8,455,517 | $ (1,409,962) | $ 7,045,555 |

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



## SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) ADJMT NO. 1 PLANT & ACCUM DEP. | (C) ADJMT NO. 2 DEFERRED INCOME TAXES | (D) ADJMT NO. 3 PER RUCO DR 1.08 | (E) ADJMT NO. 4 | (F) ADJMT NO. 5 | (G) ADJMT NO. 6 | (H) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 34,059,801 | $ - | $ - | $ - | $ - | $ - | $ - | $ 34,059,801 |
| 2 | Less: Accumulated Depreciation | (12,472,661) | (130,701) | - | - | - | - | - | (12,603,362) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 21,587,140 | $ (130,701) | $ - | $ - | $ - | $ - | $ - | $ 21,456,439 |
| | Less: | | | | | | | | |
| 4 | Advances in Aid of Construction | $ (73,648) | $ - | $ - | $ (48,724) | $ - | $ - | $ - | $ (122,372) |
| 5 | Contribution in Aid of Construction | (20,188,921) | - | - | 48,724 | - | - | - | (20,140,197) |
| 6 | Accumulated Amortization of CIAC | 6,628,197 | - | - | - | - | - | - | 6,628,197 |
| 7 | NET CIAC (L5 + L6) | $ (13,560,724) | $ - | $ - | $ 48,724 | $ - | $ - | $ - | $ (13,512,000) |
| 8 | Customer Meter Deposits | (275,455) | - | - | - | - | - | - | (275,455) |
| 9 | Deferred Income Taxes & Credits | 778,203 | - | (1,279,260) | - | - | - | - | (501,057) |
| | Plus: | | | | | | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - | - | - | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - | - | - | - | - | - |
| 12 | Allowance For Working Capital | - | - | - | - | - | - | - | - |
| 13 | Rounding | 1 | - | - | - | - | - | - | 1 |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 8,455,517 | $ (130,701) | $ (1,279,260) | $ - | $ - | $ - | $ - | $ 7,045,555 |

Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Accumulated Depreciation (See Schedule TJC-4, pages 1 - 7, and TJC Testimony)
Column (C): Adjustment No. 2 - Deferred Income Taxes (See Schedule TJC-5)
Column (D): Adjustment No. 3 - To Adjust AIAC & CIAC Balances Per Company Response to RUCO DR 1.08 and Discussed in TJC Testimony
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | (C) 12/31/2002 Per Decision No. 67279 | (D) Accumulated Depreciation Per Dec. 67279 | (E) Plant Balance 12/31/2002 |
|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | $ 5,785 | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | 417 | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | 44,194 | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | 435,181 | 104,047 | 435,181 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | 272,063 | 78,656 | 272,063 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | 29,881 | (3,617) | 29,881 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | 52,635 | 19,077 | 52,635 |
| 11 | 311 | Electtric Pumping Equipment | 3.96% | 12.50% | 1,504,459 | 508,421 | 1,504,459 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | 268,685 | 74,460 | 268,685 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | 353,111 | 106,812 | 353,111 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | 19,116,148 | 5,899,199 | 19,116,148 |
| 19 | 333 | Services | 2.49% | 3.33% | 1,465,553 | 483,437 | 1,465,553 |
| 20 | 334 | Meters | 2.49% | 8.33% | 519,191 | 82,474 | 519,191 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | 459,227 | 92,050 | 459,227 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | - | - | - |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | - | - | - |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | 22,986 | 9,507 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | 69,494 | 18,780 | 69,494 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | 2,925 | 4,954 | 2,925 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | 15,035 | 5,054 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | 3,061 | 1,378 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | 141,858 | 19,381 | 141,858 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | 7,701 | 2,709 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | | - | - |
| 34 | | Rounding | | | - | - | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 24,789,590 | $ 7,506,779 | $ 24,789,590 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 24,789,590 | $ 7,506,779 | $ 24,789,590 |
| 38 | | | | | | | |
| 39 | | **Company Direct Plant As Filed** | | | | | |
| 40 | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | |
| 42 | | | | | | | |
| 43 | | Reserve Deficiency Accrual | | | | | |
| 44 | | | | | | | |
| 45 | | Net (Salvage)/Cost of Removal | | | $ 7,506,779 | | $ 7,506,779 |
| 46 | | Accumulated Depreciation | | | - | - | - |
| 47 | | Accumulated Depreciation - PTYP | | | $ 7,506,779 | | $ 7,506,779 |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | |
| 49 | | | | | - | - | 7,506,779 |
| 50 | | Company As Filed - Accumulated Depreciation | | | | $ - | $ - |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | | | |
| 52 | | | | | | | |
| 53 | | **RUCO Net Adjustment** | | | | | |
| 54 | | | | | | | |
| 55 | | | | | | | |
| 56 | | | | | | | |
| 57 | | References: | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2003 Additions | 2003 Retirements | 2003 Adjustments | 2003 Depreciation Expense | 2003 Balance 12/31/2003 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | - | - | - | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | 253,614 | - | - | 11,184 | 688,795 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | - | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | - | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | - | - | - | 9,005 | 272,063 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | - | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | 249,272 | - | - | 2,565 | 279,153 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | 134,736 | - | - | 4,752 | 187,371 |
| 11 | 311 | Electtric Pumping Equipment | 3.96% | 12.50% | 151,098 | - | - | 62,568 | 1,655,557 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | - | - | - | 10,721 | 268,685 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | - | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | - | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | 50,494 | - | - | 7,567 | 403,605 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | - | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | - | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | 134,818 | (17,464) | - | 318,302 | 19,233,502 |
| 19 | 333 | Services | 2.49% | 3.33% | 47,278 | - | - | 37,081 | 1,512,831 |
| 20 | 334 | Meters | 2.49% | 8.33% | 42,569 | (12,864) | - | 13,298 | 548,896 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | 1,875 | (1,352) | - | 9,144 | 459,750 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | - | - | - | - | - |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | - | - | - | - | - |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | - | - | - | 1,103 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | - | - | - | 3,336 | 69,494 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | - | - | - | 975 | 2,925 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | - | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | - | - | - | 601 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | - | - | - | 122 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | - | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | - | - | - | 7,135 | 141,858 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | - | - | - | 377 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | - | - | - | - | - |
| 34 | | Rounding | | | - | - | - | | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 1,065,754 | $ (31,680) | $ - | $ 499,836 | $ 25,823,664 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 1,065,754 | $ (31,680) | $ - | $ 499,836 | $ 25,823,664 |
| 38 | | | | | | | | | |
| 39 | | **Company Direct Plant As Filed** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 42 | | | | | | | | | |
| 43 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 44 | | | | | | | | | |
| 45 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 46 | | Accumulated Depreciation | | | | | | 8,006,615 | $ 8,006,615 |
| 47 | | Accumulated Depreciation - PTYP | | | | | | - | - |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 8,006,615 | $ 8,006,615 |
| 49 | | | | | | | | | |
| 50 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 7,972,250 |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 8,006,615 | $ 34,365 |
| 52 | | | | | | | | | |
| 53 | | **RUCO Net Adjustment** | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | References: | | | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2004 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2004 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | - | - | - | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | - | - | - | 16,014 | 688,795 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | - | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | - | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | 128,294 | - | - | 11,145 | 400,357 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | - | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | - | - | - | 4,871 | 279,153 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | - | - | - | 7,907 | 187,371 |
| 11 | 311 | Electtric Pumping Equipment | 3.96% | 12.50% | 236,327 | - | - | 108,108 | 1,891,884 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | 65,200 | - | - | 11,524 | 333,885 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | - | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | - | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | 37,838 | - | - | 8,683 | 441,443 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | - | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | - | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | 431,726 | - | - | 339,391 | 19,665,227 |
| 19 | 333 | Services | 2.49% | 3.33% | 54,211 | - | - | 41,578 | 1,567,042 |
| 20 | 334 | Meters | 2.49% | 8.33% | 51,537 | (20,725) | - | 22,290 | 579,708 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | 15,453 | - | - | 9,314 | 475,203 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | - | - | - | - | - |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | - | - | - | - | - |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | - | - | - | 1,211 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | 1,320 | - | - | 6,033 | 70,814 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | - | - | - | 877 | 2,925 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | - | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | - | - | - | 639 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | - | - | - | 168 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | - | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | - | - | - | 8,898 | 141,858 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | - | - | - | 475 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | - | - | - | - | - |
| 34 | | Rounding | | | - | - | - | | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 1,021,906 | $ (20,725) | $ - | $ 599,129 | $ 26,824,845 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 1,021,906 | $ (20,725) | $ - | $ 599,129 | $ 26,824,845 |
| 38 | | | | | | | | | |
| 39 | | **Company Direct Plant As Filed** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 42 | | | | | | | | | |
| 43 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 44 | | | | | | | | - | |
| 45 | | Net (Salvage)/Cost of Removal | | | | | | 8,605,745 | $ 8,605,745 |
| 46 | | Accumulated Depreciation | | | | | | - | $ - |
| 47 | | Accumulated Depreciation - PTYP | | | | | | 8,605,745 | $ 8,605,745 |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | | |
| 49 | | | | | | | | | 8,549,777 |
| 50 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 8,605,745 | $ 55,968 |
| 52 | | | | | | | | | |
| 53 | | **RUCO Net Adjustment** | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | References: | | | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2005 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2005 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | - | - | - | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | - | - | - | 22,937 | 688,795 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | - | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | - | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | - | - | - | 13,332 | 400,357 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | - | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | - | - | - | 5,583 | 279,153 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | - | - | - | 9,369 | 187,371 |
| 11 | 311 | Electric Pumping Equipment | 3.96% | 12.50% | 507,953 | (2,008) | - | 268,107 | 2,397,829 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | 34,253 | (749) | - | 11,676 | 367,389 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | - | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | - | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | 318,417 | - | - | 13,334 | 759,861 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | - | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | - | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | 736,273 | (44,284) | - | 400,224 | 20,357,216 |
| 19 | 333 | Services | 2.49% | 3.33% | 153,500 | - | - | 54,738 | 1,720,542 |
| 20 | 334 | Meters | 2.49% | 8.33% | 82,087 | (12,138) | - | 51,203 | 649,657 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | 20,516 | (1,645) | - | 9,693 | 494,074 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | - | - | - | - | - |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | - | - | - | - | - |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | - | - | - | 1,533 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | 6,105 | - | - | 14,773 | 76,919 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | - | - | - | 585 | 2,925 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | - | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | - | - | - | 752 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | - | - | - | 306 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | - | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | 55,958 | - | - | 16,984 | 197,816 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | - | - | - | 770 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | - | - | - | - | - |
| 34 | | Rounding | | | | | | | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 1,915,062 | $ (60,824) | $ - | $ 895,900 | $ 28,679,084 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 1,915,062 | $ (60,824) | $ - | $ 895,900 | $ 28,679,084 |
| 38 | | | | | | | | | |
| 39 | | **Company Direct Plant As Filed** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 42 | | | | | | | | $ - | |
| 43 | | Reserve Deficiency Accrual | | | | | | | |
| 44 | | | | | | | | - | |
| 45 | | Net (Salvage)/Cost of Removal | | | | | | 9,501,644 | $ 9,501,644 |
| 46 | | Accumulated Depreciation | | | | | | - | - |
| 47 | | Accumulated Depreciation - PTYP | | | | | | 9,501,644 | 9,501,644 |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | | |
| 49 | | | | | - | - | - | - | 9,384,268 |
| 50 | | Company As Filed - Accumulated Depreciation | | | $ - | $ - | $ - | $ 9,501,644 | $ 117,376 |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | **RUCO Net Adjustment** | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | References: | | | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2006 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2006 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | - | - | | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | - | - | | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | - | - | | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | 545,966 | - | | 32,027 | 1,234,761 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | 53,611 | - | (147) | 14,222 | 453,821 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | - | - | | 5,583 | 279,153 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | - | - | | 9,369 | 187,371 |
| 11 | 311 | Electtric Pumping Equipment | 3.96% | 12.50% | 95,823 | - | - | 305,718 | 2,493,652 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | 5,581 | - | | 12,327 | 372,970 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | - | - | | 16,869 | 759,861 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | 741,193 | - | (1,901) | 414,537 | 21,096,508 |
| 19 | 333 | Services | 2.49% | 3.33% | 86,384 | - | | 58,732 | 1,806,926 |
| 20 | 334 | Meters | 2.49% | 8.33% | 60,552 | - | | 56,638 | 710,209 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | - | - | | 9,881 | 494,074 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | - | - | | - | - |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | - | - | - | - | - |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | - | - | | 1,533 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | - | - | | 15,384 | 76,919 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | - | - | | 585 | 2,925 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | - | - | | 752 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | - | - | | 306 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | 3,547 | - | | 19,959 | 201,363 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | - | - | | 770 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | - | - | | - | - |
| 34 | | Rounding | | | | | | | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 1,592,656 | $ - | $ (2,048) | $ 975,193 | $ 30,269,691 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 1,592,656 | $ - | $ (2,048) | $ 975,193 | $ 30,269,691 |
| 38 | | | | | | | | | |
| 39 | | **Company Direct Plant As Filed** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 42 | | | | | | | | $ - | |
| 43 | | Reserve Deficiency Accrual | | | | | | | |
| 44 | | | | | | | | - | |
| 45 | | Net (Salvage)/Cost of Removal | | | | | | 10,476,837 | $ 10,476,837 |
| 46 | | Accumulated Depreciation | | | | | | - | - |
| 47 | | Accumulated Depreciation - PTYP | | | | | | 10,476,837 | 10,476,837 |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | | |
| 49 | | | | | - | - | - | - | 10,358,875 |
| 50 | | Company As Filed - Accumulated Depreciation | | | $ - | $ - | $ - | $ 10,476,837 | $ 117,962 |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | **RUCO Net Adjustment** | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | References: | | | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2007 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2007 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | - | - | | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | - | - | | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | - | - | | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | 389,176 | - | | 47,597 | 1,623,937 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | 53,242 | - | (1,830) | 15,968 | 505,234 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | - | - | | 5,583 | 279,153 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | 5,599 | - | | 9,509 | 192,970 |
| 11 | 311 | Electric Pumping Equipment | 3.96% | 12.50% | 20,220 | - | - | 312,970 | 2,513,872 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | - | - | | 12,420 | 372,970 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | - | - | | 16,869 | 759,861 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | - | - | (2,010) | 421,910 | 21,094,498 |
| 19 | 333 | Services | 2.49% | 3.33% | 100,765 | - | | 61,848 | 1,907,691 |
| 20 | 334 | Meters | 2.49% | 8.33% | 129,225 | - | | 64,543 | 839,434 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | 56,833 | - | | 10,450 | 550,907 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | 3,848 | - | | 128 | 3,848 |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | 12,160 | - | (3,415) | 292 | 8,745 |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | - | - | | 1,533 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | - | - | | 15,384 | 76,919 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | - | - | | 585 | 2,925 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | - | - | | 752 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | - | - | | 306 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | - | - | | 20,136 | 201,363 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | - | - | | 770 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | - | - | | - | - |
| 34 | | Rounding | | | | | | | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 771,069 | $ - | $ (7,255) | $ 1,019,553 | $ 31,033,505 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 771,069 | $ - | $ (7,255) | $ 1,019,553 | $ 31,033,505 |
| 38 | | | | | | | | | |
| 39 | | **Company Direct Plant As Filed** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 42 | | | | | | | | $ - | |
| 43 | | Reserve Deficiency Accrual | | | | | | | |
| 44 | | | | | | | | - | |
| 45 | | Net (Salvage)/Cost of Removal | | | | | | 11,496,390 | $ 11,496,390 |
| 46 | | Accumulated Depreciation | | | | | | - | - |
| 47 | | Accumulated Depreciation - PTYP | | | | | | 11,496,390 | 11,496,390 |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | | |
| 49 | | | | | - | - | - | - | 11,377,844 |
| 50 | | Company As Filed - Accumulated Depreciation | | | $ - | $ - | $ - | $ 11,496,390 | $ 118,546 |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | **RUCO Net Adjustment** | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | References: | | | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2008 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/29/2008 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 301 | Organization | 0.00% | 0.00% | - | - | | $ - | $ 5,785 |
| 2 | 302 | Franchises | 0.00% | 0.00% | - | - | | - | 417 |
| 3 | 303 | Land and Land Rights | 0.00% | 0.00% | - | - | | - | 44,194 |
| 4 | 304 | Structures and Improvements | 1.99% | 3.33% | 839,316 | - | 269,580 | 72,540 | 2,732,833 |
| 5 | 305 | Collecting and Impounding Res. | 0.00% | 2.50% | - | - | | - | - |
| 6 | 306 | Lake, River and Other Intakes | 0.00% | 2.50% | - | - | | - | - |
| 7 | 307 | Wells and Springs | 3.31% | 3.33% | 3,718 | - | 54,559 | 17,795 | 563,511 |
| 8 | 308 | Infiltration Galleries and Tunnels | 0.00% | 6.67% | - | - | | - | - |
| 9 | 309 | Supply Mains | 1.66% | 2.00% | - | - | | 5,583 | 279,153 |
| 10 | 310 | Power Generation Equipment | 3.96% | 5.00% | 4,150 | - | | 9,752 | 197,120 |
| 11 | 311 | Electtric Pumping Equipment | 3.96% | 12.50% | 65,771 | - | 12,328 | 319,115 | 2,591,970 |
| 12 | 320 | Water Treatment Equipment | 3.99% | 3.33% | - | - | | 12,420 | 372,970 |
| 13 | 320.1 | Water Treatment Equipment | 3.99% | 3.33% | - | - | | - | - |
| 14 | 320.2 | Chemical Solution Feeders | 3.99% | 20.00% | - | - | | - | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 2.00% | 2.22% | - | - | | 16,869 | 759,861 |
| 16 | 330.1 | Storage Tanks | 2.00% | 2.22% | - | - | | - | - |
| 17 | 330.2 | Pressure Tanks | 2.00% | 5.00% | - | - | | - | - |
| 18 | 331 | Transmission & Distribution Mains | 1.66% | 2.00% | 980,746 | - | 13,906 | 431,836 | 22,089,150 |
| 19 | 333 | Services | 2.49% | 3.33% | 258,637 | - | 42,945 | 68,547 | 2,209,274 |
| 20 | 334 | Meters | 2.49% | 8.33% | 117,171 | - | | 74,805 | 956,605 |
| 21 | 335 | Hydrants | 1.99% | 2.00% | 17,671 | - | | 11,195 | 568,577 |
| 22 | 336 | Backflow Prevention Devices | 4.01% | 6.67% | - | - | | 257 | 3,848 |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 0.00% | 6.67% | 118,069 | - | (4,971) | 4,355 | 121,843 |
| 24 | 340 | Office Furniture and Fixtures | 4.80% | 6.67% | - | - | | 1,533 | 22,986 |
| 25 | 340.1 | Computers and Software | 4.80% | 20.00% | - | - | | 15,384 | 76,919 |
| 26 | 341 | Transportation Equipment | 33.33% | 20.00% | 108,010 | - | 108,010 | 22,187 | 218,945 |
| 27 | 342 | Stores Equipment | 0.00% | 4.00% | - | - | | - | - |
| 28 | 343 | Tools and Work Equipment | 4.00% | 5.00% | - | - | | 752 | 15,035 |
| 29 | 344 | Laboratory Equipment | 4.00% | 10.00% | - | - | | 306 | 3,061 |
| 30 | 345 | Power Operated Equipment | 0.00% | 5.00% | - | - | | - | - |
| 31 | 346 | Communication Equipment | 5.03% | 10.00% | 16,678 | - | | 20,970 | 218,040 |
| 32 | 347 | Miscellaneous Equipment | 4.89% | 10.00% | - | - | | 770 | 7,701 |
| 33 | 348 | Other Tangible Plant | 0.00% | 10.00% | - | - | | - | - |
| 34 | | Rounding | | | | | | | - |
| 35 | | **TOTAL DIRECT WATER PLANT** | | | $ 2,529,938 | $ - | $ 496,357 | $ 1,106,972 | $ 34,059,801 |
| 36 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 37 | | **RUCO Total Water Plant In Service** | | | $ 2,529,938 | $ - | $ 496,357 | $ 1,106,972 | $ 34,059,801 |
| 38 | | | | | | | | | 34,059,801 |
| 39 | | **Company Direct Plant As Filed** | | | | | | | $ - |
| 40 | | | | | | | | | |
| 41 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 42 | | | | | | | | $ - | |
| 43 | | Reserve Deficiency Accrual | | | | | | | |
| 44 | | | | | | | | - | |
| 45 | | Net (Salvage)/Cost of Removal | | | | | | 12,603,362 | $ 12,603,362 |
| 46 | | Accumulated Depreciation | | | | | | - | - |
| 47 | | Accumulated Depreciation - PTYP | | | | | | 12,603,362 | 12,603,362 |
| 48 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | | |
| 49 | | | | | - | - | - | - | 12,472,661 |
| 50 | | Company As Filed - Accumulated Depreciation | | | $ - | $ - | $ - | $ 12,603,362 | $ 130,701 |
| 51 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | | | | | |
| 52 | | | | | | | | | $ 130,701 |
| 53 | | **RUCO Net Adjustment** | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | | | | | | | | |
| 56 | | | | | | | | | |
| 57 | | References: | | | | | | | |
| 58 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 59 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

## ACCUMULATED DEFERRED INCOME TAXES

| Line No. | Deferred Income Taxes: | | Amount | Reference |
|---|---|---|---|---|
| 1 | | | | |
| 2 | | | | |
| 3 | Algonquin Accumulated Deferred Income Tax Assets | $ | 23,032,000 | 2008 Algonquin Annual Report |
| 4 | | | | |
| 5 | Algonquin Accumulated Deferred Income Tax Liabilities | | (106,983,000) | 2008 Algonquin Annual Report |
| 6 | | | | |
| 7 | Net Accumulated Deferred Income Tax Assets (Liabilities) | $ | (83,951,000) | Line 3 + Line 5 |
| 8 | | | | |
| 9 | Rio Rico Allocation | | 0.8997% | Note (A) |
| 10 | | | | |
| 11 | Rio Rico ADIT Liabilities Allocation | $ | (755,287) | Line 7 X Line 9 |
| 12 | | | | |
| 13 | Convert to US Dollars | | 0.9400 | Note (B) |
| 14 | | | | |
| 15 | Allocated ADIT Liabilites Balance | $ | (709,970) | Line 11 X Line 13 |
| 16 | | | | |
| 17 | Rio Rico Water Allocation Factor | | 0.70574 | Note (C) |
| 18 | | | | |
| 19 | Rio Rico Wastewater Allocation Factor | | 0.29426 | Note (C) |
| 20 | | | | |
| 21 | Rio Rico Water Allocation | $ | (501,057) | Line 15 X Line 17 |
| 22 | | | | |
| 23 | Rio Rico Wastewater Allocation | $ | (208,912) | Line 15 X Line 19 |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | **NOTES:** | | | |
| 29 | (A) Purchase Price of Rio Rico Utilities. Inc. | $ | 8,800,000 | |
| 30 | Algonquin Total Assets | | 978,130,000 | |
| 31 | | | | |
| 32 | Ratio | | 0.8997% | |
| 33 | | | | |
| 34 | | | | |
| 35 | (B) www.bank-banque-canada.ca on 11/19/2009 | | 0.9400 | |
| 36 | | | | |
| 37 | | | | |
| 38 | (C) Rio Rico Water Allocation | | 0.70574 | |
| 39 | | | | |
| 40 | Rio Rico Wastewater Allocation | | 0.29426 | |
| 41 | | | | |
| 42 | | | | |
| 43 | SUPPORTING SCHEDULES | | | |
| 44 | 2008 Algonquin Power Income Fund Annual Report | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Water Division
Schedule TJC-6
Page 1 of 1

## OPERATING INCOME

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO TEST YEAR ADJM'TS | (C) RUCO TEST YEAR AS ADJ'TED | (D) RUCO PROP'D CHANGES | (E) RUCO AS RECOMM'D |
|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | |
| 1 | Metered Water Revenues | $ 1,802,584 | $ 26,801 | $ 1,829,385 | $ 936,172 | $ 2,765,557 |
| 2 | Unmetered Water Revenues | - | - | - | - | - |
| 3 | Other Water Revenues | 44,672 | - | 44,672 | - | 44,672 |
| 4 | Total Revenues | $ 1,847,256 | $ 26,801 | $ 1,874,057 | $ 936,172 | $ 2,810,229 |
| | **Operating Expenses:** | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - |
| 6 | Purchased Water | - | - | - | - | - |
| 7 | Purchased Power | 441,501 | (38,924) | 402,577 | - | 402,577 |
| 8 | Fuel for Power Production | - | - | - | - | - |
| 9 | Chemicals | 9,347 | - | 9,347 | - | 9,347 |
| 10 | Materials & Supplies | 23,150 | - | 23,150 | - | 23,150 |
| 11 | Outside Services | 805,032 | (96,681) | 708,351 | - | 708,351 |
| 12 | Outside Services - Other | 76,859 | - | 76,859 | - | 76,859 |
| 13 | Outside Services - Legal | 487 | - | 487 | - | 487 |
| 14 | Water Testing | - | - | - | - | - |
| 15 | Rents | 26,954 | - | 26,954 | - | 26,954 |
| 16 | Transportation Expenses | 79,315 | - | 79,315 | - | 79,315 |
| 17 | Insurance - General Liability | 37,699 | - | 37,699 | - | 37,699 |
| 18 | Insurance - Health and Life | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 17,564 | - | 17,564 | - | 17,564 |
| 20 | Reg. Comm. Exp. - Rate Case | 70,000 | (17,500) | 52,500 | - | 52,500 |
| 21 | Miscellaneous Expense | 14,822 | (1,363) | 13,459 | - | 13,459 |
| 22 | Bad Debt Expense | 371 | 799 | 1,170 | - | 1,170 |
| 23 | Depreciation Expense | 463,297 | 1,687 | 464,984 | - | 464,984 |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Property Taxes | 130,373 | (30,611) | 99,762 | - | 99,762 |
| 26 | Federal Income Tax | (110,555) | 10,430 | (100,125) | 296,120 | 195,995 |
| 27 | State Income Tax | (24,354) | 2,298 | (22,057) | 65,232 | 43,176 |
| 28 | **Total Operating Expenses** | $ 2,061,862 | $ (169,865) | $ 1,891,997 | $ 361,352 | $ 2,253,349 |
| 29 | **Operating Income** | $ (214,606) | $ 196,666 | $ (17,940) | $ 574,820 | $ 556,881 |

References:
Column (A): Company Schedule C-1
Column (B): Schedule TJC-7, Columns (B) Thru (K)
Column (C): Column (A) + Column (B)
Column (D): TJC-1, pages 1 and 2
Column (E): Column (C) + Column (D)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**SUMMARY OF OPERATING INCOME ADJUSTMENTS**
**TEST YEAR AS FILED AND ADJUSTMENTS**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJMT NO. 1 REVENUE ANNUAL'TN | (C) ADJMT NO. 2 PURCHASED POWER | (D) ADJMT NO. 3 DEPRECIATION EXPENSE | (E) ADJMT NO. 4 PROPERTY TAX | (F) ADJMT NO. 5 RATE CASE EXPENSE | (G) ADJMT NO. 6 MISCELL. EXPENSE | (H) ADJMT NO. 7 PURCH. POWER PER GB 3.8 | (I) ADJMT NO. 8 CORPORATE ALLOCATION | (J) ADJMT NO. 9 BAD DEBT EXPENSE | (K) ADJMT NO. 10 INCOME TAXES | (L) RUCO AS ADJ'TD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | | | | | | | | |
| 1 | Metered Water Revenues | $ 1,802,584 | $ 26,801 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $1,829,385 |
| 2 | Unmetered Water Revenues | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Other Water Revenues | 44,672 | - | - | - | - | - | - | - | - | - | - | 44,672 |
| 4 | Total Revenues | $ 1,847,256 | $ 26,801 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $1,874,057 |
| | **Operating Expenses:** | | | | | | | | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 6 | Purchased Water | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | Purchased Power | 441,501 | - | 9,081 | - | - | - | - | (48,005) | - | - | - | 402,577 |
| 8 | Fuel for Power Production | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Chemicals | 9,347 | - | - | - | - | - | - | - | - | - | - | 9,347 |
| 10 | Materials & Supplies | 23,150 | - | - | - | - | - | - | - | - | - | - | 23,150 |
| 11 | Outside Services | 805,032 | - | - | - | - | - | - | - | (96,681) | - | - | 708,351 |
| 12 | Outside Services - Other | 76,859 | - | - | - | - | - | - | - | - | - | - | 76,859 |
| 13 | Outside Services - Legal | 487 | - | - | - | - | - | - | - | - | - | - | 487 |
| 14 | Water Testing | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | Rents | 26,954 | - | - | - | - | - | - | - | - | - | - | 26,954 |
| 16 | Transportation Expenses | 79,315 | - | - | - | - | - | - | - | - | - | - | 79,315 |
| 17 | Insurance - General Liability | 37,699 | - | - | - | - | - | - | - | - | - | - | 37,699 |
| 18 | Insurance - Health and Life | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 17,564 | - | - | - | - | - | - | - | - | - | - | 17,564 |
| 20 | Reg. Comm. Exp. - Rate Case | 70,000 | - | - | - | - | (17,500) | - | - | - | - | - | 52,500 |
| 21 | Miscellaneous Expense | 14,822 | - | - | - | - | - | (1,363) | - | - | - | - | 13,459 |
| 22 | Bad Debt Expense | 371 | - | - | - | - | - | - | - | - | 799 | - | 1,170 |
| 23 | Depreciation Expense | 463,297 | - | - | 1,687 | - | - | - | - | - | - | - | 464,984 |
| 24 | Taxes Other Than Income | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | Property Taxes | 130,373 | - | - | - | (30,611) | - | - | - | - | - | - | 99,762 |
| 26 | Federal Income Tax | (110,555) | - | - | - | - | - | - | - | - | - | 10,430 | (100,125) |
| 27 | State Income Tax | (24,354) | - | - | - | - | - | - | - | - | - | 2,298 | (22,057) |
| 28 | **Total Operating Expenses** | $ 2,061,862 | $ - | $ 9,081 | $ 1,687 | $ (30,611) | $ (17,500) | $ (1,363) | $ (48,005) | $ (96,681) | $ 799 | $ 12,727 | $1,891,997 |
| 29 | **Operating Income** | $ (214,606) | $ 26,801 | $ (9,081) | $ (1,687) | $ 30,611 | $ 17,500 | $ 1,363 | $ 48,005 | $ 96,681 | $ (799) | $ (12,727) | $ (17,940) |

ADJUSTMENTS:
1 - Revenue Annualization
2 - Purchased Power Expense Increase and Annualization
3 - Depreciation Expense
4 - Property Tax Expense
5 - Rate Case Expense
6 - Miscellaneous Expense
7 - Purchased Power Expense Per Staff DR GB 3.8
8 - Corporate Allocations
9 - Bad Debt Expense
10 - Income Taxes

REFERENCE:
TJC Testimony and Schedule TJC-8 Pages 1 thru 16
TJC Testimony and Schedule TJC-9
TJC Testimony and Schedule TJC-10
TJC Testimony and Schedule TJC-11
TJC Testimony and Schedule TJC-12
TJC Testimony and Schedule TJC-13
TJC Testimony
TJC Testimony and Schedule TJC-14
TJC Testimony and Schedule TJC-15
TJC Testimony and Schedule TJC-16

## OPERATING ADJUSTMENT #1 - REVENUE ANNUALIZATION

| Line No. | | |
|---|---|---|
| 1 | Revenue Annualization | |
| 2 | | |
| 3 | | |
| 4 | RUCO Revenue Annualization | $ 22,007 |
| 5 | | |
| 6 | Company Revenue Annualization | (4,794) |
| 7 | | |
| 8 | | |
| 9 | RUCO Adjustment to Revenue and/or Expense | $ 26,801 |
| 10 | | |
| 11 | | |
| 12 | | |
| 13 | SUPPORTING SCHEDULES | |
| 14 | Schedule TJC-8, pages 2 thru 16 | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 5/8" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR | AVERAGE CUSTOMERS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 AVERAGE TEST YEAR CUSTOMERS | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 5,745 | 68,940 | |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 5,628 | 5,753 | 5,721 | 5,934 | 5,786 | 5,964 | 5,822 | 5,769 | 5,662 | 5,621 | 5,647 | 5,633 | 68,940 | 5,745 |
| 3 | AVERAGE INCREASE IN CUSTOMERS | 117 | (8) | 24 | (189) | (41) | (219) | (77) | (24) | 83 | 124 | 98 | 112 | - | |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 19.72 | $ 19.99 | $ 17.23 | $ 20.18 | $ 20.70 | $ 25.43 | $ 21.77 | $ 18.56 | $ 20.16 | $ 19.77 | $ 19.86 | $ 15.92 | | |
| 5 | INCREASE IN REVENUES | $ 2,308 | $ (160) | $ 413 | $ (3,814) | $ (849) | $ (5,570) | $ (1,676) | $ (445) | $ 1,674 | $ 2,452 | $ 1,946 | $ 1,783 | $ (1,938) | |
| 6 | TOTAL INCREASE IN REVENUE | (1,938) | | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | (28,738) | | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | 26,800 | | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 8,420 | 8,576 | 6,952 | 8,687 | 8,996 | 11,590 | 9,622 | 7,734 | 8,679 | 8,449 | 8,498 | 6,181 | | |
| 10 | INCREASE IN CUSTOMERS | 117 | (8) | 24 | (189) | (41) | (219) | (77) | (24) | 83 | 124 | 98 | 112 | | |
| 11 | RUCO INCREASE IN GALLONS | 985,124 | (68,604) | 166,855 | (1,641,854) | (368,823) | (2,538,292) | (740,864) | (185,618) | 720,350 | 1,047,658 | 832,800 | 692,320 | (1,098,948) | |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | (12,565,917) | |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | 11,466,968 | | | | | | | | | | | | 11,466,968 | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 3/4" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 96 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 7 | 7 | 10 | 7 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 95 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 1 | 1 | (2) | 1 | - | - | - | - | - | - | - | - | 1 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 16.45 | $ 14.75 | $ 14.58 | $ 16.45 | $ 15.18 | $ 16.66 | $ 15.60 | $ 14.54 | $ 16.88 | $ 16.03 | $ 15.81 | $ 15.81 | |
| 5 | INCREASE IN REVENUES | $ 16 | $ 15 | $ (29) | $ 16 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 18 |
| 6 | TOTAL INCREASE IN REVENUE | 18 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 18 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 4,000 | 3,000 | 2,900 | 4,000 | 3,250 | 4,125 | 3,500 | 2,875 | 4,250 | 3,750 | 3,625 | 3,625 | |
| 10 | INCREASE IN CUSTOMERS | 1 | 1 | (2) | 1 | - | - | - | - | - | - | - | - | 5,200 |
| 11 | RUCO INCREASE IN GALLONS | 4,000 | 3,000 | (5,800) | 4,000 | - | - | - | - | - | - | - | - | 5,200 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 1" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 50 | 600 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 34 | 35 | 34 | 35 | 38 | 40 | 33 | 36 | 32 | 32 | 33 | 50 | 432 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 16 | 15 | 16 | 15 | 12 | 10 | 17 | 14 | 18 | 18 | 17 | - | 168 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 33.70 | $ 38.28 | $ 33.70 | $ 38.28 | $ 35.89 | $ 45.07 | $ 42.50 | $ 40.66 | $ 37.98 | $ 33.41 | $ 33.64 | $ 26.35 | |
| 5 | INCREASE IN REVENUES | $ 539 | $ 574 | $ 539 | $ 574 | $ 431 | $ 451 | $ 722 | $ 569 | $ 684 | $ 601 | $ 572 | $ - | $ 6,257 |
| 6 | TOTAL INCREASE IN REVENUE | 6,257 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 6,257 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 9,765 | 12,457 | 9,765 | 12,457 | 11,053 | 16,300 | 14,939 | 13,861 | 12,281 | 9,594 | 9,727 | 5,440 | |
| 10 | INCREASE IN CUSTOMERS | 16 | 15 | 16 | 15 | 12 | 10 | 17 | 14 | 18 | 18 | 17 | - | |
| 11 | RUCO INCREASE IN GALLONS | 156,235 | 186,857 | 156,235 | 186,857 | 132,632 | 163,000 | 253,970 | 194,056 | 221,063 | 172,688 | 165,364 | - | 1,988,955 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 1,988,955 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 1.5" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 96 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 3 | 3 | 3 | 3 | 3 | 4 | 4 | 3 | 3 | 3 | 3 | 8 | 43 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 5 | 5 | 5 | 5 | - | 53 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 68.13 | $ 69.33 | $ 68.13 | $ 69.33 | $ 73.13 | $ 72.03 | $ 73.45 | $ 66.43 | $ 85.80 | $ 99.73 | $ 81.37 | $ 45.11 | |
| 5 | INCREASE IN REVENUES | $ 341 | $ 347 | $ 341 | $ 347 | $ 366 | $ 288 | $ 294 | $ 332 | $ 429 | $ 499 | $ 407 | $ - | $ 3,989 |
| 6 | TOTAL INCREASE IN REVENUE | 3,989 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 3,989 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 19,667 | 20,333 | 19,667 | 20,333 | 22,333 | 21,750 | 22,500 | 18,667 | 29,000 | 36,333 | 26,667 | 6,125 | |
| 10 | INCREASE IN CUSTOMERS | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 5 | 5 | 5 | 5 | - | |
| 11 | RUCO INCREASE IN GALLONS | 98,333 | 101,667 | 98,333 | 101,667 | 111,667 | 87,000 | 90,000 | 93,333 | 145,000 | 181,667 | 133,333 | - | 1,242,000 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 1,242,000 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 2" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 60 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 3 | 3 | 3 | 3 | 3 | 4 | 6 | 4 | 7 | 3 | 4 | 5 | 48 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 2 | 2 | 2 | 2 | 2 | 1 | (1) | 1 | (2) | 2 | 1 | - | 12 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 77.23 | $ 98.20 | $ 77.23 | $ 98.20 | $ 88.57 | $ 112.23 | $ 79.50 | $ 86.73 | $ 95.53 | $ 90.27 | $ 78.65 | $ 74.74 | |
| 5 | INCREASE IN REVENUES | $ 154 | $ 196 | $ 154 | $ 196 | $ 177 | $ 112 | $ (80) | $ 87 | $ (191) | $ 181 | $ 79 | $ - | $ 1,066 |
| 6 | TOTAL INCREASE IN REVENUE | 1,066 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 1,066 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 13,667 | 26,000 | 13,667 | 26,000 | 20,333 | 34,250 | 15,000 | 19,250 | 24,429 | 21,333 | 14,500 | 12,200 | |
| 10 | INCREASE IN CUSTOMERS | 2 | 2 | 2 | 2 | 2 | 1 | (1) | 1 | (2) | 2 | 1 | - | |
| 11 | RUCO INCREASE IN GALLONS | 27,333 | 52,000 | 27,333 | 52,000 | 40,667 | 34,250 | (15,000) | 19,250 | (48,857) | 42,667 | 14,500 | - | 246,143 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 246,143 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 5/8" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 116 | 116 | 116 | 116 | 116 | 116 | 116 | 116 | 116 | 116 | 116 | 116 | 1,392 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 94 | 98 | 94 | 98 | 93 | 100 | 94 | 98 | 91 | 99 | 88 | 116 | 1,163 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 22 | 18 | 22 | 18 | 23 | 16 | 22 | 18 | 25 | 17 | 28 | - | 229 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 24.49 | $ 28.59 | $ 24.49 | $ 28.59 | $ 28.87 | $ 32.77 | $ 27.75 | $ 21.56 | $ 24.21 | $ 22.72 | $ 24.22 | $ 18.39 | |
| 5 | INCREASE IN REVENUES | $ 539 | $ 515 | $ 539 | $ 515 | $ 664 | $ 524 | $ 610 | $ 388 | $ 605 | $ 386 | $ 678 | $ - | $ 5,963 |
| 6 | TOTAL INCREASE IN REVENUE | 5,963 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 5,963 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 11,096 | 13,255 | 11,096 | 13,255 | 13,398 | 15,450 | 12,809 | 9,500 | 10,945 | 10,162 | 10,955 | 7,638 | |
| 10 | INCREASE IN CUSTOMERS | 22 | 18 | 22 | 18 | 23 | 16 | 22 | 18 | 25 | 17 | 28 | - | |
| 11 | RUCO INCREASE IN GALLONS | 244,106 | 238,592 | 244,106 | 238,592 | 308,151 | 247,200 | 281,787 | 171,000 | 273,626 | 172,747 | 306,727 | - | 2,726,635 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 2,726,635 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 1" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 552 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 45 | 46 | 43 | 41 | 45 | 46 | 42 | 38 | 41 | 40 | 42 | 46 | 515 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 1 | - | 3 | 5 | 1 | - | 4 | 8 | 5 | 6 | 4 | - | 37 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 40.41 | $ 52.31 | $ 41.49 | $ 56.97 | $ 55.44 | $ 66.68 | $ 56.53 | $ 44.75 | $ 38.58 | $ 42.52 | $ 42.56 | $ 36.95 | |
| 5 | INCREASE IN REVENUES | $ 40 | $ - | $ 124 | $ 285 | $ 55 | $ - | $ 226 | $ 358 | $ 193 | $ 255 | $ 170 | $ - | $ 1,708 |
| 6 | TOTAL INCREASE IN REVENUE | 1,708 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 1,708 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 13,711 | 20,109 | 14,349 | 22,561 | 21,756 | 27,674 | 22,333 | 16,132 | 12,634 | 14,950 | 14,976 | 11,674 | |
| 10 | INCREASE IN CUSTOMERS | 1 | - | 3 | 5 | 1 | - | 4 | 8 | 5 | 6 | 4 | - | |
| 11 | RUCO INCREASE IN GALLONS | 13,711 | - | 43,047 | 112,805 | 21,756 | - | 89,333 | 129,053 | 63,171 | 89,700 | 59,905 | - | 622,480 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 622,480 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 1.5" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 10 | 120 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 10 | 11 | 10 | 11 | 11 | 15 | 9 | 9 | 9 | 9 | 10 | 10 | 124 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | (1) | - | (1) | (1) | (5) | 1 | 1 | 1 | 1 | - | - | (4) |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 86.56 | $ 108.60 | $ 86.56 | $ 108.60 | $ 130.19 | $ 106.19 | $ 144.70 | $ 121.48 | $ 130.77 | $ 84.32 | $ 80.29 | $ 87.70 | |
| 5 | INCREASE IN REVENUES | $ - | $ (109) | $ - | $ (109) | $ (130) | $ (531) | $ 145 | $ 121 | $ 131 | $ 84 | $ - | $ - | $ (397) |
| 6 | TOTAL INCREASE IN REVENUE | (397) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (397) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 29,400 | 41,000 | 29,400 | 41,000 | 52,364 | 39,733 | 60,000 | 47,778 | 52,667 | 28,222 | 26,100 | 30,000 | |
| 10 | INCREASE IN CUSTOMERS | - | (1) | - | (1) | (1) | (5) | 1 | 1 | 1 | 1 | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | (41,000) | - | (41,000) | (52,364) | (198,667) | 60,000 | 47,778 | 52,667 | 28,222 | - | - | (144,364) |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | (144,364) |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 2" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 35 | 420 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 29 | 28 | 30 | 30 | 34 | 35 | 33 | 35 | 33 | 34 | 37 | 35 | 393 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 6 | 7 | 5 | 5 | 1 | - | 2 | - | 2 | 1 | (2) | - | 27 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 183.33 | $ 267.00 | $196.56 | $ 281.87 | $ 451.94 | $ 468.80 | $ 228.92 | $ 358.11 | $ 412.06 | $ 430.42 | $ 442.11 | $ 243.29 | |
| 5 | INCREASE IN REVENUES | $ 1,100 | $ 1,869 | $ 983 | $ 1,409 | $ 452 | $ - | $ 458 | $ - | $ 824 | $ 430 | $ (884) | $ - | $ 6,641 |
| 6 | TOTAL INCREASE IN REVENUE | 6,641 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 6,641 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 74,069 | 118,107 | 81,033 | 125,933 | 215,441 | 224,314 | 98,061 | 166,057 | 194,455 | 204,118 | 210,270 | 105,629 | |
| 10 | INCREASE IN CUSTOMERS | 6 | 7 | 5 | 5 | 1 | - | 2 | - | 2 | 1 | (2) | - | |
| 11 | RUCO INCREASE IN GALLONS | 444,414 | 826,750 | 405,167 | 629,667 | 215,441 | - | 196,121 | - | 388,909 | 204,118 | (420,541) | - | 2,890,046 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 2,890,046 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 3" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 12 | 144 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 13 | 14 | 14 | 18 | 14 | 15 | 15 | 11 | 10 | 13 | 12 | 12 | 161 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | (1) | (2) | (2) | (6) | (2) | (3) | (3) | 1 | 2 | (1) | - | - | (17) |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 614.16 | $ 493.68 | $ 427.04 | $ 582.62 | $ 879.79 | $ 871.48 | $ 436.25 | $ 638.95 | $ 675.59 | $ 260.62 | $ 678.25 | $ 661.78 | |
| 5 | INCREASE IN REVENUES | $ (614) | $ (987) | $ (854) | $ (3,496) | $ (1,760) | $ (2,614) | $ (1,309) | $ 639 | $ 1,351 | $ (261) | $ - | $ - | $ (9,905) |
| 6 | TOTAL INCREASE IN REVENUE | (9,905) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (9,905) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 273,769 | 210,357 | 175,286 | 257,167 | 413,571 | 409,200 | 180,133 | 286,818 | 306,100 | 87,692 | 307,500 | 298,833 | |
| 10 | INCREASE IN CUSTOMERS | (1) | (2) | (2) | (6) | (2) | (3) | (3) | 1 | 2 | (1) | - | - | |
| 11 | RUCO INCREASE IN GALLONS | (273,769) | (420,714) | (350,571) | (1,543,000) | (827,143) | (1,227,600) | (540,400) | 286,818 | 612,200 | (87,692) | - | - | (4,371,872) |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | (4,371,872) |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 4" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 6 | 72 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 6 | 4 | 5 | 6 | 61 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | 2 | 1 | - | 11 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 586.18 | $ 778.84 | $ 718.04 | $ 719.94 | $ 803.16 | $ 1,019.00 | $ 710.44 | $ 759.08 | $ 638.37 | $ 790.05 | $ 628.74 | $ 525.63 | |
| 5 | INCREASE IN REVENUES | $ 586 | $ 779 | $ 718 | $ 720 | $ 803 | $ 1,019 | $ 710 | $ 759 | $ - | $ 1,580 | $ 629 | $ - | $ 8,304 |
| 6 | TOTAL INCREASE IN REVENUE | 8,304 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 8,304 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 223,200 | 324,600 | 292,600 | 293,600 | 337,400 | 451,000 | 288,600 | 314,200 | 250,667 | 330,500 | 245,600 | 191,333 | |
| 10 | INCREASE IN CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | - | 2 | 1 | - | |
| 11 | RUCO INCREASE IN GALLONS | 223,200 | 324,600 | 292,600 | 293,600 | 337,400 | 451,000 | 288,600 | 314,200 | - | 661,000 | 245,600 | - | 3,431,800 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 3,431,800 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 6" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 780.75 | $ 915.65 | $ 953.65 | $ 1,297.55 | $ 1,592.05 | $ 3,203.25 | $ 927.05 | $ 1,707.95 | $ 1,236.75 | $ 2,106.95 | $ 2,249.45 | $ 1,213.95 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 255,000 | 326,000 | 346,000 | 527,000 | 682,000 | 1,530,000 | 332,000 | 743,000 | 495,000 | 953,000 | 1,028,000 | 483,000 | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Multi-Family 5/8" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 108 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 10 | 9 | 9 | 10 | 10 | 10 | 11 | 10 | 10 | 9 | 10 | 9 | 117 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | (1) | - | - | (1) | (1) | (1) | (2) | (1) | (1) | - | (1) | - | (9) |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 25.45 | $ 25.15 | $ 23.89 | $ 25.45 | $ 24.12 | $ 30.77 | $ 19.63 | $ 22.07 | $ 25.45 | $ 21.65 | $ 19.18 | $ 23.68 | |
| 5 | INCREASE IN REVENUES | $ (25) | $ - | $ - | $ (25) | $ (24) | $ (31) | $ (39) | $ (22) | $ (25) | $ - | $ (19) | $ - | $ (212) |
| 6 | TOTAL INCREASE IN REVENUE | (212) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (212) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 11,600 | 11,444 | 10,778 | 11,600 | 10,900 | 14,400 | 8,364 | 9,800 | 11,600 | 9,556 | 8,100 | 10,667 | |
| 10 | INCREASE IN CUSTOMERS | (1) | - | - | (1) | (1) | (1) | (2) | (1) | (1) | - | (1) | - | |
| 11 | RUCO INCREASE IN GALLONS | (11,600) | - | - | (11,600) | (10,900) | (14,400) | (16,727) | (9,800) | (11,600) | - | (8,100) | - | (94,727) |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | (94,727) |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Multi-Family 1.5" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 46.60 | $ 51.70 | $ 53.40 | $ 46.60 | $ 43.20 | $ 38.10 | $ 39.80 | $ 50.00 | $ 46.60 | $ 50.00 | $ 50.00 | $ 51.70 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 7,000 | 10,000 | 11,000 | 7,000 | 5,000 | 2,000 | 3,000 | 9,000 | 7,000 | 9,000 | 9,000 | 10,000 | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Private Fire



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 22 | 264 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 15 | 15 | 15 | 15 | 15 | 15 | 14 | 14 | 15 | 16 | 14 | 22 | 185 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 7 | 6 | 8 | - | 79 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | $ 6.48 | |
| 5 | INCREASE IN REVENUES | $ 45 | $ 45 | $ 45 | $ 45 | $ 45 | $ 45 | $ 52 | $ 52 | $ 45 | $ 39 | $ 52 | $ - | $ 512 |
| 6 | TOTAL INCREASE IN REVENUE | 512 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 512 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | INCREASE IN CUSTOMERS | 7 | 7 | 7 | 7 | 7 | 7 | 8 | 8 | 7 | 6 | 8 | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

**OPERATING ADJUSTMENT #2**
**REVENUE & EXPENSE ANNUALIZATION - PURCHASED POWER EXPENSE**

| LINE NO. | DESCRIPTION | | TOTAL |
|---|---|---|---|
| 1 | Annualize Purchase Power Expense | | |
| 2 | | | |
| 3 | Test Year Purchased Power Expense | $ | 435,559 |
| 4 | | | |
| 5 | Increase in Purchased Power Expense (Company Adjustment 5) | | 8,276 |
| 6 | | | |
| 7 | | | |
| 8 | Total Adjusted Test Year Purchased Power Expense | $ | 443,835 |
| 9 | | | |
| 10 | Gallons Sold during Test Year (in 1,000's) | | 754,340 |
| 11 | | | |
| 12 | Cost per 1,000 gallons | | 0.5884 |
| 13 | | | |
| 14 | Additional Gallons from Revenue Annualization (in 1,000's) | | 11,467 |
| 15 | | | |
| 16 | Increase (decrease) in Purchased Power | $ | 6,747 |
| 17 | | | |
| 18 | Company Adjustment to Revenue and/or Expense | $ | (2,334) |
| 19 | | | |
| 20 | Adjustment to Revenue and/or Expense | $ | 9,081 |
| 21 | | | |
| 22 | | | |
| 23 | | | |
| 24 | | | |
| 25 | | | |
| 26 | | | |
| 27 | | | |
| 28 | | | |
| 29 | | | |
| 30 | | | |
| 31 | | | |
| 32 | | | |
| 33 | | | |
| 34 | SUPPORTING SCHEDULES | | |
| 35 | Company Schedule C-2 | | |
| 36 | Company Adjustment #5 Schedule | | |
| 37 | Schedule TJC-8, pages 1 thru 16 | | |
| 38 | | | |
| 39 | | | |
| 40 | | | |
| 41 | | | |
| 42 | | | |
| 43 | | | |
| 44 | | | |

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3**
**TEST YEAR DEPRECIATION EXPENSE**

| LINE NO. | ACCOUNT NO. | ACCOUNT NAME | (A) RUCO PLANT VALUE | (B) COMPANY PROPOSED DEP. RATES | (C) TEST YEAR DEPRECIATION EXPENSE |
|---|---|---|---|---|---|
| 1 | 301 | Organization | $ 5,785 | 0.00% | $ - |
| 2 | 302 | Franchises | 417 | 0.00% | - |
| 3 | 303 | Land and Land Rights | 44,194 | 0.00% | - |
| 4 | 304 | Structures and Improvements | 2,732,833 | 3.33% | 91,003 |
| 5 | 305 | Collecting and Impounding Res. | - | 2.50% | - |
| 6 | 306 | Lake, River and Other Intakes | - | 2.50% | - |
| 7 | 307 | Wells and Springs | 563,511 | 3.33% | 18,765 |
| 8 | 308 | Infiltration Galleries and Tunnels | - | 6.67% | - |
| 9 | 309 | Supply Mains | 279,153 | 2.00% | 5,583 |
| 10 | 310 | Power Generation Equipment | 197,120 | 5.00% | 9,856 |
| 11 | 311 | Electtric Pumping Equipment | 2,591,970 | 12.50% | 323,996 |
| 12 | 320 | Water Treatment Equipment | 372,970 | 3.33% | 12,420 |
| 13 | 320 | Water Treatment Equipment | - | 3.33% | - |
| 14 | 320 | Chemical Solution Feeders | - | 20.00% | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 759,861 | 2.22% | 16,869 |
| 16 | 330 | Storage Tanks | - | 2.22% | - |
| 17 | 330 | Pressure Tanks | - | 5.00% | - |
| 18 | 331 | Transmission & Distribution Mains | 22,089,150 | 2.00% | 441,783 |
| 19 | 333 | Services | 2,209,274 | 3.33% | 73,569 |
| 20 | 334 | Meters | 956,605 | 8.33% | 79,685 |
| 21 | 335 | Hydrants | 568,577 | 2.00% | 11,372 |
| 22 | 336 | Backflow Prevention Devices | 3,848 | 6.67% | 257 |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 121,843 | 6.67% | 8,127 |
| 24 | 340 | Office Furniture and Fixtures | 22,986 | 6.67% | 1,533 |
| 25 | 340 | Computers and Software | 76,919 | 20.00% | * - |
| 26 | 341 | Transportation Equipment | 218,945 | 20.00% | 43,789 |
| 27 | 342 | Stores Equipment | - | 4.00% | - |
| 28 | 343 | Tools and Work Equipment | 15,035 | 5.00% | 752 |
| 29 | 344 | Laboratory Equipment | 3,061 | 10.00% | 306 |
| 30 | 345 | Power Operated Equipment | - | 5.00% | - |
| 31 | 346 | Communication Equipment | 218,040 | 10.00% | 21,804 |
| 32 | 347 | Miscellaneous Equipment | 7,701 | 10.00% | 770 |
| 33 | 348 | Other Tangible Plant | - | 10.00% | - |
| 34 | | | | | |
| 35 | | TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE | $ 34,059,801 | | $ 1,162,239 |
| 36 | | | | | |
| 37 | | | | | |
| 38 | | AMORTIZATION OF CONTRIBUTIONS | (20,140,197) | 3.46% | (697,254) |
| 39 | | | | | |
| 40 | | Rounding | | | (1) |
| 41 | | | | | |
| 42 | **TOTAL DEPRECIATION EXPENSE** | | | | $ 464,984 |
| 43 | | | | | |
| 44 | Company As Filed | | | | 463,297 |
| 45 | Difference | | | | $ 1,687 |
| 46 | | | | | |
| 47 | RUCO Adjustment | | | | $ 1,687 |

* Fully Depreciated

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4**
**PROPERTY TAX COMPUTATION**

| LINE NO. | DESCRIPTION | REFERENCE | (A) | (B) |
|---|---|---|---|---|
| | Calculation Of The Company's Full Cash Value: | | | |
| | Annual Operating Revenues: | | | |
| 1 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | $ 1,874,057 | |
| 2 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | 1,874,057 | |
| 3 | Proposed Revenues | Sch. TJC-7, Col (E), Ln 8 | 2,810,229 | |
| 4 | Total Three Year Operating Revenues | Sum Of Lines 1, 2 & 3 | $ 6,558,343 | |
| 5 | Average Annual Operating Revenues | Line 4 / 3 | 2,186,114 | |
| 6 | Two Times Three Year Average Operating Revenues | Line 5 X 2 | | $ 4,372,229 |
| | ADD: | | | |
| | 10% Of Construction Work In Progress ("CWIP"): | | | |
| 7 | Test Year CWIP | Company Schedule E | $ 95,024 | |
| 8 | 10% Of CWIP | Line 7 X 10% | | $ 9,502 |
| | SUBTRACT: | | | |
| | Transportation At Book Value: | | | |
| 9 | Original Cost Of Transportation Equipment | RUCO Plant Schedule TJC-4 | $ 218,945 | |
| 10 | Acc. Dep. Of Transportation Equipment | RUCO Plant Schedule TJC-4 | (30,748) | |
| 11 | Net Book Value Of Transportation Equipment | Line 9 + Line 10 | | $ 188,197 |
| 12 | Company's Full Cash Value ("FCV") | Sum Of Lines 6, 8 & 11 | | $ 4,193,535 |
| | Calculation Of The Company's Tax Liability: | | | |
| | MULTIPLY: | | | |
| | FCV X Valuation Assessment Ratio X Property Tax Rates: | | | |
| 13 | Assessment Ratio | House Bill 2779 | 21.0% | |
| 14 | Assessed Value | Line 12 X Line 13 | $ 880,642 | |
| | Property Tax Rates: | | | |
| 15 | Primary Tax Rate | Company Workpapers | 11.3283% | |
| 16 | Secondary Tax Rate | Company Workpapers | 0.00% | |
| 17 | Estimated Tax Rate Liability | Line 15 + Line 16 | 11.33% | |
| | Property Tax | | | $ 99,762 |
| | Tax On Parcel | | | - |
| 18 | Company's Total Tax Liability - Based On Full Cash Value | Line 14 X Line 17 | | $ 99,762 |
| 19 | Test Year Adjusted Property Tax Expense As Filed | Co. Sch. C-1 | | 130,373 |
| 20 | Decrease In Property Tax Expense | Line 18 - Line 19 | | $ (30,611) |
| | | Line 20 | | $ (30,611) |

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 5**
**RATE CASE EXPENSE**

| LINE NO. | DESCRIPTION | (A) COMPANY ESTIMATE | (B) RUCO ADJUSTMENT | (C) RUCO AS ADJUSTED |
|---|---|---|---|---|
| 1 | Rate Case Expense Total | $ 210,000 | $ (52,500) | $ 157,500 |
| 2 | Allocation Factor | | | 100% |
| 3 | Water Division (Line 1 X Line 2) | | | $ 157,500 |
| 4 | Normalization Period - 3 Years | | | 3 |
| 5 | RUCO Adjusted Rate Case Expense (Line 3 / 3 Years) | | | $ 52,500 |
| 6 | Company Rate Case Expenses As Filed (Company Sch. C-2) | | | $ 70,000 |
| 7 | RUCO Pro Forma Rate Case Expense (Lines 5 - 6) | | | $ (17,500) |
| 8 | RUCO Adjustment (Line 7) | | | $ (17,500) |

## EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
## MISCELLANEOUS EXPENSE

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Miscellaneous Expense - Disallowed: | |
| 2 | | |
| 3 | Family Traditions - Outreach Program | $ 643 |
| 4 | Family Traditions - Outreach Program | 450 |
| 5 | Arizona Highway Patrol - Donation | 150 |
| 6 | Rio Rico Rotary Tickets | 120 |
| 7 | | |
| 8 | RUCO Miscellaneous Adjustment | $ 1,363 |
| 9 | | |
| 10 | | |
| 11 | | |
| 12 | | |
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| 31 | | |
| 32 | | |
| 33 | | |
| 34 | SUPPORTING SCHEDULES | |
| 35 | RUCO Work Paper - Miscellaneous Expense Adjustment - Water | |
| 36 | | |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Water Division
Schedule TJC-14
Page 1 of 1

## OPERATING INCOME ADJUSTMENT #8 - CORPORATE ALLOCATIONS

| Line No. | Description | Company Total Cost | RUCO Disallowed Costs | | RUCO Other Disallowed Costs | RUCO Allowable Costs | RUCO 2008 Allocation Factor | RUCO Allowed Allocated Costs | Allocation % To Rio Rico | RUCO Amount Allocated To Rio Rico |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Rent | 430,739 | | | (430,739) | - | 24.29% | - | 12.92% | - |
| 2 | Audit | 507,000 | | | (380,250) | 126,750 | 24.29% | 30,782 | 12.92% | 3,976.12 |
| 3 | Tax Services | 265,000 | | | (198,750) | 66,250 | 24.29% | 16,089 | 12.92% | 2,078.25 |
| 4 | Legal - General | 300,000 | | | (225,000) | 75,000 | 24.29% | 18,214 | 12.92% | 2,352.73 |
| 5 | Other Professional Services | 455,000 | | | (455,000) | - | 24.29% | - | 12.92% | - |
| 6 | Management Fee | 636,619 | | | (636,619) | - | 24.29% | - | 12.92% | - |
| 7 | Unit Holder Communications | 314,100 | | | (314,100) | - | 24.29% | - | 12.92% | - |
| 8 | Trustee Fees | 204,000 | | | (204,000) | - | 24.29% | - | 12.92% | - |
| 9 | Office Costs | 254,100 | (46,186) | Note A | (207,914) | - | 24.29% | - | 12.92% | - |
| 10 | Licenses/Fees and Permits | 305,000 | (145,642) | Note B | (159,358) | - | 24.29% | - | 12.92% | - |
| 11 | Escrow and Transfer Fees | 75,000 | | | (75,000) | - | 24.29% | - | 12.92% | - |
| 12 | Depreciation Expense | 204,242 | | | (153,182) | 51,061 | 24.29% | 12,400 | 12.92% | 1,601.76 |
| | **Total** | 3,950,800 | (191,828) | | (3,439,912) | 319,061 | | 77,486 | | 10,009 |

| | |
|---|---|
| RUCO Allocation To Rio Rico Water Division (Based on Total Ratio of Rate Base) | 70.5745% |
| RUCO Allocation To Rio Rico Wastewater Division (Based on Total Ratio of Rate Base) | 29.4255% |
| Company's APT Cost Allocation for Water Division (Per Staff DR GB 3.7 & GB 3.15) | $ 103,745 |
| RUCO's APT Cost Allocation Allowed for Water Division | 7,064 |
| RUCO's APT Cost Allocation Adjustment for Water Division | (96,681) |
| Company's APT Cost Allocation for Wastewater Division (Per Staff DR GB 3.7 & GB 3.15) | $ 34,582 |
| RUCO's APT Cost Allocation Allowed for Wastewater Division | 2,945 |
| RUCO's APT Cost Allocation Adjustment for Wastewater Division | (31,637) |

**Note A:**

| | Description | |
|---|---|---|
| Office Costs | Wind Analysis Software | $ 15,056 |
| Office Costs | Gold Watches & Clocks | 16,864 |
| Office Costs | Pilsner Beer Glasses | 5,700 |
| Office Costs | Leafs/Raptors Tickets | 5,066 |
| Office Costs | Super Bowl Tickets | 3,500 |
| Total | | $ 46,186 |

**Note B:**

| | | |
|---|---|---|
| Licenses/Fees and Permits | Donation | $ 25,000 |
| Licenses/Fees and Permits | Donation | 25,000 |
| Licenses/Fees and Permits | Donation | 13,350 |
| Licenses/Fees and Permits | Donation | 5,000 |
| Licenses/Fees and Permits | Wind Developm | 7,887 |
| Licenses/Fees and Permits | US Trustee | 9,375 |
| Licenses/Fees and Permits | Wind Energy | 12,556 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,891 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,794 |
| Licenses/Fees and Permits | APF Inc Taxes | 23,789 |
| Licenses/Fees and Permits | KMS Tax Ruling | 10,000 |
| Total | | $ 145,642 |

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report
Company's Response to Staff GB 3.2 and 3.10 APT Affiliate Charges - Rio Rico
Company's Response to Staff GB 3.7 and 3.15

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9**
**BAD DEBT EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Normalize Bad Debt Expense: | |
| 2 | | |
| 3 | 2008 Bad Debt Expense | $ 371 |
| 4 | 2007 Bad Debt Expense | - |
| 5 | 2006 Bad Debt Expense | 3,140 |
| 6 | | |
| 7 | 3 Year Normalization | $ 1,170 |
| 8 | | |
| 9 | Company As Filed | 371 |
| 10 | | |
| 11 | RUCO Adjustment | $ 799 |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |
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| 30 | | |
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| 33 | | |
| 34 | | |
| 35 | | |
| 36 | | |
| 37 | | |
| 38 | SUPPORTING SCHEDULES | |
| 39 | Company Schedule E-2 | |
| 40 | | |
| 41 | | |

## OPERATING INCOME ADJUSTMENT #10
## INCOME TAX EXPENSE

| LINE NO. | DESCRIPTION | (A) REFERENCE | (B) AMOUNT |
|---|---|---|---|
| | **FEDERAL INCOME TAXES:** | | |
| 1 | Operating Income Before Taxes | Sch. TJC-7, Column (C), L28 + L22 + L23 | $ (140,121) |
| | LESS: | | |
| 2 | Arizona State Tax | Line 11 | (22,057) |
| 3 | Interest Expense | Note (A) Line 21 | 176,421 |
| 4 | Federal Taxable Income | Line 1 - Line 2 - Line 3 | $ (294,485) |
| 5 | Federal Tax Rate | Sch. TJC-1, Pg 2, Col. (D), L34 | 34.00% |
| 6 | Federal Income Tax Expense | Line 4 X line 5 | $ (100,125) |
| | **STATE INCOME TAXES:** | | |
| 7 | Operating Income Before Taxes | Line 1 | $ (140,121) |
| | LESS: | | |
| 8 | Interest Expense | Note (A) Line 21 | 176,421 |
| 9 | State Taxable Income | Line 7 - Line 8 | $ (316,542) |
| 10 | State Tax Rate | Tax Rate | 6.97% |
| 11 | State Income Tax Expense | Line 9 X Line 10 | $ (22,057) |
| | **TOTAL INCOME TAX EXPENSE:** | | |
| 12 | Federal Income Tax Expense | Line 6 | $ (100,125) |
| 13 | State Income Tax Expense | Line 11 | (22,057) |
| 14 | Total Income Tax Expense Per RUCO | Line12 + Line 13 | $ (122,182) |
| 15 | Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | (110,555) |
| 16 | Total State Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | (24,354) |
| 17 | RUCO Federal Income Tax Adjustment | Line 12 - Line 15 | $ 10,430 |
| 18 | RUCO State Income Tax Adjustment | Line 13 - Line 16 | $ 2,298 |

NOTE (A):
Interest Synchronization:

| | | | |
|---|---|---|---|
| 19 | Adjusted Rate Base (Sch. TJC-2, Col. (H), L17) | $ | 7,045,555 |
| 20 | Weighted Cost Of Debt (Sch. TJC-16 Col. (F), L1) | | 2.50% |
| | | $ | 176,421 |

## COST OF CAPITAL

| LINE NO. | DESCRIPTION | (B) CAPITAL RATIO | (C) COST RATE | (D) WEIGHTED COST RATE |
|---|---|---|---|---|
| 1 | Long-Term Debt | 40.00% | 6.26% | 2.50% |
| 2 | Common Equity | 60.00% | 9.00% | 5.40% |
| 3 | Total Capitalization | 100.00% | | |
| 4 | WEIGHTED AVERAGE COST OF CAPITAL | | | 7.90% |

References:
Columns (A) Thru (D): Testimony, WAR

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division

## TABLE OF CONTENTS TO TJC SCHEDULES


| SCH. NO. | PAGE NO. | TITLE |
|---|---|---|
| TJC-1 | 1 & 2 | REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR |
| TJC-2 | 1 | RATE BASE |
| TJC-3 | 1 | SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS |
| TJC-4 DIRECT PLANT | 1 TO 7 | RATE BASE ADJUSTMENT NO. 1 - PLANT & ACCUMULATED DEPRECIATION RECONCILIATION ADJUSTMENT |
| TJC-5 | 1 | RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEFERRED INCOME TAXES |
| TESTIMONY | | RATE BASE ADJUSTMENT NO. 3 - AIAC & CIAC BALANCES PER RUCO DR 1.08 & 1.09 |
| | | RATE BASE ADJUSTMENT NO. 4 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 5 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 6 - INTENTIONALLY LEFT BLANK |
| TJC-6 | 1 | OPERATING INCOME |
| TJC-7 | 1 | SUMMARY OF OPERATING INCOME ADJUSTMENTS |
| TJC-8 | 1 OF 15 | OPERATING INCOME ADJUSTMENT NO. 1 - REVENUE ANNUALIZATION |
| TJC-9 | 1 | OPERATING INCOME ADJUSTMENT NO. 2 - PURCHASED POWER INCREASE & EXPENSE ANNUALIZATION |
| TJC-10 | 1 | OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE |
| TJC-11 | 1 | OPERATING INCOME ADJUSTMENT NO. 4 - PROPERTY TAX EXPENSE |
| TJC-12 | 1 | OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSE |
| TJC-13 | 1 | OPERATING INCOME ADJUSTMENT NO. 6 - INTENTIONALLY LEFT BLANK |
| TESTIMONY | | OPERATING INCOME ADJUSTMENT NO. 7 - PURCHASED POWER EXPENSE ADJUSTMENT |
| TJC-14 | 1 | OPERATING INCOME ADJUSTMENT NO. 8 - CORPORATE ALLOCATIONS |
| TJC-15 | 1 | OPERATING INCOME ADJUSTMENT NO. 9 - NORMALIZE BAD DEBT EXPENSE |
| TJC-16 | 1 | OPERATING INCOME ADJUSTMENT NO. 10 - INCOME TAX EXPENSE |
| TJC-17 & WAR TESTIMONY | 1 | COST OF CAPITAL |

**REVENUE REQUIREMENT**

| LINE NO. | DESCRIPTION | (A) COMPANY OCRB/FVRB COST | (B) RUCO OCRB/FVRB COST |
|---|---|---|---|
| 1 | Adjusted Original Cost/Fair Value Rate Base | $ 3,516,078 | $ 2,937,595 |
| 2 | Adjusted Operating Income (Loss) | $ 490,676 | $ 569,481 |
| 3 | Current Rate of Return (L2 / L1) | 13.96% | 19.39% |
| 4 | Required Operating Income (L5 X L1) | $ 435,994 | $ 232,187 |
| 5 | Required Rate of Return on Fair Value Rate Base | 12.40% | 7.90% |
| 6 | Operating Income Deficiency (L4 - L2) | $ (54,682) | $ (337,293) |
| 7 | Gross Revenue Conversion Factor (TJC-1, Page 2) | 1.6286 | 1.6286 |
| 8 | Required Increase in Gross Revenue Requirement (L7 X L6) | $ (89,058) | $ (549,328) |
| 9 | Adjusted Test Year Revenue | $ 1,829,976 | $ 1,850,101 |
| 10 | Proposed Annual Revenue (L8 + L9) | $ 1,740,918 | $ 1,300,773 |
| 15 | Required Percentage Increase in Revenue (L8 / L9) | -4.87% | -29.69% |
| 16 | Rate of Return on Common Equity | 12.40% | 9.00% |

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-6, and TJC-17

## GROSS REVENUE CONVERSION FACTOR

| LINE NO. | DESCRIPTION | (A) | (B) | (C) | (D) |
|---|---|---|---|---|---|
| | CALCULATION OF GROSS REVENUE CONVERSION FACTOR: | | | | |
| 1 | Revenue | 1.0000 | | | |
| 2 | Combined Federal And State Tax Rate (L10) | 0.3571 | | | |
| 3 | Subtotal (L1 - L2) | 0.6429 | | | |
| 4 | **Revenue Conversion Factor** (L1 / L3) | **1.5553** | | | |
| | CALCULATION OF EFFECTIVE TAX RATE: | | | | |
| 5 | Operating Income Before Taxes (Arizona Taxable Income) | 100.0000% | | | |
| 6 | Arizona State Income Tax Rate | 6.9680% | | | |
| 7 | Federal Taxable Income (L5 - L6) | 93.0320% | | | |
| 8 | Applicable Federal Income Tax Rate (Col. (D), L34) | 30.8900% | | | |
| 9 | Effective Federal Income Tax Rate (L7 X L8) | 28.7376% | | | |
| 10 | Combined Federal And State Income Tax Rate (L6 + L9) | 35.7056% | | | |
| 11 | Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4) | $ 232,187 | | | |
| 12 | Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2) | 569,481 | | | |
| 13 | Required Increase In Operating Income (L11 - L12) | | $ (337,293) | | |
| 14 | Income Taxes On Recommended Revenue (Col. (D), L31) | $ 79,268 | | | |
| 15 | Income Taxes On Test Year Revenue (Col. (D), L32) | 275,409 | | | |
| 16 | Required Increase In Revenue To Provide For Income Taxes (L14 - L15) | | $ (196,141) | | |
| 17 | Total Required Increase In Revenue (L13 + L16) | | $ (533,434) | | |
| | CALCULATION OF INCOME TAX: | | | RUCO Recommended | |
| 18 | Revenue (Sch. TJC-1, Pg 1, Col. (B), L12) | | | $ 1,300,773 | |
| 19 | Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23) | | | 1,005,211 | |
| 20 | Synchronized Interest (Col. (C), L37) | | | 73,557 | |
| 21 | Arizona Taxable Income (L18 - L19 - L20) | | | $ 222,004 | |
| 22 | Arizona State Income Tax Rate | | | 6.9680% | |
| 23 | Arizona Income Tax (L21 X L22) | | | | $ 15,469 |
| 24 | Fed. Taxable Income (L21 - L23) | | | $ 206,535 | |
| 25 | Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15% | | | $ 7,500 | |
| 26 | Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25% | | | $ 6,250 | |
| 27 | Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34% | | | $ 8,500 | |
| 28 | Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39% | | | $ 41,549 | |
| 29 | Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34% | | | $ - | |
| 30 | Total Federal Income Tax (L25 + L26 + L27 + L28 + L29) | | | | $ 63,799 |
| 31 | Combined Federal and State Income Tax (L23 + L30) | | | | $ 79,268 |
| 32 | Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23) | | | | $ 275,409 |
| 33 | RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23) | | | | $ (196,141) |
| 34 | Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24) | | | | 30.89% |
| | CALCULATION OF INTEREST SYNCHRONIZATION: | | | | |
| 35 | Rate Base (Sch. TJC-2, Col. (C), L17) | | | $ 2,937,595 | |
| | | | | 2.50% | |
| | | | | $ 73,557 | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division
Schedule TJC-2


**RATE BASE - ORIGINAL COST**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) RUCO OCRB/FVRB ADJUSTMENTS | (C) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 11,829,043 | $ - | $ 11,829,043 |
| 2 | Less: Accumulated Depreciation | (5,110,028) | (45,969) | (5,155,998) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 6,719,014 | $ (45,969) | $ 6,673,045 |
| | Less: | | | |
| 4 | Advances in Aid of Construction | 861 | (238,783) | (237,922) |
| 5 | Contribution in Aid of Construction | (5,376,456) | 238,783 | (5,137,673) |
| 6 | Accumulated Amortization of CIAC | 1,944,057 | - | 1,944,057 |
| 7 | NET CIAC (L5 + L6) | $ (3,432,399) | $ 238,783 | $ (3,193,616) |
| 8 | Customer Meter Deposits | (95,000) | - | (95,000) |
| 9 | Deferred Income Taxes & Credits | 323,602 | (532,514) | (208,912) |
| | Plus: | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - |
| 12 | Allowance For Working Capital | - | - | - |
| 13 | Rounding | - | - | - |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 3,516,078 | $ (578,484) | $ 2,937,595 |

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



## SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) ADJMT NO. 1 PLANT & ACCUM DEP. | (C) ADJMT NO. 2 DEFERRED INCOME TAXES | (D) ADJMT NO. 3 PER RUCO DR 1.08 | (E) ADJMT NO. 4 | (F) ADJMT NO. 5 | (G) ADJMT NO. 6 | (H) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 11,829,043 | $ - | $ - | $ - | $ - | $ - | $ - | $ 11,829,043 |
| 2 | Less: Accumulated Depreciation | (5,110,028) | (45,969) | - | - | - | - | - | (5,155,998) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 6,719,014 | $ (45,969) | $ - | $ - | $ - | $ - | $ - | $ 6,673,045 |
| | Less: | | | | | | | | |
| 4 | Advances in Aid of Construction | $ 861 | $ - | $ - | $ (238,783) | $ - | $ - | $ - | $ (237,922) |
| 5 | Contribution in Aid of Construction | (5,376,456) | - | - | 238,783 | - | - | - | (5,137,673) |
| 6 | Accumulated Amortization of CIAC | 1,944,057 | - | - | - | - | - | - | 1,944,057 |
| 7 | NET CIAC (L5 + L6) | $ (3,432,399) | $ - | $ - | $ 238,783 | $ - | $ - | $ - | $ (3,193,616) |
| 8 | Customer Meter Deposits | (95,000) | - | - | - | - | - | - | (95,000) |
| 9 | Deferred Income Taxes & Credits | 323,602 | - | (532,514) | - | - | - | - | (208,912) |
| | Plus: | | | | | | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - | - | - | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - | - | - | - | - | - |
| 12 | Allowance For Working Capital | - | - | - | - | - | - | - | - |
| 13 | Rounding | - | - | - | - | - | - | - | - |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 3,516,078 | $ (45,969) | $ (532,514) | $ - | $ - | $ - | $ - | $ 2,937,595 |

Column (A): Company Schedule B-2
Column (B): Adjustment No. 1 - Adjust Accumulated Depreciation (See Schedule TJC-4, pages 1 - 7, and TJC Testimony)
Column (C): Adjustment No. 2 - Deferred Income Taxes (See Schedule TJC-5)
Column (D): Adjustment No. 3 - To Adjust AIAC & CIAC Balances Per Company Response to RUCO DR 1.08 and Discussed in TJC Testimony
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | (C) 12/31/2002 Per Decision No. 67279 | (D) Accumulated Depreciation Per Dec. 67279 | (E) Plant Balance 12/31/2002 |
|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | $ 5,785 | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | 417 | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | 7,545 | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | 28,548 | 20,590 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | - | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | 355,144 | (99,427) | 355,144 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | 4,387,284 | 1,584,087 | 4,387,284 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 1,085,957 | 441,720 | 1,085,957 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | 36,057 | 10,881 | 36,057 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | | | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | 992,546 | 48,548 | 992,546 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | 1,593,905 | 309,912 | 1,593,905 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | 972,166 | 367,586 | 972,166 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | 71,243 | 38,620 | 71,243 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | 5,514 | 2,587 | 5,514 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | 4,025 | 2,790 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | 4,015 | 2,771 | 4,015 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | 5,936 | 4,224 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | 3,913 | 1,798 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | | | - |
| 31 | 346 | Rounding | | | | 1 | - |
| 32 | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ 9,560,000 | $ 2,736,688 | $ 9,560,000 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ 9,560,000 | $ 2,736,688 | $ 9,560,000 |
| 36 | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | |
| 38 | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | |
| 40 | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | |
| 42 | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | |
| 44 | | Accumulated Depreciation | | | $ 2,736,688 | | $ 2,736,688 |
| 45 | | Accumulated Depreciation - PTYP | | | - | - | - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | $ 2,736,688 | | $ 2,736,688 |
| 47 | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | 2,736,688 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | | $ - | $ - |
| 50 | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | |
| 52 | | | | | | | |
| 53 | | | | | | | |
| 54 | | | | | | | |
| 55 | | References: | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2003 Additions | 2003 Retirements | 2003 Adjustments | 2003 Depreciation Expense | 2003 Balance 12/31/2003 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | - | - | - | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | - | - | - | 1,470 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | - | - | - | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | 295,950 | (13,062) | - | 10,230 | 638,032 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | 5,247 | (6,745) | - | 89,047 | 4,385,786 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | - | - | - | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 7,742 | - | - | 33,131 | 1,093,699 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | - | - | - | 1,814 | 36,057 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | - | - | - | - | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | - | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | - | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | - | - | - | 39,305 | 992,546 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | - | - | - | 83,999 | 1,593,905 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | - | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | - | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | - | - | - | 51,136 | 972,166 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | - | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | - | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | - | - | - | 3,776 | 71,243 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | - | - | - | 110 | 5,514 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | - | - | - | 193 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | - | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | - | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | - | - | - | 191 | 4,015 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | - | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | - | - | - | 299 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | - | - | - | 201 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | - | - | - | - | - |
| 31 | 346 | Rounding | | | - | - | - | - | - |
| 32 | | | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ 308,939 | $ (19,807) | $ - | $ 314,900 | $ 9,849,132 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ 308,939 | $ (19,807) | $ - | $ 314,900 | $ 9,849,132 |
| 36 | | | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | | | |
| 38 | | | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 42 | | | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 44 | | Accumulated Depreciation | | | | | | 3,051,588 | $ 3,051,588 |
| 45 | | Accumulated Depreciation - PTYP | | | | | | - | - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 3,051,588 | $ 3,051,588 |
| 47 | | | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 3,031,983 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 3,051,588 | $ 19,605 |
| 50 | | | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | References: | | | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2004 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2004 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | - | - | - | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | - | - | - | 1,340 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | - | - | - | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | (4,971) | - | - | 12,997 | 633,061 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | 100,106 | - | - | 89,715 | 4,485,892 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | - | - | - | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 20,057 | - | - | 30,684 | 1,113,756 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | - | - | - | 2,262 | 36,057 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | - | - | - | - | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | - | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | - | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | (125,426) | - | - | 35,357 | 867,120 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | (94,296) | - | - | 109,472 | 1,499,609 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | - | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | - | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | - | - | - | 50,504 | 972,166 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | - | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | - | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | - | - | - | 4,020 | 71,243 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | - | - | - | 175 | 5,514 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | - | - | - | 346 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | - | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | - | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | 882 | - | - | 215 | 4,897 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | - | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | - | - | - | 372 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | - | - | - | 190 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | - | - | - | - | - |
| 31 | 346 | Rounding | | | - | - | - | - | - |
| 32 | | | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ (103,647) | $ - | $ - | $ 337,648 | $ 9,745,484 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ (103,647) | $ - | $ - | $ 337,648 | $ 9,745,484 |
| 36 | | | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | | | |
| 38 | | | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 42 | | | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 44 | | Accumulated Depreciation | | | | | | 3,389,236 | $ 3,389,236 |
| 45 | | Accumulated Depreciation - PTYP | | | | | | - | $ - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 3,389,236 | $ 3,389,236 |
| 47 | | | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 3,369,631 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 3,389,236 | $ 19,605 |
| 50 | | | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | References: | | | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2005 Additions | 2005 Retirements | 2005 Adjustments | 2005 Depreciation Expense | 2005 Balance 12/30/2005 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | - | - | - | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | - | - | - | 951 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | - | - | - | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | - | - | - | 12,661 | 633,061 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | 1,331,572 | - | - | 103,034 | 5,817,464 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | - | - | - | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 2,293 | - | - | 22,298 | 1,116,049 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | - | - | - | 3,606 | 36,057 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | - | - | - | - | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | - | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | - | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | - | - | - | 28,875 | 867,120 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | 27,078 | (22,506) | - | 187,737 | 1,504,181 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | - | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | - | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | - | - | - | 48,608 | 972,166 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | - | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | - | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | - | - | - | 4,752 | 71,243 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | - | - | - | 368 | 5,514 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | - | - | - | 805 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | - | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | - | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | - | - | - | 245 | 4,897 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | - | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | - | - | - | 594 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | - | - | - | 157 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | - | - | - | - | - |
| 31 | 346 | Rounding | | | - | - | - | - | - |
| 32 | | | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ 1,360,942 | $ (22,506) | $ - | $ 414,689 | $ 11,083,921 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ 1,360,942 | $ (22,506) | $ - | $ 414,689 | $ 11,083,921 |
| 36 | | | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | | | |
| 38 | | | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 42 | | | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 44 | | Accumulated Depreciation | | | | | | 3,803,925 | $ 3,803,925 |
| 45 | | Accumulated Depreciation - PTYP | | | | | | - | - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 3,803,925 | 3,803,925 |
| 47 | | | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 3,761,705 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 3,803,925 | $ 42,220 |
| 50 | | | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | References: | | | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2006 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2006 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | - | - | - | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | - | - | - | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | - | - | - | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | - | - | - | 951 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | - | - | - | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | 1,147 | - | - | 12,673 | 634,208 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | 100,371 | - | - | 117,353 | 5,917,835 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | - | - | - | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 12,716 | - | - | 22,448 | 1,128,765 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | - | - | - | 3,606 | 36,057 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | - | - | - | - | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | - | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | - | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | - | - | - | 28,875 | 867,120 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | - | - | - | 188,023 | 1,504,181 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | - | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | - | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | - | - | - | 48,608 | 972,166 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | - | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | - | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | - | - | - | 4,752 | 71,243 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | 864 | - | - | 397 | 6,378 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | - | - | - | 805 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | - | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | - | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | - | - | - | 245 | 4,897 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | - | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | - | - | - | 594 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | - | - | - | 157 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | 427,000 | - | - | 10,675 | 427,000 |
| 31 | 346 | Rounding | | | - | - | | - | - |
| 32 | | | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ 542,099 | $ - | $ - | $ 440,160 | $ 11,626,019 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ 542,099 | $ - | $ - | $ 440,160 | $ 11,626,019 |
| 36 | | | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | | | |
| 38 | | | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 42 | | | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 44 | | Accumulated Depreciation | | | | | | 4,244,085 | $ 4,244,085 |
| 45 | | Accumulated Depreciation - PTYP | | | | | | - | - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 4,244,085 | 4,244,085 |
| 47 | | | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 4,200,913 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 4,244,085 | $ 43,172 |
| 50 | | | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | References: | | | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2007 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/30/2007 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | - | - | | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | - | - | | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | - | - | | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | - | - | | 951 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | | - | | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | 1,815 | - | | 12,702 | 636,023 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | - | - | | 118,357 | 5,917,835 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | - | - | | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 12,881 | - | (16) | 22,704 | 1,141,630 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | 6,667 | - | | 3,939 | 42,725 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | - | - | | - | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | - | - | | 28,875 | 867,120 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | - | - | | 188,023 | 1,504,181 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | 25,125 | - | | 49,236 | 997,291 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | - | - | (1,509) | 4,702 | 69,734 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | 938 | - | | 457 | 7,315 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | - | - | | 805 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | - | - | | 245 | 4,897 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | - | - | | 594 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | - | - | | 157 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | - | - | | 21,350 | 427,000 |
| 31 | 346 | Rounding | | | - | - | | - | - |
| 32 | | | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ 47,426 | $ - | $ (1,525) | $ 453,095 | $ 11,671,920 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ 47,426 | $ - | $ (1,525) | $ 453,095 | $ 11,671,920 |
| 36 | | | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | | | |
| 38 | | | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | | | |
| 40 | | | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 42 | | | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 44 | | Accumulated Depreciation | | | | | | 4,697,180 | $ 4,697,180 |
| 45 | | Accumulated Depreciation - PTYP | | | | | | - | - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 4,697,180 | 4,697,180 |
| 47 | | | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 4,652,610 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 4,697,180 | $ 44,570 |
| 50 | | | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | | | |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | References: | | | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Plant Reconciliation Schedule



| LINE NO. | ACCT NO. | DESCRIPTION | (A) DEPRECIATION RATE 1/1/2003 To 9/30/2004 | (B) DEPRECIATION RATE 10/1/2004 To 12/31/2008 | 2008 Additions | Retirements | Adjustments | Depreciation Expense | Balance 12/29/2008 |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 351 | Organization | 0.00% | 0.00% | - | - | | $ - | $ 5,785 |
| 2 | 352 | Franchises | 0.00% | 0.00% | - | - | | - | 417 |
| 3 | 353 | Land | 0.00% | 0.00% | - | - | | - | 7,545 |
| 4 | 354 | Structures and Improvements | 5.15% | 3.33% | - | - | | 951 | 28,548 |
| 5 | 355 | Power Generation | | 5.00% | - | - | | - | - |
| 6 | 360 | Collection Sewer Forced | 2.06% | 2.00% | - | - | | 12,720 | 636,023 |
| 7 | 361 | Collection Sewers Gravity | 2.03% | 2.00% | 27,713 | - | 415 | 118,638 | 5,945,962 |
| 8 | 362 | Special Collecting Structures | 3.31% | 2.00% | - | - | | - | - |
| 9 | 363 | Customer Services | 3.04% | 2.00% | 3,900 | - | | 22,872 | 1,145,530 |
| 10 | 364 | Flow Measuring Devices | 5.03% | 10.00% | 3,447 | - | 9,818 | 4,936 | 55,989 |
| 11 | 365 | Flow Measuring Installation | 5.03% | 10.00% | - | - | | - | - |
| 12 | 366 | Reuse Services | 5.03% | 2.00% | - | - | | - | - |
| 13 | 367 | Reuse Meters And Installation | | 8.33% | - | - | | - | - |
| 14 | 370 | Receiving Wells | 3.96% | 3.33% | - | - | | 28,875 | 867,120 |
| 15 | 371 | Pumping Equipment | 5.27% | 12.50% | - | - | | 188,023 | 1,504,181 |
| 16 | 374 | Reuse Distribution Reservoirs | | 2.50% | - | - | | - | - |
| 17 | 375 | Reuse Trans. and Dist. System | | 2.50% | - | - | | - | - |
| 18 | 380 | Treatment & Disposal Equipment | 5.26% | 5.00% | 9,557 | - | | 50,103 | 1,006,848 |
| 19 | 381 | Plant Sewers | 2.00% | 5.00% | - | - | | - | - |
| 20 | 382 | Outfall Sewer Lines | 1.66% | 3.33% | - | - | | - | - |
| 21 | 389 | Other Sewer Plant & Equipment | 5.30% | 6.67% | 150 | - | (1,015) | 4,622 | 68,869 |
| 22 | 390 | Office Furniture & Equipment | 2.00% | 6.67% | 103,139 | - | | 3,928 | 110,454 |
| 23 | 390.1 | Computers and Software | 4.80% | 20.00% | - | - | | 805 | 4,025 |
| 24 | 391 | Transportation Equipment | 33.33% | 20.00% | - | - | | - | - |
| 25 | 392 | Stores Equipment | | 4.00% | - | - | | - | - |
| 26 | 393 | Tools, Shop And Garage Equip | 4.76% | 5.00% | - | - | | 245 | 4,897 |
| 27 | 394 | Laboratory Equip | 2.56% | 10.00% | - | - | | - | - |
| 28 | 396 | Communication Equip | 5.03% | 10.00% | - | - | | 594 | 5,936 |
| 29 | 398 | Other Tangible Plant | 5.13% | 4.00% | - | - | | 157 | 3,913 |
| 30 | 398 | Nogales WW Trmnt Capacity | | 5.00% | - | - | | 21,350 | 427,000 |
| 31 | 346 | Rounding | | | - | - | | - | - |
| 32 | | | | | | | | | |
| 33 | | **TOTAL DIRECT WASTEWATER PLANT** | | | $ 147,905 | $ - | $ 9,217 | $ 458,818 | $ 11,829,042 |
| 34 | | Post Test Year Plant (PTYP) | | | - | - | - | - | - |
| 35 | | **RUCO Total Wastewater Plant In Service** | | | $ 147,905 | $ - | $ 9,217 | $ 458,818 | $ 11,829,042 |
| 36 | | | | | | | | | |
| 37 | | **Company Direct Plant As Filed** | | | | | | | 11,829,043 |
| 38 | | | | | | | | | |
| 39 | | **RUCO Direct Plant Adjustment** | | | | | | | $ (1) |
| 40 | | | | | | | | | |
| 41 | | Reserve Deficiency Accrual | | | | | | $ - | |
| 42 | | | | | | | | | |
| 43 | | Net (Salvage)/Cost of Removal | | | | | | - | |
| 44 | | Accumulated Depreciation | | | | | | 5,155,997 | $ 5,155,997 |
| 45 | | Accumulated Depreciation - PTYP | | | | | | - | - |
| 46 | | RUCO Total Accumulated Depreciation - Calculated | | | | | | 5,155,997 | 5,155,997 |
| 47 | | | | | | | | | |
| 48 | | Company As Filed - Accumulated Depreciation | | | - | - | - | - | 5,110,028 |
| 49 | | **RUCO Direct Plant Accumulated Depreciation Adjustment** | | | $ - | $ - | $ - | $ 5,155,997 | $ 45,969 |
| 50 | | | | | | | | | |
| 51 | | **RUCO Net Adjustment** | | | | | | | $ 45,968 |
| 52 | | | | | | | | | |
| 53 | | | | | | | | | |
| 54 | | | | | | | | | |
| 55 | | References: | | | | | | | |
| 56 | | Column (A): Approved Depreciation Rate From Decision No. | | | | | | | |
| 57 | | Columns (B): Approved Depreciation Rate From Decision No. 67279 | | | | | | | |

| Line No. | | | Amount | Reference |
|---|---|---|---|---|
| 1 | **Deferred Income Taxes:** | | | |
| 2 | | | | |
| 3 | Algonquin Accumulated Deferred Income Tax Assets | $ | 23,032,000 | 2008 Algonquin Annual Report |
| 4 | | | | |
| 5 | Algonquin Accumulated Deferred Income Tax Liabilities | | (106,983,000) | 2008 Algonquin Annual Report |
| 6 | | | | |
| 7 | Net Accumulated Deferred Income Tax Assets (Liabilities) | $ | (83,951,000) | Line 3 + Line 5 |
| 8 | | | | |
| 9 | Rio Rico Allocation | | 0.8997% | Note (A) |
| 10 | | | | |
| 11 | Rio Rico ADIT Liabilities Allocation | $ | (755,287) | Line 7 X Line 9 |
| 12 | | | | |
| 13 | Convert to US Dollars | | 0.9400 | Note (B) |
| 14 | | | | |
| 15 | Allocated ADIT Liabilites Balance | $ | (709,970) | Line 11 X Line 13 |
| 16 | | | | |
| 17 | Rio Rico Water Allocation Factor | | 0.70574 | Note (C) |
| 18 | | | | |
| 19 | Rio Rico Wastewater Allocation Factor | | 0.29426 | Note (C) |
| 20 | | | | |
| 21 | Rio Rico Water Allocation | $ | (501,057) | Line 15 X Line 17 |
| 22 | | | | |
| 23 | Rio Rico Wastewater Allocation | $ | (208,912) | Line 15 X Line 19 |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | **NOTES:** | | | |
| 29 | (A) Purchase Price of Rio Rico Utilities. Inc. | $ | 8,800,000 | |
| 30 | Algonquin Total Assets | | 978,130,000 | |
| 31 | | | | |
| 32 | Ratio | | 0.8997% | |
| 33 | | | | |
| 34 | | | | |
| 35 | (B) www.bank-banque-canada.ca on 11/19/2009 | | 0.9400 | |
| 36 | | | | |
| 37 | | | | |
| 38 | (C) Rio Rico Water Allocation | | 0.70574 | |
| 39 | | | | |
| 40 | Rio Rico Wastewater Allocation | | 0.29426 | |
| 41 | | | | |
| 42 | | | | |
| 43 | SUPPORTING SCHEDULES | | | |
| 44 | 2008 Algonquin Power Income Fund Annual Report | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division
Schedule TJC-6


## OPERATING INCOME

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO TEST YEAR ADJM'TS | (C) RUCO TEST YEAR AS ADJ'TED | (D) RUCO PROP'D CHANGES | (E) RUCO AS RECOMM'D |
|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | |
| 1 | Metered Water Revenues | $ 1,829,726 | $ 20,125 | $ 1,849,851 | $ (549,328) | $ 1,300,523 |
| 2 | Unmetered Water Revenues | - | - | - | - | - |
| 3 | Other Water Revenues | 250 | - | 250 | - | 250 |
| 4 | Total Revenues | $ 1,829,976 | $ 20,125 | $ 1,850,101 | $ (549,328) | $ 1,300,773 |
| | **Operating Expenses:** | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - |
| 6 | Purchased Water and WW Treatment | - | - | - | - | - |
| 7 | Purchased Power | 17,426 | 49,699 | 67,125 | - | 67,125 |
| 8 | Fuel for Power Production | - | - | - | - | - |
| 9 | Chemicals | 9,644 | - | 9,644 | - | 9,644 |
| 10 | Materials & Supplies | 14,304 | - | 14,304 | - | 14,304 |
| 11 | Contractual Services | 298,008 | (31,637) | 266,371 | - | 266,371 |
| 12 | Outside Services - Other | 175,196 | - | 175,196 | - | 175,196 |
| 13 | Outside Services - Legal | 367 | - | 367 | - | 367 |
| 14 | Equipment Rental | 25,781 | - | 25,781 | - | 25,781 |
| 15 | Rents - Building | - | - | - | - | - |
| 16 | Transportation Expenses | 26,817 | - | 26,817 | - | 26,817 |
| 17 | Insurance - General Liability | 12,021 | - | 12,021 | - | 12,021 |
| 18 | Insurance - Vehicle | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 994 | - | 994 | - | 994 |
| 20 | Reg. Comm. Exp. - Rate Case | 41,667 | (10,417) | 31,250 | - | 31,250 |
| 21 | Miscellaneous Expense | 155 | - | 155 | - | 155 |
| 22 | Bad Debt Expense | 64,087 | (30,315) | 33,772 | - | 33,772 |
| 23 | Depreciation and Amortization | 252,672 | 9,361 | 262,033 | - | 262,033 |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Property Taxes | 91,705 | (12,324) | 79,381 | - | 79,381 |
| 26 | Federal Income Tax | 252,773 | (31,110) | 221,662 | (157,863) | 63,799 |
| 27 | State Income Tax | 55,684 | (1,937) | 53,746 | (38,277) | 15,469 |
| 28 | **Total Operating Expenses** | $ 1,339,300 | $ (58,680) | $ 1,280,620 | $ (196,141) | $ 1,084,479 |
| 29 | **Operating Income** | $ 490,676 | $ 78,805 | $ 569,481 | $ (353,187) | $ 216,294 |

References:
Column (A): Company Schedule C-1
Column (B): Schedule TJC-7, Columns (B) Thru (K)
Column (C): Column (A) + Column (B)
Column (D): TJC-1, pages 1 and 2
Column (E): Column (C) + Column (D)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**SUMMARY OF OPERATING INCOME ADJUSTMENTS**
**TEST YEAR AS FILED AND ADJUSTMENTS**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJMT NO. 1 REVENUE ANNUALTN | (C) ADJMT NO. 2 PURCHASED POWER | (D) ADJMT NO. 3 DEPRECIATION EXPENSE | (E) ADJMT NO. 4 PROPERTY TAX | (F) ADJMT NO. 5 RATE CASE EXPENSE | (G) ADJMT NO. 6 MISCELL. EXPENSE | (H) ADJMT NO. 7 PURCH. POWER PER GB 3.8 | (I) ADJMT NO. 8 CORPORATE ALLOCATION | (J) ADJMT NO. 9 BAD DEBT EXPENSE | (K) ADJMT NO. 10 INCOME TAXES | (L) RUCO AS ADJT'D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | | | | | | | | |
| 1 | Metered Water Revenues | $ 1,829,726 | $ 20,125 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,849,851 |
| 2 | Unmetered Water Revenues | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Other Water Revenues | 250 | - | - | - | - | - | - | - | - | - | - | 250 |
| 4 | Total Revenues | $ 1,829,976 | $ 20,125 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,850,101 |
| | **Operating Expenses:** | | | | | | | | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 6 | Purchased Water and WW Treatment | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | Purchased Power | 17,426 | - | 1,694 | - | - | - | - | 48,005 | - | - | - | 67,125 |
| 8 | Fuel for Power Production | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Chemicals | 9,644 | - | - | - | - | - | - | - | - | - | - | 9,644 |
| 10 | Materials & Supplies | 14,304 | - | - | - | - | - | - | - | - | - | - | 14,304 |
| 11 | Contractual Services | 298,008 | - | - | - | - | - | - | - | (31,637) | - | - | 266,371 |
| 12 | Outside Services - Other | 175,196 | - | - | - | - | - | - | - | - | - | - | 175,196 |
| 13 | Outside Services - Legal | 367 | - | - | - | - | - | - | - | - | - | - | 367 |
| 14 | Equipment Rental | 25,781 | - | - | - | - | - | - | - | - | - | - | 25,781 |
| 15 | Rents - Building | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | Transportation Expenses | 26,817 | - | - | - | - | - | - | - | - | - | - | 26,817 |
| 17 | Insurance - General Liability | 12,021 | - | - | - | - | - | - | - | - | - | - | 12,021 |
| 18 | Insurance - Vehicle | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 994 | - | - | - | - | - | - | - | - | - | - | 994 |
| 20 | Reg. Comm. Exp. - Rate Case | 41,667 | - | - | - | - | (10,417) | - | - | - | - | - | 31,250 |
| 21 | Miscellaneous Expense | 155 | - | - | - | - | - | - | - | - | - | - | 155 |
| 22 | Bad Debt Expense | 64,087 | - | - | - | - | - | - | - | - | (30,315) | - | 33,772 |
| 23 | Depreciation and Amortization | 252,672 | - | - | 9,361 | - | - | - | - | - | - | - | 262,033 |
| 24 | Taxes Other Than Income | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | Property Taxes | 91,705 | - | - | - | (12,324) | - | - | - | - | - | - | 79,381 |
| 26 | Federal Income Tax | 252,773 | - | - | - | - | - | - | - | - | - | (31,110) | 221,662 |
| 27 | State Income Tax | 55,684 | - | - | - | - | - | - | - | - | - | (1,937) | 53,746 |
| 28 | **Total Operating Expenses** | $ 1,339,300 | $ - | $ 1,694 | $ 9,361 | $ (12,324) | $ (10,417) | $ - | $ 48,005 | $ (31,637) | $ (30,315) | $ (33,047) | $ 1,280,620 |
| 29 | **Operating Income** | $ 490,676 | $ 20,125 | $ (1,694) | $ (9,361) | $ 12,324 | $ 10,417 | $ - | $ (48,005) | $ 31,637 | $ 30,315 | $ 33,047 | $ 569,481 |

ADJUSTMENTS:
1 - Revenue Annualization
2 - Purchased Power Expense Increase and Annualization
3 - Depreciation Expense
4 - Property Tax Expense
5 - Rate Case Expense
6 - Intentionally Left Blank
7 - Purchased Power Expense Per Staff DR GB 3.8
8 - Corporate Allocations
9 - Bad Debt Expense
10 Income Taxes

REFERENCE:
TJC Testimony and Schedule TJC-8 Pages 1 thru 16
TJC Testimony and Schedule TJC-9
TJC Testimony and Schedule TJC-10
TJC Testimony and Schedule TJC-11
TJC Testimony and Schedule TJC-12
Intentionally Left Blank
TJC Testimony
TJC Testimony and Schedule TJC-14
TJC Testimony and Schedule TJC-15
TJC Testimony and Schedule TJC-16

## OPERATING ADJUSTMENT #1 - REVENUE ANNUALIZATION

| Line No. | | |
|---|---|---|
| 1 | Revenue Annualization | |
| 2 | | |
| 3 | | |
| 4 | RUCO Revenue Annualization | $ 15,620 |
| 5 | | |
| 6 | Company Revenue Annualization | (4,505) |
| 7 | | |
| 8 | | |
| 9 | RUCO Adjustment to Revenue and/or Expense | $ 20,125 |
| 10 | | |
| 11 | | |
| 12 | | |
| 13 | SUPPORTING SCHEDULES | |
| 14 | TJC-8, pages 2 thru 15 | |
| 15 | | |
| 16 | | |
| 17 | | |
| 18 | | |
| 19 | | |
| 20 | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 5/8" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 AVERAGE TEST YEAR CUSTOMERS | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 1,904 | 22,848 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1,942 | 1,942 | 1,943 | 1,940 | 1,940 | 1,917 | 1,880 | 1,863 | 1,849 | 1,874 | 1,880 | 1,878 | 22,848 |
| 3 | AVERAGE INCREASE IN CUSTOMERS | (38) | (38) | (39) | (36) | (36) | (13) | 24 | 41 | 55 | 30 | 24 | 26 | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | $ 56.36 | |
| 5 | INCREASE IN REVENUES | $ (2,142) | $ (2,142) | $ (2,198) | $ (2,029) | $ (2,029) | $ (733) | $ 1,353 | $ 2,311 | $ 3,100 | $ 1,691 | $ 1,353 | $ 1,465 | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | (17,584) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | 17,584 | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | INCREASE IN CUSTOMERS | (38) | (38) | (39) | (36) | (36) | (13) | 24 | 41 | 55 | 30 | 24 | 26 | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 3/4" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 8 | 96 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 8 | 7 | 9 | 7 | 9 | 9 | 8 | 8 | 8 | 8 | 9 | 8 | 98 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | 1 | (1) | 1 | (1) | (1) | - | - | - | - | (1) | - | (2) |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | $ 64.27 | |
| 5 | INCREASE IN REVENUES | $ - | $ 64 | $ (64) | $ 64 | $ (64) | $ (64) | $ - | $ - | $ - | $ - | $ (64) | $ - | $ (129) |
| 6 | TOTAL INCREASE IN REVENUE | (129) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (129) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | INCREASE IN CUSTOMERS | - | 1 | (1) | 1 | (1) | (1) | - | - | - | - | (1) | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 1" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 AVERAGE TEST YEAR CUSTOMERS | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 104 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 10 | 10 | 10 | 10 | 12 | 9 | 8 | 10 | 7 | 6 | 6 | 6 | 104 |
| 3 | AVERAGE INCREASE IN CUSTOMERS | (1) | (1) | (1) | (1) | (3) | (0) | 1 | (1) | 2 | 3 | 3 | 3 | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | $ 79.40 | |
| 5 | INCREASE IN REVENUES | $ (106) | $ (106) | $ (106) | $ (106) | $ (265) | $ (26) | $ 53 | $ (106) | $ 132 | $ 212 | $ 212 | $ 212 | $ (0) |
| 6 | TOTAL INCREASE IN REVENUE | (0) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (2,541) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | 2,541 | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | INCREASE IN CUSTOMERS | (1) | (1) | (1) | (1) | (3) | (0) | 1 | (1) | 2 | 3 | 3 | 3 | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 1.5" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 117.24 | $ 117.24 | $117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Residential 2" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 162.62 | $ 162.62 | $162.62 | $ 162.62 | $ 162.62 | $ 162.62 | $ 162.62 | $ 162.62 | $ 162.62 | $ 162.62 | $ 162.62 | $ 162.62 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | - | - | - | - | - | - | - | - | - | - | - | - | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 5/8" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 78 | 936 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 70 | 52 | 70 | 74 | 66 | 78 | 67 | 73 | 65 | 74 | 64 | 78 | 831 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 8 | 26 | 8 | 4 | 12 | - | 11 | 5 | 13 | 4 | 14 | - | 105 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 80.67 | $ 60.31 | $ 80.67 | $ 80.36 | $ 95.38 | $ 95.74 | $ 84.40 | $ 76.15 | $ 81.66 | $ 70.02 | $ 78.22 | $ 63.61 | |
| 5 | INCREASE IN REVENUES | $ 645 | $ 1,568 | $ 645 | $ 321 | $ 1,145 | $ - | $ 928 | $ 381 | $ 1,062 | $ 280 | $ 1,095 | $ - | $ 8,071 |
| 6 | TOTAL INCREASE IN REVENUE | 8,071 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 8,071 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 11,257 | 7,692 | 11,257 | 11,203 | 13,833 | 13,897 | 11,910 | 10,466 | 11,431 | 9,392 | 10,828 | 8,269 | |
| 10 | INCREASE IN CUSTOMERS | 8 | 26 | 8 | 4 | 12 | - | 11 | 5 | 13 | 4 | 14 | - | |
| 11 | RUCO INCREASE IN GALLONS | 90,057 | 200,000 | 90,057 | 44,811 | 166,000 | - | 131,015 | 52,329 | 148,600 | 37,568 | 151,594 | - | 1,112,030 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 1,112,030 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 1" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 41 | 492 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 38 | 38 | 44 | 32 | 38 | 39 | 35 | 31 | 34 | 31 | 36 | 41 | 437 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 3 | 3 | (3) | 9 | 3 | 2 | 6 | 10 | 7 | 10 | 5 | - | 55 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 113.36 | $ 113.51 | $103.28 | $ 160.05 | $ 137.40 | $ 190.23 | $ 155.10 | $ 128.21 | $ 106.61 | $ 112.37 | $ 114.77 | $ 98.20 | |
| 5 | INCREASE IN REVENUES | $ 340 | $ 341 | $ (310) | $ 1,440 | $ 412 | $ 380 | $ 931 | $ 1,282 | $ 746 | $ 1,124 | $ 574 | $ - | $ 7,260 |
| 6 | TOTAL INCREASE IN REVENUE | 7,260 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 7,260 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 12,947 | 12,974 | 11,182 | 21,125 | 17,158 | 26,410 | 20,257 | 15,548 | 11,765 | 12,774 | 13,194 | 10,293 | |
| 10 | INCREASE IN CUSTOMERS | 3 | 3 | (3) | 9 | 3 | 2 | 6 | 10 | 7 | 10 | 5 | - | |
| 11 | RUCO INCREASE IN GALLONS | 38,842 | 38,921 | (33,545) | 190,125 | 51,474 | 52,821 | 121,543 | 155,484 | 82,353 | 127,742 | 65,972 | - | 891,731 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 891,731 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 1.5" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 7 | 84 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 7 | 7 | 7 | 8 | 8 | 7 | 7 | 7 | 8 | 6 | 8 | 7 | 87 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | (1) | (1) | - | - | - | (1) | 1 | (1) | - | (3) |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 204.52 | $ 204.52 | $204.52 | $ 303.53 | $ 402.74 | $ 464.73 | $ 424.76 | $ 308.93 | $ 374.90 | $ 265.70 | $ 231.44 | $ 287.72 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ (304) | $ (403) | $ - | $ - | $ - | $ (375) | $ 266 | $ (231) | $ - | $ (1,047) |
| 6 | TOTAL INCREASE IN REVENUE | (1,047) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (1,047) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 22,286 | 22,286 | 22,286 | 39,625 | 57,000 | 67,857 | 60,857 | 40,571 | 52,125 | 33,000 | 27,000 | 36,857 | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | (1) | (1) | - | - | - | (1) | 1 | (1) | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | (39,625) | (57,000) | - | - | - | (52,125) | 33,000 | (27,000) | - | (142,750) |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | (142,750) |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 2" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 20 | 240 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 19 | 19 | 20 | 20 | 20 | 20 | 20 | 22 | 18 | 19 | 21 | 20 | 238 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | 1 | 1 | - | - | - | - | - | (2) | 2 | 1 | (1) | - | 2 |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 666.90 | $ 666.90 | $640.83 | $ 863.52 | $1,173.00 | $ 1,243.24 | $ 677.09 | $ 637.85 | $ 641.31 | $ 609.50 | $ 605.82 | $ 525.78 | |
| 5 | INCREASE IN REVENUES | $ 667 | $ 667 | $ - | $ - | $ - | $ - | $ - | $ (1,276) | $ 1,283 | $ 610 | $ (606) | $ - | $ 1,344 |
| 6 | TOTAL INCREASE IN REVENUE | 1,344 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 1,344 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 95,316 | 95,316 | 90,750 | 129,750 | 183,950 | 196,250 | 97,100 | 90,227 | 90,833 | 85,263 | 84,619 | 70,600 | |
| 10 | INCREASE IN CUSTOMERS | 1 | 1 | - | - | - | - | - | (2) | 2 | 1 | (1) | - | |
| 11 | RUCO INCREASE IN GALLONS | 95,316 | 95,316 | - | - | - | - | - | (180,455) | 181,667 | 85,263 | (84,619) | - | 192,488 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 192,488 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 3" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 643.03 | $ 660.16 | $ 585.93 | $ 631.61 | $ 283.30 | $ 391.79 | $ 922.82 | $ 643.03 | $ 688.71 | $ 917.11 | $ 745.81 | $ 797.20 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 273,769 | 210,357 | 175,286 | 257,167 | 413,571 | 409,200 | 180,133 | 286,818 | 306,100 | 87,692 | 307,500 | 298,833 | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 4" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 48 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 4 | 3 | 5 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 4 | 48 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | 1 | (1) | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 2,254.25 | $ 2,342.28 | $ 1,825.71 | $ 2,254.25 | $2,534.04 | $ 3,299.18 | $2,224.27 | $2,496.92 | $ 2,424.12 | $ 2,267.10 | $ 2,111.50 | $ 1,995.87 | |
| 5 | INCREASE IN REVENUES | $ - | $ 2,342 | $ (1,826) | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 517 |
| 6 | TOTAL INCREASE IN REVENUE | 517 | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ 517 | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 328,250 | 343,667 | 253,200 | 328,250 | 377,250 | 511,250 | 323,000 | 370,750 | 358,000 | 330,500 | 303,250 | 283,000 | |
| 10 | INCREASE IN CUSTOMERS | - | 1 | (1) | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | 343,667 | (253,200) | - | - | - | - | - | - | - | - | - | 90,467 |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | 90,467 |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Commercial 6" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 2,733.65 | $ 2,619.45 | $2,733.65 | $ 3,767.16 | $4,652.21 | $ 9,494.29 | $2,653.71 | $5,000.52 | $ 3,584.44 | $ 6,199.62 | $ 6,627.87 | $ 3,515.92 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 346,000 | 326,000 | 346,000 | 527,000 | 682,000 | 1,530,000 | 332,000 | 743,000 | 495,000 | 953,000 | 1,028,000 | 483,000 | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Multi-Family 5/8" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 9 | 108 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 9 | 6 | 9 | 10 | 10 | 10 | 11 | 10 | 10 | 9 | 10 | 9 | 113 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | 3 | - | (1) | (1) | (1) | (2) | (1) | (1) | - | (1) | - | (5) |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 77.93 | $ 69.68 | $ 77.93 | $ 82.63 | $ 78.63 | $ 98.61 | $ 64.15 | $ 72.35 | $ 82.63 | $ 70.95 | $ 62.64 | $ 77.30 | |
| 5 | INCREASE IN REVENUES | $ - | $ 209 | $ - | $ (83) | $ (79) | $ (99) | $ (128) | $ (72) | $ (83) | $ - | $ (63) | $ - | $ (397) |
| 6 | TOTAL INCREASE IN REVENUE | (397) | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ (397) | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 10,778 | 9,333 | 10,778 | 11,600 | 10,900 | 14,400 | 8,364 | 9,800 | 11,600 | 9,556 | 8,100 | 10,667 | |
| 10 | INCREASE IN CUSTOMERS | - | 3 | - | (1) | (1) | (1) | (2) | (1) | (1) | - | (1) | - | |
| 11 | RUCO INCREASE IN GALLONS | - | 28,000 | - | (11,600) | (10,900) | (14,400) | (16,727) | (9,800) | (11,600) | - | (8,100) | - | (55,127) |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | (55,127) |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008
Multi-Family 1.5" Meter



| LINE NO. | DESCRIPTION | JANUARY | FEBRUARY | MARCH | APRIL | MAY | JUNE | JULY | AUGUST | SEPTEMBER | OCTOBER | NOVEMBER | DECEMBER | TOTAL YEAR |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 2008 TEST YEAR END CUSTOMERS | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 2 | 2008 ACTUAL CUSTOMERS BY MONTH | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 12 |
| 3 | INCREASE IN NUMBER OF CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 4 | AVERAGE REVENUE FOR THE MONTH | $ 128.66 | $ 134.37 | $ 140.08 | $ 117.24 | $ 117.24 | $ 117.24 | $ 117.24 | $ 128.66 | $ 117.24 | $ 128.66 | $ 128.66 | $ 134.37 | |
| 5 | INCREASE IN REVENUES | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| 6 | TOTAL INCREASE IN REVENUE | - | | | | | | | | | | | | |
| 7 | INCREASE IN REVENUE PER COMPANY | $ - | | | | | | | | | | | | |
| 8 | RUCO REVENUE ADJUSTMENT | - | | | | | | | | | | | | |
| 9 | GALLONS SOLD PER AVERAGE CUSTOMER | 9,000 | 10,000 | 11,000 | 7,000 | 5,000 | 2,000 | 3,000 | 9,000 | 7,000 | 9,000 | 9,000 | 10,000 | |
| 10 | INCREASE IN CUSTOMERS | - | - | - | - | - | - | - | - | - | - | - | - | |
| 11 | RUCO INCREASE IN GALLONS | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 12 | COMPANY INCREASE IN GALLONS | | | | | | | | | | | | | - |
| 13 | RUCO DIFFERENCE IN GALLONS TO BE PRODUCED | - | | | | | | | | | | | | - |

**OPERATING ADJUSTMENT #2**
**REVENUE & EXPENSE ANNUALIZATION - PURCHASED POWER EXPENSE**

| LINE NO. | DESCRIPTION | | TOTAL |
|---|---|---|---|
| 1 | Annualize Purchase Power Expense | | |
| 2 | | | |
| 3 | Test Year Purchased Power Expense | $ | 17,482 |
| 4 | Increase in Purchased Power Expense (Company Adjustment 5) | | 332 |
| 5 | | | |
| 6 | Total Adjusted Test Year Purchased Power Expense | $ | 17,814 |
| 7 | | | |
| 8 | Gallons Treated in Test Year (in 1,000's) | | 155,443 |
| 9 | | | |
| 10 | Cost per 1,000 gallons | | 0.1146 |
| 11 | | | |
| 12 | Number of Bills During Test Year (excluding effluent) | | 24,852 |
| 13 | | | |
| 14 | Average Flow per Bill (in 1,000's) | | 6.25 |
| 15 | | | |
| 16 | Increase in Number of Bills | | 1,824 |
| 17 | | | |
| 18 | Increase in Flows (in 1,000's) | | 11,400 |
| 19 | | | |
| 20 | Increase (decrease) in Purchased Power | $ | 1,306 |
| 21 | | | |
| 22 | Company Adjustment to Revenue and/or Expense | $ | (388) |
| 23 | | | |
| 24 | RUCO Adjustment to Revenue and/or Expense | $ | 1,694 |
| 25 | | | |
| 26 | | | |
| 27 | | | |
| 28 | | | |
| 29 | | | |
| 30 | | | |
| 31 | | | |
| 32 | | | |
| 33 | | | |
| 34 | SUPPORTING SCHEDULES | | |
| 35 | Company Schedule C-2 | | |
| 36 | Company Adjustment #5 Schedule | | |
| 37 | Schedule TJC-8, pages 1 thru 16 | | |
| 38 | | | |
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| 44 | | | |

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3**
**TEST YEAR DEPRECIATION EXPENSE**

| LINE NO. | ACCOUNT NO. | ACCOUNT NAME | (A) RUCO PLANT VALUE | (B) COMPANY PROPOSED DEP. RATES | (C) TEST YEAR DEPRECIATION EXPENSE |
|---|---|---|---|---|---|
| 1 | 351 | Organization | $ 5,785 | 0.00% | $ - |
| 2 | 352 | Franchises | 417 | 0.00% | - |
| 3 | 353 | Land | 7,545 | 0.00% | - |
| 4 | 354 | Structures and Improvements | 28,548 | 3.33% | 951 |
| 5 | 355 | Power Generation | - | 5.00% | - |
| 6 | 360 | Collection Sewer Forced | 636,023 | 2.00% | 12,720 |
| 7 | 361 | Collection Sewers Gravity | 5,945,962 | 2.00% | 118,919 |
| 8 | 362 | Special Collecting Structures | - | 2.00% | - |
| 9 | 363 | Customer Services | 1,145,530 | 2.00% | 22,911 |
| 10 | 364 | Flow Measuring Devices | 55,989 | 10.00% | 5,599 |
| 11 | 365 | Flow Measuring Installation | - | 10.00% | - |
| 12 | 366 | Reuse Services | - | 2.00% | - |
| 13 | 367 | Reuse Meters And Installation | - | 8.33% | - |
| 14 | 370 | Receiving Wells | 867,120 | 3.33% | 28,875 |
| 15 | 371 | Pumping Equipment | 1,504,181 | 12.50% | 188,023 |
| 16 | 374 | Reuse Distribution Reservoirs | - | 2.50% | - |
| 17 | 375 | Reuse Trans. and Dist. System | - | 2.50% | - |
| 18 | 380 | Treatment & Disposal Equipment | 1,006,848 | 5.00% | 50,342 |
| 19 | 381 | Plant Sewers | - | 5.00% | - |
| 20 | 382 | Outfall Sewer Lines | - | 3.33% | - |
| 21 | 389 | Other Sewer Plant & Equipment | 68,869 | 6.67% | 4,594 |
| 22 | 390 | Office Furniture & Equipment | 110,454 | 6.67% | 7,367 |
| 23 | 390 | Computers and Software | 4,025 | 20.00% | 805 |
| 24 | 391 | Transportation Equipment | - | 20.00% | - |
| 25 | 392 | Stores Equipment | - | 4.00% | * - |
| 26 | 393 | Tools, Shop And Garage Equip | 4,897 | 5.00% | 245 |
| 27 | 394 | Laboratory Equip | - | 10.00% | - |
| 28 | 396 | Communication Equip | 5,936 | 10.00% | 594 |
| 29 | 398 | Other Tangible Plant | 3,913 | 4.00% | 157 |
| 30 | 398 | Nogales WW Trmnt Capacity | 427,000 | 5.00% | 21,350 |
| 31 | 346 | Rounding | 1 | | |
| 32 | | | | | |
| 33 | | TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE | $ 11,829,043 | | $ 463,451 |
| 34 | | | | | |
| 35 | | | | | |
| 36 | | AMORTIZATION OF CONTRIBUTIONS | (5,137,673) | 3.92% | (201,418) |
| 37 | | | | | |
| 38 | | Rounding | | | |
| 39 | | | | | |
| 40 | **TOTAL DEPRECIATION EXPENSE** | | | | $ 262,033 |
| 41 | | | | | |
| 42 | Company As Filed | | | | 252,672 |
| 43 | Difference | | | | $ 9,361 |
| 44 | | | | | |
| 45 | RUCO Adjustment | | | | $ 9,361 |
| 46 | | | | | |
| 47 | | | | | |

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4**
**PROPERTY TAX COMPUTATION**

| LINE NO. | DESCRIPTION | REFERENCE | (A) | (B) |
|---|---|---|---|---|
| | Calculation Of The Company's Full Cash Value: | | | |
| | Annual Operating Revenues: | | | |
| 1 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | $ 1,850,101 | |
| 2 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | 1,850,101 | |
| 3 | Proposed Revenues | Sch. TJC-7, Col (E), Ln 8 | 1,300,773 | |
| 4 | Total Three Year Operating Revenues | Sum Of Lines 1, 2 & 3 | $ 5,000,974 | |
| 5 | Average Annual Operating Revenues | Line 4 / 3 | 1,666,991 | |
| 6 | Two Times Three Year Average Operating Revenues | Line 5 X 2 | | $ 3,333,983 |
| | ADD: | | | |
| | 10% Of Construction Work In Progress ("CWIP"): | | | |
| 7 | Test Year CWIP | Company Schedule E | $ 28,150 | |
| 8 | 10% Of CWIP | Line 7 X 10% | | $ 2,815 |
| | SUBTRACT: | | | |
| | Transportation At Book Value: | | | |
| 9 | Original Cost Of Transportation Equipment | RUCO Plant Schedule TJC-4 | $ - | |
| 10 | Acc. Dep. Of Transportation Equipment | RUCO Plant Schedule TJC-4 | - | |
| 11 | Net Book Value Of Transportation Equipment | Line 9 + Line 10 | | $ - |
| 12 | Company's Full Cash Value ("FCV") | Sum Of Lines 6, 8 & 11 | | $ 3,336,798 |
| | Calculation Of The Company's Tax Liability: | | | |
| | MULTIPLY: | | | |
| | FCV X Valuation Assessment Ratio X Property Tax Rates: | | | |
| 13 | Assessment Ratio | House Bill 2779 | 21.0% | |
| 14 | Assessed Value | Line 12 X Line 13 | $ 700,728 | |
| | Property Tax Rates: | | | |
| 15 | Primary Tax Rate | Company Workpapers | 11.3283% | |
| 16 | Secondary Tax Rate | Company Workpapers | 0.00% | |
| 17 | Estimated Tax Rate Liability | Line 15 + Line 16 | 11.33% | |
| | Property Tax | | | $ 79,381 |
| | Tax On Parcel | | | - |
| 18 | Company's Total Tax Liability - Based On Full Cash Value | Line 14 X Line 17 | | $ 79,381 |
| 19 | Test Year Adjusted Property Tax Expense As Filed | Co. Sch. C-1 | | 91,705 |
| 20 | Decrease In Property Tax Expense | Line 18 - Line 19 | | $ (12,324) |
| | | Line 20 | | $ (12,324) |

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 5**
**RATE CASE EXPENSE**

| LINE NO. | DESCRIPTION | (A) COMPANY ESTIMATE | (B) RUCO ADJUSTMENT | (C) RUCO AS ADJUSTED |
|---|---|---|---|---|
| 1 | Rate Case Expense Total | $ 125,000 | $ (31,250) | $ 93,750 |
| 2 | Allocation Factor | | | 100% |
| 3 | Wastewater Division (Line 1 X Line 2) | | | $ 93,750 |
| 4 | Normalization Period - 3 Years | | | 3 |
| 5 | RUCO Adjusted Rate Case Expense (Line 3 / 3 Years) | | | $ 31,250 |
| 6 | Company Rate Case Expenses As Filed (Company Sch. C-2) | | | $ 41,667 |
| 7 | RUCO Pro Forma Rate Case Expense (Lines 5 - 6) | | | $ (10,417) |
| 8 | RUCO Adjustment (Line 7) | | | $ (10,417) |

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6**
**MISCELLANEOUS EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Intentionally Left Blank | |
| 2 | | |
| 3 | | |
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## OPERATING INCOME ADJUSTMENT #8 - CORPORATE ALLOCATIONS

| Line No. | Description | Company Total Cost | RUCO Disallowed Costs | | RUCO Other Disallowed Costs | RUCO Allowable Costs | RUCO 2008 Allocation Factor | RUCO Allowed Allocated Costs | Allocation % To Rio Rico | RUCO Amount Allocated To Rio Rico |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Rent | 430,739 | | | (430,739) | - | 24.29% | - | 12.92% | - |
| 2 | Audit | 507,000 | | | (380,250) | 126,750 | 24.29% | 30,782 | 12.92% | 3,976.12 |
| 3 | Tax Services | 265,000 | | | (198,750) | 66,250 | 24.29% | 16,089 | 12.92% | 2,078.25 |
| 4 | Legal - General | 300,000 | | | (225,000) | 75,000 | 24.29% | 18,214 | 12.92% | 2,352.73 |
| 5 | Other Professional Services | 455,000 | | | (455,000) | - | 24.29% | - | 12.92% | - |
| 6 | Management Fee | 636,619 | | | (636,619) | - | 24.29% | - | 12.92% | - |
| 7 | Unit Holder Communications | 314,100 | | | (314,100) | - | 24.29% | - | 12.92% | - |
| 8 | Trustee Fees | 204,000 | | | (204,000) | - | 24.29% | - | 12.92% | - |
| 9 | Office Costs | 254,100 | (46,186) | Note A | (207,914) | - | 24.29% | - | 12.92% | - |
| 10 | Licenses/Fees and Permits | 305,000 | (145,642) | Note B | (159,358) | - | 24.29% | - | 12.92% | - |
| 11 | Escrow and Transfer Fees | 75,000 | | | (75,000) | - | 24.29% | - | 12.92% | - |
| 12 | Depreciation Expense | 204,242 | | | (153,182) | 51,061 | 24.29% | 12,400 | 12.92% | 1,601.76 |
| | **Total** | 3,950,800 | (191,828) | | (3,439,912) | 319,061 | | 77,486 | | 10,009 |

| | |
|---|---|
| RUCO Allocation To Rio Rico Water Division (Based on Total Ratio of Rate Base) | 70.5745% |
| RUCO Allocation To Rio Rico Wastewater Division (Based on Total Ratio of Rate Base) | 29.4255% |
| Company's APT Cost Allocation for Water Division (Per Staff DR GB 3.7 & GB 3.15) | $ 103,745 |
| RUCO's APT Cost Allocation Allowed for Water Division | 7,064 |
| RUCO's APT Cost Allocation Adjustment for Water Division | (96,681) |
| Company's APT Cost Allocation for Wastewater Division (Per Staff DR GB 3.7 & GB 3.15) | $ 34,582 |
| RUCO's APT Cost Allocation Allowed for Wastewater Division | 2,945 |
| RUCO's APT Cost Allocation Adjustment for Wastewater Division | (31,637) |

**Note A:**

| | Description | |
|---|---|---|
| Office Costs | Wind Analysis Software | $ 15,056 |
| Office Costs | Gold Watches & Clocks | 16,864 |
| Office Costs | Pilsner Beer Glasses | 5,700 |
| Office Costs | Leafs/Raptors Tickets | 5,066 |
| Office Costs | Super Bowl Tickets | 3,500 |
| Total | | $ 46,186 |

**Note B:**

| | | |
|---|---|---|
| Licenses/Fees and Permits | Donation | $ 25,000 |
| Licenses/Fees and Permits | Donation | 25,000 |
| Licenses/Fees and Permits | Donation | 13,350 |
| Licenses/Fees and Permits | Donation | 5,000 |
| Licenses/Fees and Permits | Wind Developm | 7,887 |
| Licenses/Fees and Permits | US Trustee | 9,375 |
| Licenses/Fees and Permits | Wind Energy | 12,556 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,891 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,794 |
| Licenses/Fees and Permits | APF Inc Taxes | 23,789 |
| Licenses/Fees and Permits | KMS Tax Ruling | 10,000 |
| Total | | $ 145,642 |

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report
Company's Response to Staff GB 3.2 and 3.10 APT Affiliate Charges - Rio Rico
Company's Response to Staff GB 3.7 and 3.15

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 9**
**BAD DEBT EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Normalize Bad Debt Expense: | |
| 2 | | |
| 3 | 2008 Bad Debt Expense | $ 64,087 |
| 4 | 2007 Bad Debt Expense | 28,498 |
| 5 | 2006 Bad Debt Expense | 8,732 |
| 6 | | |
| 7 | 3 Year Normalization | $ 33,772 |
| 8 | | |
| 9 | Company As Filed | 64,087 |
| 10 | | |
| 11 | RUCO Adjustment | $ (30,315) |
| 12 | | |
| 13 | | |
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| 38 | SUPPORTING SCHEDULES | |
| 39 | Company Schedule E-2 | |
| 40 | | |
| 41 | | |

## OPERATING INCOME ADJUSTMENT #10
## INCOME TAX EXPENSE

| LINE NO. | DESCRIPTION | (A) REFERENCE | (B) AMOUNT |
|---|---|---|---|
| | **FEDERAL INCOME TAXES:** | | |
| 1 | Operating Income Before Taxes | Sch. TJC-7, Column (C), L28 + L22 + L23 | $ 844,889 |
| | LESS: | | |
| 2 | Arizona State Tax | Line 11 | 53,746 |
| 3 | Interest Expense | Note (A) Line 21 | 73,557 |
| 4 | Federal Taxable Income | Line 1 - Line 2 - Line 3 | $ 717,586 |
| 5 | Federal Tax Rate | Sch. TJC-1, Pg 2, Col. (D), L34 | 30.89% |
| 6 | Federal Income Tax Expense | Line 4 X line 5 | $ 221,662 |
| | **STATE INCOME TAXES:** | | |
| 7 | Operating Income Before Taxes | Line 1 | $ 844,889 |
| | LESS: | | |
| 8 | Interest Expense | Note (A) Line 21 | 73,557 |
| 9 | State Taxable Income | Line 7 - Line 8 | $ 771,332 |
| 10 | State Tax Rate | Tax Rate | 6.97% |
| 11 | State Income Tax Expense | Line 9 X Line 10 | $ 53,746 |
| | **TOTAL INCOME TAX EXPENSE:** | | |
| 12 | Federal Income Tax Expense | Line 6 | $ 221,662 |
| 13 | State Income Tax Expense | Line 11 | 53,746 |
| 14 | Total Income Tax Expense Per RUCO | Line12 + Line 13 | $ 275,409 |
| 15 | Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | 252,773 |
| 16 | Total State Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | 55,684 |
| 17 | RUCO Federal Income Tax Adjustment | Line 12 - Line 15 | $ (31,110) |
| 18 | RUCO State Income Tax Adjustment | Line 13 - Line 16 | $ (1,937) |

NOTE (A):
Interest Synchronization:

| | | | |
|---|---|---|---|
| 19 | Adjusted Rate Base (Sch. TJC-2, Col. (H), L17) | $ | 2,937,595 |
| 20 | Weighted Cost Of Debt (Sch. TJC-16 Col. (F), L1) | | 2.50% |
| | | $ | 73,557 |

## COST OF CAPITAL

| LINE NO. | DESCRIPTION | (B) CAPITAL RATIO | (C) COST RATE | (D) WEIGHTED COST RATE |
|---|---|---|---|---|
| 1 | Long-Term Debt | 40.00% | 6.26% | 2.50% |
| 2 | Common Equity | 60.00% | 9.00% | 5.40% |
| 3 | Total Capitalization | 100.00% | | |
| 4 | WEIGHTED AVERAGE COST OF CAPITAL | | | 7.90% |

References:
Columns (A) Thru (D): Testimony, WAR

ORIGINAL

EXHIBIT
R-10
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

RECEIVED

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AZ CORP COMMISSION
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KRISTIN K. MAYES
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GARY PIERCE
COMMISSIONER
SANDRA D. KENNEDY
COMMISSIONER
PAUL NEWMAN
COMMISSIONER
BOB STUMP
COMMISSIONER

| | |
|---|---|
| IN THE MATTER OF THE APPLICATION OF RIO RICO UTILITIES, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER AND WASTEWATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON. | Docket No. WS-02676A-09-0257 |

Arizona Corporation Commission
DOCKETED
FEB - 4 2010
DOCKETED BY

**NOTICE OF ERRATA**

The Residential Utility Consumer Office ("RUCO") hereby files this Notice of Errata to the Direct Required Revenue Testimony of Timothy J. Coley, which was filed December 23, 2009, in the above-referenced matter.

Please substitute the attached corrected schedules (TJC-1, TJC-6, TJC-7. TJC-11 and TJC-16), and testimony pages (7, 42, 43 and 52-57).

RESPECTFULLY SUBMITTED this 4th day of February, 2010.

Daniel W. Pozefsky
Chief Counsel

**REVENUE REQUIREMENTS**

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. RUCO's analysis found many of the Company's financial statements (i.e. balance sheets) filed with the application and invoices provided in data responses to the various intervenors in the Algonquin related cases unreliable and without sufficient detail.

RUCO's recommended fair value rate base is $7,045,555 for the Water Division and $2,937,595 for the Wastewater Division. Mr. Rigsby recommends a 9 percent return on common equity and an overall rate of return on fair value rate base of 7.90 percent.

RUCO's recommended revenue requirements increase gross revenues by $936,172 for the Water Division and decrease gross revenues in the amount of $512,396 for the Wastewater Division. RUCO's recommended increase (decrease) in gross revenues represents a 49.95 percent increase and a (27.70) percent decrease in the Water and Wastewater Divisions respectively. The details are shown on Schedules TJC-1 and TJC-17.

Q. Are there any differences between RUCO's calculation of Property Tax Expense and the Company's calculation?

A. Yes. There are three differences. First, RUCO's adjusted test-year gross revenues are not the same as the Company due to an adjustment for Revenue Annualization nor is the proposed level of gross revenues the same because RUCO recommends a lower amount of an increase in rates. Second, RUCO's calculation includes an addition of 10 percent of the amount of Construction Work in Progress ("CWIP") that was booked during the test-year. Finally, RUCO has deducted a different amount of test-year net book value (See Schedule TJC-4, page 7) of the Company's vehicles.

Q. What adjustments were necessary to reflect RUCO's differences in calculating the Property Tax Expense?

A. RUCO's adjustments decrease the Company's Property Tax Expense by $30,780 and $11,739 for the Water and Wastewater Divisions respectively.

**Operating Income Adj. #5 – Rate Case Expense**

Q. What level of Rate Case Expense is RRUI estimating in this case?

A. RRUI is estimating its Rate Case Expense to be $210,000 for the Water Division and $125,000 for the Wastewater Division. The Company

proposes that the Rate Case Expense be recovered over a three-year period.

Q. What level of rate case expense is RUCO recommending?

A. The last updated amount of invoiced Rate Case Expense that RUCO is aware of was $41,307 through October 2009. That is approximately 12 percent of the total $335,000 estimated by the Company. At this time, RUCO has made an adjustment of 25 percent to the Company's total estimated Rate Case Expense for both the Water and Wastewater Divisions. RUCO is reserving its right to make further adjustments to the Company's estimates in surrebuttal testimony and final schedules. I will review the final rate case invoices and make a reasonable adjustment as this case proceeds.

Q. What adjustments are necessary to reflect RUCO's reasonable Rate Case Expense recommendations?

A. RUCO recommended three-year normalization of Rate Case Expense decreases the annual recovery by $17,500 for the Water Division and $10,417 for the Wastewater Division. The adjustments can be seen on Schedules TJC-12 for both the Water and Wastewater Divisions.

Q. What adjustments were necessary to smooth out the wide fluctuations reported in the Wastewater Division and to normalize the Water Division's Bad Debt Expense?

A. RUCO decreased the Wastewater Bad Debt Expense by $30,315 and increased the Water Division's Bad Debt Expense by $799. These adjustments are shown on Schedules TJC-15.

**Operating Income Adj. #10 – Income Tax Expense**

Q. Have you calculated the Income Tax Expenses based on RUCO's recommended adjusted operating incomes?

A. Yes. These adjustments are shown on Schedules TJC-16 for both the Water and Wastewater Divisions.

**OTHER ISSUES**

**Low-Income Program ("LIP")**

Q. Did RRUI propose a LIP for its service territory in this case?

A. Yes.

Q. Does RUCO support the Company's LIP as proposed?

A. RUCO generally supports LIP's and has reviewed RRUI's proposed LIP in this case. RUCO found the proposed program to be similar to what was approved in the most recent Chaparral City rate case. RUCO supports

the Company's proposed LIP in this case. The Company stated that all customers would have to subsidize the program accordingly.

**Hook Up Fee**

Q. What is RUCO's position on the Company's proposed new HUF tariff?

A. RUCO is in general agreement with most HUF tariffs that are intended to fund new infrastructure created by growth and assists in equitably apportioning the cost of off-site facilities. However, RUCO does <u>not</u> support the Company's proposed HUF tariff as filed.

Q. Why doesn't RUCO support the Company's proposed hook up fee ("HUF") tariff?

A. RUCO does not support the Company's HUF tariff because of certain language contained in the tariff and the Wastewater tariff is inconsistent with the amount of the HUF in the Company's testimony.

Q. What language in the HUF tariff is RUCO opposed?

A. Both the Water and Wastewater Divisions tariff state, "The Company shall not record amounts collected under this tariff as CIAC until such amounts have been expended for plant."

...

Q. Please give RUCO's reasoning for which it is in opposition to that particular language.

A. CIAC is non-investor funded capital. From the day the Company collects the CIAC from the developer or customer, the Company has use of those funds to expend them as it wishes. CIAC also frees up the investor supplied capital to be expended on other investments. The CIAC balance at any given point in time is the amount that has been collected up to that point in time. Arizona ratemaking does not defer CIAC to be recorded at a later time in the future.

Q. Hasn't the Commission granted accounting orders that allowed a Company to not record CIAC until a particular item of plant that the CIAC is funding is fully constructed, operational, and in gross utility plant in service?

A. Yes. The Commission has approved accounting orders that allowed a company to not record CIAC until a "specific" piece of plant is fully constructed, operational, and in gross utility plant in service. Normally, the Commission approves such an accounting order only in extraordinary circumstances. RRUI's request is far from an extraordinary circumstance. In fact, the Company's request for this special treatment of CIAC is for quite ordinary purposes.

...

Q. When did the Commission approve an accounting order that delayed the recording of collecting CIAC from non-investors?

A. A case that comes to mind is an Arizona-American Water Company's ("Arizona-American" or "AZ-AM") proceeding that involved construction of the White Tank Regional Treatment Plant?

Q. What was the parties' positions regarding delaying the recording of CIAC until the plant was fully constructed, operational, and in gross utility plant in service?

A. Arizona-American requested an accounting order to delay the recording of CIAC associated only with the White Tank Water Treatment Plant, which was estimated to cost approximately $74.8 Million and originally to be funded predominantly with CIAC. AZ-AM had planned on filing a rate case several years before the completion of the White Tank Plant that included the White Tank System. If the CIAC associated with the White Tank Plant had been recorded when collected, it would distort White Tanks' rate base because of the magnitude of the CIAC balance related to the specific plant item in question. The Commission granted approval of the accounting order, which delayed the recording of the associated CIAC, based primarily on the fact that it was indeed an extraordinary circumstance. RUCO was in support of the Company's request in that extraordinary instance.

...

Q. Then, is it RUCO's position that without some extraordinary circumstance, which does not exist in RRUI's situation, the Commission should reject the Company's request to not record CIAC on its books until the CIAC has been expended for some generic plant?

A. Yes.

Q. If RRUI were to strike that sentence from its proposed HUF tariff, would RUCO be in support of the Company's HUF to be treated as CIAC?

A. Yes, with one clarification. The Company's proposed HUF tariffs for both the Water and Wastewater Divisions show the HUF to be $1,800 for a 5/8 inch meter. However, Mr. Sorensen's testimony indicates the Wastewater HUF to be $2,000 on page 10, line 23 of his testimony. RUCO would like the Company to clarify if it is $1,800 or $2,000.

**Other Tariff Changes**

Q. What changes to new service line installations charges has RRUI proposed?

A. The Company proposed a change in the cost of new service lines. RRUI has proposed that all service line installation charges be at "cost" rather than the current stated tariff rates.

...

Q. What is RUCO's position regarding that all service line installation charges be at "cost" rather than current stated tariff rates.

A. RUCO prefers that the current rates in the tariff be maintained. RUCO will defer this issue to Commission Staff engineers.

**Late Payment Finance Charge**

Q. Has the Company proposed a 1.5 percent late payment charge to be included in its tariff?

A. Yes.

Q. Is RUCO in support of the Company's proposed 1.5 percent late payment charge?

A. Yes. This is a common charge found in many utility bills.

Q. Does this conclude your testimony?

A. Yes, it does.

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division - Errata Schedules
Schedule TJC-1


**REVENUE REQUIREMENT**

| LINE NO. | DESCRIPTION | (A) COMPANY OCRB/FVRB COST | (B) RUCO OCRB/FVRB COST |
|---|---|---|---|
| 1 | Adjusted Original Cost/Fair Value Rate Base | $ 3,516,078 | $ 2,937,595 |
| 2 | Adjusted Operating Income (Loss) | $ 490,676 | $ 546,804 |
| 3 | Current Rate of Return (L2 / L1) | 13.96% | 18.61% |
| 4 | Required Operating Income (L5 X L1) | $ 435,994 | $ 232,187 |
| 5 | Required Rate of Return on Fair Value Rate Base | 12.40% | 7.90% |
| 6 | Operating Income Deficiency (L4 - L2) | $ (54,682) | $ (314,617) |
| 7 | Gross Revenue Conversion Factor (TJC-1, Page 2) | 1.6286 | 1.6286 |
| 8 | Required Increase in Gross Revenue Requirement (L7 X L6) | $ (89,058) | $ (512,396) |
| 9 | Adjusted Test Year Revenue | $ 1,829,976 | $ 1,850,101 |
| 10 | Proposed Annual Revenue (L8 + L9) | $ 1,740,918 | $ 1,337,705 |
| 15 | Required Percentage Increase in Revenue (L8 / L9) | -4.87% | -27.70% |
| 16 | Rate of Return on Common Equity | 12.40% | 9.00% |

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-6, and TJC-17

## GROSS REVENUE CONVERSION FACTOR

| LINE NO. | DESCRIPTION | (A) | (B) | (C) | (D) |
|---|---|---|---|---|---|
| | CALCULATION OF GROSS REVENUE CONVERSION FACTOR: | | | | |
| 1 | Revenue | 1.0000 | | | |
| 2 | Combined Federal And State Tax Rate (L10) | 0.3860 | | | |
| 3 | Subtotal (L1 - L2) | 0.6140 | | | |
| 4 | **Revenue Conversion Factor** (L1 / L3) | **1.6286** | | | |
| | CALCULATION OF EFFECTIVE TAX RATE: | | | | |
| 5 | Operating Income Before Taxes (Arizona Taxable Income) | 100.0000% | | | |
| 6 | Arizona State Income Tax Rate | 6.9680% | | | |
| 7 | Federal Taxable Income (L5 - L6) | 93.0320% | | | |
| 8 | Applicable Federal Income Tax Rate (Col. (D), L34) | 34.0000% | | | |
| 9 | Effective Federal Income Tax Rate (L7 X L8) | 31.6309% | | | |
| 10 | Combined Federal And State Income Tax Rate (L6 + L9) | 38.5989% | | | |
| 11 | Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4) | $ 232,187 | | | |
| 12 | Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2) | 546,804 | | | |
| 13 | Required Increase In Operating Income (L11 - L12) | | $ (314,617) | | |
| 14 | Income Taxes On Recommended Revenue (Col. (D), L31) | $ 99,720 | | | |
| 15 | Income Taxes On Test Year Revenue (Col. (D), L32) | 297,499 | | | |
| 16 | Required Increase In Revenue To Provide For Income Taxes (L14 - L15) | | $ (197,779) | | |
| 17 | Total Required Increase In Revenue (L13 + L16) | | $ (512,396) | | |
| | CALCULATION OF INCOME TAX: | | | RUCO Recommended | |
| 18 | Revenue (Sch. TJC-1, Pg 1, Col. (B), L12) | | | $ 1,337,705 | |
| 19 | Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23) | | | 1,005,797 | |
| 20 | Synchronized Interest (Col. (C), L37) | | | 73,557 | |
| 21 | Arizona Taxable Income (L18 - L19 - L20) | | | $ 258,351 | |
| 22 | Arizona State Income Tax Rate | | | 6.9680% | |
| 23 | Arizona Income Tax (L21 X L22) | | | | $ 18,002 |
| 24 | Fed. Taxable Income (L21 - L23) | | | $ 240,349 | |
| 25 | Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15% | | | $ - | |
| 26 | Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25% | | | $ - | |
| 27 | Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34% | | | $ - | |
| 28 | Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39% | | | $ - | |
| 29 | Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34% | | | $ 81,719 | |
| 30 | Total Federal Income Tax (L25 + L26 + L27 + L28 + L29) | | | | $ 81,719 |
| 31 | Combined Federal and State Income Tax (L23 + L30) | | | | $ 99,720 |
| 32 | Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23) | | | | $ 297,499 |
| 33 | RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23) | | | | $ (197,779) |
| 34 | Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24) | | | | 34.00% |
| | CALCULATION OF INTEREST SYNCHRONIZATION: | | | | |
| 35 | Rate Base (Sch. TJC-2, Col. (C), L17) | | | $ 2,937,595 | |
| | | | | 2.50% | |
| | | | | $ 73,557 | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division - Errata Schedules
Schedule TJC-6


## OPERATING INCOME

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO TEST YEAR ADJM'TS | (C) RUCO TEST YEAR AS ADJ'TED | (D) RUCO PROP'D CHANGES | (E) RUCO AS RECOMM'D |
|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | |
| 1 | Metered Water Revenues | $ 1,829,726 | $ 20,125 | $ 1,849,851 | $ (512,396) | $ 1,337,455 |
| 2 | Unmetered Water Revenues | - | - | - | - | - |
| 3 | Other Water Revenues | 250 | - | 250 | - | 250 |
| 4 | Total Revenues | $ 1,829,976 | $ 20,125 | $ 1,850,101 | $ (512,396) | $ 1,337,705 |
| | **Operating Expenses:** | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - |
| 6 | Purchased Water and WW Treatment | - | - | - | - | - |
| 7 | Purchased Power | 17,426 | 49,699 | 67,125 | - | 67,125 |
| 8 | Fuel for Power Production | - | - | - | - | - |
| 9 | Chemicals | 9,644 | - | 9,644 | - | 9,644 |
| 10 | Materials & Supplies | 14,304 | - | 14,304 | - | 14,304 |
| 11 | Contractual Services | 298,008 | (31,637) | 266,371 | - | 266,371 |
| 12 | Outside Services - Other | 175,196 | - | 175,196 | - | 175,196 |
| 13 | Outside Services - Legal | 367 | - | 367 | - | 367 |
| 14 | Equipment Rental | 25,781 | - | 25,781 | - | 25,781 |
| 15 | Rents - Building | - | - | - | - | - |
| 16 | Transportation Expenses | 26,817 | - | 26,817 | - | 26,817 |
| 17 | Insurance - General Liability | 12,021 | - | 12,021 | - | 12,021 |
| 18 | Insurance - Vehicle | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 994 | - | 994 | - | 994 |
| 20 | Reg. Comm. Exp. - Rate Case | 41,667 | (10,417) | 31,250 | - | 31,250 |
| 21 | Miscellaneous Expense | 155 | - | 155 | - | 155 |
| 22 | Bad Debt Expense | 64,087 | (30,315) | 33,772 | - | 33,772 |
| 23 | Depreciation and Amortization | 252,672 | 9,361 | 262,033 | - | 262,033 |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Property Taxes | 91,705 | (11,739) | 79,966 | - | 79,966 |
| 26 | Federal Income Tax | 252,773 | (8,979) | 243,794 | (162,075) | 81,719 |
| 27 | State Income Tax | 55,684 | (1,978) | 53,706 | (35,704) | 18,002 |
| 28 | **Total Operating Expenses** | $ 1,339,300 | $ (36,003) | $ 1,303,296 | $ (197,779) | $ 1,105,517 |
| 29 | **Operating Income** | $ 490,676 | $ 56,128 | $ 546,804 | $ (314,617) | $ 232,187 |

References:
Column (A): Company Schedule C-1
Column (B): Schedule TJC-7, Columns (B) Thru (K)
Column (C): Column (A) + Column (B)
Column (D): TJC-1, pages 1 and 2
Column (E): Column (C) + Column (D)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**SUMMARY OF OPERATING INCOME ADJUSTMENTS**
**TEST YEAR AS FILED AND ADJUSTMENTS**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJMT NO. 1 REVENUE ANNUALTN | (C) ADJMT NO. 2 PURCHASED POWER | (D) ADJMT NO. 3 DEPRECIATION EXPENSE | (E) ADJMT NO. 4 PROPERTY TAX | (F) ADJMT NO. 5 RATE CASE EXPENSE | (G) ADJMT NO. 6 MISCELL. EXPENSE | (H) ADJMT NO. 7 PURCH. POWER PER GB 3.8 | (I) ADJMT NO. 8 CORPORATE ALLOCATION | (J) ADJMT NO. 9 BAD DEBT EXPENSE | (K) ADJMT NO. 10 INCOME TAXES | (L) RUCO AS ADJT'D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | | | | | | | | |
| 1 | Metered Water Revenues | $ 1,829,726 | $ 20,125 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,849,851 |
| 2 | Unmetered Water Revenues | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Other Water Revenues | 250 | - | - | - | - | - | - | - | - | - | - | 250 |
| 4 | Total Revenues | $ 1,829,976 | $ 20,125 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,850,101 |
| | **Operating Expenses:** | | | | | | | | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 6 | Purchased Water and WW Treatment | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | Purchased Power | 17,426 | - | 1,694 | - | - | - | - | 48,005 | - | - | - | 67,125 |
| 8 | Fuel for Power Production | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Chemicals | 9,644 | - | - | - | - | - | - | - | - | - | - | 9,644 |
| 10 | Materials & Supplies | 14,304 | - | - | - | - | - | - | - | - | - | - | 14,304 |
| 11 | Contractual Services | 298,008 | - | - | - | - | - | - | - | (31,637) | - | - | 266,371 |
| 12 | Outside Services - Other | 175,196 | - | - | - | - | - | - | - | - | - | - | 175,196 |
| 13 | Outside Services - Legal | 367 | - | - | - | - | - | - | - | - | - | - | 367 |
| 14 | Equipment Rental | 25,781 | - | - | - | - | - | - | - | - | - | - | 25,781 |
| 15 | Rents - Building | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | Transportation Expenses | 26,817 | - | - | - | - | - | - | - | - | - | - | 26,817 |
| 17 | Insurance - General Liability | 12,021 | - | - | - | - | - | - | - | - | - | - | 12,021 |
| 18 | Insurance - Vehicle | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 994 | - | - | - | - | - | - | - | - | - | - | 994 |
| 20 | Reg. Comm. Exp. - Rate Case | 41,667 | - | - | - | - | (10,417) | - | - | - | - | - | 31,250 |
| 21 | Miscellaneous Expense | 155 | - | - | - | - | - | - | - | - | - | - | 155 |
| 22 | Bad Debt Expense | 64,087 | - | - | - | - | - | - | - | - | (30,315) | - | 33,772 |
| 23 | Depreciation and Amortization | 252,672 | - | - | 9,361 | - | - | - | - | - | - | - | 262,033 |
| 24 | Taxes Other Than Income | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | Property Taxes | 91,705 | - | - | - | (11,739) | - | - | - | - | - | - | 79,966 |
| 26 | Federal Income Tax | 252,773 | - | - | - | - | - | - | - | - | - | (8,979) | 243,794 |
| 27 | State Income Tax | 55,684 | - | - | - | - | - | - | - | - | - | (1,978) | 53,706 |
| 28 | **Total Operating Expenses** | $ 1,339,300 | $ - | $ 1,694 | $ 9,361 | $ (11,739) | $ (10,417) | $ - | $ 48,005 | $ (31,637) | $ (30,315) | $ (10,957) | $ 1,303,296 |
| 29 | **Operating Income** | $ 490,676 | $ 20,125 | $ (1,694) | $ (9,361) | $ 11,739 | $ 10,417 | $ - | $ (48,005) | $ 31,637 | $ 30,315 | $ 10,957 | $ 546,804 |

ADJUSTMENTS:
1 - Revenue Annualization
2 - Purchased Power Expense Increase and Annualization
3 - Depreciation Expense
4 - Property Tax Expense
5 - Rate Case Expense
6 - Intentionally Left Blank
7 - Purchased Power Expense Per Staff DR GB 3.8
8 - Corporate Allocations
9 - Bad Debt Expense
10 Income Taxes

REFERENCE:
TJC Testimony and Schedule TJC-8 Pages 1 thru 16
TJC Testimony and Schedule TJC-9
TJC Testimony and Schedule TJC-10
TJC Testimony and Schedule TJC-11
TJC Testimony and Schedule TJC-12
Intentionally Left Blank
TJC Testimony
TJC Testimony and Schedule TJC-14
TJC Testimony and Schedule TJC-15
TJC Testimony and Schedule TJC-16

**EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4**
**PROPERTY TAX COMPUTATION**

| LINE NO. | DESCRIPTION | REFERENCE | (A) | (B) |
|---|---|---|---|---|
| | Calculation Of The Company's Full Cash Value: | | | |
| | Annual Operating Revenues: | | | |
| 1 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | $ 1,850,101 | |
| 2 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | 1,850,101 | |
| 3 | Proposed Revenues | Sch. TJC-7, Col (E), Ln 8 | 1,337,705 | |
| 4 | Total Three Year Operating Revenues | Sum Of Lines 1, 2 & 3 | $ 5,037,906 | |
| 5 | Average Annual Operating Revenues | Line 4 / 3 | 1,679,302 | |
| 6 | Two Times Three Year Average Operating Revenues | Line 5 X 2 | | $ 3,358,604 |
| | ADD: | | | |
| | 10% Of Construction Work In Progress ("CWIP"): | | | |
| 7 | Test Year CWIP | Company Schedule E | $ 28,150 | |
| 8 | 10% Of CWIP | Line 7 X 10% | | $ 2,815 |
| | SUBTRACT: | | | |
| | Transportation At Book Value: | | | |
| 9 | Original Cost Of Transportation Equipment | RUCO Plant Schedule TJC-4 | $ - | |
| 10 | Acc. Dep. Of Transportation Equipment | RUCO Plant Schedule TJC-4 | - | |
| 11 | Net Book Value Of Transportation Equipment | Line 9 + Line 10 | | $ - |
| 12 | Company's Full Cash Value ("FCV") | Sum Of Lines 6, 8 & 11 | | $ 3,361,419 |
| | Calculation Of The Company's Tax Liability: | | | |
| | MULTIPLY: | | | |
| | FCV X Valuation Assessment Ratio X Property Tax Rates: | | | |
| 13 | Assessment Ratio | House Bill 2779 | 21.0% | |
| 14 | Assessed Value | Line 12 X Line 13 | $ 705,898 | |
| | Property Tax Rates: | | | |
| 15 | Primary Tax Rate | Company Workpapers | 11.3283% | |
| 16 | Secondary Tax Rate | Company Workpapers | 0.00% | |
| 17 | Estimated Tax Rate Liability | Line 15 + Line 16 | 11.33% | |
| | Property Tax | | | $ 79,966 |
| | Tax On Parcel | | | - |
| 18 | Company's Total Tax Liability - Based On Full Cash Value | Line 14 X Line 17 | | $ 79,966 |
| 19 | Test Year Adjusted Property Tax Expense As Filed | Co. Sch. C-1 | | 91,705 |
| 20 | Decrease In Property Tax Expense | Line 18 - Line 19 | | $ (11,739) |
| | | Line 20 | | $ (11,739) |

**OPERATING INCOME ADJUSTMENT #10**
**INCOME TAX EXPENSE**

| LINE NO. | DESCRIPTION | (A) REFERENCE | (B) AMOUNT |
|---|---|---|---|
| | **FEDERAL INCOME TAXES:** | | |
| 1 | Operating Income Before Taxes | Sch. TJC-7, Column (C), L28 + L22 + L23 | $ 844,304 |
| | LESS: | | |
| 2 | Arizona State Tax | Line 11 | 53,706 |
| 3 | Interest Expense | Note (A) Line 21 | 73,557 |
| 4 | Federal Taxable Income | Line 1 - Line 2 - Line 3 | $ 717,041 |
| 5 | Federal Tax Rate | Sch. TJC-1, Pg 2, Col. (D), L34 | 34.00% |
| 6 | Federal Income Tax Expense | Line 4 X line 5 | $ 243,794 |
| | **STATE INCOME TAXES:** | | |
| 7 | Operating Income Before Taxes | Line 1 | $ 844,304 |
| | LESS: | | |
| 8 | Interest Expense | Note (A) Line 21 | 73,557 |
| 9 | State Taxable Income | Line 7 - Line 8 | $ 770,746 |
| 10 | State Tax Rate | Tax Rate | 6.97% |
| 11 | State Income Tax Expense | Line 9 X Line 10 | $ 53,706 |
| | **TOTAL INCOME TAX EXPENSE:** | | |
| 12 | Federal Income Tax Expense | Line 6 | $ 243,794 |
| 13 | State Income Tax Expense | Line 11 | 53,706 |
| 14 | Total Income Tax Expense Per RUCO | Line12 + Line 13 | $ 297,499 |
| 15 | Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | 252,773 |
| 16 | Total State Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | 55,684 |
| 17 | RUCO Federal Income Tax Adjustment | Line 12 - Line 15 | $ (8,979) |
| 18 | RUCO State Income Tax Adjustment | Line 13 - Line 16 | $ (1,978) |

NOTE (A):
Interest Synchronization:

| | | | |
|---|---|---|---|
| 19 | Adjusted Rate Base (Sch. TJC-2, Col. (H), L17) | $ | 2,937,595 |
| 20 | Weighted Cost Of Debt (Sch. TJC-16 Col. (F), L1) | | 2.50% |
| | | $ | 73,557 |

EXHIBIT
Witness R-1
ADMITTED

RIO RICO UTILITIES, INC.

DOCKET NO. WS-02676A-08-09-0257

# SURREBUTTAL TESTIMONY

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

FEBRUARY 24, 2010

## TABLE OF CONTENTS

INTRODUCTION ..... 1

SUMMARY OF RUCO's RECOMMENDED REVENUE REQUIREMENTS ..... 2

SUMMARY OF RUCO's RATE BASE ADJUSTMENTS ..... 3

SUMMARY OF RUCO's OPERATING INCOME ADJUSTMENTS ..... 4

RUCO's ORIGINAL COST RATE BASE ADJUSTMENTS ..... 9

RUCO's OPERATING INCOME ADJUSTMENTS ..... 12

OTHER ISSUES ..... 25

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE ..... 26

TYPICAL RESIDENTIAL BILL ANALYSIS ..... 27

EXHIBIT 1

## INTRODUCTION

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

A. My Name is Timothy J. Coley. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously filed testimony in this docket?

A. Yes, I have. I filed direct testimony in this docket on December 23, 2009 and RUCO's rate design testimony on January 4, 2010. On February 4, 2010, I filed a notice of errata to my direct testimony accompanied with the appropriate schedules as needed.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address the Company's rebuttal comments pertaining to adjustments I recommended in my direct testimony. I will also discuss RUCO's changes in position regarding certain adjustments along with any new adjustments that RUCO made or adopted here in surrebuttal testimony. In addition, RUCO has provided a study (Exhibit 1) comparing wages/labor and contractual/corporate costs per utility customer of various Arizona water and wastewater companies to support RUCO's position on Algonquin Power Trust's ("APT") allocated costs.

**SUMMARY OF RUCO's RECOMMENDED REVENUE REQUIREMENTS**

Q. What are RUCO's recommended surrebuttal revenue requirements for RRUI Water and Wastewater Divisions?

A. For RRUI Water Division, RUCO recommends a fair value rate base in the amount of $7,175,864 compared to the Company's requested adjusted rebuttal amount of $7,992,279. RUCO recommends a required operating income of $567,180, which is $367,917 less than the Company's requested amount of $935,097. RUCO's recommended required increase in gross revenue is $929,413, which is $898,189 less than the Company's adjusted rebuttal request of $1,827,602. RUCO's recommendations represent a 50.18 percent increase to total revenues. RUCO recommends a 7.90 percent rate of return on the Company's fair value rate base (See RUCO witness Mr. Rigsby's testimony as filed) compared to RRUI's adjusted rebuttal request of 11.70 percent.

For RRUI Wastewater Division, RUCO recommends a fair value rate base in the amount of $2,983,957 compared to the Company's adjusted rebuttal amount of $3,323,449. RUCO recommends a required operating income of $235,852, which is $152,992 less than the Company's requested amount of $388,844. RUCO's recommended required decrease in gross revenue is ($493,946), which is ($374,815) less than the Company's adjusted rebuttal decrease of ($133,135). RUCO's recommendations represent a (26.93) percent decrease to total revenues. RUCO

recommends a 7.90 percent rate of return on the Company's fair value rate base (See RUCO witness Mr. Rigsby's testimony as filed) compared to RRUI's adjusted rebuttal request of 11.70 percent.

**SUMMARY OF RUCO's RATE BASE ADJUSTMENTS**

Q. What areas will you address in RUCO's surrebuttal testimony?

A. RUCO's surrebuttal testimony will address its recommended rate base and operating income adjustments to RRUI's Water and Wastewater Divisions as follows:

RUCO's RATE BASE ADJUSTMENTS TO RRUI's REBUTTAL POSITIONS

NOTE: All adjustments are common to both the Company's Water and Wastewater Divisions unless otherwise noted.

1. RUCO Surrebuttal Rate Base Adjustment No. 1 – Plant and Accumulated Depreciation: After a phone conversation with the Company's rate consultant, RUCO reviewed its plant schedules and identified a computation error in the accumulated depreciation excel sheet. RUCO corrected the formula, which eliminated the need for this adjustment in surrebuttal testimony.

...

2. Rate Base Adjustment No. 2 – Accumulated Deferred Income Tax ("ADIT"): This adjustment allocates RRUI's parent company's, Algonquin Power Income Fund's ("AAPIF"), net ADIT liability balance based on RRUI's asset value to APIF total asset value. The adjustment decreases the Company's ADIT asset by $1,279,653 for the Water Division and by $532,121 for the Wastewater Division.

3. RUCO Surrebuttal Rate Base Adjustment No. 3 – Advances in Aid of Construction ("AIAC") and Contributions in Aid of Construction ("CIAC"): This adjustment increases AIAC by $48,724 and decreases CIAC by the same $48,724 for the Water Division. For the Wastewater Division, this adjustment increases AIAC by $238,783 and decreases CIAC by the same $238,783.

All those rate base adjustments are shown on RUCO's Surrebuttal Schedules TJC-2 and TJC-3. The supporting detail for RUCO's ADIT adjustment is shown on RUCO's Surrebuttal Schedule TJC-5.

**SUMMARY OF RUCO's OPERATING INCOME ADJUSTMENTS**

RUCO's RATE BASE ADJUSTMENTS TO RRUI's REBUTTAL POSITIONS

NOTE: All adjustments are common to both the Company's Water and Wastewater Divisions unless otherwise noted.

1. RUCO Surrebuttal Operating Income Adjustment No.1 – Revenue Annualization: This adjustment reverses the Company's downward adjustment to test year revenues. It increases revenues by $4,794 for the Water Division and by $4,505 for the Wastewater Division.

2. RUCO Surrebuttal Operating Income Adjustment No.2 – Purchased Power and Chemicals Expense Annualization: This is an accompanying adjustment to RUCO rate base adjustment #1. The adjustment increases purchased power expense by $2,334 for the Water Division to account for the additional pumping costs. For the Wastewater Division, it increases purchased power expense by $388 and by $212 for chemical expenses.

3. RUCO Surrebuttal Operating Income Adjustment No.3 – Depreciation Expense: This adjustment increases depreciation expense for the Water Division by $1,687 due primarily to an adjustment that increased AIAC depreciable plant. For the Wastewater Division, this adjustment increased depreciation expense by $9,361 due primarily to an adjustment that increased AIAC depreciable plant.

4. RUCO Surrebuttal Operating Income Adjustment No.4 – Property Tax Expense: This adjustment decreases property tax expense for both the Water and Wastewater Divisions by $31,900 and $12,189

respectively. The adjustments are due to the different levels of gross revenues proposed by RUCO and the Company.

5. RUCO Surrebuttal Operating Income Adjustment No. 5 – Rate Case Expense: This adjustment reduces rate case expense by $17,500 for the Water Division and reduces the Wastewater Division's rate case expense by $10,417. The adjustment is due to RUCO's 25 percent overall reduction in rate case expense.

6. RUCO Surrebuttal Operating Income Adjustment No.6 – Miscellaneous Expense: This adjustment is specific to only RRUI's Water Division and reduces miscellaneous expense by $1,363.

7. RUCO Surrebuttal Operating Income Adjustment No.7 – Purchased Power Expense: This adjustment reduces the purchased power expense for the Water Division and increases the Wastewater Division's purchased power expense by the same $48,005 due to the Company recording the purchased power expense to the wrong division.

8. RUCO Surrebuttal Operating Income Adjustment No.8 –Transportation Expense: This adjustment was proposed by the Company in rebuttal

testimony and decreases transportation expense for both Water and Wastewater by $6,725 and $2,242 respectively.

9. RUCO Surrebuttal Operating Income Adjustment No.9 – Out of Test Year Contractual Services Expense: This adjustment is specific to the Company's Water Division only and reduces the contractual services account by $14,477.

10. RUCO Surrebuttal Operating Income Adjustment No. 10 – Additional Actual Algonquin Power Trust ("APT") Costs: This adjustment increases the contractual services account by $3,274 for the Water Division and by $1,346 for the Wastewater Division due to truing up estimated costs to actual costs.

11. RUCO Surrebuttal Operating Income Adjustment No. 11 – APT Corporate Allocation Costs: This adjustment removes excessive corporate expenses for the provisioning of utility services. It reduces the contractual services account by $96,643 and $31,604 for the Water and Wastewater Divisions respectively.

12. RUCO Surrebuttal Operating Income Adjustment No.12 – Unamortized Rate Case Expense: This adjustment is specific to RRUI's Water Division only and reduces the regulatory commission

expense account by $17,564 for what appears to be unamortized rate case expense from a prior rate case.

13. RUCO Surrebuttal Operating Income Adjustment No.13 – Bad Debt Expense: This adjustment normalizes bad debt expense and increases it by $799 for the Water Division and decreases it by $30,315 for the Wastewater Division.

14. RUCO Surrebuttal Operating Income Adjustment No.14 – Income Tax Expense: This adjustment reflects RUCO's recommended operating income before income taxes and increases the Water Division's income tax expense by $19,760 and decreases the Wastewater Division's income tax expense by $16,504.

These operating income adjustments are shown on RUCO's Surrebuttal Schedules TJC-6 and TJC-7. The supporting details are shown on RUCO's Surrebuttal Schedule TJC-8 thru TJC-19.

## RUCO's ORIGINAL COST RATE BASE ADJUSTMENTS

### RUCO Surrebuttal OCRB Adjustment No. 1 – Plant and Accumulated Depreciation:

Q. Please explain RUCO's surrebuttal rate base adjustment #1 for plant and accumulated depreciation.

A. This adjustment was recommended in RUCO's direct testimony schedules but was eliminated in RUCO's surrebuttal testimony schedules. The Company's witness, Mr. Bourassa, phoned me with some concerns regarding my direct testimony plant schedules. Mr. Bourassa stated that he thought my plant schedules were over-depreciating some accounts that should have been fully depreciated and in the year of a retirement, he didn't think I was taking the half-year convention when calculating that year's depreciation expense.

After reviewing my plant schedules, I agreed with Mr. Bourassa that a few accounts had been fully depreciated and thus, no further depreciation should be taken on those accounts. The retirements, however, had been treated properly using the half-year convention. The primary problem in RUCO's direct plant schedules was the failure to remove the retirements from the accumulated depreciation balances. Once that was corrected, RUCO was in substantial agreement with the Company. RUCO

recommends eliminating that direct testimony adjustment in its surrebuttal testimony for both RRUI's Water and Wastewater Divisions;

RUCO Surrebuttal OCRB Adjustment No. 2 – Accumulated Deferred Income Tax ("ADIT")

Q. Please explain RUCO's surrebuttal rate base adjustment #2 for ADIT.

A. The adjustment to ADIT is fully explained in RUCO's direct testimony. This adjustment is the same in both RUCO's direct and surrebuttal schedules.

Q. Does the Company agree with RUCO's ADIT calculation?

A. No.

Q. How did the Company respond to RUCO's methodology used to calculate its ADIT balance?

A. Primarily, the Company claims that RUCO's approach to calculating RRUI's ADIT balance fails to use both the assets and liabilities method as prescribed by SFAS No. 109.

Q. Do you agree with the Company that RUCO's method fails to use both the assets and liabilities as prescribed by SFAS No. 109?

A. No. RUCO's method for calculating ADIT does use both assets and liabilities because RUCO netted the total ADIT assets and liabilities that

are on the parent company's, Algonquin Power Trust Fund ("APTF"), books. Therefore, both assets and liabilities are used in RUCO's ADIT calculation.

Q. Has the Company changed its ADIT balance in rebuttal testimony?

A. Yes. The Company recalculated its ADIT balance in its rebuttal testimony. The new calculation reduces the Company's original ADIT asset balance by roughly 60 percent from approximately $1.1 million to $445,000.

Q. Are there any other issues regarding ADIT that RUCO would like to address?

A. Yes. The Company claims that the large AIAC balances on its books are a major reason for contributing to its ADIT asset balance, which is an addition to rate base. RUCO performed a study that included Black Mountain Sewer, Litchfield Park Service Water and Wastewater Divisions, Rio Rico Water and Wastewater Divisions, Bella Vista Water, and the Northern and Southern Water Companies, which are all owned by APTF. RUCO compared all APTF's referenced companies to Arizona Water Company's ("AWC") seventeen systems and determined that AWC's total rate base is comprised of 49 percent AIAC whereas the APTF's referenced companies are comprised of 44 percent AIAC to total rate base.

...

Q. Did AWC have an ADIT balance in its last rate application?

A. Yes.

Q. What was AWC's ADIT balance in its last rate application?

A. AWC had a $19 million ADIT liability balance, which is the natural balance that reduces rate base accordingly. Not the reverse of what RRUI proposes for an addition to rate base in this case. RUCO finds it perplexing that AWC's total rate base is funded by similar means and shows a $19 million ADIT liability balance while APTF's Arizona utilities claim an ADIT asset balance that increases rate base.

**RUCO's OPERATING INCOME ADJUSTMENTS**

RUCO Surrebuttal Operating Income Adjustment No. 1 – Revenue Annualization

Q. Does RUCO continue to recommend annualizing revenues to the average test year customer count here in its surrebuttal testimony?

A. No. RUCO now recommends reversing the Company's revenue annualization that decreases revenue. RUCO also recommends reversing the Company's adjustment that decreases the purchased power and chemical expenses associated with RRUI revenue annualization expense adjustment.

...

Q. Why did RUCO change its position on revenue annualization to average test year customer count?

A. In the spirit of compromise and an attempt to reach some agreement with the Company, RUCO proposes a position that should be more amiable to the Company and to eliminate some of contested issues in the case.

Q. Why does RUCO disagree with RRUI's proposed customer annualization adjustment that reduces revenues?

A. RUCO disagrees with the Company's proposed customer annualization adjustment because it does not make sense to reduce test year revenue when RRUI has continued, through the test year, to experience year after year customer growth. Consequently, RUCO has recommended that the test year revenue be used to set rates and to reverse the Company's proposed annualization adjustment. In my direct testimony, RUCO illustrated, in detail, comparisons of total average customers and customer counts historically and through the test year.

Q. What is the purpose of a revenue annualization adjustment normally in a utility rate case?

A. When a utility is growing and having to add plant during a test year to serve additional customers, a revenue annualization adjustment is typically utilized in order to capture the impact on revenue from customer growth that has occurred, and to better match the revenue with the test

year plant that has been added to serve the new customers. The revenue growth that relates to the addition of customers is captured in a revenue annualization adjustment to increase revenue related to the increased plant which has been added to serve additional customers during the test year. Moreover, the decrease in revenue produced by the Company's calculation appears to be related to customer seasonality rather than a permanent decline in customer count during the test year, and therefore should not be adopted because it would understate test year and going-forward revenues.

RRUI has added, on average, both residential and commercial customers in each and every year, including the test year. Consequently, an adjustment to decrease test year revenue would be inappropriate by understating test year and going-forward revenues. Test year revenue of $4,794 and $4,505 for the Company's Water and Wastewater Divisions respectively should not be removed as proposed by the Company. RUCO's adjustments restore revenues to test year levels.

...

RUCO Surrebuttal Operating Income Adjustment No. 2 – Expense Annualization

Q. Has RUCO made adjustments to reverse the expenses associated with the Company's proposed downward revenue annualization?

A. Yes. Adjustments have been made to increase the Company's purchased power expenses in the amount of $2,334 and $388 respectively for RRUI's Water and Wastewater Divisions. An additional adjustment to increase chemical expenses by $212 was made for the Company's Wastewater Division. These adjustments are shown on RUCO's Schedules TJC-7.

RUCO Surrebuttal Operating Income Adjustment No. 3 – Depreciation Expense

Q. Are RUCO and the Company in general agreement on the appropriate levels of depreciation expense?

A. Yes. There is a slight difference in the amount of CIAC amortization to be removed from depreciation expense. This appears to be due to a rounding issue of the amortization rate utilized by the parties.

...

RUCO Surrebuttal Operating Income Adjustment No. 4 – Property Tax Expense

Q. Are RUCO and the Company in general agreement on the methodology to calculate property tax expense?

A. Yes. RUCO and the Company use the same methodology and inputs with the exception of the adjusted levels of test year revenues and proposed levels of revenues. This is due to the parties' different levels of recommended revenue requirements. Once the Commission approves the levels of revenues to set rates, either RUCO's or the Company's property tax model should produce the same level of property tax expense to be embedded in rates.

RUCO Surrebuttal Operating Income Adjustment No. 5 – Rate Case Expense

Q. How did the Company respond to RUCO's 25 percent downward adjustment to rate case expense?

A. The Company did not explicitly express an opinion either way to RUCO's 25 percent downward adjustment to rate case expense. However, the Company did address RUCO's rate case adjustment as follows:

> RUCO appears to base its 25 percent reduction on the fact that through October 2009, the Company has only incurred about $41,000 of rate case expense. It is entirely premature to make any meaningful determinations about the ultimate level of rate case expense that will be incurred in the instant case. This is obviously true, given that at the time of Mr. Coley's testimony the Company had yet to incur the costs for

> the preparation of its rebuttal testimonies, rejoinder testimonies, any discovery, hearing preparation and hearings, post hearing briefs, and final decision.
>
> In this light, RRUI continues to estimate rate case expense of $210,000 for the water division. But this is still an estimate, which the Company will true-up at a later date when more of the costs are known, as needed.

Q. How did the Company respond concerning RUCO's downward adjustment to rate case expense for the Wastewater Division?

A. The Company made reference to what it had previously stated (See statement above) in the water section of its rebuttal testimony. The Company further stated, "As discussed above, RUCO is recommending a downward adjust [sic] of 25 percent to the company's proposed level of rate case expense. This translated to a reduction to total rate case expense of $31,250, or a total rate case expense of $93,750. For the reasons I identified above, RUCO's adjustment is premature, at best."

Q. Does RUCO maintain its 25 percent downward adjustment to rate case expense in surrebuttal testimony?

A. Yes. Until further updates are provided by the Company to be reviewed by RUCO, RUCO, like the Company seems to be doing, reserves the right to adjust its rate case expense adjustment prior to hearing.

...

RUCO Surrebuttal Operating Income Adjustment No. 6 – Miscellaneous Expense

Q. Did the Company accept RUCO's adjustment to remove $1,363 of miscellaneous expense relating to charitable contributions and donations from RRUI's Water Division?

A. Yes. This adjustment applies only to the Water Division.

RUCO Surrebuttal Operating Income Adjustment No. 7 – Purchased Power Expense

Q. Did the Company accept RUCO's adjustment to reclassify $48,005 of purchased power expense from the Company's Water Division to the Wastewater Division?

A. Yes. This adjustment was agreed upon during the discovery period. RRUI inadvertently charged the purchased power expense to the Company's Water Division when it was actually attributable to the Company's Wastewater Division.

RUCO Surrebuttal Operating Income Adjustment No. 8 – Transportation Expense

Q. Please explain RRUI's rebuttal adjustment to transportation expense?

A. This adjustment originated in the Company's Litchfield Park Service Company's hearing when it was discovered that the corporate parent has a fleet of corporate executive jets and the costs were being allocated to

the various affiliates. The Company agreed to remove the costs associated with its Airlink affiliate in that case. This is merely an accommodating adjustment proposed by the Company.

Q. Does RUCO accept the Company's proposed adjustment to transportation expense?

A. Yes.

RUCO Surrebuttal Operating Income Adjustment No. 9 – Out of Test Year Contractual Services' Costs

Q. Please explain RUCO's surrebuttal adjustment that removes contractual services' costs that were identified as costs incurred that were out of the test year.

A. Staff identified $14,477 of contractual services' costs that were incurred by the Company but not in the 2008 test year. RRUI accepted Staff's adjustment in rebuttal testimony.

Q. Does RUCO accept the Company's rebuttal adjustment in RUCO's surrebuttal testimony?

A. Yes.

...

RUCO Surrebuttal Operating Income Adjustment No. 10 – Actual Additional Algonquin Power Trust ("APT") Central Office Costs

Q. Please explain the Company's rebuttal adjustment that increases the APT central office cost pool to contractual services account.

A. This particular adjustment arose after the Company filed its rate application. As the rate proceeding progressed, the Company determined that its original rate application, which contained a cost pool of APT costs in the amount of $3,950,800 that are allocated 100 percent to its affiliates,[1] failed to include all of APT's actual costs. In rebuttal testimony, the Company added an additional $1,319,082 for a total APT cost pool of $5,269,882 that it deemed as its actual APT costs. RRUI received an additional APT cost allocation of $27,574 for the Water Division and $8,474 for the Wastewater Division per the Company's allocation methodology.

Q. Please explain RUCO's adjustment to the additional APT cost pool allocations that the Company added in its rebuttal testimony.

A. As discussed in detail in RUCO's direct testimony and further here in surrebuttal testimony, RUCO disallowed the majority of the APT costs in direct testimony. RUCO included the additional "actual" APT costs in RUCO Surrebuttal Schedule TJC-15 and determined that an additional

[1] See RUCO witness Timothy J. Coley's Direct Testimony for a full explanation of APT cost allocations.

$3,274 and $1,361 should be allocated to RRUI's Water and Wastewater Divisions respectively using RUCO's allocation methodology.

Q. Does RUCO disagree with the Company's additional APT cost pool allocation adjustments?

A. Yes. As I stated earlier, RUCO disallowed a majority of the APT cost pool allocations and allowed only 25 percent of some of the costs (See Coley Direct Testimony). RUCO's additional APT allocation adjustments are much smaller than the Company's, as discussed earlier.

<u>RUCO Surrebuttal Operating Income Adjustment No. 11 – APT Central Office Cost Allocations</u>

Q. Did the Company accept RUCO's APT cost pool allocation adjustments?

A. No.

Q. Does RUCO maintain its original direct testimony position regarding the APT cost allocations?

A. Yes.

Q. Does RUCO provide any further analysis or studies in surrebuttal that support its conclusions regarding the APT cost allocations?

A. Yes. RUCO Surrebuttal Exhibit 1, as attached, is a study of a number of other Arizona water and wastewater companies. The study's focus is the

amount of total labor, wages, and corporate costs per customer on an annual and monthly basis. The results support RUCO's conclusions and position regarding the APT cost pool allocations.

RUCO Surrebuttal Operating Income Adjustment No. 12 – Prior Rate Case Unamortized Rate Case Expense

Q. Please explain RUCO's adjustment that removes the prior rate case expense from RRUI's Water Division that was not fully amortized.

A. This adjustment was overlooked in RUCO's direct testimony. It appears that the amount in the Regulatory Commission Expense account for $17,564 is nearly identical to the amount of annual rate case expense authorized in the prior Rio Rico rate case for the Company's Water Division. RUCO routinely recommends disallowance of any unamortized prior rate case expense when new rates are established in a current proceeding.

Q. Did Staff make a similar adjustment to remove this expense in its direct testimony?

A. Yes.

...

Q. How did the Company respond to Staff regarding the disallowance of the unamortized rate case expense?

A. The Company's rebuttal response to the adjustment claimed that it was not unamortized rate case expense from a prior proceeding "at all." The Company adds, "These costs are related to ADEQ annual registration fees, ADOT registration fees, annual software license fees, right of way permit fees, and some membership dues to organizations like the American Water Works Association and the Arizona Water Pollution Control Association."

Q. What is RUCO's surrebuttal position regarding the costs in the Regulatory Commission Expense account in the Company's Water Division?

A. RUCO is taking a conservative approach and recommends removal of these expenses until the nature of the costs can be verified.

Q. Does RUCO plan on issuing discovery for these related expenses?

A. Yes.

...

RUCO Surrebuttal Operating Income Adjustment No. 13 – Normalize Bad Debt Expense

Q. Did the Company accept RUCO's normalization of bad debt expense adjustment?

A. Yes. However, the Company made an erroneous entry for the Water Division's bad debt adjustment.

Q. Please explain the Company's erroneous entry for the Water Division's bad debt expense adjustment.

A. When the Company made its adjustment, RRUI reduced bad debt expense for the Water Division. The correct entry would increase bad debt expense in the amount of $799 rather than decrease it.

RUCO Surrebuttal Operating Income Adjustment No. 14 – Income Tax Expense

Q. Please explain RUCO's income tax expense adjustment and the Company's position on this adjustment.

A. This adjustment is a function of RUCO's recommended level of operating income before income taxes. The Company did not raise any issue with the adjustment to income taxes in rebuttal.

...

Q. After RUCO filed its direct testimony and schedules, did RUCO identify a problem with its recommended income taxes?

A. Yes. RUCO reviewed its Direct Schedules TJC-1, TJC-2, and TJC-6 and found an error in the gross revenue conversion factor schedule (TJC-1, page 2).

Q. Did RUCO correct the income tax problem?

A. Yes. RUCO filed errata to its direct testimony that corrected the problem.

**OTHER ISSUES**

Q. Is it true that the version of your direct testimony filed on December 23, 2009, contained RUCO's positions regarding other issues that were incorrect at that time?

A. Yes. RUCO filed a notice of errata to correct its position regarding the other issues addressed in that version of my direct testimony.

Q. Would you please clarify for the record what RUCO's positions are concerning the other issues in this case?

A. Yes.

<u>Low-Income Program ("LIP")</u>

RUCO does not oppose the LIP as proposed by the Company.

Hook Up Fee ("HUF")

RUCO does not support the Company's HUF as proposed by the Company for the reason given in its errata filing.

New Service Line Installations

RUCO prefers that the current rates in the tariff be maintained.

Late Payment Finance Charge

RUCO supports the late payment finance charge as proposed by RRUI.

**RATE DESIGN AND PROOF OF RECOMMENDED REVENUE**

Q. Have you revised your surrebuttal schedules presenting your surrebuttal recommended rate designs?

A. Yes, as shown on Schedules SURR TJC-RD1, the rate design is consistent with RUCO's recommended revenue allocations and requirement as in RUCO's direct rate design testimonies.

Q. Have you updated your Schedules presenting proof of your recommended revenue?

A. Yes, I have. As shown on Schedules SURR TJC-RD1, my recommended rate design will produce the recommended required revenue as recommended in my surrebuttal testimony.

**TYPICAL RESIDENTIAL BILL ANALYSIS**

Q. Has RUCO revised its Schedules representing the financial impact of RUCO's surrebuttal recommended rate designs on the typical residential customer?

A. Yes. The impact of RUCO's surrebuttal recommended revenues is presented on the divisions Surrebuttal Schedules TJC-RD2. This typical bill analysis for residential customers shows the financial impact with various levels of usage.

Q. Does your silence on any issues or matters pertaining to the Company's application constitute RUCO's acceptance of the Company's position?

A. No.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

# RUCO'S SURREBUTAL

## EXHIBIT 1

## A Synopsis for RUCO Surrebuttal Exhibit 1

RUCO Exhibit 1 is a study that analyzed various Arizona utilities, both water and wastewater, to determine the levels of labor/wages expense, including outside contractual services, per each utility customer. The results are then compared to the Arizona Algonquin Water and Wastewater Utilities. The results are shown on the following seven pages and are segregated by water and wastewater utility services. Some of the utilities that were used in RUCO's study employ the shared services concept, as Algonquin's Liberty Water does, and others are stand-alone utilities. The utilities that have shared services are shown on separate pages from those that are stand-alone companies. I will briefly describe what each of the seven pages represents.

Page 1 – This page shows RRUI's Wastewater Division's cost of labor/wages expense, including outside contractual services, per each utility customer. It then shows the same costs for three of Arizona American's ("AZ-AM") Wastewater Districts that utilize the shared services concept. A comparison can then be drawn between RRUI and AZ-AM's costs for labor/wages expense, including outside contractual services, per each utility customer. The average cost for the utility groupings are shown on each page.

Page 2 – The same information is provided on page 2 for RRUI Wastewater Division but the comparable companies used in RUCO's study are stand-alone companies that do <u>not</u> utilize the shared services concept. Again, comparisons between the costs can be made. The average cost for the utility groupings are shown on each page.

Page 3 - This page shows RRUI's Water Division's cost of labor/wages expense, including outside contractual services, per each utility customer. It then shows the same costs for five of Arizona Water Company's ("AWC") Water Systems and a total of all AWC's systems, which consist of seventeen systems, cost of labor/wages expense, including outside contractual services, per each utility customer. A second group of AZ-AM Water Districts are shown which consist of five more water districts. All 22 systems on this page, consisting of AWC's total seventeen systems and AZ-AM's five districts, utilize the shared services concept. A comparison can then be drawn between RRUI, AWC, and AZ-AM's costs for labor/wages expense, including outside contractual services, per each utility customer. The average cost for the utility groupings are shown on each page.

Page 4 – This page shows the same information as provided on page 3 but for an American States Water affiliate, Chaparral City Water Company. Chaparral also utilizes the shared services concept. The same comparisons can be drawn between RRUI and Chaparral.

Page 5 - This page shows the same information as provided on the previous pages but for three various Arizona stand-alone water companies for a comparison to be made to RRUI. The average cost for the utility groupings are shown on this page too.

Page 6 - This page shows RRUI's rebuttal position regarding its costs of labor/wages expense, including outside contractual services, per each utility customer. A comparison can then be drawn between RRUI to the other 32 Arizona utility companies' costs associated with labor/wages expense, including outside contractual services, per each utility customer that is included in this study. The average cost for the Algonquin Water and Wastewater groupings are shown on this page.

Page 7 – The same information for RRUI is provided on this page that was shown on page 6 but with all of the APT costs removed. The average cost, after removing all APT costs, for the Algonquin Water and Wastewater groupings are shown on this page.

**Results of the Study**

Page 1 and 6 of the study shows Algonquin's sewer operations' cost of labor/wages expense, including outside contractual services, per each utility customer is on average 95 percent higher than the other three sewer companies in RUCO's study that utilize the shared services concept. Page 2 and 6 shows Algonquin's sewer operations' cost of labor/wages expense, including outside contractual services, per each utility customer is on average 115 percent higher than the other three stand-alone sewer companies that was included in RUCO's study. When combining RUCO's study samples of three shared services sewer companies (Page 1) and the three stand-alone sewer companies (Page 2), Algonquin on average is higher than the six sample companies by 104 percent.

Page 3, 4, and 6 of the study shows Algonquin's water operations' cost of labor/wages expense, including outside contractual services, per each utility customer is on average 50 percent higher than the eleven water companies in RUCO's study that utilize the shared services concept. Page 5 and of the study shows Algonquin's water operations' cost of labor/wages expense, including outside contractual services, per each utility customer is on average 66 percent higher than the three stand-alone water companies that was included in RUCO's study. When combining RUCO's study samples of seventeen AWC systems, five AZ-AM Districts, and a single Chaparral system that all utilize the shared services concept and the three stand-alone water companies, Algonquin on average is higher than the 26 sample companies by 54 percent.

When all of the APT costs are removed, as shown on page 7 of RUCO's study, Algonquin's sewer operations' cost of labor/wages expense, including outside contractual services, per each utility customer on average decreases from 95 percent higher than the three sewer companies (Page 1) included in RUCO's

study that utilize the shared services concept to 77 percent higher than the three companies in RUCO's study. Page 2 and 7 of the study shows Algonquin's sewer operations' cost of labor/wages expense, including outside contractual services, per each utility customer on average decreases from 115 percent higher to 96 percent higher than the three stand-alone sewer companies that was included in RUCO's study. When combining RUCO's study samples of three shared services sewer companies and three stand-alone sewer companies, Algonquin on average is higher than the six sample companies by 86 percent.

When the APT costs are removed, as shown on page 7 of RUCO's study, Algonquin's water operations' cost of labor/wages expense, including outside contractual services, per each utility customer on average decreases from 50 to 30 percent higher than RUCO's 23 sample water systems (Page 3 and 4) that utilize the shared services concept. When the APT costs are removed, Algonquin's water operations' cost of labor/wages expense, including outside contractual services, per each utility customer on average decreases from 66 percent higher to 44 percent higher than the three stand-alone water companies (Page 5) that was included in RUCO's study. When combining RUCO's study samples of seventeen AWC systems, five AZ-AM districts, and a single Chaparral system that all utilize the shared services concept and the three stand-alone water companies, Algonquin on average is higher than the 26 sample companies by 34 percent.

SEWER COMPANIES IN ARIZONA
TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS
COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA WASTEWATER COMPANIES WITH SHARED SERVICES

Algonquin Wastewater Services

| Line No. | | Note | 2008 Pro-Forma Wages Expensed | 2008 Average Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|---|
| 1 | Rio Rico Utilities, Inc Sewer | 1 | $ 482,045 | 2,071 | $ 232.76 | $ 19.40 |

Arizona American Water Company

| | Individual Systems: | Note | As Company Filed | Note | As Company Filed | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for AZ-AM |
|---|---|---|---|---|---|---|---|---|
| 2. | Sun City - Sewer | 2 | 1,387,684 | 3 | 21,965 | 63.18 | 5.26 | |
| 3 | Sun City West - Sewer | 2 | 1,556,363 | 3 | 14,968 | 103.98 | 8.66 | |
| 4 | Mohave Sewer | 4 | 232,661 | 4 | 1,235 | 188.39 | 15.70 | |
| 5 | Average Labor and Wage Cost per Customer per Month for AZ-AM Sewer Companies | | | | | | | 9.88 |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
2. As Originally Filed by the Company in Docket No. SW-01303A-09-0343 - 2008 Test Year
3. Water Infrastructure Finance Authority of Arizona (WIFA) 2008 Water and Wastewater Residential Rate Survey for the State of Arizona
4. As Originally Filed by the Company in Docket No. SW-01303A-08-0227 - 2007 Test Year

SEWER COMPANIES IN ARIZONA
TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS
COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA STAND-ALONE WASTEWATER COMPANIES WITHOUT SHARED SERVICES

Algonquin Wastewater Services

| Line No. | | Note | 2008 Pro-Forma Wages Expensed | 2008 Average Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|---|
| 1 | **Rio Rico Utilities, Inc Sewer** | 1 | **$ 482,045** | **2,071** | **$ 232.76** | **$ 19.40** |

Various Arizona Wastewater Companies

| | | Note | 2008 Annual Report Wages Expensed | Note | 2008 Annual Report Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for Various Co. |
|---|---|---|---|---|---|---|---|---|
| 2 | Ajo Improvement Co. - Sewer | 5 | 87,645 | 5 | 1,065 | 82.32 | 6.86 | |
| 3 | Rio Verde Utilities, Inc. - Sewer | 5 | 224,012 | 5 | 1,622 | 138.07 | 11.51 | |
| 4 | Far West Sewer | 5 | 724,159 | 5 | 7,166 | 101.05 | 8.42 | |
| 5 | Average Labor and Wage Cost per Customer per Month for Various Stand-Alone Arizona Sewer Companies | | | | | | | 8.93 |
| 6 | Average Labor and Wage Cost per Customer each Month for All 6 Companies on Pages 1 & 2 | | | | | | | 9.40 |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
5. As Filed by the Various Wastewater Companies in its 2008 Annual Report Filed with the Commission

WATER COMPANIES IN ARIZONA
TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS
COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA WATER COMPANIES WITH SHARED SERVICES

Algonquin Water Services

| | Note | 2008 Pro-Forma Wages Expensed | 2008 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|
| Rio Rico Utilities, Inc Water | 1 | $ 895,475 | 6,025 | $ 148.63 | $ 12.39 |

Arizona Water Company

| Line No. | Individual Systems: | Note | 2007 Pro-Forma Wages Expensed | 2007 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for AZ Water |
|---|---|---|---|---|---|---|---|
| 1 | Coolidge Water | 2 | $ 352,652 | 4,703 | $ 74.98 | $ 6.25 | |
| 2 | Lakeside Water | 2 | 369,614 | 4,954 | 74.61 | 6.22 | |
| 3 | Sedona Water | 2 | 523,727 | 6,298 | 83.16 | 6.93 | |
| 4 | Casa Grande | 2 | 1,786,887 | 22,529 | 79.31 | 6.61 | |
| 5 | Winkelman | 2 | 18,962 | 168 | 112.87 | 9.41 | |
| | | | | | | | 7.08 |
| 6 | Total Arizona Water Company for All AWC 17 Water Systems | 2 | 8,933,310 | 82,886 | 107.78 | | 8.98 |

Arizona American Water Company

| | | Note | 2007 Pro-Forma Wages Expensed | 2007 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for AZ-AM |
|---|---|---|---|---|---|---|---|
| 7 | Agua Fria Water | 3 | $ 4,216,281 | 34,402 | $ 122.56 | $ 10.21 | |
| 8 | Havasu Water | 3 | 371,202 | 2,565 | 144.72 | 12.06 | |
| 9 | Mohave Water | 3 | 1,840,872 | 16,635 | 110.66 | 9.22 | |
| 10 | Sun City Water | 4 | 2,734,992 | 23,140 | 118.19 | 9.85 | |
| 11 | Sun City West Water | 3 | 1,703,120 | 15,465 | 110.13 | 9.18 | |
| 12 | Average Cost for the 5 AZ-AM Districts listed Above | | | | | | 10.10 |
| 13 | Average Cost per Month for All 10 Systems on Page 3 | | | | | | 9.54 |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
2. As Originally Filed by the Company in Docket No. W-01445A-08-0440
3. As Originally Filed by the Company in Docket No. W-01303A-08-0227
4. As Originally Filed by the Company in Docket No. W-01303A-09-0343

WATER COMPANIES IN ARIZONA
TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS
COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA WATER COMPANIES WITH SHARED SERVICES

Algonquin Water Services

| | Note | 2008 Pro-Forma Wages Expensed | 2008 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|
| Rio Rico Utilities, Inc Water | 1 | $ 895,475 | 6,025 | $ 148.63 | $ 12.39 |

American States Water

| | | Note | 2006 Pro-Forma Wages Expensed | 2006 Average Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|---|
| 12 | Chaparral City Water Company | 5 | $ 1,197,740 | 13,333 | $ 89.83 | $ 7.49 |
| 13 | Total Average Costs for Total AWC 17 systems, 5 AZ-AM districts, and 1 Chaparral System that utilize the Shared Services Concept | | | | | $ 8.86 |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
5. As Originally Filed by the Company in Docket No. W-02113A-07-0551

TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS (continued)
COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA STAND-ALONE WATER COMPANIES WITHOUT SHARED SERVICES

Algonquin Water Services

| | Note | 2008 Pro-Forma Wages Expensed | 2008 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|
| **Rio Rico Utilities, Inc Water** | 1 | $ 895,475 | 6,025 | $ 148.63 | $ 12.39 |

Various Stand-Alone Water Companies

| Line No. | Individual Systems: | Note | 2008 Annual Report Wages Expensed | 2008 Annual Report Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for Various Co. |
|---|---|---|---|---|---|---|---|
| 1 | Rio Verde Utilities, Inc. - Water | 2 | $ 239,802 | 1,688 | $ 142.06 | $ 11.84 | |
| 2 | Bermuda Water Company | 2 | 810,371 | 7,672 | 105.63 | 8.80 | |
| 3 | Lago Del Oro Water Company | 2 | 242,391 | 6,046 | 40.09 | 3.34 | |
| 4 | Average Cost per Month for the 3 Systems listed Above | | | | | | 7.99 |
| 5 | Average for Pages 3, 4, and 5 | | | | | | 8.64 |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
2. As Filed by the Company in its 2008 Annual Report Filed with the Commission

## TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS
## INCLUDING APT COSTS AS PROPOSED BY ALGONQUIN UTILITY SERVICES

Arizona's Algonquin Utility Services

| Line No. | | Note | Test Year Company Proposed Wages Expensed | Test Year Average Customer Count | Annual Wage Cost Proposed Per Customer | Monthly Wage Cost Proposed Per Customer |
|---|---|---|---|---|---|---|
| 1 | Black Mountain Sewer | 1 | $ 560,744 | 2,106 | $ 266.26 | $ 22.19 |
| 2 | LIPSCO Water Division | 2 | 2,405,353 | 15,594 | 154.25 | 12.85 |
| 3 | LIPSCO Sewer Division | 3 | 2,816,007 | 14,589 | 193.02 | 16.09 |
| 4 | Rio Rico Utilities, Inc Water | 4 | 895,475 | 6,025 | 148.63 | 12.39 |
| 5 | Rio Rico Utilities, Inc Sewer | 5 | 482,045 | 2,071 | 232.76 | 19.40 |
| 6 | Bella Vista Consolidated | 6 | 1,646,008 | 9,400 | 175.11 | 14.59 |
| 7 | Average for Algonquin Water Companies Above | | | | | 13.28 |
| 8 | Average for Algonquin Sewer Companies Above | | | | | 19.22 |

Notes:
1. As Filed by the Company in Rejoinder in Docket No. SW-02361A-08-0609
2. As Filed by the Company in Rejoinder in Docket No. SW-01428A-09-0103
2. As Filed by the Company in Rejoinder in Docket No. SW-01428A-09-0103
4. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
5. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
6. As Originally Filed by the Company in Direct in Docket No. W-02465A-09-0414, W-20453A-09-0414, and W-20454A-09-0414

TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS
WITHOUT THE APT CENTRAL OFFICE COSTS

Arizona's Algonquin Utility Services

| Line No. | | Note | Test Year Company Proposed Wages Expensed | Test Year Average Customer Count | Annual Wage Cost Proposed Per Customer | Monthly Wage Cost Proposed Per Customer |
|---|---|---|---|---|---|---|
| 1 | Black Mountain Sewer | 1 | $ 525,277 | 2,106 | $ 249.42 | $ 20.78 |
| 2 | LIPSCO Water Division | 2 | 2,094,874 | 15,594 | 134.34 | 11.19 |
| 3 | LIPSCO Sewer Division | 3 | 2,472,319 | 14,589 | 169.46 | 14.12 |
| 4 | Rio Rico Utilities, Inc Water | 4 | 764,941 | 6,025 | 126.96 | 10.58 |
| 5 | Rio Rico Utilities, Inc Sewer | 5 | 438,989 | 2,071 | 211.97 | 17.66 |
| 6 | Bella Vista Consolidated | 6 | 1,447,487 | 9,400 | 153.99 | 12.83 |
| 7 | Average for Algonquin Water Companies Above | | | | | 11.54 |
| 8 | Average for Algonquin Sewer Companies Above | | | | | 17.52 |

Notes:
1. As Filed by the Company in Rejoinder in Docket No. SW-02361A-08-0609
2. As Filed by the Company in Rejoinder in Docket No. SW-01428A-09-0103
2. As Filed by the Company in Rejoinder in Docket No. SW-01428A-09-0103
4. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
5. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
6. As Originally Filed by the Company in Direct in Docket No. W-02465A-09-0414, W-20453A-09-0414, and W-20454A-09-0414

## TABLE OF CONTENTS TO TJC SCHEDULES


| SCHEDULE NO. | PAGE NO. | TITLE |
|---|---|---|
| TJC-1 | 1 & 2 | REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR |
| TJC-2 | 1 | RATE BASE |
| TJC-3 | 1 | SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS |
| TJC-4 DIRECT PLANT | 1 | RATE BASE ADJUSTMENT NO. 1 - INTENTIONALLY LEFT BLANK |
| TJC-5 | 1 | RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEFERRED INCOME TAXES |
| TESTIMONY | | RATE BASE ADJUSTMENT NO. 3 - AIAC & CIAC BALANCES PER RUCO DR 1.08 & 1.09 |
| | | RATE BASE ADJUSTMENT NO. 4 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 5 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 6 - INTENTIONALLY LEFT BLANK |
| TJC-6 | 1 | OPERATING INCOME |
| TJC-7 | 1 | SUMMARY OF OPERATING INCOME ADJUSTMENTS |
| TESTIMONY | | OPERATING INCOME ADJUSTMENT NO. 1 - REVENUE ANNUALIZATION |
| TESTIMONY | 1 | OPERATING INCOME ADJUSTMENT NO. 2 - PURCHASED POWER INCREASE & EXPENSE ANNUALIZATION |
| TJC-8 | 1 | OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE |
| TJC-9 | 1 | OPERATING INCOME ADJUSTMENT NO. 4 - PROPERTY TAX EXPENSE |
| TJC-10 | 1 | OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSE |
| TJC-11 | 1 | OPERATING INCOME ADJUSTMENT NO. 6 - MISCELLANEOUS EXPENSE |
| TJC-12 | 1 | OPERATING INCOME ADJUSTMENT NO. 7 - PURCHASED POWER EXPENSE ADJUSTMENT |
| TJC-13 | 1 | OPERATING INCOME ADJUSTMENT NO. 8 - TRANSPORTATION EXPENSE |
| TJC-14 | 1 | OPERATING INCOME ADJUSTMENT NO. 9 - OUT OF TEST YEAR CORPORATE EXPENSES |
| TJC-15 | 1 | OPERATING INCOME ADJUSTMENT NO. 10 - ACTUAL CORPORATE APT COSTS |
| TJC-16 | 1 | OPERATING INCOME ADJUSTMENT NO. 11 - APT CORPORATE COSTS ADJUSTMENT |
| TJC-17 | 1 | OPERATING INCOME ADJUSTMENT NO. 12 - REMOVE UNAMORTIZED RATE CASE EXPENSE |
| TJC-18 | 1 | OPERATING INCOME ADJUSTMENT NO. 13 - NORMALIZE BAD DEBT EXPENSE |
| TJC-19 | 1 | OPERATING INCOME ADJUSTMENT NO. 14 - INCOME TAX EXPENSE |
| TJC-20 & WAR TESTIMONY | 1 | COST OF CAPITAL |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**REVENUE REQUIREMENT**

| LINE NO. | DESCRIPTION | (A) COMPANY OCRB/FVRB COST | (B) RUCO OCRB/FVRB COST |
|---|---|---|---|
| 1 | Adjusted Original Cost/Fair Value Rate Base | $ 8,455,517 | $ 7,175,864 |
| 2 | Adjusted Operating Income (Loss) | $ (214,606) | $ (3,490) |
| 3 | Current Rate of Return (L2 / L1) | -2.54% | -0.05% |
| 4 | Required Operating Income (L5 X L1) | $ 1,048,484 | $ 567,180 |
| 5 | Required Rate of Return on Fair Value Rate Base | 12.40% | 7.90% |
| 6 | Operating Income Deficiency (L4 - L2) | $ 1,263,090 | $ 570,670 |
| 7 | Gross Revenue Conversion Factor (TJC-1, Page 2) | 1.6286 | 1.6286 |
| 8 | Required Increase in Gross Revenue Requirement (L7 X L6) | $ 2,057,112 | $ 929,413 |
| 9 | Adjusted Test Year Revenue | $ 1,847,256 | $ 1,852,050 |
| 10 | Proposed Annual Revenue (L8 + L9) | $ 3,904,369 | $ 2,781,463 |
| 15 | Required Percentage Increase in Revenue (L8 / L9) | 111.36% | 50.18% |
| 16 | Rate of Return on Common Equity | 12.40% | 9.00% |

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-6, and TJC-17

## GROSS REVENUE CONVERSION FACTOR

| LINE NO. | DESCRIPTION | (A) | (B) | (C) | (D) |
|---|---|---|---|---|---|
| | CALCULATION OF GROSS REVENUE CONVERSION FACTOR: | | | | |
| 1 | Revenue | 1.0000 | | | |
| 2 | Combined Federal And State Tax Rate (L10) | 0.3860 | | | |
| 3 | Subtotal (L1 - L2) | 0.6140 | | | |
| 4 | **Revenue Conversion Factor** (L1 / L3) | **1.6286** | | | |
| | CALCULATION OF EFFECTIVE TAX RATE: | | | | |
| 5 | Operating Income Before Taxes (Arizona Taxable Income) | 100.0000% | | | |
| 6 | Arizona State Income Tax Rate | 6.9680% | | | |
| 7 | Federal Taxable Income (L5 - L6) | 93.0320% | | | |
| 8 | Applicable Federal Income Tax Rate (Col. (D), L34) | 34.0000% | | | |
| 9 | Effective Federal Income Tax Rate (L7 X L8) | 31.6309% | | | |
| 10 | Combined Federal And State Income Tax Rate (L6 + L9) | 38.5989% | | | |
| 11 | Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4) | $ 567,180 | | | |
| 12 | Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2) | (3,490) | | | |
| 13 | Required Increase In Operating Income (L11 - L12) | | $ 570,670 | | |
| 14 | Income Taxes On Recommended Revenue (Col. (D), L31) | $ 243,594 | | | |
| 15 | Income Taxes On Test Year Revenue (Col. (D), L32) | (115,149) | | | |
| 16 | Required Increase In Revenue To Provide For Income Taxes (L14 - L15) | | $ 358,743 | | |
| 17 | Total Required Increase In Revenue (L13 + L16) | | $ 929,413 | | |
| | CALCULATION OF INCOME TAX: | | | RUCO Recommended | |
| 18 | Revenue (Sch. TJC-1, Pg 1, Col. (B), L12) | | | $ 2,781,463 | |
| 19 | Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23) | | | 1,970,689 | |
| 20 | Synchronized Interest (Col. (C), L37) | | | 179,684 | |
| 21 | Arizona Taxable Income (L18 - L19 - L20) | | | $ 631,091 | |
| 22 | Arizona State Income Tax Rate | | | 6.9680% | |
| 23 | Arizona Income Tax (L21 X L22) | | | | $ 43,974 |
| 24 | Fed. Taxable Income (L21 - L23) | | | $ 587,116 | |
| 25 | Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15% | | | $ 7,500 | |
| 26 | Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25% | | | $ 6,250 | |
| 27 | Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34% | | | $ 8,500 | |
| 28 | Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39% | | | $ 91,650 | |
| 29 | Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34% | | | $ 85,719 | |
| 30 | Total Federal Income Tax (L25 + L26 + L27 + L28 + L29) | | | | $ 199,619 |
| 31 | Combined Federal and State Income Tax (L23 + L30) | | | | $ 243,594 |
| 32 | Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23) | | | | $ (115,149) |
| 33 | RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23) | | | | $ 358,743 |
| 34 | Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24) | | | | 34.00% |
| | CALCULATION OF INTEREST SYNCHRONIZATION: | | | | |
| 35 | Rate Base (Sch. TJC-2, Col. (C), L17) | | | $ 7,175,864 | |
| | | | | 2.50% | |
| | | | | $ 179,684 | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Water Division - Surrebuttal Schedules
Schedule TJC-2


## RATE BASE - ORIGINAL COST

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) RUCO OCRB/FVRB ADJUSTMENTS | (C) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 34,059,801 | $ - | $ 34,059,801 |
| 2 | Less: Accumulated Depreciation | (12,472,661) | - | (12,472,661) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 21,587,140 | $ - | $ 21,587,140 |
| | Less: | | | |
| 4 | Advances in Aid of Construction | (73,648) | (48,724) | (122,372) |
| 5 | Contribution in Aid of Construction | (20,188,921) | 48,724 | (20,140,197) |
| 6 | Accumulated Amortization of CIAC | 6,628,197 | - | 6,628,197 |
| 7 | NET CIAC (L5 + L6) | $ (13,560,724) | $ 48,724 | $ (13,512,000) |
| 8 | Customer Meter Deposits | (275,455) | - | (275,455) |
| 9 | Deferred Income Taxes & Credits | 778,203 | (1,279,653) | (501,450) |
| | Plus: | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - |
| 12 | Allowance For Working Capital | - | - | - |
| 13 | Rounding | 1 | - | 1 |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 8,455,517 | $ (1,279,653) | $ 7,175,864 |

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



## SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) ADJMT NO. 1 PLANT & ACCUM DEP. | (C) ADJMT NO. 2 DEFERRED INCOME TAXES | (D) ADJMT NO. 3 PER RUCO DR 1.08 | (E) ADJMT NO. 4 | (F) ADJMT NO. 5 | (G) ADJMT NO. 6 | (H) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 34,059,801 | $ - | $ - | $ - | $ - | $ - | $ - | $ 34,059,801 |
| 2 | Less: Accumulated Depreciation | (12,472,661) | | - | - | - | - | - | (12,472,661) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 21,587,140 | $ - | $ - | $ - | $ - | $ - | $ - | $ 21,587,140 |
| | Less: | | | | | | | | |
| 4 | Advances in Aid of Construction | $ (73,648) | $ - | $ - | $ (48,724) | $ - | $ - | $ - | $ (122,372) |
| 5 | Contribution in Aid of Construction | (20,188,921) | - | - | 48,724 | - | - | - | (20,140,197) |
| 6 | Accumulated Amortization of CIAC | 6,628,197 | - | - | - | - | - | - | 6,628,197 |
| 7 | NET CIAC (L5 + L6) | $ (13,560,724) | $ - | $ - | $ 48,724 | $ - | $ - | $ - | $ (13,512,000) |
| 8 | Customer Meter Deposits | (275,455) | - | - | - | - | - | - | (275,455) |
| 9 | Deferred Income Taxes & Credits | 778,203 | - | (1,279,653) | - | - | - | - | (501,450) |
| | Plus: | | | | | | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - | - | - | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - | - | - | - | - | - |
| 12 | Allowance For Working Capital | - | - | - | - | - | - | - | - |
| 13 | Rounding | 1 | - | - | - | - | - | - | 1 |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 8,455,517 | $ - | $ (1,279,653) | $ - | $ - | $ - | $ - | $ 7,175,864 |

Column (A): Company Schedule B-2
Column (B): Adjustment #1 - See TJC Testimony
Column (C): Adjustment No. 2 - Deferred Income Taxes (See Schedule TJC-5)
Column (D): Adjustment No. 3 - To Adjust AIAC & CIAC Balances Per Company Response to RUCO DR 1.08 and Discussed in TJC Testimony
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank

**RATE BASE ADJUSTMENT NO. 1**
**PLANT & ACCUMULATED DEPRECIATION**

Intentionally Left Blank - See TJC Testimony

## RATE BASE ADJUSTMENT NO. 2
## ACCUMULATED DEFERRED INCOME TAXES

| Line No. | Deferred Income Taxes: | Amount | Reference |
|---|---|---|---|
| 1 | | | |
| 2 | | | |
| 3 | Algonquin Accumulated Deferred Income Tax Assets | $ 23,032,000 | 2008 Algonquin Annual Report |
| 4 | | | |
| 5 | Algonquin Accumulated Deferred Income Tax Liabilities | (106,983,000) | 2008 Algonquin Annual Report |
| 6 | | | |
| 7 | Net Accumulated Deferred Income Tax Assets (Liabilities) | $ (83,951,000) | Line 3 + Line 5 |
| 8 | | | |
| 9 | Rio Rico Allocation | 0.8997% | Note (A) |
| 10 | | | |
| 11 | Rio Rico ADIT Liabilities Allocation | $ (755,287) | Line 7 X Line 9 |
| 12 | | | |
| 13 | Convert to US Dollars | 0.9400 | Note (B) |
| 14 | | | |
| 15 | Allocated ADIT Liabilites Balance | $ (709,970) | Line 11 X Line 13 |
| 16 | | | |
| 17 | Rio Rico Water Allocation Factor | 0.70630 | Note (C) |
| 18 | | | |
| 19 | Rio Rico Wastewater Allocation Factor | 0.29370 | Note (C) |
| 20 | | | |
| 21 | Rio Rico Water Allocation | $ (501,450) | Line 15 X Line 17 |
| 22 | | | |
| 23 | Rio Rico Wastewater Allocation | $ (208,519) | Line 15 X Line 19 |
| 24 | | | |
| 25 | | | |
| 26 | | | |
| 27 | | | |
| 28 | **NOTES:** | | |
| 29 | (A) Purchase Price of Rio Rico Utilities. Inc. | $ 8,800,000 | |
| 30 | Algonquin Total Assets | 978,130,000 | |
| 31 | | | |
| 32 | Ratio | 0.8997% | |
| 33 | | | |
| 34 | | | |
| 35 | (B) www.bank-banque-canada.ca on 11/19/2009 | 0.9400 | |
| 36 | | | |
| 37 | | | |
| 38 | (C) Rio Rico Water Allocation | 0.7063 | |
| 39 | | | |
| 40 | Rio Rico Wastewater Allocation | 0.2937 | |
| 41 | | | |
| 42 | | | |
| 43 | SUPPORTING SCHEDULES | | |
| 44 | 2008 Algonquin Power Income Fund Annual Report | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



## OPERATING INCOME

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO TEST YEAR ADJM'TS | (C) RUCO TEST YEAR AS ADJ'TED | (D) RUCO PROP'D CHANGES | (E) RUCO AS RECOMM'D |
|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | |
| 1 | Metered Water Revenues | $ 1,802,584 | $ 4,794 | $ 1,807,378 | $ 929,413 | $ 2,736,791 |
| 2 | Unmetered Water Revenues | - | - | - | - | - |
| 3 | Other Water Revenues | 44,672 | - | 44,672 | - | 44,672 |
| 4 | Total Revenues | $ 1,847,256 | $ 4,794 | $ 1,852,050 | $ 929,413 | $ 2,781,463 |
| | **Operating Expenses:** | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - |
| 6 | Purchased Water | - | - | - | - | - |
| 7 | Purchased Power | 441,501 | (45,671) | 395,830 | - | 395,830 |
| 8 | Fuel for Power Production | - | - | - | - | - |
| 9 | Chemicals | 9,347 | - | 9,347 | - | 9,347 |
| 10 | Materials & Supplies | 23,150 | - | 23,150 | - | 23,150 |
| 11 | Outside Services | 805,032 | (107,846) | 697,186 | - | 697,186 |
| 12 | Outside Services - Other | 76,859 | - | 76,859 | - | 76,859 |
| 13 | Outside Services - Legal | 487 | - | 487 | - | 487 |
| 14 | Water Testing | - | - | - | - | - |
| 15 | Rents | 26,954 | - | 26,954 | - | 26,954 |
| 16 | Transportation Expenses | 79,315 | (6,725) | 72,590 | - | 72,590 |
| 17 | Insurance - General Liability | 37,699 | - | 37,699 | - | 37,699 |
| 18 | Insurance - Health and Life | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 17,564 | (17,564) | - | - | - |
| 20 | Reg. Comm. Exp. - Rate Case | 70,000 | (17,500) | 52,500 | - | 52,500 |
| 21 | Miscellaneous Expense | 14,822 | (1,363) | 13,459 | - | 13,459 |
| 22 | Bad Debt Expense | 371 | 799 | 1,170 | - | 1,170 |
| 23 | Depreciation Expense | 463,297 | 1,687 | 464,984 | - | 464,984 |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Property Taxes | 130,373 | (31,900) | 98,474 | - | 98,474 |
| 26 | Federal Income Tax | (110,555) | 16,193 | (94,362) | 293,982 | 199,619 |
| 27 | State Income Tax | (24,354) | 3,567 | (20,787) | 64,761 | 43,974 |
| 28 | **Total Operating Expenses** | $ 2,061,862 | $ (206,322) | $ 1,855,540 | $ 358,743 | $ 2,214,283 |
| 29 | **Operating Income** | $ (214,606) | $ 211,116 | $ (3,490) | $ 570,670 | $ 567,180 |

References:
Column (A): Company Schedule C-1
Column (B): Schedule TJC-7, Columns (B) Thru (K)
Column (C): Column (A) + Column (B)
Column (D): TJC-1, pages 1 and 2
Column (E): Column (C) + Column (D)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**SUMMARY OF OPERATING INCOME ADJUSTMENTS**
**TEST YEAR AS FILED AND ADJUSTMENTS**

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJMT NO. 1 REVENUE ANNUAL'TN | (C) ADJMT NO. 2 PURCHASED POWER | (D) ADJMT NO. 3 DEPRECIATION EXPENSE | (E) ADJMT NO. 4 PROPERTY TAX | (F) ADJMT NO. 5 RATE CASE EXPENSE | (G) ADJMT NO. 6 MISCELL. EXPENSE | (H) ADJMT NO. 7 PURCH. POWER PER GB 3.8 | (I) ADJMT NO. 8 TRANSPORTATION EXPENSE | (J) ADJMT NO. 9 OUT OF PERIOD EXP. | (K) ADJMT NO. 10 CENTRAL OFFICE COSTS | (L) ADJMT NO. 11 CORPORATE ALLOCATION | (M) ADJMT NO. 12 RATE CASE EXPENSE | (N) ADJMT NO. 13 BAD DEBT EXPENSE | (O) ADJMT NO. 14 INCOME TAXES | (P) RUCO AS ADJ'TD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | | | | | | | | | | | | |
| 1 | Metered Water Revenues | $ 1,802,584 | $ 4,794 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,807,378 |
| 2 | Unmetered Water Revenues | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Other Water Revenues | 44,672 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 44,672 |
| 4 | Total Revenues | $ 1,847,256 | $ 4,794 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,852,050 |
| | **Operating Expenses:** | | | | | | | | | | | | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 6 | Purchased Water | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | Purchased Power | 441,501 | - | 2,334 | - | - | - | - | (48,005) | - | - | - | - | - | - | - | 395,830 |
| 8 | Fuel for Power Production | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Chemicals | 9,347 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 9,347 |
| 10 | Materials & Supplies | 23,150 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 23,150 |
| 11 | Outside Services | 805,032 | - | - | - | - | - | - | - | - | (14,477) | 3,274 | (96,643) | - | - | - | 697,186 |
| 12 | Outside Services - Other | 76,859 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 76,859 |
| 13 | Outside Services - Legal | 487 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 487 |
| 14 | Water Testing | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 15 | Rents | 26,954 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 26,954 |
| 16 | Transportation Expenses | 79,315 | - | - | - | - | - | - | - | (6,725) | - | - | - | - | - | - | 72,590 |
| 17 | Insurance - General Liability | 37,699 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 37,699 |
| 18 | Insurance - Health and Life | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 17,564 | - | - | - | - | - | - | - | - | - | - | - | (17,564) | - | - | - |
| 20 | Reg. Comm. Exp. - Rate Case | 70,000 | - | - | - | - | (17,500) | - | - | - | - | - | - | - | - | - | 52,500 |
| 21 | Miscellaneous Expense | 14,822 | - | - | - | - | - | (1,363) | - | - | - | - | - | - | - | - | 13,459 |
| 22 | Bad Debt Expense | 371 | - | - | - | - | - | - | - | - | - | - | - | - | 799 | - | 1,170 |
| 23 | Depreciation Expense | 463,297 | - | - | 1,687 | - | - | - | - | - | - | - | - | - | - | - | 464,984 |
| 24 | Taxes Other Than Income | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | Property Taxes | 130,373 | - | - | - | (31,900) | - | - | - | - | - | - | - | - | - | - | 98,474 |
| 26 | Federal Income Tax | (110,555) | - | - | - | - | - | - | - | - | - | - | - | - | - | 16,193 | (94,362) |
| 27 | State Income Tax | (24,354) | - | - | - | - | - | - | - | - | - | - | - | - | - | 3,567 | (20,787) |
| 28 | Total Operating Expenses | $ 2,061,862 | $ - | $ 2,334 | $ 1,687 | $ (31,900) | $ (17,500) | $ (1,363) | $ (48,005) | $ (6,725) | $ (14,477) | $ 3,274 | $ (96,643) | $ (17,564) | $ 799 | $ 19,760 | $ 1,865,540 |
| 29 | Operating Income | $ (214,606) | $ 4,794 | $ (2,334) | $ (1,687) | $ 31,900 | $ 17,500 | $ 1,363 | $ 48,005 | $ 6,725 | $ 14,477 | $ (3,274) | $ 96,643 | $ 17,564 | $ (799) | $ (19,760) | $ (13,490) |

ADJUSTMENTS:
1 - Revenue Annualization
2 - Purchased Power Expense Increase and Annualization
3 - Depreciation Expense
4 - Property Tax Expense
5 - Rate Case Expense
6 - Miscellaneous Expense
7 - Purchased Power Expense Per Staff DR GB 3.8

REFERENCE:
TJC Testimony and Schedule TJC-8 Pages 1 thru 18
TJC Testimony and Schedule TJC-9
TJC Testimony and Schedule TJC-10
TJC Testimony and Schedule TJC-11
TJC Testimony and Schedule TJC-12
TJC Testimony and Schedule TJC-13
TJC Testimony and Schedule TJC-14

ADJUSTMENTS:
8 - Transportation Expense
9 - Out of Test Year Expense
10 - Actual Central Office Cost Allocations
11 - Corporate Allocations
12 - Prior Rate Case Unamortized Expense
13 - Bad Debt Expense
14 - Income Taxes

REFERENCE:
Schedule TJC-15 - See TJC Testimony
TJC Testimony and Schedule TJC-16
TJC Testimony and Schedule TJC-17
TJC Testimony and Schedule TJC-18
TJC Testimony and Schedule TJC-19
TJC Testimony and Schedule TJC-20
TJC Testimony and Schedule TJC-21

**OPERATING INCOME ADJUSTMENT NO. 3**
**TEST YEAR DEPRECIATION EXPENSE**

| LINE NO. | ACCOUNT NO. | ACCOUNT NAME | (A) RUCO PLANT VALUE | (B) COMPANY PROPOSED DEP. RATES | (C) TEST YEAR DEPRECIATION EXPENSE |
|---|---|---|---|---|---|
| 1 | 301 | Organization | $ 5,785 | 0.00% | $ - |
| 2 | 302 | Franchises | 417 | 0.00% | - |
| 3 | 303 | Land and Land Rights | 44,194 | 0.00% | - |
| 4 | 304 | Structures and Improvements | 2,732,833 | 3.33% | 91,003 |
| 5 | 305 | Collecting and Impounding Res. | - | 2.50% | - |
| 6 | 306 | Lake, River and Other Intakes | - | 2.50% | - |
| 7 | 307 | Wells and Springs | 563,511 | 3.33% | 18,765 |
| 8 | 308 | Infiltration Galleries and Tunnels | - | 6.67% | - |
| 9 | 309 | Supply Mains | 279,153 | 2.00% | 5,583 |
| 10 | 310 | Power Generation Equipment | 197,120 | 5.00% | 9,856 |
| 11 | 311 | Electtric Pumping Equipment | 2,591,970 | 12.50% | 323,996 |
| 12 | 320 | Water Treatment Equipment | 372,970 | 3.33% | 12,420 |
| 13 | 320 | Water Treatment Equipment | - | 3.33% | - |
| 14 | 320 | Chemical Solution Feeders | - | 20.00% | - |
| 15 | 330 | Distribution Reservoirs & Standpipe | 759,861 | 2.22% | 16,869 |
| 16 | 330 | Storage Tanks | - | 2.22% | - |
| 17 | 330 | Pressure Tanks | - | 5.00% | - |
| 18 | 331 | Transmission & Distribution Mains | 22,089,150 | 2.00% | 441,783 |
| 19 | 333 | Services | 2,209,274 | 3.33% | 73,569 |
| 20 | 334 | Meters | 956,605 | 8.33% | 79,685 |
| 21 | 335 | Hydrants | 568,577 | 2.00% | 11,372 |
| 22 | 336 | Backflow Prevention Devices | 3,848 | 6.67% | 257 |
| 23 | 339 | Other Plant and Miscellaneous Equipment | 121,843 | 6.67% | 8,127 |
| 24 | 340 | Office Furniture and Fixtures | 22,986 | 6.67% | 1,533 |
| 25 | 340 | Computers and Software | 76,919 | 20.00% | * - |
| 26 | 341 | Transportation Equipment | 218,945 | 20.00% | 43,789 |
| 27 | 342 | Stores Equipment | - | 4.00% | - |
| 28 | 343 | Tools and Work Equipment | 15,035 | 5.00% | 752 |
| 29 | 344 | Laboratory Equipment | 3,061 | 10.00% | 306 |
| 30 | 345 | Power Operated Equipment | - | 5.00% | - |
| 31 | 346 | Communication Equipment | 218,040 | 10.00% | 21,804 |
| 32 | 347 | Miscellaneous Equipment | 7,701 | 10.00% | 770 |
| 33 | 348 | Other Tangible Plant | - | 10.00% | - |
| 34 | | | | | |
| 35 | | TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE | $ 34,059,801 | | $ 1,162,239 |
| 36 | | | | | |
| 37 | | | | | |
| 38 | | AMORTIZATION OF CONTRIBUTIONS | (20,140,197) | 3.46% | (697,254) |
| 39 | | | | | |
| 40 | | Rounding | | | (1) |
| 41 | | | | | |
| 42 | **TOTAL DEPRECIATION EXPENSE** | | | | $ 464,984 |
| 43 | | | | | |
| 44 | Company As Filed | | | | 463,297 |
| 45 | Difference | | | | $ 1,687 |
| 46 | | | | | |
| 47 | RUCO Adjustment | | | | $ 1,687 |

**OPERATING INCOME ADJUSTMENT NO. 4**
**PROPERTY TAX COMPUTATION**

| LINE NO. | DESCRIPTION | REFERENCE | (A) | (B) |
|---|---|---|---|---|
| | Calculation Of The Company's Full Cash Value: | | | |
| | Annual Operating Revenues: | | | |
| 1 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | $ 1,852,050 | |
| 2 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | 1,852,050 | |
| 3 | Proposed Revenues | Sch. TJC-7, Col (E), Ln 8 | 2,781,463 | |
| 4 | Total Three Year Operating Revenues | Sum Of Lines 1, 2 & 3 | $ 6,485,564 | |
| 5 | Average Annual Operating Revenues | Line 4 / 3 | 2,161,855 | |
| 6 | Two Times Three Year Average Operating Revenues | Line 5 X 2 | | $ 4,323,709 |
| | ADD: | | | |
| | 10% Of Construction Work In Progress ("CWIP"): | | | |
| 7 | Test Year CWIP | Company Schedule E | $ 95,024 | |
| 8 | 10% Of CWIP | Line 7 X 10% | | $ 9,502 |
| | SUBTRACT: | | | |
| | Transportation At Book Value: | | | |
| 9 | Original Cost Of Transportation Equipment | RUCO Plant Schedule TJC-4 | $ 218,945 | |
| 10 | Acc. Dep. Of Transportation Equipment | RUCO Plant Schedule TJC-4 | (25,112) | |
| 11 | Net Book Value Of Transportation Equipment | Line 9 + Line 10 | | $ 193,833 |
| 12 | Company's Full Cash Value ("FCV") | Sum Of Lines 6, 8 & 11 | | $ 4,139,378 |
| | Calculation Of The Company's Tax Liability: | | | |
| | MULTIPLY: | | | |
| | FCV X Valuation Assessment Ratio X Property Tax Rates: | | | |
| 13 | Assessment Ratio | House Bill 2779 | 21.0% | |
| 14 | Assessed Value | Line 12 X Line 13 | $ 869,269 | |
| | Property Tax Rates: | | | |
| 15 | Primary Tax Rate | Company Workpapers | 11.3283% | |
| 16 | Secondary Tax Rate | Company Workpapers | 0.00% | |
| 17 | Estimated Tax Rate Liability | Line 15 + Line 16 | 11.33% | |
| | Property Tax | | | $ 98,473 |
| | Tax On Parcel | | | - |
| 18 | Company's Total Tax Liability - Based On Full Cash Value | Line 14 X Line 17 | | $ 98,473 |
| 19 | Test Year Adjusted Property Tax Expense As Filed | Co. Sch. C-1 | | 130,373 |
| 20 | Decrease In Property Tax Expense | Line 18 - Line 19 | | $ (31,900) |
| | | Line 20 | | $ (31,900) |

**OPERATING INCOME ADJUSTMENT NO. 5**
**RATE CASE EXPENSE**

| LINE NO. | DESCRIPTION | (A) COMPANY ESTIMATE | (B) RUCO ADJUSTMENT | (C) RUCO AS ADJUSTED |
|---|---|---|---|---|
| 1 | Rate Case Expense Total | $ 210,000 | $ (52,500) | $ 157,500 |
| 2 | Allocation Factor | | | 100% |
| 3 | Water Division - Surrebuttal Schedules (Line 1 X Line 2) | | | $ 157,500 |
| 4 | Normalization Period - 3 Years | | | 3 |
| 5 | RUCO Adjusted Rate Case Expense (Line 3 / 3 Years) | | | $ 52,500 |
| 6 | Company Rate Case Expenses As Filed (Company Sch. C-2) | | | $ 70,000 |
| 7 | RUCO Pro Forma Rate Case Expense (Lines 5 - 6) | | | $ (17,500) |
| 8 | RUCO Adjustment (Line 7) | | | $ (17,500) |

**OPERATING INCOME ADJUSTMENT NO. 6**
**MISCELLANEOUS EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Miscellaneous Expense - Disallowed: | |
| 2 | | |
| 3 | Family Traditions - Outreach Program | $ 643 |
| 4 | Family Traditions - Outreach Program | 450 |
| 5 | Arizona Highway Patrol - Donation | 150 |
| 6 | Rio Rico Rotary Tickets | 120 |
| 7 | | |
| 8 | RUCO Miscellaneous Adjustment | $ 1,363 |
| 9 | | |
| 10 | | |
| 11 | | |
| 12 | | |
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| 30 | | |
| 31 | | |
| 32 | | |
| 33 | | |
| 34 | SUPPORTING SCHEDULES | |
| 35 | RUCO Work Paper - Miscellaneous Expense Adjustment - Water | |
| 36 | | |
| 37 | | |
| 38 | | |
| 39 | | |
| 40 | | |
| 41 | | |

**OPERATING INCOME ADJUSTMENT NO. 7**
**PURCHASED POWER**

Intentionally Left Blank - See TJC Testimony

**OPERATING INCOME ADJUSTMENT NO. 8**
**TRANSPORTATION EXPENSE**

Intentionally Left Blank - See TJC Testimony

**OPERATING INCOME ADJUSTMENT NO. 9**
**OUT OF PERIOD CENTRAL OFFICE COSTS**

Intentionally Left Blank - See TJC Testimony

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



## OPERATING INCOME ADJUSTMENT #10 - ACTUAL CORPORATE COST ALLOCATIONS

| Line No. | Description | Company Actual Costs | RUCO Disallowed Costs | | RUCO Other Disallowed Costs | RUCO Allowable Costs | RUCO 2008 Allocation Factor | RUCO Allowed Allocated Costs | Allocation % To Rio Rico | RUCO Amount Allocated To Rio Rico |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Rent | 299,586 | | | (299,586) | - | 24.29% | - | 12.92% | - |
| 2 | Audit | 1,021,609 | | | (766,207) | 255,402 | 24.29% | 62,026 | 12.92% | 8,011.91 |
| 3 | Tax Services | 322,446 | | | (241,835) | 80,612 | 24.29% | 19,577 | 12.92% | 2,528.76 |
| 4 | Legal - General | 767,451 | (113,853) | Note A | (575,588) | 78,010 | 24.29% | 18,945 | 12.92% | 2,447.15 |
| 5 | Other Professional Services | 565,649 | | | (565,649) | - | 24.29% | - | 12.92% | - |
| 6 | Management Fee | 642,771 | | | (642,771) | - | 24.29% | - | 12.92% | - |
| 7 | Unit Holder Communications | 289,796 | | | (289,796) | - | 24.29% | - | 12.92% | - |
| 8 | Trustee Fees | 129,000 | | | (129,000) | - | 24.29% | - | 12.92% | - |
| 9 | Office Costs | 808,101 | (74,847) | Note A | (733,254) | - | 24.29% | - | 12.92% | - |
| 10 | Licenses/Fees and Permits | 140,852 | (140,852) | Note A | - | - | 24.29% | - | 12.92% | - |
| 11 | Escrow and Transfer Fees | 71,366 | | | (71,366) | - | 24.29% | - | 12.92% | - |
| 12 | Depreciation Expense | 211,253 | | | (158,440) | 52,813 | 24.29% | 12,826 | 12.92% | 1,656.74 |
| | **Total** | 5,269,882 | (329,552) | | (4,473,492) | 466,837 | | 113,375 | | 14,645 |

| | |
|---|---|
| RUCO Direct Testimony Amount of APT Costs Allowed | 10,009 |
| RUCO Surrebuttal Testimony Additional Amount of Actual APT Costs Allowed | 4,636 |
| RUCO Allocation To Rio Rico Water Division (Based on Total Ratio of Rate Base) | 0.7063 |
| RUCO Allocation To Rio Rico Wastewater Division (Based on Total Ratio of Rate Base) | 0.2937 |
| RUCO's Additional APT Cost Allocation Allowed for Water Division | 3,274 |
| RUCO's Additional APT Cost Allocation Allowed for Wastewater Division | 1,361 |

**Note A:**

| | |
|---|---|
| Per Company Rebuttal Schedule C-2 | $ (113,853) |
| Per Company Rebuttal Schedule C-2 | (74,847) |
| Per Company Rebuttal Schedule C-2 | (140,852) |

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report
Company's Response to Staff GB 3.2 and 3.10 APT Affiliate Charges - Rio Rico
Company's Response to Staff GB 3.7 and 3.15

## OPERATING INCOME ADJUSTMENT #11 - CORPORATE ALLOCATIONS

| Line No. | Description | Company Total Cost | RUCO Disallowed Costs | | RUCO Other Disallowed Costs | RUCO Allowable Costs | RUCO 2008 Allocation Factor | RUCO Allowed Allocated Costs | Allocation % To Rio Rico | RUCO Amount Allocated To Rio Rico |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Rent | 430,739 | | | (430,739) | - | 24.29% | - | 12.92% | - |
| 2 | Audit | 507,000 | | | (380,250) | 126,750 | 24.29% | 30,782 | 12.92% | 3,976.12 |
| 3 | Tax Services | 265,000 | | | (198,750) | 66,250 | 24.29% | 16,089 | 12.92% | 2,078.25 |
| 4 | Legal - General | 300,000 | | | (225,000) | 75,000 | 24.29% | 18,214 | 12.92% | 2,352.73 |
| 5 | Other Professional Services | 455,000 | | | (455,000) | - | 24.29% | - | 12.92% | - |
| 6 | Management Fee | 636,619 | | | (636,619) | - | 24.29% | - | 12.92% | - |
| 7 | Unit Holder Communications | 314,100 | | | (314,100) | - | 24.29% | - | 12.92% | - |
| 8 | Trustee Fees | 204,000 | | | (204,000) | - | 24.29% | - | 12.92% | - |
| 9 | Office Costs | 254,100 | (49,686) | Note A | (204,414) | - | 24.29% | - | 12.92% | - |
| 10 | Licenses/Fees and Permits | 305,000 | (145,642) | Note B | (159,358) | - | 24.29% | - | 12.92% | - |
| 11 | Escrow and Transfer Fees | 75,000 | | | (75,000) | - | 24.29% | - | 12.92% | - |
| 12 | Depreciation Expense | 204,242 | | | (153,182) | 51,061 | 24.29% | 12,400 | 12.92% | 1,601.76 |
| | **Total** | 3,950,800 | (195,328) | | (3,436,412) | 319,061 | | 77,486 | | 10,009 |

| | |
|---|---|
| RUCO Allocation To Rio Rico Water Division (Based on Total Ratio of Rate Base) | 70.9536% |
| RUCO Allocation To Rio Rico Wastewater Division (Based on Total Ratio of Rate Base) | 29.0464% |
| Company's APT Cost Allocation for Water Division (Per Staff DR GB 3.7 & GB 3.15) | $ 103,745 |
| RUCO's APT Cost Allocation Allowed for Water Division | 7,102 |
| RUCO's APT Cost Allocation Adjustment for Water Division | (96,643) |
| Company's APT Cost Allocation for Wastewater Division (Per Staff DR GB 3.7 & GB 3.15) | $ 34,582 |
| RUCO's APT Cost Allocation Allowed for Wastewater Division | 2,907 |
| RUCO's APT Cost Allocation Adjustment for Wastewater Division | (31,675) |

**Note A:**

| | Description | |
|---|---|---|
| Office Costs | Wind Analysis Software | $ 15,056 |
| Office Costs | Gold Watches & Clocks | 16,864 |
| Office Costs | Pilsner Beer Glasses | 5,700 |
| Office Costs | Leafs/Raptors Tickets | 5,066 |
| Office Costs | Super Bowl Tickets | 7,000 |
| Total | | $ (49,686) |

**Note B:**

| | | |
|---|---|---|
| Licenses/Fees and Permits | Donation | $ 25,000 |
| Licenses/Fees and Permits | Donation | 25,000 |
| Licenses/Fees and Permits | Donation | 13,350 |
| Licenses/Fees and Permits | Donation | 5,000 |
| Licenses/Fees and Permits | Wind Developm | 7,887 |
| Licenses/Fees and Permits | US Trustee | 9,375 |
| Licenses/Fees and Permits | Wind Energy | 12,556 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,891 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,794 |
| Licenses/Fees and Permits | APF Inc Taxes | 23,789 |
| Licenses/Fees and Permits | KMS Tax Ruling | 10,000 |
| Total | | $ (145,642) |

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report
Company's Response to Staff GB 3.2 and 3.10 APT Affiliate Charges - Rio Rico
Company's Response to Staff GB 3.7 and 3.15

**OPERATING INCOME ADJUSTMENT NO. 12**
**REMOVE UNAMORTIZED PRIOR RATE CASE EXPENSE**

Intentionally Left Blank - See TJC Testimony

**OPERATING INCOME ADJUSTMENT NO. 13**
**BAD DEBT EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Normalize Bad Debt Expense: | |
| 2 | | |
| 3 | 2008 Bad Debt Expense | $ 371 |
| 4 | 2007 Bad Debt Expense | - |
| 5 | 2006 Bad Debt Expense | 3,140 |
| 6 | | |
| 7 | 3 Year Normalization | $ 1,170 |
| 8 | | |
| 9 | Company As Filed | 371 |
| 10 | | |
| 11 | RUCO Adjustment | $ 799 |
| 12 | | |
| 13 | | |
| 14 | | |
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| 36 | | |
| 37 | | |
| 38 | SUPPORTING SCHEDULES | |
| 39 | Company Schedule E-2 | |
| 40 | | |
| 41 | | |

## OPERATING INCOME ADJUSTMENT #14
## INCOME TAX EXPENSE

| LINE NO. | DESCRIPTION | (A) REFERENCE | (B) AMOUNT |
|---|---|---|---|
| | **FEDERAL INCOME TAXES:** | | |
| 1 | Operating Income Before Taxes | Sch. TJC-7, Column (C), L28 + L22 + L23 | $ (118,639) |
| | LESS: | | |
| 2 | Arizona State Tax | Line 11 | (20,787) |
| 3 | Interest Expense | Note (A) Line 21 | 179,684 |
| 4 | Federal Taxable Income | Line 1 - Line 2 - Line 3 | $ (277,535) |
| 5 | Federal Tax Rate | Sch. TJC-1, Pg 2, Col. (D), L34 | 34.00% |
| 6 | Federal Income Tax Expense | Line 4 X line 5 | $ (94,362) |
| | **STATE INCOME TAXES:** | | |
| 7 | Operating Income Before Taxes | Line 1 | $ (118,639) |
| | LESS: | | |
| 8 | Interest Expense | Note (A) Line 21 | 179,684 |
| 9 | State Taxable Income | Line 7 - Line 8 | $ (298,322) |
| 10 | State Tax Rate | Tax Rate | 6.97% |
| 11 | State Income Tax Expense | Line 9 X Line 10 | $ (20,787) |
| | **TOTAL INCOME TAX EXPENSE:** | | |
| 12 | Federal Income Tax Expense | Line 6 | $ (94,362) |
| 13 | State Income Tax Expense | Line 11 | (20,787) |
| 14 | Total Income Tax Expense Per RUCO | Line12 + Line 13 | $ (115,149) |
| 15 | Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | (110,555) |
| 16 | Total State Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | (24,354) |
| 17 | RUCO Federal Income Tax Adjustment | Line 12 - Line 15 | $ 16,193 |
| 18 | RUCO State Income Tax Adjustment | Line 13 - Line 16 | $ 3,567 |

NOTE (A):
Interest Synchronization:

| | | | |
|---|---|---|---|
| 19 | Adjusted Rate Base (Sch. TJC-2, Col. (H), L17) | $ | 7,175,864 |
| 20 | Weighted Cost Of Debt (Sch. TJC-16 Col. (F), L1) | | 2.50% |
| | | $ | 179,684 |

**COST OF CAPITAL**

| LINE NO. | DESCRIPTION | (B) CAPITAL RATIO | (C) COST RATE | (D) WEIGHTED COST RATE |
|---|---|---|---|---|
| 1 | Long-Term Debt | 40.00% | 6.26% | 2.50% |
| 2 | Common Equity | 60.00% | 9.00% | 5.40% |
| 3 | Total Capitalization | 100.00% | | |
| 4 | WEIGHTED AVERAGE COST OF CAPITAL | | | 7.90% |

References:
Columns (A) Thru (D): Testimony, WAR

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division - Surrebuttal Schedules

## TABLE OF CONTENTS TO TJC SCHEDULES


| SCHEDULE NO. | PAGE NO. | TITLE |
|---|---|---|
| TJC-1 | 1 & 2 | REVENUE REQUIREMENT AND GROSS REVENUE CONVERSION FACTOR |
| TJC-2 | 1 | RATE BASE |
| TJC-3 | 1 | SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS |
| TJC-4 DIRECT PLANT | 1 | RATE BASE ADJUSTMENT NO. 1 - INTENTIONALLY LEFT BLANK |
| TJC-5 | 1 | RATE BASE ADJUSTMENT NO. 2 - ACCUMULATED DEFERRED INCOME TAXES |
| TESTIMONY | | RATE BASE ADJUSTMENT NO. 3 - AIAC & CIAC BALANCES PER RUCO DR 1.08 & 1.09 |
| | | RATE BASE ADJUSTMENT NO. 4 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 5 - INTENTIONALLY LEFT BLANK |
| | | RATE BASE ADJUSTMENT NO. 6 - INTENTIONALLY LEFT BLANK |
| TJC-6 | 1 | OPERATING INCOME |
| TJC-7 | 1 | SUMMARY OF OPERATING INCOME ADJUSTMENTS |
| TESTIMONY | | OPERATING INCOME ADJUSTMENT NO. 1 - REVENUE ANNUALIZATION |
| TESTIMONY | 1 | OPERATING INCOME ADJUSTMENT NO. 2 - PURCHASED POWER INCREASE & EXPENSE ANNUALIZATION |
| TJC-8 | 1 | OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE |
| TJC-9 | 1 | OPERATING INCOME ADJUSTMENT NO. 4 - PROPERTY TAX EXPENSE |
| TJC-10 | 1 | OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSE |
| TJC-11 | 1 | OPERATING INCOME ADJUSTMENT NO. 6 - MISCELLANEOUS EXPENSE |
| TJC-12 | 1 | OPERATING INCOME ADJUSTMENT NO. 7 - PURCHASED POWER EXPENSE ADJUSTMENT |
| TJC-13 | 1 | OPERATING INCOME ADJUSTMENT NO. 8 - TRANSPORTATION EXPENSE |
| TJC-14 | 1 | OPERATING INCOME ADJUSTMENT NO. 9 - OUT OF TEST YEAR CORPORATE EXPENSES |
| TJC-15 | 1 | OPERATING INCOME ADJUSTMENT NO. 10 - ACTUAL CORPORATE APT COSTS |
| TJC-16 | 1 | OPERATING INCOME ADJUSTMENT NO. 11 - APT CORPORATE COSTS ADJUSTMENT |
| TJC-17 | 1 | OPERATING INCOME ADJUSTMENT NO. 12 - REMOVE UNAMORTIZED RATE CASE EXPENSE |
| TJC-18 | 1 | OPERATING INCOME ADJUSTMENT NO. 13 - NORMALIZE BAD DEBT EXPENSE |
| TJC-19 | 1 | OPERATING INCOME ADJUSTMENT NO. 14 - INCOME TAX EXPENSE |
| TJC-20 & WAR TESTIMONY | 1 | COST OF CAPITAL |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**REVENUE REQUIREMENT**

| LINE NO. | DESCRIPTION | (A) COMPANY OCRB/FVRB COST | (B) RUCO OCRB/FVRB COST |
|---|---|---|---|
| 1 | Adjusted Original Cost/Fair Value Rate Base | $ 3,516,078 | $ 2,983,957 |
| 2 | Adjusted Operating Income (Loss) | $ 490,676 | $ 539,140 |
| 3 | Current Rate of Return (L2 / L1) | 13.96% | 18.07% |
| 4 | Required Operating Income (L5 X L1) | $ 435,994 | $ 235,852 |
| 5 | Required Rate of Return on Fair Value Rate Base | 12.40% | 7.90% |
| 6 | Operating Income Deficiency (L4 - L2) | $ (54,682) | $ (303,288) |
| 7 | Gross Revenue Conversion Factor (TJC-1, Page 2) | 1.6286 | 1.6286 |
| 8 | Required Increase in Gross Revenue Requirement (L7 X L6) | $ (89,058) | $ (493,946) |
| 9 | Adjusted Test Year Revenue | $ 1,829,976 | $ 1,834,481 |
| 10 | Proposed Annual Revenue (L8 + L9) | $ 1,740,918 | $ 1,340,535 |
| 15 | Required Percentage Increase in Revenue (L8 / L9) | -4.87% | -26.93% |
| 16 | Rate of Return on Common Equity | 12.40% | 9.00% |

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule TJC-2, TJC-6, and TJC-17

## GROSS REVENUE CONVERSION FACTOR

| LINE NO. | DESCRIPTION | (A) | (B) | (C) | (D) |
|---|---|---|---|---|---|
| | CALCULATION OF GROSS REVENUE CONVERSION FACTOR: | | | | |
| 1 | Revenue | 1.0000 | | | |
| 2 | Combined Federal And State Tax Rate (L10) | 0.3860 | | | |
| 3 | Subtotal (L1 - L2) | 0.6140 | | | |
| 4 | **Revenue Conversion Factor** (L1 / L3) | **1.6286** | | | |
| | CALCULATION OF EFFECTIVE TAX RATE: | | | | |
| 5 | Operating Income Before Taxes (Arizona Taxable Income) | 100.0000% | | | |
| 6 | Arizona State Income Tax Rate | 6.9680% | | | |
| 7 | Federal Taxable Income (L5 - L6) | 93.0320% | | | |
| 8 | Applicable Federal Income Tax Rate (Col. (D), L34) | 34.0000% | | | |
| 9 | Effective Federal Income Tax Rate (L7 X L8) | 31.6309% | | | |
| 10 | Combined Federal And State Income Tax Rate (L6 + L9) | 38.5989% | | | |
| 11 | Required Operating Income (Sch. TJC-1, Pg 1, C (B), L4) | $ 235,852 | | | |
| 12 | Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Pg 1, C (B), L2) | 539,140 | | | |
| 13 | Required Increase In Operating Income (L11 - L12) | | $ (303,288) | | |
| 14 | Income Taxes On Recommended Revenue (Col. (D), L31) | $ 101,294 | | | |
| 15 | Income Taxes On Test Year Revenue (Col. (D), L32) | 291,952 | | | |
| 16 | Required Increase In Revenue To Provide For Income Taxes (L14 - L15) | | $ (190,657) | | |
| 17 | Total Required Increase In Revenue (L13 + L16) | | $ (493,946) | | |
| | | | | RUCO Recommended | |
| | CALCULATION OF INCOME TAX: | | | | |
| 18 | Revenue (Sch. TJC-1, Pg 1, Col. (B), L12) | | | $ 1,340,535 | |
| 19 | Operating Expense Excluding Income Tax (TJC-7, Col. (E), L27 - L22 - L23) | | | 1,003,389 | |
| 20 | Synchronized Interest (Col. (C), L37) | | | 74,718 | |
| 21 | Arizona Taxable Income (L18 - L19 - L20) | | | $ 262,428 | |
| 22 | Arizona State Income Tax Rate | | | 6.9680% | |
| 23 | Arizona Income Tax (L21 X L22) | | | | $ 18,286 |
| 24 | Fed. Taxable Income (L21 - L23) | | | $ 244,142 | |
| 25 | Fed. Tax on 1st Inc. Bracket ($1 - $50,000) @ 15% | | | $ - | |
| 26 | Fed. Tax on 2nd Inc. Bracket ($50,001 - $75,000) @ 25% | | | $ - | |
| 27 | Fed. Tax on 3rd Inc. Bracket ($75,001 - $100,000) @ 34% | | | $ - | |
| 28 | Fed. Tax on 4th Inc. Bracket ($100,001 - $335,000) @ 39% | | | $ - | |
| 29 | Fed. Tax on 5th Inc. Bracket ($335,001 - $10M) @ 34% | | | $ 83,008 | |
| 30 | Total Federal Income Tax (L25 + L26 + L27 + L28 + L29) | | | | $ 83,008 |
| 31 | Combined Federal and State Income Tax (L23 + L30) | | | | $ 101,294 |
| 32 | Test Year Combined Income Tax, RUCO as Adjusted (TJC-7, Col. (C), L22 + L23) | | | | $ 291,952 |
| 33 | RUCO Adjustment (L31 - L32) (See TJC-6, Col. (D), L23) | | | | $ (190,657) |
| 34 | Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24) | | | | 34.00% |
| | CALCULATION OF INTEREST SYNCHRONIZATION: | | | | |
| 35 | Rate Base (Sch. TJC-2, Col. (C), L17) | | | $ 2,983,957 | |
| | | | | 2.50% | |
| | | | | $ 74,718 | |

## RATE BASE - ORIGINAL COST

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) RUCO OCRB/FVRB ADJUSTMENTS | (C) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 11,829,043 | $ - | $ 11,829,043 |
| 2 | Less: Accumulated Depreciation | (5,110,028) | - | (5,110,028) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 6,719,014 | $ - | $ 6,719,014 |
| | Less: | | | |
| 4 | Advances in Aid of Construction | 861 | (238,783) | (237,922) |
| 5 | Contribution in Aid of Construction | (5,376,456) | 238,783 | (5,137,673) |
| 6 | Accumulated Amortization of CIAC | 1,944,057 | - | 1,944,057 |
| 7 | NET CIAC (L5 + L6) | $ (3,432,399) | $ 238,783 | $ (3,193,616) |
| 8 | Customer Meter Deposits | (95,000) | - | (95,000) |
| 9 | Deferred Income Taxes & Credits | 323,602 | (532,121) | (208,519) |
| | Plus: | | | |
| 10 | Unamortized Debt Issuance Costs | - | - | - |
| 11 | Deferred Regulatory Assets | - | - | - |
| 12 | Allowance For Working Capital | - | - | - |
| 13 | Rounding | - | - | - |
| 14 | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 3,516,078 | $ (532,121) | $ 2,983,957 |

References:
Column (A): Company Schedule B-1
Column (B): Schedule TJC-3
Column (C): Column (A) + Column (B)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division - Surrebuttal Schedules
Schedule TJC-3
Page 1 of 1

## SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED OCRB/FVRB | (B) ADJMT NO. 1 PLANT & ACCUM DEP. | (C) ADJMT NO. 2 DEFERRED INCOME TAXES | (D) ADJMT NO. 3 PER RUCO DR 1.08 | (E) ADJMT NO. 4 | (F) ADJMT NO. 5 | (G) ADJMT NO. 6 | (H) RUCO ADJ'TED OCRB/FVRB |
|---|---|---|---|---|---|---|---|---|---|
| 1 | Gross Utility Plant in Service | $ 11,829,043 | $ - | $ - | $ - | $ - | $ - | $ - | $ 11,829,043 |
| 2 | Less: Accumulated Depreciation | (5,110,028) | - | - | - | - | - | - | (5,110,028) |
| 3 | Net Utility Plant In Service (Sum L1 & L2) | $ 6,719,014 | $ - | $ - | $ - | $ - | $ - | $ - | $ 6,719,014 |
| 4 | Less: | | | | | | | | |
| 5 | Advances in Aid of Construction | - | - | - | - | - | - | - | - |
| 6 | Contribution in Aid of Construction | $ 861 | $ - | $ - | $ - | $ - | $ - | $ - | $ 861 |
| 7 | Accumulated Amortization of CIAC | (5,376,456) | - | - | - | - | - | - | (5,376,456) |
| 8 | NET CIAC (L5 + L6) | $ (3,432,399) | $ - | $ - | $ - | $ - | $ - | $ - | $ (3,432,399) |
| 9 | Customer Meter Deposits | (95,000) | - | - | - | - | - | - | (95,000) |
| 10 | Deferred Income Taxes & Credits | 323,602 | - | $ (238,783) | $ 238,783 | $ - | $ - | $ - | $ 323,602 |
| 11 | Plus: | | | | | | | | |
| 12 | Unamortized Debt Issuance Costs | - | - | - | - | - | - | - | - |
| 13 | Deferred Regulatory Assets | - | - | - | - | - | - | - | - |
| 14 | Allowance For Working Capital | - | (532,121) | - | - | - | - | $ (237,922) | (237,922) |
| | Rounding | - | - | - | - | - | - | - | (5,137,673) |
| | TOTAL RATE BASE (Sum L's 3, 4, & 7 Thru 16) | $ 3,516,078 | $ - | $ (532,121) | $ - | $ - | $ - | $ - | 1,944,057 |
| | | | | | | | | | $ (3,193,616) |
| | | | | | | | | | (95,000) |
| | | | | | | | | | (208,519) |
| | | | | | | | | | - |
| | | | | | | | | | - |
| | | | | | | | | | - |
| | | | | | | | | | - |
| | | | | | | | | | $ 2,983,957 |

Column (A): Company Schedule B-2
Column (B): Adjustment #1 - See TJC Testimony
Column (C): Adjustment No. 2 - Deferred Income Taxes (See Schedule TJC-5)
Column (D): Adjustment No. 3 - To Adjust AIAC & CIAC Balances Per Company Response to RUCO DR 1.08 and Discussed in TJC Testimony
Column (E): Adjustment No. 4 - Intentionally Left Blank
Column (F): Adjustment No. 5 - Intentionally Left Blank

**RATE BASE ADJUSTMENT NO. 1**
**PLANT & ACCUMULATED DEPRECIATION**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Intentionally Left Blank - See TJC Testimony | |
| 2 | | |
| 3 | | |
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| 40 | | |
| 41 | | |

**RATE BASE ADJUSTMENT NO. 2**
**ACCUMULATED DEFERRED INCOME TAXES**

| Line No. | Deferred Income Taxes: | | Amount | Reference |
|---|---|---|---|---|
| 1 | **Deferred Income Taxes:** | | **Amount** | **Reference** |
| 2 | | | | |
| 3 | Algonquin Accumulated Deferred Income Tax Assets | $ | 23,032,000 | 2008 Algonquin Annual Report |
| 4 | | | | |
| 5 | Algonquin Accumulated Deferred Income Tax Liabilities | | (106,983,000) | 2008 Algonquin Annual Report |
| 6 | | | | |
| 7 | Net Accumulated Deferred Income Tax Assets (Liabilities) | $ | (83,951,000) | Line 3 + Line 5 |
| 8 | | | | |
| 9 | Rio Rico Allocation | | 0.8997% | Note (A) |
| 10 | | | | |
| 11 | Rio Rico ADIT Liabilities Allocation | $ | (755,287) | Line 7 X Line 9 |
| 12 | | | | |
| 13 | Convert to US Dollars | | 0.9400 | Note (B) |
| 14 | | | | |
| 15 | Allocated ADIT Liabilites Balance | $ | (709,970) | Line 11 X Line 13 |
| 16 | | | | |
| 17 | Rio Rico Water Allocation Factor | | 0.70630 | Note (C) |
| 18 | | | | |
| 19 | Rio Rico Wastewater Allocation Factor | | 0.29370 | Note (C) |
| 20 | | | | |
| 21 | Rio Rico Water Allocation | $ | (501,450) | Line 15 X Line 17 |
| 22 | | | | |
| 23 | Rio Rico Wastewater Allocation | $ | (208,519) | Line 15 X Line 19 |
| 24 | | | | |
| 25 | | | | |
| 26 | | | | |
| 27 | | | | |
| 28 | **NOTES:** | | | |
| 29 | (A) Purchase Price of Rio Rico Utilities. Inc. | $ | 8,800,000 | |
| 30 | Algonquin Total Assets | | 978,130,000 | |
| 31 | | | | |
| 32 | Ratio | | 0.8997% | |
| 33 | | | | |
| 34 | | | | |
| 35 | (B) www.bank-banque-canada.ca on 11/19/2009 | | 0.9400 | |
| 36 | | | | |
| 37 | | | | |
| 38 | (C) Rio Rico Water Allocation | | 0.70630 | |
| 39 | | | | |
| 40 | Rio Rico Wastewater Allocation | | 0.29370 | |
| 41 | | | | |
| 42 | | | | |
| 43 | SUPPORTING SCHEDULES | | | |
| 44 | 2008 Algonquin Power Income Fund Annual Report | | | |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division - Surrebuttal Schedules
Schedule TJC-6


## OPERATING INCOME

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) RUCO TEST YEAR ADJM'TS | (C) RUCO TEST YEAR AS ADJ'TED | (D) RUCO PROP'D CHANGES | (E) RUCO AS RECOMM'D |
|---|---|---|---|---|---|---|
| | **Revenues:** | | | | | |
| 1 | Metered Water Revenues | $ 1,829,726 | $ 4,505 | $ 1,834,231 | $ (493,946) | $ 1,340,285 |
| 2 | Unmetered Water Revenues | - | - | - | - | - |
| 3 | Other Water Revenues | 250 | - | 250 | - | 250 |
| 4 | Total Revenues | $ 1,829,976 | $ 4,505 | $ 1,834,481 | $ (493,946) | $ 1,340,535 |
| | **Operating Expenses:** | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - |
| 6 | Purchased Water and WW Treatment | - | - | - | - | - |
| 7 | Purchased Power | 17,426 | 48,393 | 65,819 | - | 65,819 |
| 8 | Fuel for Power Production | - | - | - | - | - |
| 9 | Chemicals | 9,644 | 212 | 9,856 | - | 9,856 |
| 10 | Materials & Supplies | 14,304 | - | 14,304 | - | 14,304 |
| 11 | Contractual Services | 298,008 | (30,258) | 267,750 | - | 267,750 |
| 12 | Outside Services - Other | 175,196 | - | 175,196 | - | 175,196 |
| 13 | Outside Services - Legal | 367 | - | 367 | - | 367 |
| 14 | Equipment Rental | 25,781 | - | 25,781 | - | 25,781 |
| 15 | Rents - Building | - | - | - | - | - |
| 16 | Transportation Expenses | 26,817 | (2,242) | 24,575 | - | 24,575 |
| 17 | Insurance - General Liability | 12,021 | - | 12,021 | - | 12,021 |
| 18 | Insurance - Vehicle | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 994 | - | 994 | - | 994 |
| 20 | Reg. Comm. Exp. - Rate Case | 41,667 | (10,417) | 31,250 | - | 31,250 |
| 21 | Miscellaneous Expense | 155 | - | 155 | - | 155 |
| 22 | Bad Debt Expense | 64,087 | (30,315) | 33,772 | - | 33,772 |
| 23 | Depreciation and Amortization | 252,672 | 9,361 | 262,033 | - | 262,033 |
| 24 | Taxes Other Than Income | - | - | - | - | - |
| 25 | Property Taxes | 91,705 | (12,189) | 79,516 | - | 79,516 |
| 26 | Federal Income Tax | 252,773 | (13,525) | 239,248 | (156,239) | 83,008 |
| 27 | State Income Tax | 55,684 | (2,979) | 52,704 | (34,418) | 18,286 |
| 28 | **Total Operating Expenses** | $ 1,339,300 | $ (43,959) | $ 1,295,341 | $ (190,657) | $ 1,104,683 |
| 29 | **Operating Income** | $ 490,676 | $ 48,464 | $ 539,140 | $ (303,288) | $ 235,852 |

References:
Column (A): Company Schedule C-1
Column (B): Schedule TJC-7, Columns (B) Thru (K)
Column (C): Column (A) + Column (B)
Column (D): TJC-1, pages 1 and 2
Column (E): Column (C) + Column (D)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



## SUMMARY OF OPERATING INCOME ADJUSTMENTS
## TEST YEAR AS FILED AND ADJUSTMENTS

| LINE NO. | DESCRIPTION | (A) COMPANY AS FILED | (B) ADJMT NO. 1 REVENUE ANNUAL'TN | (C) ADJMT NO. 2 EXPENSE ANNUAL'ZED | (D) ADJMT NO. 3 DEPRECIATION EXPENSE | (E) ADJMT NO. 4 PROPERTY TAX | (F) ADJMT NO. 5 RATE CASE EXPENSE | (G) ADJMT NO. 8 BLANK | (H) ADJMT NO. 7 PURCH. POWER PER GB 3.8 | (I) ADJMT NO. 6 TRANSPORTATION EXPENSE | (J) ADJMT NO. 9 BLANK | (K) ADJMT NO. 10 CENTRAL OFFICE COSTS | (L) ADJMT NO. 11 CORPORATE ALLOCATION | (M) ADJMT NO. 12 BLANK | (N) ADJMT NO. 13 BAD DEBT EXPENSE | (O) ADJMT NO. 14 INCOME TAXES | (P) RUCO AS ADJ'T'D |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Revenues: | | | | | | | | | | | | | | | | |
| 1 | Metered Water Revenues | $ 1,828,726 | $ 4,505 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,834,231 |
| 2 | Unmetered Water Revenues | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 3 | Other Water Revenues | 250 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 250 |
| 4 | Total Revenues | $ 1,828,976 | $ 4,505 | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ 1,834,481 |
| | Operating Expenses: | | | | | | | | | | | | | | | | |
| 5 | Salaries and Wages | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | - |
| 6 | Purchased Water and WW Treatment | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 7 | Purchased Power | 17,426 | - | 388 | - | - | - | - | 49,005 | - | - | - | - | - | - | - | 66,819 |
| 8 | Fuel for Power Production | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 9 | Chemicals | 9,644 | - | 212 | - | - | - | - | - | - | - | - | - | - | - | - | 9,856 |
| 10 | Materials & Supplies | 14,304 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 14,304 |
| 11 | Contractual Services | 268,008 | - | - | - | - | - | - | - | - | - | 1,346 | (31,604) | - | - | - | 267,750 |
| 12 | Outside Services - Other | 175,198 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 175,198 |
| 13 | Outside Services - Legal | 367 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 367 |
| 14 | Equipment Rental | 25,781 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 25,781 |
| 15 | Rents - Building | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 16 | Transportation Expenses | 26,817 | - | - | - | - | - | - | - | (2,242) | - | - | - | - | - | - | 24,575 |
| 17 | Insurance - General Liability | 12,021 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 12,021 |
| 18 | Insurance - Vehicle | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 19 | Regulatory Commission Expense | 894 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 894 |
| 20 | Reg. Comm. Exp. - Rate Case | 41,667 | - | - | - | - | (10,417) | - | - | - | - | - | - | - | - | - | 31,250 |
| 21 | Miscellaneous Expense | 155 | - | - | - | - | - | - | - | - | - | - | - | - | - | - | 155 |
| 22 | Bad Debt Expense | 64,087 | - | - | - | - | - | - | - | - | - | - | - | - | (30,315) | - | 33,772 |
| 23 | Depreciation and Amortization | 252,672 | - | - | 9,361 | - | - | - | - | - | - | - | - | - | - | - | 262,033 |
| 24 | Taxes Other Than Income | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - | - |
| 25 | Property Taxes | 91,705 | - | - | - | (12,189) | - | - | - | - | - | - | - | - | - | - | 79,516 |
| 26 | Federal Income Tax | 252,773 | - | - | - | - | - | - | - | - | - | - | - | - | - | (13,525) | 239,248 |
| 27 | State Income Tax | 65,884 | - | - | - | - | - | - | - | - | - | - | - | - | - | (2,979) | 52,704 |
| 28 | Total Operating Expenses | $ 1,338,900 | $ - | $ 600 | $ 9,361 | $ (12,189) | $ (10,417) | $ - | $ 49,005 | $ (2,242) | $ - | $ 1,346 | $ (31,604) | $ - | $ (30,315) | $ (16,504) | $ 1,295,341 |
| 29 | Operating Income | $ 490,076 | $ 4,505 | $ (600) | $ (9,361) | $ 12,189 | $ 10,417 | $ - | $ (49,005) | $ 2,242 | $ - | $ (1,346) | $ 31,604 | $ - | $ 30,315 | $ 16,504 | $ 539,140 |

ADJUSTMENTS:
1 - Revenue Annualization
2 - Purchased Power Expense Increase and Annualization
3 - Depreciation Expense
4 - Property Tax Expense
5 - Rate Case Expense
6 - Intentionally Left Blank
7 - Purchased Power Expense Per Staff DR GB 3.8

REFERENCE:
TJC Testimony and Schedule TJC-8 Pages 1 thru 15
TJC Testimony and Schedule TJC-9
TJC Testimony and Schedule TJC-10
TJC Testimony and Schedule TJC-11
TJC Testimony and Schedule TJC-12
Schedule TJC-13 - Intentionally Left Blank
Schedule TJC-14 - See TJC Testimony

ADJUSTMENTS:
8 - Transportation Expense
9 - Intentionally Left Blank
10 - Actual Central Office Cost Allocations
11 - Corporate Allocations
12 - Intentionally Left Blank
13 - Bad Debt Expense
14 - Income Taxes

REFERENCE:
Schedule TJC-14 - See TJC Testimony
Intentionally Left Blank
TJC Testimony and Schedule TJC-17
TJC Testimony and Schedule TJC-18
Intentionally Left Blank
Schedule TJC-20 - See TJC Testimony
TJC Testimony and Schedule TJC-21

## OPERATING INCOME ADJUSTMENT NO. 3
## TEST YEAR DEPRECIATION EXPENSE

| LINE NO. | ACCOUNT NO. | ACCOUNT NAME | (A) RUCO PLANT VALUE | (B) COMPANY PROPOSED DEP. RATES | (C) TEST YEAR DEPRECIATION EXPENSE |
|---|---|---|---|---|---|
| 1 | 351 | Organization | $ 5,785 | 0.00% | $ - |
| 2 | 352 | Franchises | 417 | 0.00% | - |
| 3 | 353 | Land | 7,545 | 0.00% | - |
| 4 | 354 | Structures and Improvements | 28,548 | 3.33% | 951 |
| 5 | 355 | Power Generation | - | 5.00% | - |
| 6 | 360 | Collection Sewer Forced | 636,023 | 2.00% | 12,720 |
| 7 | 361 | Collection Sewers Gravity | 5,945,962 | 2.00% | 118,919 |
| 8 | 362 | Special Collecting Structures | - | 2.00% | - |
| 9 | 363 | Customer Services | 1,145,530 | 2.00% | 22,911 |
| 10 | 364 | Flow Measuring Devices | 55,989 | 10.00% | 5,599 |
| 11 | 365 | Flow Measuring Installation | - | 10.00% | - |
| 12 | 366 | Reuse Services | - | 2.00% | - |
| 13 | 367 | Reuse Meters And Installation | - | 8.33% | - |
| 14 | 370 | Receiving Wells | 867,120 | 3.33% | 28,875 |
| 15 | 371 | Pumping Equipment | 1,504,181 | 12.50% | 188,023 |
| 16 | 374 | Reuse Distribution Reservoirs | - | 2.50% | - |
| 17 | 375 | Reuse Trans. and Dist. System | - | 2.50% | - |
| 18 | 380 | Treatment & Disposal Equipment | 1,006,848 | 5.00% | 50,342 |
| 19 | 381 | Plant Sewers | - | 5.00% | - |
| 20 | 382 | Outfall Sewer Lines | - | 3.33% | - |
| 21 | 389 | Other Sewer Plant & Equipment | 68,869 | 6.67% | 4,594 |
| 22 | 390 | Office Furniture & Equipment | 110,454 | 6.67% | 7,367 |
| 23 | 390 | Computers and Software | 4,025 | 20.00% | 805 |
| 24 | 391 | Transportation Equipment | - | 20.00% | - |
| 25 | 392 | Stores Equipment | - | 4.00% | * - |
| 26 | 393 | Tools, Shop And Garage Equip | 4,897 | 5.00% | 245 |
| 27 | 394 | Laboratory Equip | - | 10.00% | - |
| 28 | 396 | Communication Equip | 5,936 | 10.00% | 594 |
| 29 | 398 | Other Tangible Plant | 3,913 | 4.00% | 157 |
| 30 | 398 | Nogales WW Trmnt Capacity | 427,000 | 5.00% | 21,350 |
| 31 | 346 | Rounding | 1 | | |
| 32 | | | | | |
| 33 | | TEST YEAR GROSS PLANT AND DEPRECIATION EXPENSE | $ 11,829,043 | | $ 463,451 |
| 34 | | | | | |
| 35 | | | | | |
| 36 | | AMORTIZATION OF CONTRIBUTIONS | (5,137,673) | 3.92% | (201,418) |
| 37 | | | | | |
| 38 | | Rounding | | | |
| 39 | | | | | |
| 40 | **TOTAL DEPRECIATION EXPENSE** | | | | $ 262,033 |
| 41 | | | | | |
| 42 | Company As Filed | | | | 252,672 |
| 43 | Difference | | | | $ 9,361 |
| 44 | | | | | |
| 45 | RUCO Adjustment | | | | $ 9,361 |
| 46 | | | | | |
| 47 | | | | | |

**OPERATING INCOME ADJUSTMENT NO. 4**
**PROPERTY TAX COMPUTATION**

| LINE NO. | DESCRIPTION | REFERENCE | (A) | (B) |
|---|---|---|---|---|
| | Calculation Of The Company's Full Cash Value: | | | |
| | Annual Operating Revenues: | | | |
| 1 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | $ 1,834,481 | |
| 2 | Adjusted Revenues In Year Ended December 2007 | Sch. TJC-7, Col (C), Ln 8 | 1,834,481 | |
| 3 | Proposed Revenues | Sch. TJC-7, Col (E), Ln 8 | 1,340,535 | |
| 4 | Total Three Year Operating Revenues | Sum Of Lines 1, 2 & 3 | $ 5,009,497 | |
| 5 | Average Annual Operating Revenues | Line 4 / 3 | 1,669,832 | |
| 6 | Two Times Three Year Average Operating Revenues | Line 5 X 2 | | $ 3,339,664 |
| | ADD: | | | |
| | 10% Of Construction Work In Progress ("CWIP"): | | | |
| 7 | Test Year CWIP | Company Schedule E | $ 28,150 | |
| 8 | 10% Of CWIP | Line 7 X 10% | | $ 2,815 |
| | SUBTRACT: | | | |
| | Transportation At Book Value: | | | |
| 9 | Original Cost Of Transportation Equipment | RUCO Plant Schedule TJC-4 | $ - | |
| 10 | Acc. Dep. Of Transportation Equipment | RUCO Plant Schedule TJC-4 | - | |
| 11 | Net Book Value Of Transportation Equipment | Line 9 + Line 10 | | $ - |
| 12 | Company's Full Cash Value ("FCV") | Sum Of Lines 6, 8 & 11 | | $ 3,342,479 |
| | Calculation Of The Company's Tax Liability: | | | |
| | MULTIPLY: | | | |
| | FCV X Valuation Assessment Ratio X Property Tax Rates: | | | |
| 13 | Assessment Ratio | House Bill 2779 | 21.0% | |
| 14 | Assessed Value | Line 12 X Line 13 | $ 701,921 | |
| | Property Tax Rates: | | | |
| 15 | Primary Tax Rate | Company Workpapers | 11.3283% | |
| 16 | Secondary Tax Rate | Company Workpapers | 0.00% | |
| 17 | Estimated Tax Rate Liability | Line 15 + Line 16 | 11.33% | |
| | Property Tax | | | $ 79,516 |
| | Tax On Parcel | | | - |
| 18 | Company's Total Tax Liability - Based On Full Cash Value | Line 14 X Line 17 | | $ 79,516 |
| 19 | Test Year Adjusted Property Tax Expense As Filed | Co. Sch. C-1 | | 91,705 |
| 20 | Decrease In Property Tax Expense | Line 18 - Line 19 | | $ (12,189) |
| | | Line 20 | | $ (12,189) |

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008



**OPERATING INCOME ADJUSTMENT NO. 5**
**RATE CASE EXPENSE**

| LINE NO. | DESCRIPTION | (A) COMPANY ESTIMATE | (B) RUCO ADJUSTMENT | (C) RUCO AS ADJUSTED |
|---|---|---|---|---|
| 1 | Rate Case Expense Total | $ 125,000 | $ (31,250) | $ 93,750 |
| 2 | Allocation Factor | | | 100% |
| 3 | Wastewater Division - Surrebuttal Schedule (Line 1 X Line 2) | | | $ 93,750 |
| 4 | Normalization Period - 3 Years | | | 3 |
| 5 | RUCO Adjusted Rate Case Expense (Line 3 / 3 Years) | | | $ 31,250 |
| 6 | Company Rate Case Expenses As Filed (Company Sch. C-2) | | | $ 41,667 |
| 7 | RUCO Pro Forma Rate Case Expense (Lines 5 - 6) | | | $ (10,417) |
| 8 | RUCO Adjustment (Line 7) | | | $ (10,417) |

**OPERATING INCOME ADJUSTMENT NO. 6**
**MISCELLANEOUS EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Intentionally Left Blank - See TJC Testimony | |
| 2 | | |
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**OPERATING INCOME ADJUSTMENT NO. 7**
**PURCHASED POWER**

Intentionally Left Blank - See TJC Testimony

**OPERATING INCOME ADJUSTMENT NO. 8**
**TRANSPORTATION EXPENSE**

Intentionally Left Blank - See TJC Testimony

**OPERATING INCOME ADJUSTMENT NO. 9**
**OUT OF PERIOD CENTRAL OFFICE COSTS**

Intentionally Left Blank - See TJC Testimony

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Wastewater Division - Surrebuttal Schedules
Schedule TJC-15
Page 1 of 1

## OPERATING INCOME ADJUSTMENT #10 - ACTUAL CORPORATE COST ALLOCATIONS

| Line No. | Description | Company Actual Costs | RUCO Disallowed Costs | | RUCO Other Disallowed Costs | RUCO Allowable Costs | RUCO 2008 Allocation Factor | RUCO Allowed Allocated Costs | Allocation % To Rio Rico | RUCO Amount Allocated To Rio Rico |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Rent | 299,586 | | | (299,586) | - | 24.29% | - | 12.92% | - |
| 2 | Audit | 1,021,609 | | | (766,207) | 255,402 | 24.29% | 62,026 | 12.92% | 8,011.91 |
| 3 | Tax Services | 322,446 | | | (241,835) | 80,612 | 24.29% | 19,577 | 12.92% | 2,528.76 |
| 4 | Legal - General | 767,451 | (113,853) | Note A | (575,588) | 78,010 | 24.29% | 18,945 | 12.92% | 2,447.15 |
| 5 | Other Professional Services | 565,649 | | | (565,649) | - | 24.29% | - | 12.92% | - |
| 6 | Management Fee | 642,771 | | | (642,771) | - | 24.29% | - | 12.92% | - |
| 7 | Unit Holder Communications | 289,796 | | | (289,796) | - | 24.29% | - | 12.92% | - |
| 8 | Trustee Fees | 129,000 | | | (129,000) | - | 24.29% | - | 12.92% | - |
| 9 | Office Costs | 808,101 | (74,847) | Note A | (733,254) | - | 24.29% | - | 12.92% | - |
| 10 | Licenses/Fees and Permits | 140,852 | (140,852) | Note A | - | - | 24.29% | - | 12.92% | - |
| 11 | Escrow and Transfer Fees | 71,366 | | | (71,366) | - | 24.29% | - | 12.92% | - |
| 12 | Depreciation Expense | 211,253 | | | (158,440) | 52,813 | 24.29% | 12,826 | 12.92% | 1,656.74 |
| | **Total** | 5,269,882 | (329,552) | | (4,473,492) | 466,837 | | 113,375 | | 14,645 |

| | |
|---|---|
| RUCO Direct Testimony Amount of APT Costs Allowed | 10,009 |
| RUCO Surrebuttal Testimony Additional Amount of Actual APT Costs Allowed | 4,636 |
| RUCO Allocation To Rio Rico Water Division (Based on Total Ratio of Rate Base) | 70.9536% |
| RUCO Allocation To Rio Rico Wastewater Division (Based on Total Ratio of Rate Base) | 29.0464% |
| RUCO's Additional APT Cost Allocation Allowed for Water Division | 3,289 |
| RUCO's Additional APT Cost Allocation Allowed for Wastewater Division | 1,346 |

**Note A:**

| | |
|---|---|
| Per Company Rebuttal Schedule C-2 | $ (113,853) |
| Per Company Rebuttal Schedule C-2 | (74,847) |
| Per Company Rebuttal Schedule C-2 | (140,852) |

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report
Company's Response to Staff GB 3.2 and 3.10 APT Affiliate Charges - Rio Rico
Company's Response to Staff GB 3.7 and 3.15

## OPERATING INCOME ADJUSTMENT #11- CORPORATE ALLOCATIONS

| Line No. | Description | Company Total Cost | RUCO Disallowed Costs | | RUCO Other Disallowed Costs | RUCO Allowable Costs | RUCO 2008 Allocation Factor | RUCO Allowed Allocated Costs | Allocation % To Rio Rico | RUCO Amount Allocated To Rio Rico |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Rent | 430,739 | | | (430,739) | - | 24.29% | - | 12.92% | - |
| 2 | Audit | 507,000 | | | (380,250) | 126,750 | 24.29% | 30,782 | 12.92% | 3,976.12 |
| 3 | Tax Services | 265,000 | | | (198,750) | 66,250 | 24.29% | 16,089 | 12.92% | 2,078.25 |
| 4 | Legal - General | 300,000 | | | (225,000) | 75,000 | 24.29% | 18,214 | 12.92% | 2,352.73 |
| 5 | Other Professional Services | 455,000 | | | (455,000) | - | 24.29% | - | 12.92% | - |
| 6 | Management Fee | 636,619 | | | (636,619) | - | 24.29% | - | 12.92% | - |
| 7 | Unit Holder Communications | 314,100 | | | (314,100) | - | 24.29% | - | 12.92% | - |
| 8 | Trustee Fees | 204,000 | | | (204,000) | - | 24.29% | - | 12.92% | - |
| 9 | Office Costs | 254,100 | (46,186) | Note A | (207,914) | - | 24.29% | - | 12.92% | - |
| 10 | Licenses/Fees and Permits | 305,000 | (145,642) | Note B | (159,358) | - | 24.29% | - | 12.92% | - |
| 11 | Escrow and Transfer Fees | 75,000 | | | (75,000) | - | 24.29% | - | 12.92% | - |
| 12 | Depreciation Expense | 204,242 | | | (153,182) | 51,061 | 24.29% | 12,400 | 12.92% | 1,601.76 |
| | **Total** | 3,950,800 | (191,828) | | (3,439,912) | 319,061 | | 77,486 | | 10,009 |

| | |
|---|---|
| RUCO Allocation To Rio Rico Water Division (Based on Total Ratio of Rate Base) | 70.2482% |
| RUCO Allocation To Rio Rico Wastewater Division (Based on Total Ratio of Rate Base) | 29.7518% |
| Company's APT Cost Allocation for Water Division (Per Staff DR GB 3.7 & GB 3.15) | $ 103,745 |
| RUCO's APT Cost Allocation Allowed for Water Division | 7,031 |
| RUCO's APT Cost Allocation Adjustment for Water Division | (96,714) |
| Company's APT Cost Allocation for Wastewater Division (Per Staff DR GB 3.7 & GB 3.15) | $ 34,582 |
| RUCO's APT Cost Allocation Allowed for Wastewater Division | 2,978 |
| RUCO's APT Cost Allocation Adjustment for Wastewater Division | (31,604) |

**Note A:**

| | Description | |
|---|---|---|
| Office Costs | Wind Analysis Software | $ 15,056 |
| Office Costs | Gold Watches & Clocks | 16,864 |
| Office Costs | Pilsner Beer Glasses | 5,700 |
| Office Costs | Leafs/Raptors Tickets | 5,066 |
| Office Costs | Super Bowl Tickets | 3,500 |
| Total | | $ 46,186 |

**Note B:**

| | | |
|---|---|---|
| Licenses/Fees and Permits | Donation | $ 25,000 |
| Licenses/Fees and Permits | Donation | 25,000 |
| Licenses/Fees and Permits | Donation | 13,350 |
| Licenses/Fees and Permits | Donation | 5,000 |
| Licenses/Fees and Permits | Wind Developm | 7,887 |
| Licenses/Fees and Permits | US Trustee | 9,375 |
| Licenses/Fees and Permits | Wind Energy | 12,556 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,891 |
| Licenses/Fees and Permits | APF Inc Taxes | 6,794 |
| Licenses/Fees and Permits | APF Inc Taxes | 23,789 |
| Licenses/Fees and Permits | KMS Tax Ruling | 10,000 |
| Total | | $ 145,642 |

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report
Company's Response to Staff GB 3.2 and 3.10 APT Affiliate Charges - Rio Rico
Company's Response to Staff GB 3.7 and 3.15

**OPERATING INCOME ADJUSTMENT NO. 12**
**REMOVE UNAMORTIZED PRIOR RATE CASE EXPENSE**

Intentionally Left Blank - See TJC Testimony

**OPERATING INCOME ADJUSTMENT NO. 13**
**BAD DEBT EXPENSE**

| LINE NO. | DESCRIPTION | (A) AMOUNT |
|---|---|---|
| 1 | Normalize Bad Debt Expense: | |
| 2 | | |
| 3 | 2008 Bad Debt Expense | $ 64,087 |
| 4 | 2007 Bad Debt Expense | 28,498 |
| 5 | 2006 Bad Debt Expense | 8,732 |
| 6 | | |
| 7 | 3 Year Normalization | $ 33,772 |
| 8 | | |
| 9 | Company As Filed | 64,087 |
| 10 | | |
| 11 | RUCO Adjustment | $ (30,315) |
| 12 | | |
| 13 | | |
| 14 | | |
| 15 | | |
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| 38 | SUPPORTING SCHEDULES | |
| 39 | Company Schedule E-2 | |
| 40 | | |
| 41 | | |

## OPERATING INCOME ADJUSTMENT #14
## INCOME TAX EXPENSE

| LINE NO. | DESCRIPTION | (A) REFERENCE | (B) AMOUNT |
|---|---|---|---|
| | **FEDERAL INCOME TAXES:** | | |
| 1 | Operating Income Before Taxes | Sch. TJC-7, Column (C), L28 + L22 + L23 | $ 831,092 |
| | LESS: | | |
| 2 | Arizona State Tax | Line 11 | 52,704 |
| 3 | Interest Expense | Note (A) Line 21 | 74,718 |
| 4 | Federal Taxable Income | Line 1 - Line 2 - Line 3 | $ 703,669 |
| 5 | Federal Tax Rate | Sch. TJC-1, Pg 2, Col. (D), L34 | 34.00% |
| 6 | Federal Income Tax Expense | Line 4 X line 5 | $ 239,248 |
| | **STATE INCOME TAXES:** | | |
| 7 | Operating Income Before Taxes | Line 1 | $ 831,092 |
| | LESS: | | |
| 8 | Interest Expense | Note (A) Line 21 | 74,718 |
| 9 | State Taxable Income | Line 7 - Line 8 | $ 756,373 |
| 10 | State Tax Rate | Tax Rate | 6.97% |
| 11 | State Income Tax Expense | Line 9 X Line 10 | $ 52,704 |
| | **TOTAL INCOME TAX EXPENSE:** | | |
| 12 | Federal Income Tax Expense | Line 6 | $ 239,248 |
| 13 | State Income Tax Expense | Line 11 | 52,704 |
| 14 | Total Income Tax Expense Per RUCO | Line12 + Line 13 | $ 291,952 |
| 15 | Total Federal Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | 252,773 |
| 16 | Total State Income Tax Expense Per Company (Per Company Sch. C-1, L28) | | 55,684 |
| 17 | RUCO Federal Income Tax Adjustment | Line 12 - Line 15 | $ (13,525) |
| 18 | RUCO State Income Tax Adjustment | Line 13 - Line 16 | $ (2,979) |

NOTE (A):
Interest Synchronization:

| | | |
|---|---|---|
| 19 | Adjusted Rate Base (Sch. TJC-2, Col. (H), L17) | $ 2,983,957 |
| 20 | Weighted Cost Of Debt (Sch. TJC-16 Col. (F), L1) | 2.50% |
| | | $ 74,718 |

## COST OF CAPITAL

| LINE NO. | DESCRIPTION | (B) CAPITAL RATIO | (C) COST RATE | (D) WEIGHTED COST RATE |
|---|---|---|---|---|
| 1 | Long-Term Debt | 40.00% | 6.26% | 2.50% |
| 2 | Common Equity | 60.00% | 9.00% | 5.40% |
| 3 | Total Capitalization | 100.00% | | |
| 4 | WEIGHTED AVERAGE COST OF CAPITAL | | | 7.90% |

References:
Columns (A) Thru (D): Testimony, WAR

# TJC-RD1

**RATE DESIGN AND PROOF OF RECOMMENDED REVENUE**
**RUCO SURREBUTTAL RECOMMENDED REVENUE**

| LINE NO. | DESCRIPTION | (A) TEST YEAR DETERMIN'TS | (B) RUCO ANN'ZED ADJTM'TS | (C) RUCO ADJUSTED DETERMIN'TS | (D) RUCO RECOMND'ED RATES | (E) RUCO PROPOSED REVENUES | (F) RUCO TOTAL REVENUES |
|---|---|---|---|---|---|---|---|
| | **RESIDENTIAL CUSTOMERS** | | | | | | |
| 1 | 5/8" | 68,940 | 1,344 | 70,284 | $ 9.43 | $ 662,823 | $ 662,823 |
| | Commodity Usage | | | | | | |
| 2 | First Tier - First 4,000 Gals. | 235,875 | 5,804 | 241,679 | $ 2.02 | $ 487,092 | |
| 3 | Second Tier - Next 6,000 Gals. | 198,643 | 4,015 | 202,658 | $ 2.53 | $ 512,996 | |
| 4 | Third Tier - Over 10,000 Gals. | 154,775 | 1,648 | 156,423 | $ 2.88 | $ 449,761 | |
| | | | | | | | $ 1,449,849 |
| 5 | 3/4" | 95 | 1 | 96 | $ 14.11 | $ 1,354 | $ 1,354 |
| | Commodity Usage | | | | | | |
| 6 | First Tier - First 6,000 Gals. | 334 | 3 | 337 | $ 2.53 | $ 854 | |
| 7 | Second Tier - Over 6,000 Gals. | 4 | 2 | 6 | $ 2.88 | $ 16 | |
| | | | | | | | $ 870 |
| 8 | 1" | 432 | 168 | 600 | $ 25.00 | $ 14,998 | $ 14,998 |
| | Commodity Usage | | | | | | |
| 9 | First Tier - First 15,000 Gals. | 3,417 | 1,976 | 5,393 | $ 2.53 | $ 13,651 | |
| 10 | Second Tier - Over 15,000 Gals. | 1,476 | 13 | 1,489 | $ 2.88 | $ 4,281 | |
| | | | | | | | $ 17,933 |
| 11 | 1.5" | 43 | 53 | 96 | $ 50.72 | $ 4,869 | $ 4,869 |
| | Commodity Usage | | | | | | |
| 12 | First Tier - First 20,000 Gals. | 600 | 1,050 | 1,650 | $ 2.53 | $ 4,177 | |
| 13 | Second Tier - Over 20,000 Gals. | 265 | 192 | 457 | $ 2.88 | $ 1,314 | |
| | | | | | | | $ 5,491 |
| 14 | 2" | 48 | 12 | 60 | $ 78.93 | $ 4,736 | $ 4,736 |
| | Commodity Usage | | | | | | |
| 15 | First Tier - First 57,000 Gals. | 872 | 246 | 1,118 | $ 2.53 | $ 2,830 | |
| 16 | Second Tier - Over 57,000 Gals. | 85 | (0) | 85 | $ 2.88 | $ 244 | |
| | | | | | | | $ 3,075 |
| 17 | Total Residential Customers | 69,558 | 1,578 | 71,136 | | | |
| 18 | Total Residential Usage | 596,346 | 14,949 | 611,295 | | | |
| 19 | TOTAL RESIDENTIAL CUSTOMERS REVENUE | | | | | | $ 2,165,998 |
| | **COMMERCIAL CUSTOMERS** | | | | | | |
| 20 | 5/8" | 1,163 | 229 | 1,392 | $ 9.43 | $ 13,127 | $ 13,127 |
| | Commodity Usage | | | | | | |
| 21 | First Tier - First 4,000 Gals. | 3,255 | 1,193 | 4,448 | $ 2.02 | $ 8,965 | |
| 22 | Second Tier - Next 6,000 Gals. | 3,111 | 673 | 3,784 | $ 2.53 | $ 9,578 | |
| 23 | Third Tier - Over 10,000 Gals. | 7,096 | 861 | 7,957 | $ 2.88 | $ 22,879 | |
| | | | | | | | $ 41,421 |
| 24 | 1" | 515 | 37 | 552 | $ 25.00 | $ 13,798 | $ 13,798 |
| | Commodity Usage | | | | | | |
| 25 | First Tier - First 15,000 Gals. | 4,169 | 540 | 4,709 | $ 2.53 | $ 11,919 | |
| 26 | Second Tier - Over 15,000 Gals. | 5,000 | 83 | 5,083 | $ 2.88 | $ 14,615 | |
| | | | | | | | $ 26,534 |
| 27 | 1-1/2" | 124 | (4) | 120 | $ 50.72 | $ 6,087 | $ 6,087 |
| | Commodity Usage | | | | | | |
| 28 | First Tier - First 20,000 Gals. | 1,867 | (80) | 1,787 | $ 2.53 | $ 4,524 | |
| 29 | Second Tier - Over 20,000 Gals. | 3,054 | (64) | 2,990 | $ 2.88 | $ 8,596 | |
| | | | | | | | $ 13,120 |
| 30 | 2" | 393 | 27 | 420 | $ 78.93 | $ 33,152 | $ 33,152 |
| | Commodity Usage | | | | | | |
| 31 | First Tier - First 57,000 Gals. | 12,341 | 1,539 | 13,880 | $ 2.53 | $ 35,135 | |
| 32 | Second Tier - Over 57,000 Gals. | 48,381 | 1,351 | 49,732 | $ 2.88 | $ 142,993 | |
| | | | | | | | $ 178,129 |
| 33 | 3" | 161 | (17) | 144 | $ 154.07 | $ 22,186 | $ 22,186 |
| | Commodity Usage | | | | | | |
| 34 | First Tier - First 57,000 Gals. | 4,188 | (969) | 3,219 | $ 2.53 | $ 8,148 | |
| 35 | Second Tier - Over 57,000 Gals. | 38,661 | (3,403) | 35,258 | $ 2.88 | $ 101,377 | |
| | | | | | | | $ 109,525 |

## RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
## RUCO SURREBUTTAL RECOMMENDED REVENUE

| LINE NO. | DESCRIPTION | (A) TEST YEAR DETERMIN'TS | (B) RUCO ANN'ZED ADJTM'TS | (C) RUCO ADJUSTED DETERMIN'TS | (D) RUCO RECOMND'ED RATES | (E) RUCO PROPOSED REVENUES | (F) RUCO TOTAL REVENUES |
|---|---|---|---|---|---|---|---|
| 1 | 4" | 61 | 11 | 72 | $ 253.61 | $ 18,260 | $ 18,260 |
| | Commodity Usage | | | | | | |
| 2 | First Tier - First 57,000 Gals. | 3,063 | 627 | 3,690 | $ 2.53 | $ 9,341 | |
| 3 | Second Tier - Over 57,000 Gals. | 14,765 | 2,805 | 17,570 | $ 2.88 | $ 50,518 | |
| | | | | | | | $ 59,859 |
| 4 | 6" | 12 | - | 12 | $ 469.58 | $ 5,635 | $ 5,635 |
| | Commodity Usage | | | | | | |
| 5 | First Tier - First 125,000 Gals. | 1,500 | - | 1,500 | $ 2.53 | $ 3,797 | |
| 6 | Second Tier - Over 125,000 Gals. | 6,200 | - | 6,200 | $ 2.88 | $ 17,827 | |
| | | | | | | | $ 21,624 |
| 7 | Total Commercial Customers | 2,429 | 283 | 2,712 | | | |
| 8 | Total Commercial Usage | 156,651 | 5,155 | 161,806 | | | |
| 9 | TOTAL COMMERCIAL CUSTOMERS REVENUE | | | | | | $ 562,456 |
| | **Multi-Family** | | | | | | |
| 10 | 5/8" | 117 | (9) | 108 | $ 9.43 | $ 1,019 | $ 1,019 |
| | Commodity Usage | | | | | | |
| 11 | First Tier - First 4,000 Gals. | 433 | (33) | 400 | $ 2.02 | $ 806 | |
| 12 | Second Tier - Next 6,000 Gals. | 439 | (32) | 407 | $ 2.53 | $ 1,030 | |
| 13 | Third Tier - Over 10,000 Gals. | 382 | (30) | 352 | $ 2.88 | $ 1,013 | |
| | | | | | | | $ 2,849 |
| 14 | 1-1/2" | 12 | - | 12 | $ 50.72 | $ 609 | $ 609 |
| | Commodity Usage | | | | | | |
| 15 | First Tier - First 20,000 Gals. | 89 | - | 89 | $ 2.53 | $ 225 | |
| 16 | Second Tier - Over 20,000 Gals. | 0 | - | 0 | $ 2.88 | $ - | |
| | | | | | | | $ 225 |
| 17 | Total Multi-Family Customers | 129 | (9) | | | | |
| 18 | Total Commercial Usage | 1,343 | (95) | | | | |
| 19 | TOTAL MULTI-FAMILY CUSTOMER REVENUE | | | | | | $ 4,702 |
| | **PRIVATE FIRE PROTECTION CUSTOMERS** | | | | | | |
| 20 | Fire Lines Up to 8" | 185 | 79 | 264 | $ 13.77 | $ 3,635 | $ 3,635 |
| 21 | Commodity Usage | 0 | - | - | No Charge | | |
| 22 | TOTAL PRIVATE FIRE PROTECTION CUSTOMERS REVENUE | | | | | | $ 3,635 |
| 23 | COMPANY TOTAL PROPOSED REVENUE PER BILL DETERMINANTS | | | | | | $ 3,859,697 |
| 24 | Other Revenue | | | | | | 44,672 |
| 25 | COMPANY PROPOSED TOTAL REVENUES | | | | | | $ 3,904,369 |
| 26 | RUCO TOTAL SURREBUTTAL RECOMMENDED REVENUE PER BILL DETERMINANTS | | | | | | $ 2,736,791 |
| 27 | Other Revenue | | | | | | $ 44,672 |
| 28 | TOTAL RUCO SURREBUTTAL RECOMMENDED REVENUE PER TJC-1 | | | | | | $ 2,781,463 |

# TJC-RD2

Rio Rico Utilities, Inc.
Docket No. WS-02676A-09-0257
Test Year Ended December 31, 2008

Water Division
Surrebuttal Schedule TJC-RD2
Page 1 of 1

## TYPICAL RESIDENTIAL BILL ANALYSIS

| LINE NO. | DESCRIPTION | (A) PRESENT | (B) PRESENT | (C) COMPANY PROPOSED | (D) COMPANY PROPOSED | (E) RUCO PROPOSED | (F) RUCO PROPOSED |
|---|---|---|---|---|---|---|---|
| | **TOTAL REVENUES** | | | | | | |
| 1 | RESIDENTIAL | $ 1,440,833 | 79.66% | $ 3,067,443 | 79.29% | $ 2,165,998 | 79.14% |
| 2 | COMMERCIAL | 363,332 | 20.09% | 791,256 | 20.45% | 562,456 | 20.55% |
| 3 | MULTI-FAMILY | 3,418 | 0.19% | 7,297 | 0.19% | 4,702 | 0.17% |
| | PRIVATE FIRE | 1,199 | 0.07% | 2,547 | 0.07% | 3,635 | 0.13% |
| | TOTAL | $ 1,808,782 | 100.00% | $ 3,868,544 | 100.00% | $ 2,736,791 | 100.00% |
| | **ALLOCATION RATIOS** | | | | | | |
| 4 | FIX REVENUE | $ 532,661 | 29.45% | $ 1,133,658 | 29.38% | $ 806,288 | 29.46% |
| 5 | VARIABLE REVENUE | 1,276,120 | 70.55% | 2,725,445 | 70.62% | 1,930,503 | 70.54% |
| 6 | TOTAL | $ 1,808,782 | 100.00% | $ 3,859,103 | 100.00% | $ 2,736,791 | 100.00% |

| | **RES. G-1 (5/8" X 3/4") RATE DESIGN** | | PRESENT | COMPANY PROPOSED | RUCO PROPOSED |
|---|---|---|---|---|---|
| 7 | BASIC MONTHLY CHARGE | | $ 6.45 | $ 13.71 | $ 9.43 |
| | COMMODITY CHARGE | | | | |
| | PRESENT | PROPOSED | | | |
| 8 | First Tier - First 4,000 Gals. | First Tier - First 4,000 Gals. | $ 1.4400 | $ 2.9300 | $ 2.0154 |
| 9 | Second Tier - Next 6,000 Gals. | Second Tier - Next 6,000 Gals. | $ 1.7000 | $ 3.6800 | $ 2.5313 |
| 10 | Third Tier - Over 10,000 Gals. | Third Tier - Over 10,000 Gals. | $ 1.9000 | $ 4.1800 | $ 2.8753 |

| | **RESIDENTIAL BILL COMPARISONS** COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL | % OF AVERAGE MONTH USAGE OF 8,548 Gal. | GALLONS USED AT VARIOUS USAGE | PRESENT MONTHLY WATER COST | RUCO PROP'D MONTHLY WATER COST | RUCO PROP'D MONTHLY INCREASE | RUCO PROP'D MONTHLY % INCREASE |
|---|---|---|---|---|---|---|---|
| 11 | | 25.00% | 2,137 | $ 9.53 | $ 13.74 | $ 4.21 | 44.19% |
| 12 | | 50.00% | 4,274 | $ 12.68 | $ 18.19 | $ 5.51 | 43.47% |
| 13 | | 100.00% | 8,548 | $ 19.94 | $ 29.00 | $ 9.06 | 45.45% |
| 14 | | 150.00% | 12,822 | $ 27.77 | $ 40.79 | $ 13.02 | 46.89% |
| 15 | | 200.00% | 17,096 | $ 35.89 | $ 53.08 | $ 17.19 | 47.90% |

**TJC-RD1**

**RATE DESIGN AND PROOF OF RECOMMENDED REVENUE**
**RUCO SURREBUTTAL PROPOSED REVENUE**

| LINE NO. | DESCRIPTION | (A) TEST YEAR DETERMIN'TS | (B) RUCO ANN'ZED ADJTM'TS | (C) RUCO ADJUSTED DETERMIN'TS | (D) RUCO RECOMND'ED RATES | (E) RUCO PROPOSED REVENUES | (F) RUCO TOTAL REVENUES |
|---|---|---|---|---|---|---|---|
| | **RESIDENTIAL CUSTOMERS** | | | | | | |
| 1 | 5/8" | 22,848 | 16 | 22,864 | $ 40.84 | $ 933,676 | $ 933,676 |
| | Commodity Usage | | | | | | |
| 2 | First Tier - First 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 3 | Second Tier - Over 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 4 | 3/4" | 98 | (2) | 96 | $ 46.57 | $ 4,471 | $ 4,471 |
| | Commodity Usage | | | | | | |
| 5 | First Tier - First 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 6 | Second Tier - Over 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 7 | 1" | 104 | 2 | 106 | $ 57.53 | $ 6,076 | $ 6,076 |
| | Commodity Usage | | | | | | |
| 8 | First Tier - First 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 9 | Second Tier - Over 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 10 | 1.5" | 0 | 0 | 0 | $ 84.95 | $ - | $ - |
| | Commodity Usage | | | | | | |
| 11 | First Tier - First 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 12 | Second Tier - Over 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 13 | 2" | 12 | 0 | 12 | $ 117.83 | $ 1,414 | $ 1,414 |
| | Commodity Usage | | | | | | |
| 14 | First Tier - First 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 15 | Second Tier - Over 7,000 Gals. | 0 | 0 | 0 | $ - | $ - | $ - |
| 16 | Total Residential Usage | 23,062 | 15 | 23,077 | | | |
| 17 | Total Residential Usage | 0 | 0 | 0 | | | |
| 18 | TOTAL RESIDENTIAL CUSTOMERS REVENUE | | | | | | $ 945,637 |
| | **COMMERCIAL CUSTOMERS** | | | | | | |
| 19 | 5/8" | 831 | 105 | 936 | $ 40.84 | $ 38,223 | $ 38,223 |
| | Commodity Usage | | | | | | |
| 20 | First Tier - First 7,000 Gals. | 3,681 | 735 | 4,416 | $ - | $ - | |
| 21 | Second Tier - Over 7,000 Gals. | 5,459 | 377 | 5,836 | $ 4.14 | $ 24,145 | |
| | | | | | | | $ 24,145 |
| 22 | 1" | 437 | 55 | 492 | $ 57.53 | $ 28,305 | $ 28,305 |
| | Commodity Usage | | | | | | |
| 23 | First Tier - First 7,000 Gals. | 2,079 | 385 | 2,464 | $ - | $ - | |
| 24 | Second Tier - Over 7,000 Gals. | 4,640 | 507 | 5,147 | $ 4.14 | $ 21,293 | |
| | | | | | | | $ 21,293 |
| 25 | 1-1/2" | 87 | (3) | 84 | $ 84.95 | $ 7,136 | $ 7,136 |
| | Commodity Usage | | | | | | |
| 26 | First Tier - First 7,000 Gals. | 545 | (23) | 522 | $ - | $ - | |
| 27 | Second Tier - Over 7,000 Gals. | 2,970 | (122) | 2,848 | $ 4.14 | $ 11,784 | |
| | | | | | | | $ 11,784 |
| 28 | 2" | 238 | 2 | 240 | $ 117.83 | $ 28,279 | $ 28,279 |
| | Commodity Usage | | | | | | |
| 29 | First Tier - First 7,000 Gals. | 1,511 | 14 | 1,525 | $ - | $ - | |
| 30 | Second Tier - Over 7,000 Gals. | 24,496 | 178 | 24,674 | $ 4.14 | $ 102,085 | |
| | | | | | | | $ 102,085 |
| 31 | 3" | 12 | 0 | 12 | $ 205.27 | $ 2,463 | $ 2,463 |
| | Commodity Usage | | | | | | |
| 32 | First Tier - First 7,000 Gals. | 77 | 0 | 77 | $ - | $ - | |
| 33 | Second Tier - Over 7,000 Gals. | 790 | 0 | 790 | $ 4.14 | $ 3,268 | |
| | | | | | | | $ 3,268 |

**RATE DESIGN AND PROOF OF RECOMMENDED REVENUE**
**RUCO SURREBUTTAL PROPOSED REVENUE**

| LINE NO. | DESCRIPTION | (A) TEST YEAR DETERMIN'TS | (B) RUCO ANN'ZED ADJTM'TS | (C) RUCO ADJUSTED DETERMIN'TS | (D) RUCO RECOMND'ED RATES | (E) RUCO PROPOSED REVENUES | (F) RUCO TOTAL REVENUES |
|---|---|---|---|---|---|---|---|
| 1 | 4" | 48 | 0 | 48 | $ 304.25 | $ 14,604 | $ 14,604 |
| | Commodity Usage | | | | | | |
| 2 | First Tier - First 7,000 Gals. | 336 | 0 | 336 | $ - | $ - | |
| 3 | Second Tier - Over 7,000 Gals. | 16,015 | 90 | 16,105 | $ 4.14 | $ 66,633 | |
| | | | | | | | $ 66,633 |
| 4 | 6" | 12 | 0 | 12 | $ 578.17 | $ 6,938 | $ 6,938 |
| | Commodity Usage | | | | | | |
| 5 | First Tier - First 7,000 Gals. | 84 | 0 | 84 | $ - | $ - | |
| 6 | Second Tier - Over 7,000 Gals. | 7,707 | 0 | 7,707 | $ 4.14 | $ 31,886 | |
| | | | | | | | $ 31,886 |
| | | | | | | $ - | $ - |
| 7 | Total Commercial Customers | 1,665 | 159 | 1,824 | | | |
| 8 | Total Commercial Usage | 70,390 | 2,142 | 72,532 | | | |
| 9 | TOTAL COMMERCIAL CUSTOMERS REVENUE | | | | | | $ 387,043 |
| | **Multi-Family** | | | | | | |
| 10 | 5/8" | 113 | (5) | 108 | $ 40.84 | $ 4,410 | $ 4,410 |
| | Commodity Usage | | | | | | |
| 11 | First Tier - First 7,000 Gals. | 660 | (35) | 625 | $ - | $ - | |
| 12 | Second Tier - Over 7,000 Gals. | 528 | (20) | 508 | $ 4.14 | $ 2,101 | |
| | | | | | | | $ 2,101 |
| 13 | 1-1/2" | 12 | 0 | 12 | $ 84.95 | $ 1,019 | $ 1,019 |
| | Commodity Usage | | | | | | |
| 14 | First Tier - First 7,000 Gals. | 73 | 0 | 73 | $ - | $ - | |
| 15 | Second Tier - Over 7,000 Gals. | 18 | 0 | 18 | $ 4.14 | $ 74 | |
| | | | | | | | $ 74 |
| 16 | Total Multi-Family Customers | 125 | (5.00) | 120 | | | |
| 17 | Total Commercial Usage | 1,279 | (55) | 1,224 | | | |
| 18 | TOTAL MULTI-FAMILY CUSTOMER REVENUE | | | | | | $ 7,605 |
| 23 | **COMPANY TOTAL PROPOSED REVENUE PER BILL DETERMINANTS** | | | | | | $ 1,740,668 |
| 24 | Other Revenue | | | | | | 250 |
| 25 | **COMPANY PROPOSED TOTAL REVENUES** | | | | | | $ 1,740,918 |
| 26 | **RUCO TOTAL SURREBUTTAL RECOMMENDED REVENUE PER BILL DETERMINANTS** | | | | | | $ 1,340,285 |
| 27 | Other Revenue | | | | | | 250 |
| 28 | **TOTAL RUCO SURREBUTTAL RECOMMENDED REVENUE PER TJC-1** | | | | | | $ 1,340,535 |

**TJC-RD2**

## TYPICAL RESIDENTIAL BILL ANALYSIS

| LINE NO. | DESCRIPTION | (A) PRESENT | (B) PRESENT | (C) COMPANY PROPOSED | (D) COMPANY PROPOSED | (E) RUCO PROPOSED | (F) RUCO PROPOSED |
|---|---|---|---|---|---|---|---|
| | **REVENUE ALLOCATION** | | | | | | |
| 1 | RESIDENTIAL | $ 1,304,221 | 71.10% | $ 1,241,618 | 71.15% | $ 945,637 | 70.55% |
| 2 | COMMERCIAL | 518,027 | 28.24% | 493,162 | 28.26% | 387,043 | 28.88% |
| 3 | MULTI-FAMILY | 10,893 | 0.59% | 10,370 | 0.59% | 7,605 | 0.57% |
| | Unreconciled Difference | 1,090 | 0.06% | - | 0.00% | - | 0.00% |
| | TOTAL | $ 1,834,231 | 100.00% | $ 1,745,150 | 100.00% | $ 1,340,285 | 100.00% |
| | **ALLOCATION RATIOS** | | | | | | |
| 4 | FIXED REVENUE | $ 1,475,564 | 80.45% | $ 1,414,966 | 80.36% | $ 1,077,014 | 80.36% |
| 5 | VARIABLE REVENUE | 357,577 | 19.49% | 345,878 | 19.64% | 263,270 | 19.64% |
| | Unreconciled Difference | 1,090 | 0.06% | - | 0.00% | - | 0.00% |
| 6 | TOTAL | $ 1,834,231 | 100.00% | $ 1,760,844 | 100.00% | $ 1,340,285 | 100.00% |

| | **RESIDENTIAL 5/8" METER RATE DESIGN** | | PRESENT | COMPANY PROPOSED | RUCO PROPOSED |
|---|---|---|---|---|---|
| 7 | BASIC MONTHLY CHARGE | | $ 56.36 | $ 53.65 | $ 40.84 |
| | COMMODITY CHARGE: (Commercial & Mult-Family Only | | | | |
| | PRESENT | PROPOSED | | | |
| 8 | First Tier - 0 Gals. To & 7,000 Gals. | First Tier - 0 Gals. To & 7,000 Gals. | $ - | $ - | $ - |
| 9 | Second Tier - Over 7,000 Gals. | Second Tier - Over 7,000 Gals. | $ 5.71 | $ 5.44 | $ 4.14 |

EXHIBIT
R-12
ADMITTED



**SEWER COMPANIES IN ARIZONA**
**TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS**
**COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA WASTEWATER COMPANIES WITH SHARED SERVICES**

Algonquin Wastewater Services

| Line No. | | Note | 2008 Pro-Forma Wages Expensed | 2008 Average Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|---|
| 1 | **Rio Rico Utilities, Inc Sewer** | 1 | **$ 482,045** | 2,071 | **$ 232.76** | **$ 19.40** |

Arizona American Water Company

| | Individual Systems: | Note | As Company Filed | Note | As Company Filed | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for AZ-AM |
|---|---|---|---|---|---|---|---|---|
| 2 | Sun City - Sewer | 2 | 1,750,158 | 3 | 21,965 | 79.68 | 6.64 | |
| 3 | Sun City West - Sewer | 2 | 2,097,680 | 3 | 14,968 | 140.14 | 11.68 | |
| 4 | Mohave Sewer | 4 | 291,651 | 4 | 1,235 | 236.15 | 19.68 | |
| 5 | Average Labor and Wage Cost per Customer per Month for AZ-AM Sewer Companies | | | | | | | 12.67 |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
2. As Originally Filed by the Company in Docket No. SW-01303A-09-0343 - 2008 Test Year
3. Water Infrastructure Finance Authority of Arizona (WIFA) 2008 Water and Wastewater Residential Rate Survey for the State of Arizona
4. As Originally Filed by the Company in Docket No. SW-01303A-08-0227 - 2007 Test Year

**SEWER COMPANIES IN ARIZONA**
**TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS**
**COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA STAND-ALONE WASTEWATER COMPANIES WITHOUT SHARED SERVICES**

Algonquin Wastewater Services

| Line No. | | Note | 2008 Pro-Forma Wages Expensed | 2008 Average Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|---|
| 1 | **Rio Rico Utilities, Inc Sewer** | 1 | **$ 482,045** | **2,071** | **$ 232.76** | **$ 19.40** |

Various Arizona Wastewater Companies

| | | Note | 2008 Annual Report Wages Expensed | Note | 2008 Annual Report Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for Various Co. |
|---|---|---|---|---|---|---|---|---|
| 2 | Ajo Improvement Co. - Sewer | 5 | 87,645 | 5 | 1,065 | 82.32 | 6.86 | |
| 3 | Rio Verde Utilities, Inc. - Sewer | 5 | 224,012 | 5 | 1,622 | 138.07 | 11.51 | |
| 4 | Far West Sewer | 5 | 724,159 | 5 | 7,166 | 101.05 | 8.42 | |
| 5 | Average Labor and Wage Cost per Customer per Month for Various Stand-Alone Arizona Sewer Companies | | | | | | | **8.93** |
| 6 | Average Labor and Wage Cost per Customer each Month for All 6 Companies on Pages 1 & 2 | | | | | | | **10.80** |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
5. As Filed by the Various Wastewater Companies in its 2008 Annual Report Filed with the Commission

**WATER COMPANIES IN ARIZONA**
**TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS**
**COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA WATER COMPANIES WITH SHARED SERVICES**

Algonquin Water Services

| | Note | 2008 Pro-Forma Wages Expensed | 2008 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|
| **Rio Rico Utilities, Inc Water** | 1 | $ 895,475 | 6,025 | $ 148.63 | $ 12.39 |

Arizona Water Company

| Line No. | Individual Systems: | Note | 2007 Pro-Forma Wages Expensed | 2007 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for AZ Water |
|---|---|---|---|---|---|---|---|
| 1 | Coolidge Water | 2 | $ 619,942 | 4,703 | $ 131.82 | $ 10.98 | |
| 2 | Lakeside Water | 2 | 645,507 | 4,954 | 130.30 | 10.86 | |
| 3 | Sedona Water | 2 | 846,835 | 6,298 | 134.46 | 11.21 | |
| 4 | Casa Grande | 2 | 2,696,271 | 22,529 | 119.68 | 9.97 | |
| 5 | Winkelman | 2 | 30,294 | 168 | 180.32 | 15.03 | |
| | | | | | | | **11.61** |
| 6 | Total Arizona Water Company for All AWC 17 Water Systems | 2 | 12,923,552 | 82,886 | 155.92 | | **12.99** |

Arizona American Water Company

| | | Note | 2007 Pro-Forma Wages Expensed | 2007 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for AZ-AM |
|---|---|---|---|---|---|---|---|
| 7 | Agua Fria Water | 3 | $ 4,216,281 | 34,402 | $ 122.56 | $ 10.21 | |
| 8 | Havasu Water | 3 | 371,202 | 2,565 | 144.72 | 12.06 | |
| 9 | Mohave Water | 3 | 1,840,872 | 16,635 | 110.66 | 9.22 | |
| 10 | Sun City Water | 4 | 2,734,992 | 23,140 | 118.19 | 9.85 | |
| 11 | Sun City West Water | 3 | 1,703,120 | 15,465 | 110.13 | 9.18 | |
| 12 | Average Cost for the 5 AZ-AM Districts listed Above | | | | | | **10.10** |
| 13 | Average Cost per Month for All 10 Systems on Page 3 | | | | | | **11.55** |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
2. As Originally Filed by the Company in Docket No. W-01445A-08-0440
3. As Originally Filed by the Company in Docket No. W-01303A-08-0227
4. As Originally Filed by the Company in Docket No. W-01303A-09-0343

**WATER COMPANIES IN ARIZONA**
**TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS**
**COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA WATER COMPANIES WITH SHARED SERVICES**

Algonquin Water Services

| | Note | 2008 Pro-Forma Wages Expensed | 2008 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|
| **Rio Rico Utilities, Inc Water** | **1** | **$ 895,475** | **6,025** | **$ 148.63** | **$ 12.39** |

American States Water

| | | Note | 2006 Pro-Forma Wages Expensed | 2006 Average Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|---|
| 12 | Chaparral City Water Company | 5 | $ 1,506,886 | 13,333 | $ 113.02 | **$ 9.42** |
| 13 | Total Average Costs for Total AWC 17 systems, 5 AZ-AM districts, and 1 Chaparral System that utilize the Shared Services Concept | | | | | **$ 10.84** |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
5. As Originally Filed by the Company in Docket No. W-02113A-07-0551

**TOTAL LABOR / WAGE DOLLARS PER CUSTOMER ANALYSIS (continued)**
**COMPARISON OF ALGONQUIN UTILITIES WITH OTHER ARIZONA STAND-ALONE WATER COMPANIES WITHOUT SHARED SERVICES**

Algonquin Water Services

| | Note | 2008 Pro-Forma Wages Expensed | 2008 Pro-Forma Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer |
|---|---|---|---|---|---|
| **Rio Rico Utilities, Inc Water** | 1 | **$ 895,475** | **6,025** | **$ 148.63** | **$ 12.39** |

Various Stand-Alone Water Companies

| Line No. | Individual Systems: | Note | 2008 Annual Report Wages Expensed | 2008 Annual Report Customer Count | Annual Wage Cost Per Customer | Monthly Wage Cost Per Customer | Average Cost for Various Co. |
|---|---|---|---|---|---|---|---|
| 1 | Rio Verde Utilities, Inc. - Water | 2 | $ 239,802 | 1,688 | $ 142.06 | $ 11.84 | |
| 2 | Bermuda Water Company | 2 | 810,371 | 7,672 | 105.63 | 8.80 | |
| 3 | Lago Del Oro Water Company | 2 | 242,391 | 6,046 | 40.09 | 3.34 | |
| 4 | Average Cost per Month for the 3 Systems listed Above | | | | | | **7.99** |
| 5 | Average for Pages 3, 4, and 5 | | | | | | **10.13** |

Notes:
1. As Filed by the Company in Rebuttal in Docket No. WS-02676A-09-0257
2. As Filed by the Company in its 2008 Annual Report Filed with the Commission

EXHIBIT

R-13 admin notice

**BEFORE THE ARIZONA CORPORATION COMMISSION**

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

Arizona Corporation Commission
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IN THE MATTER OF THE APPLICATION OF H20, INC. FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PROPERTY AND FOR AN INCREASE IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE.

DOCKET NO. W-02234A-07-0557

DECISION NO. 71414

**OPINION AND ORDER**

DATES OF HEARING: March 9, 2009 (Public Comment); May 1, 2009 (Pre-Hearing Conference); and May 4, 2009 (Evidentiary Hearing)

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

APPEARANCES: Mr. Richard L. Sallquist, SALLQUIST, DRUMMOND & O'CONNOR, P.C., on behalf of H20, Inc.; and

Mr. Charles Hains, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

**BY THE COMMISSION:**

**Procedural History**

On October 1, 2007, H2O, Inc. ("H2O" or "Company") filed with the Arizona Corporation Commission ("Commission") an application for a determination of the current fair value of its utility property and for an increase in its rates and charges for water utility service provided to customers in the Company's certificated service area in parts of Maricopa and Pinal counties, Arizona. As part of its application, H2O filed supporting schedules and the Direct Testimony of its witness Thomas Bourassa.

On November 2, 2007, the Commission's Utilities Division Staff ("Staff") filed a Letter of Insufficiency stating that the application did not meet the sufficiency requirements outlined in Arizona Administrative Code ("A.A.C.") R14-2-103.

authorized), based on a FVRB of *negative* $363,842 and using a 10 percent operating margin approach to achieve the revenue requirement. (Ex. S-4, Sched. BCA-1.)

A summary of the parties' final revenue requirement positions follows:

| | Company Proposed | Staff Proposed |
|---|---|---|
| ORIGINAL COST | | |
| Adjusted Rate Base | $1,995,695 | $(363,842) |
| Rate of Return | 11.46% | 10% Op. Mar. |
| Req'd Operating Inc. | 228,614 | 321,871 |
| Operating Inc. Excess | (82,508) | (96,269) |
| Rev. Conver. Factor | 1.6259 | 1.6614 |
| Gross Rev. Decrease | (134,153) | (159,937) |
| FAIR VALUE | | |
| Adjusted Rate Base | $1,995,695 | $(363,842) |
| Rate of Return | 11.46% | 10% Op. Mar. |
| Req'd Operating Inc. | 228,614 | 321,871 |
| Operating Inc. Excess | (82,508) | (96,269) |
| Rev, Conver. Factor | 1.6259 | 1.6614 |
| Gross Rev. Decrease | (134,153) | (159,937) |

Three primary issues remain in dispute between H2O and Staff. The first, and most contentious, is whether unexpended hook-up fees and developer advances should be treated as contributions in aid of construction ("CIAC") and advances in aid of construction ("AIAC"), respectively, for purposes of reducing H2O's authorized rate base. The second issue is whether the Company's current off-site capacity reservation charge tariff should be eliminated. The final disputed issue is the appropriate allocation of annual revenue between the monthly minimum charge and commodity charges. Each of these issues is discussed below.

Treatment of Contributions and Advances

During the last 20 years, H2O was authorized to collect hook-up fees that were to be used to construct plant needed to serve its growing service area. In Decision No. 56486 (May 17, 1989), the Company was permitted to collect a Facilities Construction Charge ("FCC") that was limited to 280 residential units and no more than $120,000. The FCC was superseded by an Off-Site Capacity Reservation Charge ("CRC") in Decision No. 63259 (December 14, 2000) that eliminated the restriction on number of customers imposed by the FCA. In Decision No. 63259, the Commission

indicated that the CRC was intended to collect hook-up fees sufficient to fund an off-site water plant as well as the cost of upgrading adjacent transmission mains.

There is no disagreement between the Company and Staff regarding the amount of plant-in-service of $12,996,414 and test year accumulated depreciation of $1,497,950. (Ex. A-3, Sched. B-2, at 5.) However, the parties remain at odds over the appropriate rate base treatment of $2,859,339 of unexpended CIAC and AIAC, and currently funded construction work in progress ("CWIP"). At the end of the 2006 test year, H2O had collected approximately $8.6 million of CIAC through hook-up fees (after removing accumulated amortization) and more than $3 million in AIAC from developer advances.

According to H2O, a mismatch would be created if the Commission were to adopt Staff's recommendation to deduct CIAC and AIAC from the Company's rate base because there is no corresponding plant-in-service amount to "match" the contributions and advances received by H2O. The Company claims that it has approximately $2.7 million in unexpended funds that are being held to construct future plant for future customers.

Company witness Bourassa testified that H2O's proposed treatment of the unexpended CIAC and AIAC funds is consistent with the Commission's rules because the funds were collected pursuant to an approved CRC tariff and main extension agreements with developers. H2O claims that the contributions and advances collected from developers must be held to construct specific future infrastructure associated with the projects for which the funds were collected. The Company contends that since it may not use these funds for other purposes, deducting unexpended CIAC and AIAC from rate base would be inappropriate. H2O argues that adoption of Staff's proposal to treat unexpended CIAC and AIAC from rate base would effectively penalize the Company for not building infrastructure that it properly determined would result in excess capacity due to slowing of the housing market. In addition, H2O claims that adoption of Staff's recommendation would result in negative consequences for the Company by reducing its cash flow. By including unexpended CIAC in H2O's rate base, the Company's cash flow would be reduced by approximately $195,000 per year as a result of increased depreciation expense under Staff's recommendation. (Tr. at 131.)

The Company also criticizes Staff's reliance on A.A.C. R14-2-103 to support Staff's position.

In Appendix B, Schedule B-1, to Commission rule R14-2-103, CIAC and AIAC are shown as *deductions* to rate base in the calculation of OCRB (Ex. S-5, attached hereto as Attachment 1) and, accordingly, Staff witness Aladi testified that the rule requires the treatment proposed by Staff. (Tr. 147-148.) H2O argues that, contrary to Staff's interpretation, the rule does not address the larger ratemaking "matching" concept. Further, according to the Company, Staff's reliance on the rule as a reflection of Commission "policy" represents an over-simplification that would achieve an inequitable result harmful to H2O's long-term viability.

Two recent Commission Decisions addressed the treatment of unexpended advances[1]. In both cases, the utility companies argued that it is unfair to exclude advances from rate base if the plant associated with those advances is not yet in service and not included in rate base, and that such treatment would discourage companies from seeking advances to offset infrastructure capital costs. The Commission rejected the companies' arguments in those cases, citing to the Commission's rule discussed above (Attachment 1 hereto), as well as the long-standing Commission policy of excluding advances and contributions from rate base. (*Id.*)

The Company argues that the facts in the UNS cases differ from those presented in the instant case. The alleged distinctions include: (1) no CWIP is being requested by H2O unlike the UNS Gas and UNS Electric cases; (2) the disputed amount of rate base is significantly greater in this case; (3) H2O is much smaller than UNS Gas and UNS Electric and H2O is heavily dependent on developer contributions to fund growth; and (4) H2O did not have the ability to choose its test year, unlike the scenario presented in the UNS Gas and UNS Electric cases, because H2O was ordered to file based on a 2006 test year. H2O argues that, due to these factual differences, the conclusions reached in Decision Nos. 70011 and 70360 have little, if any, precedential value for the determination in this case.

The Company's attempt to distinguish the prior cases is not persuasive. First, although the companies in those cases sought inclusion of CWIP (which requests were rejected), both UNS Gas and UNS Electric also submitted as back-up, stand-alone proposals that, absent the inclusion of

[1] *UNS Gas, Inc.*, Decision No. 70011 (November 27, 2007), at 8-10; *UNS Electric, Inc.*, Decision No. 70360 (May 27, 2008), at 10-11.

CWIP or post-test-year plant in rate base, the Commission should decline to deduct advances from rate base. As noted above, we rejected those arguments based on the Commission's rules, as well as consistency with the treatment afforded other utilities historically.

The next alleged distinction between the UNS cases and the facts presented herein is H2O's claim that the CWIP and/or post-test-year plant requests represented a small fraction of the UNS companies' rate base compared to H2O. H2O does not set forth the point at which the magnitude of contributions and advances should give rise to an exemption from the Commission's rules, other than to suggest that perhaps the Commission should know it when it sees it.

Similarly, the third difference cited by H2O is the argument that the UNS companies are larger and better capitalized compared to H2O's reliance on developer contributions to meet growth infrastructure needs. H2O adds that the UNS companies received rate increases in the prior cases, whereas ratepayers will receive a rate decrease as a result of this case under either the Staff or Company proposals. It is curious that H2O cites to its reliance on developer funding as a basis for seeking what amounts to a waiver of the Commission's rule governing treatment of AIAC and CIAC, since it was H2O's unilateral decision that resulted in a capital structure consisting almost entirely of contributions and advances. The failure by H2O's owners to inject sufficient equity, combined with the Company's continued collection of hook-up fees (see discussion of hook-up fees below), has resulted in a situation in which H2O currently has a negative rate base. Although Mr. Bourassa attempted to dismiss H2O's reliance on contributed capital as a "timing problem," he conceded that such reliance could be detrimental to the Company and its customers in the long-term because, once growth ceases (and by extension the CIAC and AIAC associated with growth), the Company would be left with an inability to earn a return on rate base and would therefore be unable to make necessary repairs and improvements. (Tr. at 53-55.)

The final distinction offered by the Company is that the UNS companies were able to choose their test years whereas H2O was ordered to file a rate case using a 2006 or later test year. It is ironic that H2O raises the voluntary nature of the test year in support of its position given that the reason the Company was ordered to file a rate case with a given test year is that it has not filed a rate case since 1994 and therefore has not undergone an analysis and audit of its rates and operations during that

time. Given that both the Company and Staff recommend a rate reduction in this case, there is a strong possibility that H2O has been over-earning for a number of years and reinforces the conclusion that the Commission's rate filing requirement in Decision No. 69413 was necessary to determine the extent of such over-earning.

Nor are we persuaded by H2O's contention that Staff's negative rate base recommendation is punitive to the Company. H2O argues that adoption of Staff's proposal would make it more difficult for the Company to attract potential buyers that are well capitalized and could move the Company towards a more balanced capital structure. In effect, acceptance of H2O's position would confer special treatment that falls outside of the Commission's rules and would reward the Company for its failure to undertake any significant equity investment. For these reasons we find Staff's recommendation for a negative $363,842 rate base is reasonable and should be adopted as the Company's FVRB in this proceeding.

Elimination of Hook-Up Fee Tariff

At the end of the test year, H2O's capital structure consisted of approximately $12.34 million of customer-supplied funds ($9.27 million CIAC and $3.07 million AIAC) and only $820,000 in debt or equity. The vast majority of these funds were collected through H2O's CRC tariff. According to the Company, the significant amount of contributions collected under the CRC and advances received pursuant to main extension agreements has enabled the Company to fund growth with zero-cost capital, allowing H2O to keep rates low for all customers by requiring growth to pay for growth. H2O contends that Staff's recommendation to discontinue the CRC tariff would be devastating to the Company because it does not have the ability to access capital from a corporate parent or through the capital markets[2].

Even Company witness Bourassa agreed that the financing model currently being used by H2O is not sustainable in the long-term and that it may be appropriate at some point for the

[2] H2O also opposes refund of any portion of the $2.7 million unexpended CIAC, as was suggested as a possibility at the hearing. In a prior case involving Black Mountain Sewer Company (Decision No. 69164, December 5, 2006), the Commission ordered Black Mountain to refund more than $800,000 in unexpended CIAC. H2O argues that the facts in that case are distinguishable because, unlike the instant case involving H2O, Staff had suggested that some of contributed funds were misspent by Black Mountain, Black Mountain's parent company is well capitalized, and Black Mountain ultimately agreed to the customer refund. (*Id.* at 28.)

IT IS FURTHER ORDERED that, after review of the Company's filing, Staff shall present for the Commission's consideration an Order that addresses the Company's plan, including a discussion of any additional Staff recommendations.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN

COMMISSIONER

COMMISSIONER

COMMISSIONER

COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 8th day of December, 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT _____

DISSENT _____

EXHIBIT
R-14
admin notice

BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

Arizona Corporation Commission
DOCKETED
DEC -8 2009
DOCKETED BY nr

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|---|---|
| IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES BASED THEREON FOR UTILITY SERVICE BY ITS AGUA FRIA WATER DISTRICT, HAVASU WATER DISTRICT, MOHAVE WATER DISTRICT, PARADISE VALLEY WATER DISTRICT, SUN CITY WEST WATER DISTRICT AND TUBAC WATER DISTRICT. | DOCKET NO. W-01303A-08-0227 |
| IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES BASED THEREON FOR UTILITY SERVICE BY ITS MOHAVE WASTEWATER DISTRICT. | DOCKET NO. SW-01303A-08-0227<br><br>DECISION NO. 71410<br><br>**OPINION AND ORDER** |

DATES OF HEARING: March 13 (Pre-Hearing Conference), 17, (Public Comments in Phoenix), 18 (Public Comments in Tubac), 19, 20, 23, 25, 26, and 30, 2009

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Teena Wolfe

IN ATTENDANCE: Kristin K. Mayes, Chairman
Gary Pierce, Commissioner
Paul Newman, Commissioner
Sandra D. Kennedy, Commissioner
Bob Stump, Commissioner

APPEARANCES: Mr. Craig A. Marks, CRAIG A. MARKS, PLC, on behalf of Arizona- American Water Company.

Mr. Daniel Pozefsky, Chief Counsel, on behalf of the Residential Utility Consumer Office.

additions that Staff could not verify.[105]

The Company included all the plant discussed above in its plant in service balances in its application despite the fact that it could make no supporting documentation for the plant available to the parties for audit. The Company claims that plant which lacks supporting documentation should be included in rate base, simply because the Company has engineering estimates for it, the plant is "providing service," and no party has demonstrated that it is not used and useful, and that its disallowance would be inappropriate.[106] The Company contends that it would be punitive to exclude the estimated, unsupported costs. We strongly disagree. Because the Company could not make invoices available for audit when the rate case was filed, the requested plant costs could not be verified. They are not known and measurable costs. It is the Company, and not the other parties to this case, who bears the burden of demonstrating that plant is used and useful, and that the Company's requested rates are based on known and measurable costs. The exclusion of undocumented plant costs in this case does not prevent the Company from submitting proper documentation evidencing the actual costs paid for the plant for audit in a future rate proceeding. Staff's proposed adjustments are reasonable and will be adopted.

### H. AIAC and CIAC in CWIP

The Company contends that Advances in Aid of Construction ("AIAC") and CIAC associated with CWIP and not yet in rate base should not be deducted from rate base, because there is no offsetting plant in rate base.[107] The balances in dispute total $3,942,844 in CIAC and $312,175 in AIAC.[108] The Company states that when the plant moves into Utility Plant in Service, then it is appropriate to deduct the associated AIAC and CIAC when calculating rate base, but contends that it is improper to do so before that time.[109] Staff states that the CIAC and AIAC funds that the Company asserts are in CWIP should be reflected in the CIAC and AIAC balances used to calculate

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[105] *Id.*

[106] Company Brief at 32, citing Rebuttal Testimony of Company witness Linda J. Gutowski (Exh. A-26) at 4.

[107] Company Brief at 33; Rejoinder Testimony of Company witness Linda J. Gutowski (Exh. A-27) at 7-8

[108] *Id.* at 7. By district, the disputed amounts are as follows for CIAC: Agua Fria Water, $3,432,286; Havasu Water, $10,845; Mohave Water, $94,452; Paradise Valley Water, $322,588; Sun City West Water, $17,318; and Mohave Wastewater, $65,395. The AIAC amounts in dispute are as follows: Mohave Water, $291,909; and Tubac Water, $20,266.

[109] Rejoinder Testimony of Company witness Linda J. Gutowski (Exh. A-27) at 7.

and properly reflect a reduction to rate base, regardless of the form of the CIAC or AIAC or how it is used.[110] Staff argues that reducing rate base by CIAC and AIAC preserves the ratemaking balance and removes the possibility of the Company earning an excess.[111] RUCO and Staff contend that it is the Company's choice whether to accept plant or funds from developers, and that if the Company chooses to accept plant, then the Company is not expending funds for the plant and thus has funds for other uses.[112] The Company disagrees, arguing that the fact that developers build and contribute plant does not make any funds available to the Company to build other components of plant.[113] RUCO and Staff both argue that regardless of how the Company accepts AIAC or CIAC, whether in plant or in funds, the ratemaking treatment should not change.[114] Staff and RUCO assert that the Company's position is contrary to traditional ratemaking practices and contrary to the National Association of Regulatory Commissioners ("NARUC") definition of CIAC, which does not distinguish between CIAC associated with CWIP and CIAC associated with plant in service.[115]

The Company argues that the Commission has accepted adjustments excluding CWIP-related CIAC in the past,[116] but in a case cited by the Company, the issue was not contested or discussed. As Staff states, the issue of customer-supplied advances associated with CWIP was raised most recently in Docket No. G-04204A-06-0463 et al., and was discussed in Decision No. 70011 in that docket.[117] We agree with RUCO and Staff that the Company's choice whether to accept plant or funds from developers is irrelevant, and does not change the nature of AIAC or CIAC. The evidence in this case

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[110] Surrebuttal Testimony of Staff witness Gerald Becker (Exh. S-8) at 10.
[111] Staff Brief at 11.
[112] RUCO Reply Brief at 4-5; Staff Brief at 11.
[113] Company Brief at 33.
[114] Staff Brief at 11; RUCO Reply Brief at 4-5.
[115] RUCO Reply Brief at 4; Staff Brief at 11, citing to the NARUC Uniform System of Accounts as follows:

> 271. Contributions in Aid of Construction
> A. This account shall include:
> 1. Any amount or item of money, services or property received by a utility from any person or governmental agency, any portion of which is provided at no cost to the utility, which represents an addition or transfer to the capital of the utility, and which is utilized to offset the acquisition, improvement to offset the utility's property, facilities or equipment used to provide utility services to the public.

[116] Company Brief at 34, citing Decision No. 68302 (November 14, 2005), Docket No. W-01445A-04-0650; Rejoinder Testimony of Company witness Linda J. Gutowski (Exh. A-27) at 8, citing schedules from a Staff witness's testimony in that docket.
[117] *See* Decision No. 70011 at 8-10.

does not persuade us to depart from the traditional ratemaking treatment of deducting AIAC and CIAC from rate base. The adjustments recommended by RUCO and Staff will be adopted.

### I. Arsenic Treatment Facilities (Agua Fria, Havasu, and Sun City West Water districts)

To meet the new federal arsenic standard, the Company constructed and installed arsenic treatment facilities in its Agua Fria Water, Havasu Water, Paradise Valley Water, and Sun City West Water districts.[118] Staff is recommending that a portion of the costs of the arsenic treatment facilities installed by the Company in its Agua Fria Water, Havasu Water, and Sun City West Water districts be disallowed from plant in service due to overcapacity.

Based on the analysis of Staff's Engineering witness, for the Agua Fria Arsenic Treatment Plant No. 5, Staff recommends disallowance of $126,352 of the Company's cost of the facility (Staff's estimated cost difference between three 11 foot diameter vessels and the four 11 foot diameter vessels installed by the Company); for Havasu Arsenic Treatment Plant, Staff recommends disallowance of $34,266 of the Company's $286,960 cost of the facility (Staff's estimated cost difference between two 11 foot diameter vessels and the two 14 foot diameter vessels installed by the Company); and for Sun City West Arsenic Treatment Plant No. 2, Staff recommends disallowance of $92,080 of the Company's $575,380 cost of the facility (Staff's estimated difference between four 11 foot diameter vessels and the four 12 foot diameter vessels installed by the Company).[119]

The Company contends that Staff's claims concerning the overcapacity of the installed arsenic treatment vessels are without merit.[120] The Company's witness Joseph E. Gross testified that the Company designed its iron-oxide based arsenic treatment systems to operate in series mode instead of a parallel configuration, which allows for greater maximum flow rates and reduced empty bed minimum contact time.[121] For a system operating in parallel configuration, which Staff used in its analysis of the facilities, the literature recommends minimum empty bed contact time of no less than five minutes and maximum flow rates of not greater than five gallons per minute per square foot

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[118] *See* Decision No. 68310 (November 14, 2005); Decision No. 68858 (July 28, 2006).
[119] Surrebuttal Testimony of Staff witness Dorothy Hains (Exh. S-4) at 3-5
[120] Company Brief at 35.
[121] Tr. at 150-54; *See* Exhs. A-3, A-4, and A-5

IT IS FURTHER ORDERED that Arizona-American shall submit within 120 days of the effective date of this Decision at least ten Best Management Practices (as outlined in ADWR's Modified Non-Per Capita Conservation Program) in each of the water systems that are the subject of this rate case to Docket Control for Commission approval. The Company may request cost recovery of actual costs associated with the BMPs implemented.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

BY ORDER OF THE ARIZONA CORPORATION COMMISSION.

CHAIRMAN COMMISSIONER

COMMISSIONER COMMISSIONER COMMISSIONER

IN WITNESS WHEREOF, I, ERNEST G. JOHNSON, Executive Director of the Arizona Corporation Commission, have hereunto set my hand and caused the official seal of the Commission to be affixed at the Capitol, in the City of Phoenix, this 8th day of December 2009.

ERNEST G. JOHNSON
EXECUTIVE DIRECTOR

DISSENT

DISSENT

EXHIBIT
R-15
ADMITTED

**RIO RICO UTILITIES, INC.**
**DOCKET NO. WS-02676A-09-0257**
**RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS**

October 2, 2009

| | |
|---|---|
| Response provided by: | Gerald Tremblay |
| Title: | Director of Finance |
| Company Name: | Algonquin Power Income Fund |
| Address: | 2845 Bristol Circle<br>Oakville, Ontario Canada L6H 7H7 |
| Company Response Number: | GB 3.4 |

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WATER

Q. Please provide schedules of the Company's AIAC and CIAC starting with the amounts approved in the last rate case.

RESPONSE: Please see the attached files.

**RIO RICO UTILITIES, INC.**
**DOCKET NO. WS-02676A-09-0257**
**RESPONSE TO STAFF'S THIRD SET OF DATA REQUESTS**

October 2, 2009

| | |
|---|---|
| Response provided by: | Gerald Tremblay |
| Title: | Director of Finance |
| Company Name: | Algonquin Power Income Fund |
| Address: | 2845 Bristol Circle<br>Oakville, Ontario Canada L6H 7H7 |
| Company Response Number: | GB 3.12 |

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WASTEWATER

Q. Please provide schedules of the Company's AIAC and CIAC starting with the amounts approved in the last rate case.

RESPONSE: Please see the attached files.

**Rio Rico Utilities**
**Reconciliation of what AIAC balance should be**
**GB 3.4 and 3.12 AIAC Schedule**

| | | | Refunds | | | | | | | | | Finaled | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | AIAC | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | Agreement | Balance | |
| *water 8134.2.0100.20.2911.0000* | | | | | | | | | | | | | | |
| Luis & Elizabeth Parra | 488 Corinto Ct | 3,049.00 | 10.55 | 37.86 | 36.07 | 40.85 | 45.30 | 85.08 | 90.07 | 121.99 | 76.76 | | 2,504.47 | |
| Pilot Corporation | Store 279 | 35,145.00 | 285.89 | 495.69 | 471.15 | 385.00 | 422.41 | 556.39 | 664.82 | 696.36 | 646.58 | | 30,520.71 | |
| Rio Rico Fire District | Fire Station #2 | 89,799.00 | | | | | 20.21 | 98.19 | 99.31 | 94.72 | 140.08 | | 89,346.49 | |
| | | | | | | | | | | | | | 122,371.67 | s/b AIAC Balance |
| | | | | | | | | | | | | | 73,647.84 | GL AIAC Balance |
| | | | | | | | | | | | | | 48,723.83 | Dr CIAC & Cr AIAC |
| *sewer 8134.2.0200.20.2911.0000* | | | | | | | | | | | | | | |
| SCHOOL35 | Santa Cruz Valley Sch. Dist No. 35 | 261,316.00 | | | | | 1,588.84 | 3,637.51 | 6,788.22 | 6,071.41 | 5,308.62 | | 237,921.40 | |
| PILOT279 | Pilot Corporation - Store 279 | 48,552.00 | 773.33 | 743.54 | 935.21 | 737.39 | 630.19 | 1,142.37 | | | | | 43,589.97 | |
| | | | | | | | | | | | | | 281,511.37 | s/b AIAC Balance |
| | | | | | | | | | | | | | (861.31) | GL AIAC Balance |
| | | | | | | | | | | | | | 282,372.68 | Dr CIAC & Cr AIAC |

**Rio Rico Utilities**
**Reconciliation of what AIAC balance should be**
**GB 3.4 and 3.12 AIAC Schedule**

| | | | Refunds | | | | | | | | | Total Dollars | | Total Percentage |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | | AIAC | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | Refunded | Balance | Refunded |
| *water 8134.2.0100.20.2911.0000* | | | | | | | | | | | | | | |
| Luis & Elizabeth Parra | 488 Corinto Ct | 3,049.00 | 10.55 | 37.86 | 36.07 | 40.85 | 45.30 | 85.08 | 90.07 | 121.99 | 76.76 | **544.53** | 2,504.47 | 17.9% |
| Pilot Corporation | Store 279 | 35,145.00 | 285.89 | 495.69 | 471.15 | 385.00 | 422.41 | 556.39 | 664.82 | 696.36 | 646.58 | **4,624.29** | 30,520.71 | 13.2% |
| Rio Rico Fire District | Fire Station #2 | 89,799.00 | | | | | 20.21 | 98.19 | 99.31 | 94.72 | 140.08 | **452.51** | 89,346.49 | 0.5% |
| | | | | | | | | | | | | | 122,371.67 | s/b AIAC Balance |
| | | | | | | | | | | | | | 73,647.84 | GL AIAC Balance |
| | | | | | | | | | | | | | 48,723.83 | Dr CIAC & Cr AIAC |
| *sewer 8134.2.0200.20.2911.0000* | | | | | | | | | | | | | | |
| SCHOOL35 | Santa Cruz Valley Sch. Dist No. 35 | 261,316.00 | | | | | 1,588.84 | 3,637.51 | 6,788.22 | 6,071.41 | 5,308.62 | **23,394.60** | 214,526.80 | 9.0% |
| PILOT279 | Pilot Corporation - Store 279 | 48,552.00 | 773.33 | 743.54 | 935.21 | 737.39 | 630.19 | 1,142.37 | | | | **4,962.03** | 38,627.94 | 10.2% |
| | | | | | | | | | | | | | 253,154.74 | s/b AIAC Balance |
| | | | | | | | | | | | | | (861.31) | GL AIAC Balance |
| | | | | | | | | | | | | | 254,016.05 | Dr CIAC & Cr AIAC |

# RIO RICO UTILITIES, INC.

## DOCKET NO. WS-02676A-08-09-0257

## DIRECT TESTIMONY
## ON COST OF CAPITAL

## OF

## WILLIAM A. RIGSBY, CRRA

## ON BEHALF OF

## THE

## RESIDENTIAL UTILITY CONSUMER OFFICE

## DECEMBER 15, 2009

## TABLE OF CONTENTS

INTRODUCTION ..... 1

SUMMARY OF TESTIMONY AND RECOMMENDATIONS ..... 6

COST OF EQUITY CAPITAL ..... 9

Discounted Cash Flow (DCF) Method ..... 10
Capital Asset Pricing Model (CAPM) Method ..... 30
Current Economic Environment ..... 38

CAPITAL STRUCTURE AND COST OF DEBT ..... 53

COMMENTS ON RRUI'S COST OF EQUITY CAPITAL TESTIMONY ..... 58

APPENDIX 1 – Qualifications of William A. Rigsby, CRRA

ATTACHMENT A – Value Line Water Utility Industry Update

ATTACHMENT B – Value Line Natural Gas Utility Industry Update

ATTACHMENT C – Zacks Earnings Projections

ATTACHMENT D – Value Line Selected Yields

SCHEDULES WAR-1 THROUGH WAR-9

## INTRODUCTION

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

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

Q. Please describe your qualifications in the field of utilities regulation and your educational background.

A. I have been involved with utilities regulation in Arizona since 1994. During that period of time I have worked as a utilities rate analyst for both the Arizona Corporation Commission ("ACC" or "Commission") and for RUCO. I hold a Bachelor of Science degree in the field of finance from Arizona State University and a Master of Business Administration degree, with an emphasis in accounting, from the University of Phoenix. I have been awarded the professional designation, Certified Rate of Return Analyst ("CRRA") by the Society of Utility and Regulatory Financial Analysts ("SURFA"). The CRRA designation is awarded based upon experience and the successful completion of a written examination. Appendix I, which is attached to my direct testimony on operating income further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Rio Rico Utilities, Inc.'s ("RRUI" or the "Company") application for a permanent rate increase ("Application). RRUI filed the Application with the Arizona Corporation Commission ("ACC" or "Commission") on May 21, 2009. The Company has chosen the operating period ended December 31, 2008 for the test year ("Test Year") in this proceeding.

Q. Briefly describe RRUI.

A. RRUI[1] is a wholly owned subsidiary of Algonquin Water Resources of America, which is a wholly owned subsidiary of the Algonquin Power Income Fund ("Algonquin Fund" or "Parent"), a mutual fund, or trust, which is listed on the Toronto Stock Exchange (ticker symbol APF.UN). Rio Rico Utilities, Inc., provides service to the community of Rio Rico in Santa Cruz County. The Company's service area is located just north of Nogales on the border between Arizona and Mexico. In addition to RRUI, the Algonquin Fund also owns and operates six other ACC regulated utilities: Black Mountain Sewer Corporation, which serves Carefree and the

[1] Based on documents provided by the Company during the recent Litchfield Park Service Company proceeding, RRUI officially changed its name to Liberty Water on April 27, 2009. According to the Company response to ACC Staff's data request JMM 7.3, dated October 23, 2009 in the prior proceeding, the name change was actually the registration of Litchfield Park Service Company dba Liberty Water. The holding company for RRUI, Algonquin Water Resources of America, Inc., did actually change its name to Liberty Water Co. There was no sale of stock or assets involved. In order to maintain consistency with the Company's Application, RUCO will continue to refer to the Company as RRUI and its holding company and parent under the Algonquin monicker.

Boulders Resort community located north of Scottsdale; Gold Canyon Sewer Company, located east of Apache Junction; Litchfield Park Services Company, situated on the west side of the Phoenix metropolitan area; Bella Vista Water Company, Northern Sunrise Water Company and Southern Sunrise Water Company located in or near Sierra Vista. The Algonquin Fund also owns Algonquin Water Services, which directly oversees the daily operations of the aforementioned Arizona public service companies.

Q. Briefly explain what is a mutual fund?

A. A mutual fund is a type of investment vehicle that generally provides investors with the opportunity to place their funds into a professionally managed portfolio of financial instruments such as stocks or bonds. In the case of a stock mutual fund, the fund's manager will buy and sell on the basis of how well a stock meets the fund's investment criteria, such as providing a specific level of dividend income and/or achieving projected levels of capital appreciation. Unlike the price of a stock or bond, the value of a mutual fund is expressed as its net asset value ("NAV"). Fund managers generally realize a profit from management fees, which are normally collected as a fixed percentage, typically between 0.5 percent and 2.00 percent a year, of the fund's NAV. Management fees are normally deducted from shareholder's assets on an annual basis. Closed-ended funds have a fixed number of shares that are bought and sold on

securities exchanges in the same manner as individual stocks and bonds. Open-ended funds, on the other hand, offer new shares and redeem existing shares on a continual basis.

Q. How is the Algonquin Fund structured?

A. The Algonquin Fund is an open-ended fund with an investment portfolio comprised of utilities involved in the production of electricity and the provision of water and wastewater services. These individual utilities make up the Algonquin Fund's Hydroelectric, Cogeneration, Alternative Fuels and Infrastructure Divisions. Instead of a collection of stocks or bonds, the fund is comprised of utilities that are bought, held and sold in the hope of achieving desired returns on investment. In this respect, the Algonquin fund is no different than a utility holding company whose shares are publicly traded in the financial markets. Shares of the funds are referred to as units and shareholders are referred to as unitholders. As I explained above, the Algonquin Fund's managers derive their income from management fees.

Q, Is this form of ownership common for utilities operating in Arizona?

A. No, most investor owned utilities operating in Arizona are either closely held corporate entities, are owned by a utility holding company or, as in the case of many water and wastewater utilities, are owned by a firm that is engaged in land development.

Q. Please explain your role in RUCO's analysis of RRUI's Application.

A. I reviewed RRUI's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended hypothetical capital structure, my direct testimony will present my recommended costs of common equity (RRUI has no preferred stock) and my recommended cost of hypothetical debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Application and from market-based research that I conducted during my analysis.

Q. Were you also responsible for conducting an analysis on the Company's proposed revenue level, rate base and rate design?

A. No. Those aspects of the case will be addressed in the direct testimony of RUCO witness Timothy J. Coley.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Schedules WAR-1 through WAR-9.

## SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your cost of capital testimony is organized.

A. My cost of capital testimony is organized into six sections. First, the introduction I have just presented and second, a summary of my testimony that I am about to give. Third, I will present the findings of my cost of equity capital analysis, which utilized both the discounted cash flow ("DCF") method, and the capital asset pricing model ("CAPM"). These are the two methods that RUCO and ACC Staff have consistently used for calculating the cost of equity capital in rate case proceedings in the past, and are the methodologies that the ACC has given the most weight to in setting allowed rates of returns for utilities that operate in the Arizona jurisdiction. In this third section I will also provide a brief overview of the current economic climate within which RRUI is operating. Fourth, I will discuss my recommended capital structure, my recommended cost of long-term debt and my recommended weighted average cost of capital. Sixth, I will comment on RRUI's cost of capital testimony. Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of RRUI, I am making the following recommendations:

Cost of Equity Capital – I am recommending a 9.00 percent cost of equity capital. This 9.00 percent figure is based on the results that I obtained in my cost of equity analysis, which employed both the DCF and CAPM methodologies. My 9.00 percent cost of equity capital is 340 basis points lower than the 12.40 percent cost of equity capital being proposed by the Company.

Capital Structure – I am recommending that the Company-proposed capital structure, which is comprised of approximately 100 percent common equity be rejected by the ACC and that my recommended hypothetical capital structure, which is comprised of 60 percent common equity and 40 percent debt, be adopted by the Commission.

Cost of Debt – I am recommending that the Commission adopt a hypothetical cost of debt of 6.26 percent, which is the average weighted cost of debt of eight publicly traded water companies that are followed by securities analysts with The Value Line Investment Survey.

Weighted Average Cost of Capital – Based on the results of my recommended hypothetical capital structure, I am recommending a 7.90 percent cost of capital for RRUI, which is the weighted cost of my recommended costs of common equity and hypothetical debt. My recommended weighted average cost of capital is 450 basis points lower

than the 12.40 percent weighted average cost of capital being proposed by the Company.

Q. Why do you believe that your recommended 7.90 percent weighted average cost of capital is an appropriate rate of return for RRUI to earn on its invested capital?

A. The 7.90 percent weighted average cost of capital figure that I am 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. The rate of return adopted for the utility should also be comparable to a return that investors would expect to receive from investments with similar risk.

The Hope decision allows for the rate of return to cover both the operating expenses and the "capital costs of the business" which includes interest on debt and dividend payment to shareholders. This is predicated on the belief that, in the long run, a company that cannot meet its debt obligations

and provide its shareholders with an adequate rate of return will not continue to supply adequate public utility service to ratepayers.

Q. Do the Bluefield and Hope decisions indicate that a rate of return sufficient to cover all operating and capital costs is guaranteed?

A. No. Neither case *guarantees* a rate of return on utility investment. What the Bluefield and Hope decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as RRUI, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

**COST OF EQUITY CAPITAL**

Q. What is your final recommended cost of equity capital for RRUI?

A. I am recommending a cost of equity of 9.00 percent. My recommended 9.00 percent cost of equity figure falls on the high end of a range of estimates obtained from my DCF and CAPM analyses, which utilized both a sample of publicly traded water providers and a sample of publicly traded natural gas local distribution companies ("LDC"). A summary of the results of my analysis is exhibited on page 3 of my Schedule WAR-1.

**Discounted Cash Flow (DCF) Method**

Q. Please explain the DCF method that you used to estimate RRUI's cost of equity capital.

A. The DCF method employs a stock valuation model known as the constant growth valuation model, that bears the name of Dr. Myron J. Gordon (i.e. the Gordon model), the professor of finance who was responsible for its development. Simply stated, the DCF model is based on the premise that the current price of a given share of common stock is determined by the present value of all of the future cash flows that will be generated by that share of common stock. The rate that is used to discount these cash flows back to their present value is often referred to as the investor's cost of capital (i.e. the cost at which an investor is willing to forego other investments in favor of the one that he or she has chosen).

Another way of looking at the investor's cost of capital is to consider it from the standpoint of a company that is offering its shares of stock to the investing public. In order to raise capital, through the sale of common stock, a company must provide a required rate of return on its stock that will attract investors to commit funds to that particular investment. In this respect, the terms "cost of capital" and "investor's required return" are one in the same. For common stock, this required return is a function of the dividend that is paid on the stock. The investor's required rate of return can be expressed as the percentage of the dividend that is paid on the

stock (dividend yield) plus an expected rate of future dividend growth. This is illustrated in mathematical terms by the following formula:

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

where: $k$ = the required return (cost of equity, equity capitalization rate),

$\frac{D_1}{P_0}$ = the dividend yield of a given share of stock calculated by dividing the expected dividend by the current market price of the given share of stock, and

$g$ = the expected rate of future dividend growth

This formula is the basis for the standard growth valuation model that I used to determine RRUI's cost of equity capital.

Q. In determining the rate of future dividend growth for RRUI, what assumptions did you make?

A. There are two primary assumptions regarding dividend growth that must be made when using the DCF method. First, dividends will grow by a constant rate into perpetuity, and second, the dividend payout ratio will remain at a constant rate. Both of these assumptions are predicated on the traditional DCF model's basic underlying assumption that a company's earnings, dividends, book value and share growth all increase at the same constant rate of growth into infinity. Given these assumptions, if the

dividend payout ratio remains constant, so does the earnings retention ratio (the percentage of earnings that are retained by the company as opposed to being paid out in dividends). This being the case, a company's dividend growth can be measured by multiplying its retention ratio (1 - dividend payout ratio) by its book return on equity. This can be stated as g = b x r.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[2]

Table I

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Growth |
|---|---|---|---|---|---|---|
| Book Value | $10.00 | $10.40 | $10.82 | $11.25 | $11.70 | 4.00% |
| Equity Return | 10% | 10% | 10% | 10% | 10% | N/A |
| Earnings/Sh. | $1.00 | $1.04 | $1.082 | $1.125 | $1.170 | 4.00% |
| Payout Ratio | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | N/A |
| Dividend/Sh | $0.60 | $0.624 | $0.649 | $0.675 | $0.702 | 4.00% |

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book

[2] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

value of $10.00 per share, an investor-expected equity return of ten percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0.60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by

themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Growth |
|---|---|---|---|---|---|---|
| Book Value | $10.00 | $10.40 | $10.82 | $11.47 | $12.158 | 5.00% |
| Equity Return | 10% | 10% | 15% | 15% | 15% | 10.67% |
| Earnings/Sh | $1.00 | $1.04 | $1.623 | $1.720 | $1.824 | 16.20% |
| Payout Ratio | 0.60 | 0.60 | 0.60 | 0.60 | 0.60 | N/A |
| Dividend/Sh | $0.60 | $0.624 | $0.974 | $1.032 | $1.094 | 16.20% |

In the example displayed in Table II, a sustainable growth rate of four percent[3] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[4] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

[3] [ ( Year 2 Earnings/Sh – Year 1 Earnings/Sh ) ÷ Year 1 Earnings/Sh ] = [ ( $1.04 - $1.00 ) ÷ $1.00 ] = [ $0.04 ÷ $1.00 ] = 4.00%

[4] [ ( 1 – Payout Ratio ) x Rate of Return ] = [ ( 1 - 0.60 ) x 15.00% ] = 0.40 x 15.00% = 6.00%

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning

base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book

value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[5] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where: $g$ = DCF expected growth rate,
$b$ = the earnings retention ratio,
$r$ = the return on common equity,
$s$ = the fraction of new common stock sold that accrues to a current shareholder, and
$v$ = funds raised from the sale of stock as a fraction of existing equity.

and $v = 1 - [(BV) \div (MP)]$

where: $BV$ = book value per share of common stock, and
$MP$ = the market price per share of common stock.

[5] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[6], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill

[6] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. How did you develop your dividend growth rate estimate?

A. I analyzed data on two separate proxy groups. A water company proxy group comprised of three publicly traded water companies and a natural gas proxy group consisting of ten natural gas local distribution companies ("LDC") that have similar operating characteristics to water providers.

Q. Why did you use a proxy group methodology as opposed to a direct analysis of RRUI?

A. One of the problems in performing this type of analysis is that the utility applying for a rate increase is not always a publicly traded company, as is the case with RRUI itself. Consequently it was necessary to create a proxy by analyzing publicly traded water companies and LDC's with similar risk characteristics.

...

Q. In determining your dividend growth rate estimates, both you and the Company's witness analyzed the data on publicly traded water utilities. Why did you and the Company witness analyze only publicly traded water utilities as opposed to firms that provide wastewater service?

A. The use of water utilities was necessitated by the fact that there is a lack of financial and market information available on stand-alone wastewater utilities. This in itself is not a problem, given the fact that both water and wastewater utilities share similar risk characteristics. Both types of utilities provide a basic service for which there are no substitutes and are also subject to strict federal and state regulations.

Q. Are there any other advantages to the use of a proxy?

A. Yes. As I noted earlier, the U.S. Supreme Court ruled in the Hope decision that a utility is entitled to earn a rate of return that is commensurate with the returns on investments of other firms with comparable risk. The proxy technique that I have used derives that rate of return. One other advantage to using a sample of companies is that it reduces the possible impact that any undetected biases, anomalies, or measurement errors may have on the DCF growth estimate.

...

Q. What criteria did you use in selecting the companies that make up your water company proxy for RRUI?

A. Three of the four water companies used in the proxy are publicly traded on the New York Stock Exchange ("NYSE") and one of them, Southwest Water Company, is traded over the counter through the National Association of Securities Dealers Automated Quotation System ("NASDAQ"). All four water companies are followed by The Value Line Investment Survey ("Value Line") and are the same companies that comprise Value Line's large capitalization Water Utility Industry segment of the U.S. economy (Attachment A contains Value Line's October 23, 2009 update of the water utility industry and evaluations of the water companies used in my proxy).

Q. Are these the same water utilities that you have used in prior rate case proceedings?

A. Yes.

Q. Please describe the companies that comprise your water company proxy group.

A. My water company proxy group includes American States Water Co. (stock ticker symbol "AWR"), California Water Service Group ("CWT"), Southwest Water Company ("SWWC") and Aqua America, Inc. ("WTR"). Each of these water companies face the same types of risk that RRUI

faces. For the sake of brevity, I will refer to each of these companies by their appropriate stock ticker symbols henceforth.

Q. Briefly describe the areas served by the companies in your water company sample proxy.

A. In addition to providing water service to residents of Fountain Hills, Arizona through its wholly owned subsidiary Chaparral City Water Company, AWR also serves communities located in Los Angeles, Orange and San Bernardino counties in California. CWT provides service to customers in seventy-five communities in California, New Mexico and Washington. CWT's principal service areas are located in the San Francisco Bay area, the Sacramento, Salinas and San Joaquin Valleys and parts of Los Angeles. SWWC owns and manages regulated systems in California, New Mexico, Oklahoma and Texas. WTR is a holding company for a large number of water and wastewater utilities operating in nine different states including Pennsylvania, Ohio, New Jersey, Illinois, Maine, North Carolina, Texas, Florida and Kentucky.

Q. Are these the same water companies that RRUI used in its application?

A. RRUI's cost of equity witness, Mr. Thomas J. Bourassa, used all of the water companies included in my water proxy with the exception of SWWC.

Mr. Bourassa also used three other water companies in his cost of capital analysis[7] which are included in Value Line's Small and Mid Cap Edition.

Q. Why did you exclude the water companies that are followed in Value Line's Small and Mid Cap Edition?

A. Value Line does not provide the same type of forward-looking information (i.e. long-term estimates on return on common equity and share growth) on small and mid-cap companies that it provides on the four water companies that I used in my proxy. Consequently, these water providers are not as suitable as the ones that I have used in my analysis.

Q. What criteria did you use in selecting the natural gas LDC's included in your proxy for RRUI?

A. As are the water companies that I just described, each of the natural gas LDC's used in the proxy are publicly traded on a major stock exchange (all ten trade on the NYSE) and are followed by Value Line. Each of the ten LDC's in my sample are tracked in Value Line's natural gas Utility industry segment. All of the companies in the proxy are engaged in the provision of regulated natural gas distribution services. Attachment B of my testimony contains Value Line's most recent evaluation of the natural gas proxy group that I used for my cost of common equity analysis.

[7] Connecticut Water Service, Inc., Middlesex Water Company and SJW Corp.

Q. What companies are included your natural gas proxy?

A. The ten natural gas LDC's included in my proxy (and their NYSE ticker symbols) are AGL Resources, Inc. ("AGL"), Atmos Energy Corp. ("ATO"), Laclede Group, Inc. ("LG"), New Jersey Resources Corporation ("NJR"), Nicor, Inc. ("GAS"), Northwest Natural Gas Co. ("NWN"), Piedmont Natural Gas Company ("PNY"), South Jersey Industries, Inc. ("SJI") Southwest Gas Corporation ("SWX"), which is the dominant natural gas provider in Arizona, and WGL Holdings, Inc. ("WGL"). These are the same ten LDC's that I analyzed in the most recent UNS Gas, Inc. proceeding.[8]

Q. Briefly describe the regions of the U.S. served by the ten natural gas LDC's that make up your sample proxy.

A. The ten LDC's listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJI which serves portions of northern New Jersey, SJI which serves southern New Jersey and WGL which serves the Washington D.C. metro area), the Southeast and South Central portions of the U.S. (i.e. AGL which serves Virginia, southern Tennessee and the Atlanta, Georgia area and PNY which serves customers in North Carolina, South Carolina and Tennessee), the South, deep South and Midwest (i.e. ATO which serves customers in Kentucky, Mississippi, Louisiana, Texas, Colorado and Kansas, GAS which provides service to northern and

[8] Docket No. G-04204A-08-0571

western Illinois, and LG which serves the St. Louis area), and the Pacific Northwest (i.e. NWN which serves Washington state and Oregon). Portions of Arizona, Nevada and California are served by SWX.

Q. Did the Company's witness also perform a similar analysis using natural gas LDC's?

A. No, he did not.

Q. Please explain your DCF growth rate calculations for the sample companies used in your proxy.

A. Schedule WAR-5 provides retention ratios, returns on book equity, internal growth rates, book values per share, numbers of shares outstanding, and the compounded share growth for each of the utilities included in the sample for the historical observation period 2004 to 2008 for both the water and LDC industries. Schedule WAR-5 also includes Value Line's projected 2009, 2010 and 2012-14 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for both the water utilities and the LDC's.

Q. Please describe how you used the information displayed in Schedule WAR-5 to estimate each comparable utility's dividend growth rate.

A. In explaining my analysis, I will use AWR as an example. The first dividend growth component that I evaluated was the internal growth rate.

I used the "b x r" formula (described on pages 12 and 13) to multiply AWR's earned return on common equity by its earnings retention ratio for each year in the 2004 to 2008 observation period to derive the utility's annual internal growth rates. I used the mean average of this five-year period as a benchmark against which I compared the projected growth rate trends provided by Value Line. Because an investor is more likely to be influenced by recent growth trends, as opposed to historical averages, the five-year mean noted earlier was used only as a benchmark figure. As shown on Schedule WAR-5, Page 1, AWR's average internal growth rate of 2.62% over the 2004 to 2008 period reflects an up and down pattern of growth that ranged from a low of 1.01% in 2002 to a high of 3.79% during 2007. Value Line is predicting that growth will increase steadily from 3.05% in 2008, to 6.23% by the end of the 2012-14 time frame. After weighing Value Line's projections for internal growth, stable outlook for earnings per share, increased growth for dividends per share and no change in book value per share growth, I believe that a 6.20% rate of internal growth is reasonable for AWR. (Schedule WAR-4, Page 1 of 2).

Q. Please continue with the external growth rate component portion of your analysis.

A. Schedule WAR-5 demonstrates that the pattern of shares outstanding for AWR increased from 16.75 million to 17.30 million from 2004 to 2008. Value Line is predicting that this level will increase from 18.50 million in

2009 to 20.00 million by the end of 2014. Based on this data, I believe that a 5.00 percent growth in shares is not unreasonable for AWR (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for AWR is 8.86 percent (6.20 percent internal + 2.66 percent external) and is shown on Page 1 of Schedule WAR-4.

Q. What is your average DCF dividend growth rate estimate for your sample of water utilities?

A. My average DCF dividend growth rate estimate for my water company sample is 7.14 percent as displayed on page 1 of Schedule WAR-4.

Q. Did you use the same approach to determine an average dividend growth rate for the proxy comprised of natural gas LDC's?

A. Yes.

Q. What is your average DCF dividend growth rate estimate for the sample natural gas utilities?

A. My average DCF dividend growth rate estimate is 5.23 percent, which is also displayed on page 1 of Schedule WAR-4.

Q. How does your average dividend growth rate estimates on water companies compare to the growth rate data published by Value Line and other analysts?

A. Schedule WAR-6 compares my sustainable growth estimates with the five-year projections of analysts at both Zacks Investment Research, Inc. ("Zacks") (Attachment C) and Value Line. In the case of the water companies, my 7.14 percent estimate exceeds Zacks' average long-term EPS projection of 6.13 percent and Value Line's growth projection of 3.74 percent (which is an average of EPS, DPS and BVPS). My 7.14 percent estimate is 313 basis points higher than the 4.01 percent average of Value Line's historical and projected data averaged with the consensus opinions published by Zacks. My 7.14 percent growth estimate is also 591 basis points higher than Value Line's 1.23 percent 5-year compound historical average of EPS, DPS and BVPS. The estimates of analysts at Value Line indicate that investors are expecting somewhat higher performance from the water utility industry in the future given their 7.00 percent to 7.50 percent book return on common equity over the 2009 to 2014 period. On balance, I would say my 7.14 percent estimate is an optimistic representation of the growth projections that are available to the investing public.

Q. How do your average dividend growth rate estimates on natural gas LDC's compare to the growth rate data published by Value Line and other analysts?

A. In regard to the natural gas LDC's, my 5.23 percent estimate is 84 basis points lower than the average 6.07 percent long-term EPS consensus

projections published by Zacks, and 85 basis points higher than the 4.38 percent Value Line projected estimate (which is an average of EPS, DPS and BVPS). As can also be seen on Schedule WAR-6, the 5.23 percent estimate that I have calculated is 54 basis points lower than the 5.77 percent average of the 5-year historic EPS, DPS and BVPS means of Value Line and 13 basis points lower than the 5.36 percent five-year compound historical average of Value Line data (on EPS, DPS and BVPS). In fact, my 5.23 percent estimate is 7 basis points higher than the combined 5.16 percent Value Line and Zacks averages displayed in Schedule WAR-6. In the case of the LDC's I would say that my 5.23 percent estimate, which is lower than Zack's but higher than Value Line's forecasts, is a fairly good representation of the growth projections presented by securities analysts at this point in time.

Q. How did you calculate the dividend yields displayed in Schedule WAR-3?

A. For both the water companies and the natural gas LDC's I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's October 23, 2009 Ratings and Reports water utility industry update and Value Line's September 11, 2009 Ratings and Reports natural gas utility update. I then divided those figures by the eight-week average closing price per share of the appropriate utility's common stock. The eight-week average price is based on the daily

adjusted closing stock prices for each of the companies in my proxies for the period October 5, 2009 to November 27, 2009.

Q. Based on the results of your DCF analysis, what is your cost of equity capital estimate for the water and natural gas utilities included in your sample?

A. As shown on Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 9.94 percent for the water utilities and 9.48 percent for the natural gas LDC's.

**Capital Asset Pricing Model (CAPM) Method**

Q. Please explain the theory behind CAPM and why you decided to use it as an equity capital valuation method in this proceeding.

A. CAPM is a mathematical tool that was developed during the early 1960's by William F. Sharpe[9], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[10] In this regard, CAPM can help an investor to

[9] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[10] Beta is defined as an index of volatility, or risk, in the return of an asset relative to the return of a market portfolio of assets. It is a measure of systematic or non-diversifiable risk. The returns on a stock with a beta of 1.0 will mirror the returns of the overall stock market. The returns on stocks with betas greater than 1.0 are more volatile or riskier than those of the overall stock

determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification. Thus, systematic risk is the only risk of importance to investors. Simply stated, the underlying theory behind CAPM states that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\, ]$$

where: $k$ = the expected return of a given security,

$r_f$ = risk-free rate of return,

$ß$ = beta coefficient, a statistical measurement of a security's systematic risk,

$r_m$ = average market return (e.g. S&P 500), and

market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

$r_m - r_f$ = market risk premium.

Q. What types of financial instruments are generally used as a proxy for the risk-free rate of return in the CAPM model?

A. Generally speaking, the yields of U.S. Treasury instruments are used by analysts as a proxy for the risk-free rate of return component.

Q. Please explain why U.S. Treasury instruments are regarded as a suitable proxy for the risk-free rate of return?

A. As citizens and investors, we would like to believe that U.S. Treasury securities (which are backed by the full faith and credit of the United States Government) pose no threat of default no matter what their maturity dates are. However, a comparison of various Treasury instruments will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[11] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost

[11] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

standpoint. When an investor locks up funds in long-term T-Bonds, compensation must be provided for future investment opportunities foregone. This is often described as maturity or interest rate risk and it can affect an investor adversely if market rates increase before the instrument matures (a rise in interest rates would decrease the value of the debt instrument). As discussed earlier in the DCF portion of my testimony, this compensation translates into higher rates of returns to the investor.

Q. What security did you use for a risk-free rate of return in your CAPM analysis?

A. I used an eight-week average of the yield on a 5-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated October 16, 2009 through December 4, 2009 (Attachment D). This resulted in a risk-free ($r_f$) rate of return of 2.26 percent.

Q. Why did you use the yield on a 5-year year U.S. Treasury instrument as opposed to a short-term T-Bill?

A. While a shorter term instrument, such as a 91-day T-Bill, presents the lowest possible total 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. How did you calculate the market risk premium used in your CAPM analysis?

A. I used both a geometric and an arithmetic mean of the historical total returns on the S&P 500 index from 1926 to 2008 as the proxy for the market rate of return ($r_m$). For the risk-free portion of the risk premium component ($r_f$), I used the geometric mean of the total returns of intermediate-term government bonds for the same eighty-two year period. The market risk premium ($r_m$ - $r_f$) that results by using the geometric mean of these inputs is 4.20 percent (9.60% - 5.40% = 4.20%). The market risk premium that results by using the arithmetic mean calculation is 6.10 percent (11.70% - 5.60% = 6.10%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of October 23, 2009 for the water companies and September 11, 2009 for the natural gas LDC's. Value Line calculates its betas by using a regression analysis

between weekly percentage changes in the market price of the security being analyzed and weekly percentage changes in the NYSE Composite Index over a five-year period. The betas are then adjusted by Value Line for their long-term tendency to converge toward 1.00. The beta coefficients for the service providers included in my water company sample ranged from 0.65 to 1.10 with an average beta of 0.83. The beta coefficients for the LDC's included in my natural gas sample ranged from 0.60 to 0.75 with an average beta of 0.67.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.72 percent for the water companies and 5.05 percent for the natural gas LDC's. My calculation using an arithmetic mean results in an average expected return of 7.29 percent for the water companies and 6.32 percent for the natural gas LDC's.

Q. Please summarize the results derived under each of the methodologies presented in your testimony.

A. The following is a summary of the cost of equity capital derived under each methodology used:

| METHOD | RESULTS |
|---|---|
| DCF (Water Sample) | 9.94% |
| DCF (Natural Gas Sample) | 9.48% |
| CAPM (Water Sample) | 5.72% – 7.29% |
| CAPM (Natural Gas) | 5.05% – 6.32% |

Based on these results, my best estimate of an appropriate range for a cost of common equity for RRUI is 5.05 percent to 9.94 percent. My final recommended cost of common equity figure is 9.00 percent.

Q How did you arrive at your final recommended 9.00 percent cost of common equity?

A. My recommended 9.00 percent cost of common equity falls on the high end of the range of estimates produced by my DCF and CAPM results. My final estimate takes into consideration recent information on the improving state of the economy, a rejuvenated stock market and reports in the financial press which anticipate Federal Reserve actions to raise interest rates.

Q. Can you provide some examples of the reports that you noted above that that influenced your common equity estimate of 9.00 percent?

A. Yes. Value Line analysts recently summed up the improving economic situation in the Economic and Stock Market Commentary section of its Selection & Opinion publication dated November 27, 2009:

> **The long recession has faded into history,** brought to an end in the third quarter when the nation's gross domestic product increased by a solid 3.5% [later revised to 2.8%]. That notable rebound followed four straight quarters of contracting economic activity. The recession was the worst in decades. The third quarter's surge in activity, which was underpinned to some degree by federal programs to assist the troubled auto and housing industries, may not continue to the same degree in the current period. In fact, we expect GDP growth to ease to a level closer to 2.0%-2.5% during the fourth quarter. We think that the evolving expansion will then remain on a similarly subdued path for much of 2010. Thereafter, an increasing level of aggregate demand is likely to develop—with belated help from better employment and housing trends—and push the economy onto a materially faster track by 2011. The 3.0%, or better, pace of economic growth that we see evolving by that time is likely to then continue through the middle years of the coming decade.

Value Line's analysts had this to say about the current state of the stock market:

> Unlike the economy, which has proceeded on an irregular path during the formative stages of its comeback, the stock market, which lost more than half of its value from October, 2007 through March, 2009, has come roaring back. At press time, the Dow Jones Industrial Average was up about 60% from its bear market lows of this past March. However, it was still some 25% below the record highs set in late 2007. The market's revival, which began as the worst fears on the credit and business fronts didn't materialize, has been sustained with an assist from the Federal Reserve, the government's stimulus efforts, and the aforementioned revivals on the economic and profit fronts. Now, with valuations having become a little stretched following eight months of steady market increases, the bulls may have to deliver even more good news to keep the rally going.

In regard to possible Federal Reserve action on interest rates, Wall Street Journal correspondent Jon Hilsenrath recently reported[12] that "Federal Reserve officials are thinking mostly these days about how to unwind the unprecedented stimulus they've pumped into the economy" and that

[12] Hilsenrath, Jon, "WSJ Fed's Path to Higher Interest Rates Begins to Take Shape" The Wall Street Journal, November 2, 2009

eventually will mean raising interest rates. Mr. Hilsenrath quoted former Fed governor Frederic Mishkin, a former Fed governor who advocated moving rates down swiftly leading up to crises and who says they might someday need to move up swiftly too, as saying "If you move in a very gradual fashion back up when you need to, you'll get behind the curve in terms of tightening fast enough."

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 12.40 percent cost of equity capital proposed by the Company is 340 basis points higher than the 9.00 percent cost of equity capital that I am recommending.

**Current Economic Environment**

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a

regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please discuss your analysis of the current economic environment.

A. My analysis includes a brief review of the economic events that have occurred since 1990. Schedule WAR-8 displays various economic indicators and other data that I will refer to during this portion of my testimony.

In 1991, as measured by the most recently revised annual change in gross domestic product ("GDP"), the U.S. economy experienced a rate of growth of negative 0.20 percent. This decline in GDP marked the beginning of a mild recession that ended sometime before the end of the first half of 1992. Reacting to this situation, the Federal Reserve Board ("Federal Reserve" or "Fed"), then chaired by noted economist Alan Greenspan, lowered its benchmark federal funds rate[13] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged

[13] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

by banks to their best customers) had dropped to 6.00 percent from a 1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998 respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors,

who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000.

Q. What has been the state of the economy since 2001?

A. The U.S. economy entered into a recession near the end of the first quarter of 2001. The bullish trend, which had characterized the last half of the 1990's, had already run its course sometime during the third quarter of 2000. Economic data released since the beginning of 2001 had already been disappointing during the months preceding the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon. Slower growth figures, rising layoffs in the high technology manufacturing sector, and falling equity prices (due to lower earnings expectations) prompted the Fed to begin cutting interest rates as it had done in the early 1990's. The now infamous terrorist attacks on New York City and Washington D.C. marked a defining point in this economic slump and prompted the Federal Reserve to continue its rate cutting actions through December 2001. Prior to the 9/11 attacks, commentators, reporting in both the mainstream financial press and various economic publications including

Value Line, believed that the Federal Reserve was cutting rates in the hope of avoiding a recession.

Despite several intervals during 2002 and 2003 in which the Federal Open Market Committee ("FOMC") decided not to change interest rates – moves which indicated that the worst may be over and that the recession might have bottomed out during the last quarter of 2001 – a lackluster economy persisted. The continuing economic malaise and even fears of possible deflation prompted the FOMC to make a thirteenth rate cut on June 25, 2003. The quarter point cut reduced the federal funds rate to 1.00 percent, the lowest level in forty-five years.

Even though some signs of economic strength, mainly attributed to consumer spending, began to crop up during the latter part of 2002 and into 2003, Chairman Greenspan appeared to be concerned with sharp declines in capital spending in the business sector.

During the latter part of 2003, the FOMC went on record as saying that it intended to leave interest rates low "for a considerable period." After its two-day meeting that ended on January 28, 2004, the FOMC announced "that with inflation 'quite low' and plenty of excess capacity in the economy, policy-makers 'can be patient in removing its policy accommodation.'[14]

[14] Wolk, Martin, "Fed holds interest rates steady," MSNBC, January 28, 2004.

Q. What actions has the Federal Reserve taken in terms of interest rates since the beginning of 2001?

A. As noted earlier, from January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times. During this period, the federal funds rate fell from 6.50 percent to 1.00 percent. The FOMC reversed this trend on June 29, 2004 and raised the federal funds rate 25 basis points to 1.25 percent. From June 29, 2004 to January 31, 2006, the FOMC raised the federal funds rate thirteen more times to a level of 4.50 percent.

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief.

As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates.

Q. What was the reaction in the financial community to the Fed's decision not to raise interest rates?

A. As in the past, banks followed the Fed's lead once again and held the prime rate to a level of 8.25 percent, or 300 basis points higher than the federal funds rate of 5.25 percent established on June 29, 2006.

Q. How did analysts view the Fed's actions between January 2001 and August 2006?

A. According to an article that appeared in the December 2, 2004 edition of The Wall Street Journal, the FOMC's decision to begin raising rates two years ago was viewed as a move to increase rates from emergency lows in order to avoid creating an inflation problem in the future as opposed to slowing down the strengthening economy.[15] In other words, the Fed was trying to head off inflation *before* it became a problem. During the period following the August 8, 2006 FOMC meeting, the Fed's decisions not to raise rates were viewed as a gamble that a slower U.S. economy would help to cap growing inflationary pressures.[16]

...

[15] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[16] Ip, Greg, "Fed Holds Interest Rates Steady As Slowdown Outweighs Inflation," The Wall Street Journal Online Edition, August 8, 2006.

Q. Was the Fed attempting to engineer another "soft landing", as it did in the mid-nineties, by holding interest rates steady?

A. Yes, however, as pointed out in an August 2006 article in The Wall Street Journal by E.S. Browning, soft landings – like the one that the Fed managed to pull off during the 1994-95 time frame, in which a recession or a bear market were avoided – rarely happen[17]. Since it began increasing the federal funds rate in June 2004, the Fed had assured investors that it would increase rates at a "measured" pace. Many analysts and economists interpreted this language to mean that former Chairman Greenspan would be cautious in increasing interest rates too quickly in order to avoid what is considered to be one of the Fed's few blunders during Greenspan's tenure – a series of increases in 1994 that caught the financial markets by surprise after a long period of low rates. The rapid rise in rates contributed to the bankruptcy of Orange County, California and the Mexican peso crisis[18]. According to Mr. Browning, at the time that his article was published, the hope was that Chairman Bernanke would succeed in slowing the economy "just enough to prevent serious inflation, but not enough to choke off growth." In other words, "a 'Goldilocks economy,' in which growth is not too hot and not too cold."

[17] Browning, E.S, "Not Too Fast, Not Too Slow…," The Wall Street Journal Online Edition, August 21, 2006.

[18] Associated Press (AP), "Fed begins debating interest rates" USA Today, June 29, 2004.

Q. Was the Fed's attempt to engineer a soft landing successful during the period that followed the August 8, 2006 FOMC meeting?

A. It would appear so. Articles published in the mainstream financial press were generally upbeat on the economy during that period. An example of this is an article written by Nell Henderson that appeared in the January 30, 2007 edition of The Washington Post. According to Ms. Henderson, "a year into [Fed Chairman] Bernanke's tenure, the [economic] picture has turned considerably brighter. Inflation is falling; unemployment is low; wages are rising; and the economy, despite continued problems in housing, is growing at a brisk clip."[19]

Q. What has been the state of the economy over the past two years?

A. Reports in the mainstream financial press during the majority of 2007 reflected the view that the U.S. economy was slowing as a result of a worsening situation in the housing market and higher oil prices. The overall outlook for the economy was one of only moderate growth at best. Also during this period the Fed's key measure of inflation began to exceed the rate setting body's comfort level.

On August 7, 2007, the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate

[19] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

unchanged at 5.25 percent.[20] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages and securities linked to them, forced the Fed to inject $24 billion in funds (raised through open market operations) into the credit markets.[21] By Friday, August 17, 2007, after a turbulent week on Wall Street, the Fed made the decision to lower its discount rate (i.e. the rate charged on direct loans to banks) by 50 basis points, from 6.25 percent to 5.75 percent, and took steps to encourage banks to borrow from the Fed's discount window in order to provide liquidity to lenders. According to an article that appeared in the August 18, 2007 edition of The Wall Street Journal, [22] the Fed had used all of its tools to restore normalcy to the financial markets. If the markets failed to settle down, the Fed's only weapon left was to cut the Federal Funds rate – possibly before the next FOMC meeting scheduled on September 18, 2007.

[20] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[21] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[22] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

Q. Did the Fed cut rates as a result of the subprime mortgage borrowing crises?

A. Yes. At its regularly scheduled meeting on September 18, 2007, the FOMC surprised the investment community and cut both the federal funds rate and the discount rate by 50 basis points (25 basis points more than what was anticipated). This brought the federal funds rate down to a level of 4.75 percent. The Fed's action was seen as an effort to curb the aforementioned slowdown in the economy. Over the course of the next four months, the FOMC reduced the Federal funds rate by a total 175 basis points to a level of 3.00 percent – mainly as a result of concerns that the economy was slipping into a recession. This included a 75 basis point reduction that occurred one week prior to the FOMC's meeting on January 29, 2008.

Q. What actions has the Fed taken in regard to interest rates since the beginning of 2008?

A. The Fed made two more rate cuts which included a 75 basis point reduction in the federal funds rate on March 18, 2008 and an additional 25 basis point reduction on April 30, 2008. The Fed's decision to cut rates was based on its belief that the slowing economy was a greater concern than the current rate of inflation (which the majority of FOMC members

believed would moderate during the economic slowdown).[23] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[24]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another 50 basis points in a coordinated move with foreign central banks on October 8, 2008. This was followed by another 50 basis point cut during the regular FOMC meeting on October 29, 2008. At the time of this writing, the federal funds target rate now stands at 0.25 percent, the result of a 75 basis point cut announced on December 16, 2008. After FOMC meetings in January, March April, June, August, September and November of 2009, the Fed elected not to make any changes in the

[23] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[24] Soloman, Deborah, Michael R. Crittenden and Damian Paletta, "U.S. Bailout Plan Calms Markets, But Struggle Looms Over Details" The Wall Street Journal, September 20, 2008

federal funds rate, stating in January that the rate would remain low "for some time."[25] Presently, the Fed's discount rate is at 0.50 percent, a level not seen since the 1940s.[26] Based on data released during the early part of December 2008, the U.S. has officially been in a recession since December of 2007.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected benchmark rates?

A. U.S. Treasury instruments are for the most part still at historically low levels. As can be seen on the first page of Attachment D, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has fallen to 0.50 percent from 1.25 percent in 2008.

Q. What has been the trend in other leading interest rates over the last year?

A. As of November 24, 2009, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have dropped from their 2008 levels. Longer term yields including the 5-year, 10-year, 30-year constant maturity and 30-year Zero rates, have increased from levels that existed a year ago (Attachment D, Value Line Selection & Opinion page 3177). The prime rate has fallen from 4.00 percent a year ago to 3.25 percent. The

[25] Hilsenrath, Jon and Liz Rappaport, "Fed Weighs Idea of Buying Treasurys as Focus Shifts" The Wall Street Journal, January 29, 2009

[26] Hilsenrath, Jon, "Fed Cuts Rates Near Zero to Battle Slump" The Wall Street Journal, December 17, 2008

benchmark federal funds rate, just discussed, has decreased from 1.00 percent, in November 2008, to a level of 0.00 - 0.25 percent (as a result of the December 16, 2008 rate cut discussed above). A previous trend, described by former Chairman Greenspan as a "conundrum"[27], in which long-term rates fell as short-term rates increased, thus creating a somewhat inverted yield curve that existed as late as June 2007, is completely reversed and a more traditional yield curve (one where yields increase as maturity dates lengthen) presently exists (Attachment D). The 5-year Treasury yield, used in my CAPM analysis, has increased 6 basis points from 2.03 percent, in November 2008, to 2.09 percent as of November 24, 2009. As noted above, the 30-Year Treasury constant maturity rate increased from 3.62 percent over the past year to 4.25 percent. These current yields are considerably lower than corresponding yields that existed during the early nineties and at the beginning of the current decade (as can be seen on Schedule WAR-8).

Q. What is the current outlook for the economy?

A. Value Line's analysts have become increasingly optimistic in their outlook on the economy as of late and had this to say in the December 4, 2009 edition of Value Line's Selection and Opinion publication:

> **Elsewhere, the U.S. economy is on a three steps forward, two steps backward path.** Reports for October showed a nice rebound in consumer spending, mild strength in industrial production, a lesser increase in the leading indicators than in the prior month, a surprising

[27] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

> drop in durable goods orders, and a modest gain in consumer confidence. The U.S. gross domestic product—which rose by a downwardly revised 2.8% in the third quarter — may increase by a slightly more modest 2.0% - 2.5% in the current period.

Value Line's analysts went on to state

> **Investors are still buying,** as the stock market is now much more richly capitalized than it was earlier in 2009, when equities were in a freefall.

Q. How are water utilities faring in the current economic environment?

A. Although there are some concerns regarding long-term infrastructure requirements, water utilities still appear to a good investment according to Value Line analyst Andre J. Costanza. In the October 23, 2009 quarterly update on the water utility industry Mr. Costanza stated the following:

> This industry is a good place for cautious investors looking to park themselves until a sustained market recovery is evident. Water utility stocks are historically more recession proof than the broader market, with their steady dividend growth reducing turbulence in share price and padding returns

Q. After weighing the economic information that you've just discussed, do you believe that the 9.00 percent cost of equity capital that you have estimated is reasonable for RRUI?

A. I believe that my recommended 9.00 percent cost of equity will provide RRUI with a reasonable rate of return on the Company's invested capital when economic data on interest rates (that are low by historical standards), the current situation in new housing construction, and the Fed's ability to keep inflation in check are all taken into consideration. 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 cost of equity analysis, which is an average of the results of both the DCF and CAPM models, has produced such a return.

**CAPITAL STRUCTURE AND COST OF DEBT**

Q. Have you reviewed RRUI's testimony regarding the Company's proposed capital structure?

A. Yes, I have.

Q. Please describe the Company's proposed capital structure.

A. The Company is proposing a capital structure comprised of 100 percent common equity.

Q. Is RRUI's proposed capital structure in line with industry averages?

A. No. RRUI's capital structure is comprised entirely of equity as opposed to the capital structures of the other water companies included in my cost of capital analysis (Schedule WAR-9). The capital structures for those utilities averaged 51.4 percent for debt and 48.6 percent for equity.

Q. In terms of risk, how does RRUI's capital structure compare to the water utilities in your sample?

A. The water utilities in my sample, from which I derived an estimated cost of common equity of 9.00 percent versus the Company-proposed 12.40

percent, would be considered as having a higher level of financial risk (i.e. the risk associated with debt repayment) because of their higher levels of debt. The additional financial risk due to debt leverage is embedded in the cost of equities derived for those companies through the DCF analysis. Thus, the cost of equity derived in my DCF analysis is applicable to companies that are more leveraged and, theoretically speaking, riskier than a utility such as RRUI, which has no debt in its capital structure. In the case of a publicly traded company, like those included in my proxy, a company with RRUI's level of equity would be perceived as having extremely low to no financial risk and would therefore also have a lower expected return on common equity. Because of this, I believe a hypothetical capital structure that produces a lower weighted cost of common equity is warranted for RRUI.

Q. What capital structure are you recommending for RRUI?

A. I am recommending a hypothetical capital structure comprised of 60 percent equity and 40 percent debt.

Q. Has the Commission addressed the issue of capital structures comprised of 100 percent common equity in prior cases?

A. Yes. This issue was addressed in a prior Gold Canyon Sewer Company ("Gold Canyon") case in which the Commission adopted both a hypothetical capital structure and a hypothetical cost of debt in order to

remedy a capital structure comprised of 100 percent common equity (Gold Canyon is also owned by the Algonquin Fund). In Decision No. 70662, dated December 23, 2008, the Commission stated the following:

> We agree with RUCO's hypothetical structure of 40 percent debt and 60 percent equity. A capital structure comprised of 100 percent equity would be viewed as having little to no financial risk. The proposed capital structure adopted by the Commission will bring the Company's capital structure and weighted cost of capital in line with the industry average and it will result in lower rates for the customers of the system. We therefore adopt a hypothetical capital structure of 40 percent debt and 60 percent equity.

Q. Why are you recommending a higher 60 percent level of equity for RRUI, in your hypothetical capital structure, than the average 49.6 percent level of equity of your sample companies?

A. My hypothetical capital structure takes into account any perceived additional business risk that RRUI may face and for that reason I believe a higher level of equity is reasonable.

Q. What are you recommending as a hypothetical cost of debt?

A. I am recommending a hypothetical cost of debt of 6.26 percent.

Q. How did you determine your hypothetical cost of debt?

A. As can be viewed on page 2 of Schedule WAR-1, my recommended 6.26 percent hypothetical cost of debt is an average of the weighted costs of long-term debt of seven publicly traded water utilities followed by Value Line analysts. Three of these water utilities are the same ones that I described earlier and were used in my DCF and CAPM analyses. Three

of the remaining four (Connecticut Water Service, Inc., Middlesex Water Company, and SJW Corp.) are ones that I noted earlier in my testimony that were included in the Company's proxy. The seventh water utility, York Water Company, is also followed in Value Line's Small & Mid-Cap Edition.

Q. Why do you believe your recommended 6.26 percent hypothetical cost of debt is reasonable given the recent turbulence in the financial markets?

A. My recommended 6.26 percent hypothetical cost of debt is close to the current yield of 6.22 percent on Baa/BBB-rated utility bonds that was reported in the December 4, 2009 Value line Selection and Opinion publication (Attachment D). In addition to this, Arizona Water Company, the second largest water provider in the state, privately placed $35 million in bonds at a stated rate of 6.67 percent on the first day of September 2008 during a period when the yield on Baa/BBB-rated utility bonds averaged 6.63 percent. Given RRUI's parent company's ability to access capital, it is reasonable to believe that Algonquin Fund can obtain debt at a cost in the A-rated to Baa/BBB-rated range of 5.52 percent to 6.22 percent exhibited on the first page of my Attachment D. For the reasons stated above, I believe for the reasons stated above, I believe my recommended 6.26 percent hypothetical cost of debt is reasonable and there is no need for additional basis points.

Q. How does your recommended 6.26 percent hypothetical cost of debt compare to the weighted costs of debt of other Arizona water providers?

A. In its most recent rate case before the Commission, Arizona-American Water Company, the largest investor owned water utility in the state, had a weighted cost of debt of approximately 5.50 percent. Arizona Water Company's weighted cost of debt as of the last quarter of 2008 was 6.83 percent. The midpoint of these two figures is 6.17 percent which is 9 basis points lower than my recommended 6.26 percent hypothetical cost of debt.

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. As explained earlier, RRUI has proposed a weighted average cost of capital of 12.40 percent which reflects the total absence of debt financing in the Company-proposed capital structure. The Company-proposed 12.40 percent weighted average cost of capital is 450 basis points higher than the 7.90 percent weighted cost that I am recommending.

...

Q. Please summarize why you believe that the Commission should adopt your recommended 7.90 percent weighted average cost of capital that is the result of your recommended hypothetical capital structure and hypothetical cost of debt.

A. I believe that the approach that I have taken in this case provides the Company with a rate of return that meets the standards established in the Hope and Bluefield cases while also providing lower rates to RRUI's customers. My recommended capital structure of 60 percent equity and 40 percent debt is more favorable to the Company than the average capital structure of the water utilities in my sample. Ratepayers also benefit from my recommended weighted average cost of capital which is lower than what would have been obtained from a capital structure comprised of 100 percent common equity. In short, I believe that my analysis has produced a rate of return that is just and reasonable and should be adopted by the Commission.

**COMMENTS ON RRUI'S COST OF EQUITY CAPITAL TESTIMONY**

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The Company's cost of capital witness, Mr. Bourassa is recommending a cost of common equity of 12.40 percent. His 12.40 percent cost of equity

capital is 340 basis points higher than the 9.00 percent cost of equity capital that I have calculated.

Q. What methods did Mr. Bourassa use to arrive at his cost of common equity for RRUI?

A. Mr. Bourassa used both the DCF and CAPM methods. His DCF analysis relies on the same constant growth version of the DCF model that I have used with two different growth estimates: a past and future growth estimate which produces an 11.1 percent indicated cost of equity, and a future growth estimate which produces a 12.6 percent indicated cost of equity. Mr. Bourassa's CAPM analysis also uses the same model that I have used but he obtains two different results: one obtained by using an historical risk premium and the other by using a current market risk premium. His CAPM analysis produces results of 10.1 percent using an historical risk premium and 19.5 percent using a current market risk premium. His average CAPM result is 14.8 percent.

Q. What are the main reasons for the difference in the results that you obtained from your DCF analysis and the results that Mr. Bourassa obtained from his DCF analysis using the constant growth model?

A. Mr. Bourassa conducted his analysis in April of 2009 and consequently much of the data that he used in his analysis is now stale. This can be seen in a price comparison of three of the water company stocks that we

both used in our samples: The difference between the average adjusted closing stock prices used in my DCF model and spot prices used by Mr. Bourassa in his DCF models are as follows:

| | Rigsby | Bourassa | Difference |
|---|---|---|---|
| AWR | $34.19 | $33.40 | $0.79 |
| CWT | $37.45 | $36.46 | $0.99 |
| WTR | $16.09 | $18.88 | - $2.79 |

Q. What are the differences between your constant growth DCF results and Mr. Bourassa's first constant growth model which relied strictly on earnings growth?

A. As I stated earlier, Mr. Bourassa did not rely on a sample of natural gas utilities so my comparison is limited to our respective water utility samples. Much of the difference between our results is attributable to the utilities that were included in our samples. Mr. Bourassa's sample included utilities that I excluded because Value Line does not provide projections on them which I use to develop my growth estimates for the "g" component of the DCF model. His average dividend yields of 3.73 percent to 3.78 percent are 93 to 98 basis points higher than my average dividend yield of 2.80 percent. The current dividend yield of the three utilities that are samples have in common (based on my 8-week average adjusted closing prices listed above) would be 3.19 percent relying on Mr.

Bourassa's method for calculating the current dividend yield. In regard to our growth (i.e. "g" component of the DCF model) estimates, Mr. Bourassa's estimates of 7.41 percent to 8.85 percent are 27 to 171 basis points higher than my average growth estimate of 7.14 percent. However the average future growth rate estimates that Mr. Bourassa uses in his models excludes DPS growth rates. This is because Mr. Bourassa believes that historical DPS growth rates depress the growth estimates used in the DCF model.

Q. Do you agree with Mr. Bourassa's logic for not using DCF growth rates in the estimation of a growth rate for the DCF model?

A. No, I do not. Mr. Bourassa states on page 30 of his direct testimony that his DCF result of 7.05 percent that includes DCF growth is lower than the yields of investment grade bonds and Baa/BBB-rated utility bonds and should be excluded. A review of my attachment D will show that, as of November 24, 2009, the yields of A-rated corporate bonds and Baa/BBB rated utility bonds ranged from 5.19 percent to 6.22 percent which are actually lower than the 7.05 result that he obtained. Given the fact that water utilities are being viewed as safe investments during the current economic environment, it is only reasonable to assume that the spread between bond yields and the results produced by stock valuation models such as the DCF would not be that large.

Q. What are the main differences between your CAPM results and Mr. Bourassa's CAPM results?

A. The differences between our CAPM results is attributable to his selection of forecasted long-term U.S. Treasury instrument yields used as inputs for the risk-free rate of return and the time period that has expired since Mr. Bourassa filed his direct testimony. Mr. Bourassa's average beta of 0.84 has also fallen since his testimony was filed, and his current market risk premium figure of 17.74 percent is simply not realistic when compared with the market risk premiums, ranging from 4.20 percent to 6.10 percent, that I obtained from Morningstar's 2009 SBBI Yearbook.

Q. Please explain the differences in your risk free rates of return.

A. I relied on a 2.26 percent yield on a 5-year treasury rate whereas Mr. Bourassa relied on a 4.60 percent average of forecasted 20 and 30-year Treasury yields as opposed to my use of a 5-year Treasury yield.

Q. Do you agree with Mr. Bourassa's reliance on forecasted yields of long-term Treasury instruments?

A. No. I believe that a shorter term instrument is more appropriate when one takes into account that utilities generally file for new rates every three to five years.

Q. What is the current average beta for the water utilities included in Mr. Bourassa's sample?

A. The current average beta for the water utilities included in Mr. Bourassa's sample is 0.80 as opposed to the 0.84 used in his CAPM analysis and the 0.83 used in my CAPM analysis.

Q. What are the differences in the market risk premiums that you used in your CAPM analyses?

A. As I explained earlier in my testimony, my market risk premiums are the 6.10 percent arithmetic and 4.20 percent geometric means of the differences between the return on the broader stock market and the yields of intermediate term U.S. Treasury instruments over the 1926 – 2008 time frame (obtained from Morningstar's SBBI Yearbook). Mr. Bourassa relied on a 6.5 percent historical risk premium (which also relied on Morningstar data) and a 17.7 percent current market risk premium, which was computed using the DCF model and data on 1,700 stocks followed by Value Line.

Q. Do you agree with Mr. Bourassa's 17.7 percent current market risk premium?

A. No. Mr. Bourassa's 17.7 percent market risk premium is clearly excessive. He calculates it by using a DCF model that relies on stock price appreciation for the growth component (i.e. "g"). This results in a 24-

month average expected return of 22.21 percent. His 17.7 percent risk premium is the difference from the 22.21 percent DCF result and the 24-month average of the yields on a 30-year Treasury instrument. Mr. Bourassa's current market risk premium is not even realistic considering the historic market risk premiums that take into consideration the full spectrum of economic conditions that have occurred since 1926. His current market risk premium also flies in the face of recent empirical research that pegs the market risk premium at approximately 4.00 percent.

Q. How did Mr. Bourassa arrive at his final 12.40 percent cost of common equity for RRUI?

A. Mr. Bourassa's final estimate of 12.40 percent was calculated by taking the 13.3 percent average of the midpoints of his DCF and CAPM results and then adding to it a financial risk adjustment of negative 1.4 percent and a specific company risk return of 0.5 percent. His negative 1.4 percent financial risk adjustment was calculated by finding the difference between the results obtained from his CAPM model using an average beta of 0.84, and the results of his CAPM model using relevered beta of 0.72 which was obtained through the use of the Hamada methodology. The use of the Hamada methodology adjusts his average beta of 0.84, which was derived from a sample of water utilities with both debt and equity in

their capital structures, to a beta that is reflective of a utility with zero debt, and no financial risk such as RRUI, in its capital structure.

Q. Do you agree with Mr. Bourassa's averaging of his CAPM results?

A. No. I believe his most realistic estimate for RRUI's cost of equity capital was derived using the CAPM with his relevered beta of 0.72 and his historic market risk premium of 6.5 percent. This produces an expected return of 9.3 percent.

Q. Is there any merit in the rationale used by Mr. Bourassa in regard to the size arguments stated in his direct testimony?

A. No. As I stated earlier in my testimony, RRUI is a wholly owned subsidiary of Algonquin Power Income Fund, a large publicly traded mutual fund that has direct access to the capital markets. In addition to this, to the best of my knowledge, the Commission has never granted a higher cost of common equity based on company size.

Q. Does your cost of capital recommendation take into consideration any perceived business risks that RRUI might face?

A. Yes. I believe that the amount of equity contained in my recommended hypothetical capital structure mitigates any perceived business risk that investors might think RRUI faces.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Bourassa or any other witness for RRUI constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on RRUI?

A. Yes, it does.

# Qualifications of William A. Rigsby, CRRA

**EDUCATION:**

University of Phoenix
Master of Business Administration, Emphasis in Accounting, 1993

Arizona State University
College of Business
Bachelor of Science, Finance, 1990

Mesa Community College
Associate of Applied Science, Banking and Finance, 1986

Society of Utility and Regulatory Financial Analysts
38th Annual Financial Forum and CRRA Examination
Georgetown University Conference Center, Washington D.C.
Awarded the Certified Rate of Return Analyst designation
after successfully completing SURFA's CRRA examination.

Michigan State University
Institute of Public Utilities
N.A.R.U.C. Annual Regulatory Studies Program, 1997 &1999

Florida State University
Center for Professional Development & Public Service
N.A.R.U.C. Annual Western Utility Rate School, 1996

**EXPERIENCE:**

Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
Phoenix, Arizona
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
Phoenix, Arizona
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
Phoenix, Arizona
July 1991 – October 1994

**Appendix 1**

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| ICR Water Users Association | U-2824-94-389 | Original CC&N |
| Rincon Water Company | U-1723-95-122 | Rate Increase |
| Ash Fork Development Association, Inc. | E-1004-95-124 | Rate Increase |
| Parker Lakeview Estates Homeowners Association, Inc. | U-1853-95-328 | Rate Increase |
| Mirabell Water Company, Inc. | U-2368-95-449 | Rate Increase |
| Bonita Creek Land and Homeowner's Association | U-2195-95-494 | Rate Increase |
| Pineview Land & Water Company | U-1676-96-161 | Rate Increase |
| Pineview Land & Water Company | U-1676-96-352 | Financing |
| Montezuma Estates Property Owners Association | U-2064-96-465 | Rate Increase |
| Houghland Water Company | U-2338-96-603 et al | Rate Increase |
| Sunrise Vistas Utilities Company – Water Division | U-2625-97-074 | Rate Increase |
| Sunrise Vistas Utilities Company – Sewer Division | U-2625-97-075 | Rate Increase |
| Holiday Enterprises, Inc. dba Holiday Water Company | U-1896-97-302 | Rate Increase |
| Gardener Water Company | U-2373-97-499 | Rate Increase |
| Cienega Water Company | W-2034-97-473 | Rate Increase |
| Rincon Water Company | W-1723-97-414 | Financing/Auth. To Issue Stock |
| Vail Water Company | W-01651A-97-0539 et al | Rate Increase |
| Bermuda Water Company, Inc. | W-01812A-98-0390 | Rate Increase |
| Bella Vista Water Company | W-02465A-98-0458 | Rate Increase |
| Pima Utility Company | SW-02199A-98-0578 | Rate Increase |

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| Pineview Water Company | W-01676A-99-0261 | WIFA Financing |
| I.M. Water Company, Inc. | W-02191A-99-0415 | Financing |
| Marana Water Service, Inc. | W-01493A-99-0398 | WIFA Financing |
| Tonto Hills Utility Company | W-02483A-99-0558 | WIFA Financing |
| New Life Trust, Inc. dba Dateland Utilities | W-03537A-99-0530 | Financing |
| GTE California, Inc. | T-01954B-99-0511 | Sale of Assets |
| Citizens Utilities Rural Company, Inc. | T-01846B-99-0511 | Sale of Assets |
| MCO Properties, Inc. | W-02113A-00-0233 | Reorganization |
| American States Water Company | W-02113A-00-0233 | Reorganization |
| Arizona-American Water Company | W-01303A-00-0327 | Financing |
| Arizona Electric Power Cooperative | E-01773A-00-0227 | Financing |
| 360networks (USA) Inc. | T-03777A-00-0575 | Financing |
| Beardsley Water Company, Inc. | W-02074A-00-0482 | WIFA Financing |
| Mirabell Water Company | W-02368A-00-0461 | WIFA Financing |
| Rio Verde Utilities, Inc. | WS-02156A-00-0321 et al | Rate Increase/ Financing |
| Arizona Water Company | W-01445A-00-0749 | Financing |
| Loma Linda Estates, Inc. | W-02211A-00-0975 | Rate Increase |
| Arizona Water Company | W-01445A-00-0962 | Rate Increase |
| Mountain Pass Utility Company | SW-03841A-01-0166 | Financing |
| Picacho Sewer Company | SW-03709A-01-0165 | Financing |
| Picacho Water Company | W-03528A-01-0169 | Financing |
| Ridgeview Utility Company | W-03861A-01-0167 | Financing |
| Green Valley Water Company | W-02025A-01-0559 | Rate Increase |
| Bella Vista Water Company | W-02465A-01-0776 | Rate Increase |
| Arizona Water Company | W-01445A-02-0619 | Rate Increase |

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| Arizona-American Water Company | W-01303A-02-0867 et al. | Rate Increase |
| Arizona Public Service Company | E-01345A-03-0437 | Rate Increase |
| Rio Rico Utilities, Inc. | WS-02676A-03-0434 | Rate Increase |
| Qwest Corporation | T-01051B-03-0454 | Renewed Price Cap |
| Chaparral City Water Company | W-02113A-04-0616 | Rate Increase |
| Arizona Water Company | W-01445A-04-0650 | Rate Increase |
| Tucson Electric Power | E-01933A-04-0408 | Rate Review |
| Southwest Gas Corporation | G-01551A-04-0876 | Rate Increase |
| Arizona-American Water Company | W-01303A-05-0405 | Rate Increase |
| Black Mountain Sewer Corporation | SW-02361A-05-0657 | Rate Increase |
| Far West Water & Sewer Company | WS-03478A-05-0801 | Rate Increase |
| Gold Canyon Sewer Company | SW-02519A-06-0015 | Rate Increase |
| Arizona Public Service Company | E-01345A-05-0816 | Rate Increase |
| Arizona-American Water Company | W-01303A-05-0718 | Transaction Approval |
| Arizona-American Water Company | W-01303A-05-0405 | ACRM Filing |
| Arizona-American Water Company | W-01303A-06-0014 | Rate Increase |
| UNS Gas, Inc. | G-04204A-06-0463 | Rate Increase |
| Arizona-American Water Company | WS-01303A-06-0491 | Rate Increase |
| UNS Electric, Inc. | E-04204A-06-0783 | Rate Increase |
| Arizona-American Water Company | W-01303A-07-0209 | Rate Increase |
| Tucson Electric Power | E-01933A-07-0402 | Rate Increase |
| Southwest Gas Corporation | G-01551A-07-0504 | Rate Increase |
| Chaparral City Water Company | W-02113A-07-0551 | Rate Increase |
| Arizona-American Water Company | W-01303A-08-0227 et al. | Rate Increase |
| Far West Water & Sewer Company | WS-03478A-08-0608 | Interim Rate Increase |
| Johnson Utilities, LLC | WS-02987A-08-0180 | Rate Increase |

## RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

| Utility Company | Docket No. | Type of Proceeding |
|---|---|---|
| UNS Gas, Inc. | G-04204A-08-0571 | Rate Increase |
| Arizona Water Company | W-01445A-08-0440 | Rate Increase |
| Black Mountain Sewer Corporation | SW-02361A-08-0609 | Rate Increase |
| Global Utilities | SW-02445A-09-0077 et al. | Rate Increase |
| Litchfield Park Service Company | SW-01428A-09-0104 et al. | Rate Increase |
| UNS Electric, Inc. | E-04204A-09-0206 | Rate Increase |

# ATTACHMENT A

**There has not been much change in the Water Utility Industry since our last review in July. Providers continued to reap the benefits of an increasingly favorable regulatory backing, with most in the group posting solid top- and bottom-line growth in the second quarter (September results were not out as of the date this issue was published).**

**However, the industry has fallen well into the bottom half of our *Survey* for Timeliness, as share-price gains paled in comparison to those enjoyed by the seemingly revitalized broader market. We suspect that water utility stocks will continue to lose some of their shine in the months ahead for similar reasons, as hopes of economic stability prompt many to look outside this relative safe-haven in hopes of securing wider gains. Making matter worse, earnings growth is likely to slow in the second half of the year and remain weak thereafter, due to tougher comparisons and burgeoning operating costs.**

**Longer-term growth prospects are not much better either. Despite the brighter regulatory landscape, infrastructure costs are expected to continue ramping up due to aging water systems, geographic expansion, and increasingly stringent EPA regulations. These, along with the subsequent financing expenses, will offset most of the aforementioned help, and thus limit appreciation potential going forward. As a result, most of the stocks in this segment offer minimal 3-to 5-year appeal.**

## Bright Demand Picture

These utilities have the ultimate job security. Water is a necessity, a fact that cannot be changed no matter what. Recognizing that a community's well being is closely tied to a providers health, many state regulatory bodies that were once antagonists, have changed their tune and taken on a more business approach. These authorities, which were put in place to help maintain a balance of power between customers and providers and to ensure fair business practices, are now handing down more favorable rulings. Responsible for reviewing and ruling on general rate requests made by utilities to help recover costs, they hold tremendous power and can potentially make or break a company. The recent about face in demeanor creates a far more favorable climate

**INDUSTRY TIMELINESS: 72 (of 98)**

and augurs well for providers.

## Alarming Costs

That said, the water utility industry has some issues to contend with. Infrastructures are getting older and becoming inadequate in many cases. Some will require heavy investment in order to make the necessary repairs, while EPA standards get tougher due to the potential threat of bioterrorism. In all, infrastructure costs are estimated to amount to hundreds of millions of dollars over the next decade. Unfortunately, most operating in this space are laden with debt and strapped for cash. They will be forced to seek outside financing in order to meet the growing capital outlays, with the higher interest rate costs and greater share counts thwarting shareholder returns. Note, however, that, as a result of the industry's capital intensive nature, consolidation is white hot. Those with the flexibility to meet its commitments have ample opportunity to make deals and grow their customer base.

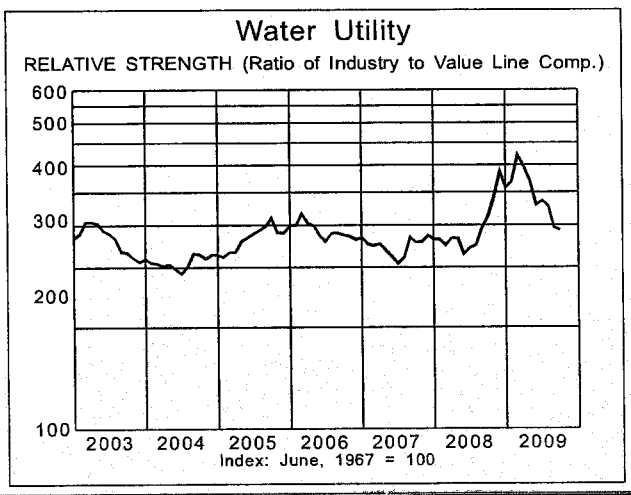
## Conclusion

This industry is a good place for cautious investors looking to park themselves until a sustained market recovery is evident. Water utility stocks are historically more recession proof than the broader market, with their steady dividend growth reducing turbulence in share price and padding returns. However, those with a penchant for growth will probably want to take a pass, opting for an area with more upside. There are a couple of issues here that stand out for 3- to 5-year appreciation potential, namely *Aqua America* and *Southwest Water Company*, but the latter's Below Average (4) Safety rank and poor Financial Strength rating may evoke some apprehension. Meanwhile, *Aqua*'s dependence on an aggressive acquisition tendency to drive gains may well need to be tempered if finances continue to deteriorate. *American Water Works* is another interesting option, but its short trading history and lack of performance indicators should scare off most. As always, we advise potential investors to read the individual reports of each stock before making a financial commitment.

*Andre J. Costanza*

Composite Statistics: Water Utility Industry

| 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|
| 1256.9 | 3454.1 | 3702.5 | 3913.8 | ***4180*** | ***4475*** | Revenues ($mill) | ***5425*** |
| 148.2 | d5.8 | d183.0 | 352.7 | ***425*** | ***485*** | Net Profit ($mill) | ***625*** |
| 40.5% | NMF | NMF | 37.0% | ***38.0%*** | ***39.0%*** | Income Tax Rate | ***40.0%*** |
| 1.1% | NMF | NMF | 6.5% | ***8.0%*** | ***10.0%*** | AFUDC % to Net Profit | ***15.0%*** |
| 50.4% | 54.0% | 51.0% | 52.6% | ***54.0%*** | ***52.5%*** | Long-Term Debt Ratio | ***50.0%*** |
| 49.5% | 45.9% | 49.0% | 47.4% | ***46.0%*** | ***47.5%*** | Common Equity Ratio | ***50.0%*** |
| 3053.8 | 12113.9 | 12985.9 | 12629.1 | ***13600*** | ***14125*** | Total Capital ($mill) | ***16250*** |
| 4200.7 | 13308.3 | 14315.2 | 15356.1 | ***16180*** | ***16950*** | Net Plant ($mill) | ***19375*** |
| 6.3% | 1.6% | .2% | 4.3% | ***5.0%*** | ***5.0%*** | Return on Total Cap'l | ***6.0%*** |
| 9.8% | NMF | NMF | 5.9% | ***7.0%*** | ***7.0%*** | Return on Shr. Equity | ***7.5%*** |
| 9.8% | NMF | NMF | 5.9% | ***7.0%*** | ***7.0%*** | Return on Com Equity | ***7.5%*** |
| 3.7% | NMF | NMF | 2.9% | ***3.0%*** | ***3.5%*** | Retained to Com Eq | ***4.5%*** |
| 62% | NMF | NMF | 51% | ***65%*** | ***62%*** | All Div'ds to Net Prof | ***60%*** |
| 29.4 | NMF | NMF | | ***Bold figures are Value Line estimates*** | | Avg Ann'l P/E Ratio | ***22.0*** |
| 1.57 | NMF | NMF | | | | Relative P/E Ratio | ***1.45*** |
| 2.1% | 2.0% | 2.3% | | | | Avg Ann'l Div'd Yield | ***2.5%*** |

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# AMER. STATES WATER NYSE-AWR

RECENT PRICE 36.04 | P/E RATIO 18.8 (Trailing: 22.4 Median: 22.0) | RELATIVE P/E RATIO 1.08 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 6/5/09
SAFETY 3 New 2/4/00
TECHNICAL 3 Raised 10/23/09
BETA .80 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 19.5 | 26.5 | 25.3 | 26.4 | 29.0 | 29.0 | 26.8 | 34.6 | 43.8 | 46.1 | 42.0 | 38.8 |
| Low: | 14.1 | 14.8 | 16.7 | 19.0 | 20.3 | 21.6 | 20.8 | 24.3 | 30.3 | 33.6 | 27.0 | 29.8 |

Target Price Range 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

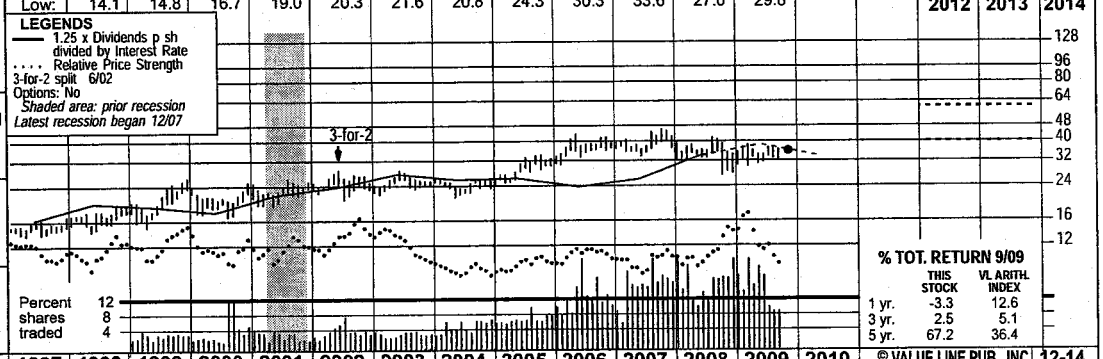
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+65%) | 16% |
| Low | 40 | (+10%) | 6% |

**Insider Decisions**

| | N | D | J | F | M | A | M | J | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 1 | 2 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 64 | 55 | 66 |
| to Sell | 52 | 66 | 53 |
| Hld's(000) | 8980 | 9283 | 10578 |




**% TOT. RETURN 9/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -3.3 | 12.6 |
| 3 yr. | 2.5 | 5.1 |
| 5 yr. | 67.2 | 36.4 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 9.27 | 10.43 | 11.03 | 11.37 | 11.44 | 11.02 | 12.91 | 12.17 | 13.06 | 13.78 | 13.98 | 13.61 | 14.06 | 15.76 | 17.49 | 18.42 | *18.90* | *19.75* | Revenues per sh | *21.75* |
| 1.67 | 1.68 | 1.75 | 1.75 | 1.85 | 2.04 | 2.26 | 2.20 | 2.53 | 2.54 | 2.08 | 2.23 | 2.64 | 2.89 | 3.31 | 3.37 | *3.80* | *3.95* | "Cash Flow" per sh | *4.60* |
| 1.11 | .95 | 1.03 | 1.13 | 1.04 | 1.08 | 1.19 | 1.28 | 1.35 | 1.34 | .78 | 1.05 | 1.32 | 1.33 | 1.62 | 1.55 | *1.90* | *2.05* | Earnings per sh A | *2.60* |
| .79 | .80 | .81 | .82 | .83 | .84 | .85 | .86 | .87 | .87 | .88 | .89 | .90 | .91 | .96 | 1.00 | *1.02* | *1.08* | Div'd Decl'd per sh B■ | *1.25* |
| 1.90 | 2.43 | 2.19 | 2.40 | 2.58 | 3.11 | 4.30 | 3.03 | 3.18 | 2.68 | 3.76 | 5.03 | 4.24 | 3.91 | 2.89 | 4.45 | *4.00* | *4.25* | Cap'l Spending per sh | *5.00* |
| 9.95 | 10.07 | 10.29 | 11.01 | 11.24 | 11.48 | 11.82 | 12.74 | 13.22 | 14.05 | 13.97 | 15.01 | 15.72 | 16.64 | 17.53 | 17.95 | *16.55* | *19.45* | Book Value per sh | *22.00* |
| 11.71 | 11.77 | 11.77 | 13.33 | 13.44 | 13.44 | 13.44 | 15.12 | 15.12 | 15.18 | 15.21 | 16.75 | 16.80 | 17.05 | 17.23 | 17.30 | *18.50* | *18.75* | Common Shs Outst'g C | *20.00* |
| 13.4 | 12.8 | 11.6 | 12.6 | 14.5 | 15.5 | 17.1 | 15.9 | 16.7 | 18.3 | 31.9 | 23.2 | 21.9 | 27.7 | 24.0 | 22.6 | *Bold figures are* | | Avg Ann'l P/E Ratio | *20.0* |
| .79 | .84 | .78 | .79 | .84 | .81 | .97 | 1.03 | .86 | 1.00 | 1.82 | 1.23 | 1.17 | 1.50 | 1.27 | 1.37 | *Value Line* | | Relative P/E Ratio | *1.35* |
| 5.3% | 6.6% | 6.7% | 5.8% | 5.5% | 5.0% | 4.2% | 4.2% | 3.9% | 3.6% | 3.5% | 3.6% | 3.1% | 2.5% | 2.5% | 2.9% | *estimates* | | Avg Ann'l Div'd Yield | *2.5%* |
| | | | | | | 173.4 | 184.0 | 197.5 | 209.2 | 212.7 | 228.0 | 236.2 | 268.6 | 301.4 | 318.7 | *350* | *370* | Revenues ($mill) | *435* |
| | | | | | | 16.1 | 18.0 | 20.4 | 20.3 | 11.9 | 16.5 | 22.5 | 23.1 | 28.0 | 26.8 | *35.0* | *39.0* | Net Profit ($mill) | *52.0* |
| | | | | | | 46.0% | 45.7% | 43.0% | 38.9% | 43.5% | 37.4% | 47.0% | 40.5% | 42.6% | 37.8% | *35.5%* | *37.0%* | Income Tax Rate | *40.0%* |
| | | | | | | -- | -- | -- | -- | -- | -- | -- | 12.2% | 8.5% | 6.9% | *5.0%* | *5.0%* | AFUDC % to Net Profit | *5.0%* |
| | | | | | | 51.0% | 47.5% | 54.9% | 52.0% | 52.0% | 47.7% | 50.4% | 48.6% | 46.9% | 46.2% | *46.5%* | *46.0%* | Long-Term Debt Ratio | *46.5%* |
| | | | | | | 48.4% | 51.9% | 44.7% | 48.0% | 48.0% | 52.3% | 49.6% | 51.4% | 53.1% | 53.8% | *53.5%* | *54.0%* | Common Equity Ratio | *53.5%* |
| | | | | | | 328.2 | 371.1 | 447.6 | 444.4 | 442.3 | 480.4 | 532.5 | 551.6 | 569.4 | 577.0 | *665* | *675* | Total Capital ($mill) | *825* |
| | | | | | | 449.6 | 509.1 | 539.8 | 563.3 | 602.3 | 664.2 | 713.2 | 750.6 | 776.4 | 825.3 | *870* | *925* | Net Plant ($mill) | *1025* |
| | | | | | | 6.6% | 6.4% | 6.1% | 6.5% | 4.6% | 5.2% | 5.4% | 6.0% | 6.7% | 6.4% | *7.0%* | *7.5%* | Return on Total Cap'l | *8.5%* |
| | | | | | | 10.0% | 9.2% | 10.1% | 9.5% | 5.6% | 6.6% | 8.5% | 8.1% | 9.3% | 8.6% | *10.0%* | *10.5%* | Return on Shr. Equity | *12.0%* |
| | | | | | | 10.1% | 9.3% | 10.1% | 9.5% | 5.6% | 6.6% | 8.5% | 8.1% | 9.3% | 8.6% | *10.0%* | *10.5%* | Return on Com Equity | *12.0%* |
| | | | | | | 2.9% | 3.0% | 3.6% | 3.3% | NMF | 1.0% | 2.8% | 2.7% | 3.9% | 3.1% | *5.0%* | *5.5%* | Retained to Com Eq | *6.0%* |
| | | | | | | 72% | 68% | 65% | 65% | 113% | 84% | 67% | 67% | 58% | 64% | *56%* | *52%* | All Div'ds to Net Prof | *48%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $317.8 mill. **Due in 5 Yrs** $12.0 mill.
**LT Debt** $306.3 mill. **LT Interest** $22.0 mill.
(LT interest earned: 4.8x: total interest coverage: 4.4x) (46% of Cap'l)

**Leases, Uncapitalized:** Annual rentals $2.9 mill.

**Pension Assets-12/08** $54.2 mill. **Oblig.** $94.5 mill.

**Pfd Stock** None.

**Common Stock** 18,499,423 shs. as of 8/5/09
**MARKET CAP: $675 million (Small Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 1.7 | 7.3 | 9.8 |
| Other | 43.7 | 66.9 | 87.6 |
| Current Assets | 63.1 | 90.6 | 97.4 |
| Accts Payable | 29.1 | 36.6 | 39.6 |
| Debt Due | 37.8 | 75.3 | 11.5 |
| Other | 27.4 | 25.5 | 37.8 |
| Current Liab. | 94.3 | 137.4 | 88.9 |
| Fix. Chg. Cov. | 314% | 293% | 440% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 4.5% | 5.0% | *4.0%* |
| "Cash Flow" | 5.5% | 6.0% | *6.5%* |
| Earnings | 3.5% | 5.5% | *9.5%* |
| Dividends | 1.5% | 2.0% | *4.5%* |
| Book Value | 4.5% | 5.0% | *4.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 64.3 | 63.0 | 75.0 | 66.3 | 268.6 |
| 2007 | 72.3 | 79.3 | 75.8 | 74.0 | 301.4 |
| 2008 | 68.9 | 80.3 | 85.3 | 84.2 | 318.7 |
| 2009 | 79.6 | 93.6 | *91.8* | *85.0* | *350* |
| 2010 | *83.0* | *99.0* | *98.0* | *90.0* | *370* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .35 | .36 | .32 | .30 | 1.33 |
| 2007 | .40 | .42 | .44 | .35 | 1.62 |
| 2008 | .30 | .53 | .26 | .43 | 1.55 |
| 2009 | .28 | .64 | *.56* | *.42* | *1.90* |
| 2010 | *.30* | *.65* | *.60* | *.50* | *2.05* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .225 | .225 | .225 | .225 | .90 |
| 2006 | .225 | .225 | .225 | .235 | .91 |
| 2007 | .235 | .235 | .235 | .250 | .96 |
| 2008 | .250 | .250 | .250 | .250 | 1.00 |
| 2009 | .250 | .250 | .250 | | |

**BUSINESS:** American States Water Co. operates as a holding company. Through its principal subsidiary, Golden State Water Company, it supplies water to more than 250,000 customers in 75 communities in 10 counties. Service areas include the greater metropolitan areas of Los Angeles and Orange Counties. The company also provides electric utility services to nearly 23,250 customers in the city of Big Bear Lake and in areas of San Bernardino County. Acquired Chaparral City Water of Arizona (10/00). Has roughly 675 employees. Officers & directors own 2.5% of common stock (4/09 Proxy). Chairman: Lloyd Ross. President & CEO: Floyd Wicks. Inc: CA. Addr.: 630 East Foothill Boulevard, San Dimas, CA 91773. Tele.: 909-394-3600. Internet: www.aswater.com.

**Recent regulatory changes are fueling strength at American States Water.** The water utility provider posted earnings of $0.64 a share in the second quarter, 21% better than last year, as a more business friendly approach by the California Public Utilities Commission helped sales improve 17%, to $94 million, despite a decrease in water consumption. Specifically, the adoption of a water rate adjustment mechanism and a modified cost balancing account were $2.2 million accretive to the top line and boosted share earnings by $0.07. We suspect that third-quarter results were probably even more impressive, with the bottom line nearly doubling from last year's weak tally. As a result, we've raised our full-year earnings estimate by 12% to $1.90.

**We think there could be some hurdles ahead, however.** Comparisons get much tougher beginning with the December quarter and are likely to remain so henceforth. Meanwhile, operating costs appear to be on the rise, with infrastructure and maintenance expenses continuing to mount due to aging water systems. Thus, we look for growth to slow considerably in the fourth quarter and 2010.

**Finances remain a major concern.** Although management paid down roughly $45 million in debt in the June quarter, it was forced to issue shares to do so. Further debt reduction is highly unlikely going forward, with ongoing financing likely to be used to meet capital requirements. In fact, we look for AWR to tap debt and equity markets in the future in order to comply with increasingly stringent EPA regulations and improve infrastructures. The increased interest rate expense and greater share count that will accompany such maneuverings are likely to dilute future gains, though.

**Growth-minded investors can find better options.** AWR does not stand out for Timeliness or 3- to 5-year appreciation potential, as infrastructure costs mire future growth rates. Although income-minded investors may be hesitant to jump aboard, given that there has yet to be an announcement about a dividend increase, we are not concerned and suspect that a raise is on the horizon, thus maintaining the history of annual dividend growth.

*Andre J. Costanza* *October 23, 2009*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 14¢; '05, 25¢; '06, 6¢; '08, (27¢). Next earnings report due early Nov. May not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 70 |

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# CALIFORNIA WATER NYSE-CWT

RECENT PRICE 39.52 | P/E RATIO 18.7 (Trailing: 18.7 Median: 22.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 3.0% | VALUE LINE

TIMELINESS 3 Lowered 7/3/09
SAFETY 3 Lowered 7/27/07
TECHNICAL 4 Raised 10/23/09
BETA .75 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 33.8 | 32.0 | 31.4 | 28.6 | 26.9 | 31.4 | 37.9 | 42.1 | 45.8 | 45.4 | 46.6 | 48.3 |
| Low: | 20.8 | 22.6 | 21.5 | 22.9 | 20.5 | 23.7 | 26.1 | 31.2 | 32.8 | 34.2 | 27.7 | 33.5 |

Target Price Range 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

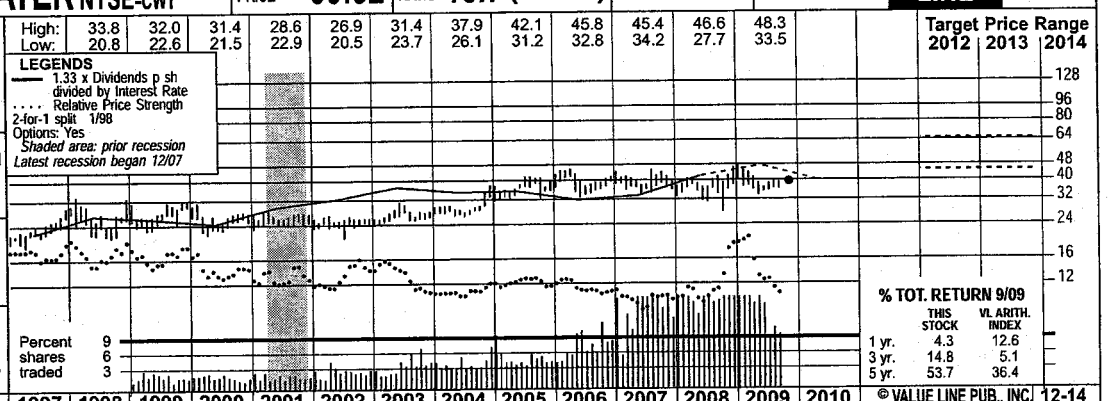
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 65 | (+65%) | 15% |
| Low | 45 | (+15%) | 6% |

**Insider Decisions**

| | N | D | J | F | M | A | M | J | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 107 | 83 | 76 |
| to Sell | 46 | 81 | 85 |
| Hld's(000) | 9799 | 10000 | 10018 |




**% TOT. RETURN 9/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 4.3 | 12.6 |
| 3 yr. | 14.8 | 5.1 |
| 5 yr. | 53.7 | 36.4 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 13.34 | 12.59 | 13.17 | 14.48 | 15.48 | 14.76 | 15.96 | 16.16 | 16.26 | 17.33 | 16.37 | 17.18 | 17.44 | 16.20 | 17.76 | 19.80 | 21.45 | 21.85 | Revenues per sh | 24.45 |
| 2.25 | 2.02 | 2.07 | 2.50 | 2.92 | 2.60 | 2.75 | 2.52 | 2.20 | 2.65 | 2.51 | 2.83 | 3.03 | 2.71 | 3.12 | 3.72 | 4.15 | 4.20 | "Cash Flow" per sh | 4.65 |
| 1.35 | 1.22 | 1.17 | 1.51 | 1.83 | 1.45 | 1.53 | 1.31 | .94 | 1.25 | 1.21 | 1.46 | 1.47 | 1.34 | 1.50 | 1.90 | 2.10 | 2.20 | Earnings per sh A | 2.65 |
| .96 | .99 | 1.02 | 1.04 | 1.06 | 1.07 | 1.09 | 1.10 | 1.12 | 1.12 | 1.12 | 1.13 | 1.14 | 1.15 | 1.16 | 1.17 | 1.18 | 1.19 | Div'd Decl'd per sh B ■ | 1.34 |
| 2.53 | 2.26 | 2.17 | 2.83 | 2.61 | 2.74 | 3.44 | 2.45 | 4.09 | 5.82 | 4.39 | 3.73 | 4.01 | 4.28 | 3.68 | 4.82 | 5.00 | 5.00 | Cap'l Spending per sh | 5.00 |
| 10.90 | 11.56 | 11.72 | 12.22 | 13.00 | 13.38 | 13.43 | 12.90 | 12.95 | 13.12 | 14.44 | 15.66 | 15.79 | 18.15 | 18.50 | 19.44 | 19.75 | 20.45 | Book Value per sh C | 22.20 |
| 11.38 | 12.49 | 12.54 | 12.62 | 12.62 | 12.62 | 12.94 | 15.15 | 15.18 | 15.18 | 16.93 | 18.37 | 18.39 | 20.66 | 20.67 | 20.72 | 21.00 | 21.50 | Common Shs Outst'g D | 22.50 |
| 13.6 | 14.1 | 13.7 | 11.9 | 12.6 | 17.8 | 17.8 | 19.6 | 27.1 | 19.8 | 22.1 | 20.1 | 24.9 | 29.2 | 26.1 | 19.8 | Bold figures are | | Avg Ann'l P/E Ratio | 21.0 |
| .80 | .92 | .92 | .75 | .73 | .93 | 1.01 | 1.27 | 1.39 | 1.08 | 1.26 | 1.06 | 1.33 | 1.58 | 1.39 | 1.20 | Value Line | | Relative P/E Ratio | 1.40 |
| 5.2% | 5.8% | 6.4% | 5.8% | 4.6% | 4.2% | 4.0% | 4.3% | 4.4% | 4.5% | 4.2% | 3.9% | 3.1% | 2.9% | 3.0% | 3.1% | estimates | | Avg Ann'l Div'd Yield | 2.4% |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $398.2 mill. **Due in 5 Yrs** $39.8 mill.
**LT Debt** $383.5 mill. **LT Interest** $24.0 mill.

(LT interest earned: 4.7x; total int. cov.: 4.3x)

**Pension Assets-12/08** $66.9 mill. **Oblig.** $192.9 mill.

**Pfd Stock** None

**Common Stock** 20,744,952 shs. as of 8/3/09

**MARKET CAP: $825 million (Small Cap)**

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 206.4 | 244.8 | 246.8 | 263.2 | 277.1 | 315.6 | 320.7 | 334.7 | 367.1 | 410.3 | 450 | 470 | Revenues ($mill) E | 550 |
| 19.9 | 20.0 | 14.4 | 19.1 | 19.4 | 26.0 | 27.2 | 25.6 | 31.2 | 39.8 | 45.0 | 47.0 | Net Profit ($mill) | 60.0 |
| 37.9% | 42.3% | 39.4% | 39.7% | 39.9% | 39.6% | 42.4% | 37.4% | 39.9% | 37.7% | 38.5% | 38.5% | Income Tax Rate | 39.0% |
| -- | -- | -- | -- | 10.3% | 3.2% | 3.3% | 10.6% | 8.3% | 8.6% | 8.5% | 10.0% | AFUDC % to Net Profit | 10.0% |
| 46.9% | 48.9% | 50.3% | 55.3% | 50.2% | 48.6% | 48.3% | 43.5% | 42.9% | 41.6% | 48.5% | 47.0% | Long-Term Debt Ratio | 45.0% |
| 52.0% | 50.2% | 48.8% | 44.0% | 49.1% | 50.8% | 51.1% | 55.9% | 56.6% | 58.4% | 51.5% | 53.0% | Common Equity Ratio | 55.0% |
| 333.8 | 388.8 | 402.7 | 453.1 | 498.4 | 565.9 | 568.1 | 670.1 | 674.9 | 690.4 | 800 | 825 | Total Capital ($mill) | 950 |
| 515.4 | 582.0 | 624.3 | 697.0 | 759.5 | 800.3 | 862.7 | 941.5 | 1010.2 | 1112.4 | 1175 | 1240 | Net Plant ($mill) | 1425 |
| 7.8% | 6.8% | 5.3% | 5.9% | 5.6% | 6.1% | 6.3% | 5.2% | 5.9% | 7.1% | 7.0% | 7.0% | Return on Total Cap'l | 8.0% |
| 11.2% | 10.0% | 7.2% | 9.4% | 7.8% | 8.9% | 9.3% | 6.8% | 8.1% | 9.9% | 11.5% | 10.5% | Return on Shr. Equity | 12.0% |
| 11.4% | 10.1% | 7.2% | 9.5% | 7.9% | 9.0% | 9.3% | 6.8% | 8.1% | 9.9% | 11.5% | 10.5% | Return on Com Equity | 12.0% |
| 3.5% | 1.8% | NMF | 1.0% | .7% | 2.1% | 2.1% | 1.0% | 1.8% | 3.8% | 5.0% | 5.0% | Retained to Com Eq | 6.0% |
| 70% | 82% | 119% | 90% | 91% | 77% | 78% | 86% | 77% | 61% | 55% | 54% | All Div'ds to Net Prof | 50% |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 6.7 | 13.9 | 41.5 |
| Other | 53.3 | 65.9 | 83.0 |
| Current Assets | 60.0 | 79.8 | 124.5 |
| Accts Payable | 36.7 | 45.1 | 48.3 |
| Debt Due | 2.7 | 42.8 | 14.7 |
| Other | 30.3 | 35.3 | 38.2 |
| Current Liab. | 69.7 | 123.2 | 101.2 |
| Fix. Chg. Cov. | 333% | 398% | 432% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 2.0% | 1.5% | 5.5% |
| "Cash Flow" | 2.0% | 5.5% | 6.5% |
| Earnings | -- | 7.0% | 9.0% |
| Dividends | 1.0% | 0.5% | 2.5% |
| Book Value | 4.0% | 6.5% | 3.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.)E Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 65.2 | 81.1 | 107.8 | 80.6 | 334.7 |
| 2007 | 71.6 | 95.8 | 113.8 | 85.9 | 367.1 |
| 2008 | 72.9 | 105.6 | 131.7 | 100.1 | 410.3 |
| 2009 | 86.7 | 116.7 | 138.6 | 108 | 450 |
| 2010 | 90.0 | 120 | 145 | 115 | 470 |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .04 | .31 | .68 | .31 | 1.34 |
| 2007 | .07 | .37 | .67 | .39 | 1.50 |
| 2008 | .01 | .48 | 1.06 | .35 | 1.90 |
| 2009 | .12 | .58 | 1.04 | .36 | 2.10 |
| 2010 | .13 | .60 | 1.08 | .39 | 2.20 |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .285 | .285 | .285 | .285 | 1.14 |
| 2006 | .2875 | .2875 | .2875 | .2875 | 1.15 |
| 2007 | .290 | .290 | .290 | .290 | 1.16 |
| 2008 | .293 | .293 | .293 | .293 | 1.17 |
| 2009 | .295 | .295 | .295 | | |

**BUSINESS:** California Water Service Group provides regulated and nonregulated water service to roughly 463,600 customers in 83 communities in California, Washington, New Mexico, and Hawaii. Main service areas: San Francisco Bay area, Sacramento Valley, Salinas Valley, San Joaquin Valley & parts of Los Angeles. Acquired Rio Grande Corp; West Hawaii Utilities (9/08). Revenue breakdown, '08: residential, 69%; business, 18%; public authorities, 5%; industrial, 5%; other, 3%. '08 reported depreciation rate: 2.4%. Has roughly 929 employees. Chairman: Robert W. Foy. President & CEO: Peter C. Nelson (4/09 Proxy). Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwatergroup.com.

**An improved regulatory environment has created a more favorable backdrop for California Water Service Group.** Indeed, the water utility provider exceeded high expectations in the second quarter, reporting earnings of $0.58 a share, 21% better than last year. The top line advanced 11%, to $116 million, with rate increases adding $19.2 million and offsetting lower usage by existing customers. We expect the top line to continue benefiting from ongoing progress on this front, particularly the California Public Utilities Commission's recent adoption of a water revenue adjustment mechanism, the implementation of a modified cost balancing account, and tiered rates. The company filed a general rate case seeking an additional $70.6 million in 2011, with requests of roughly $25 million for 2012 and 2013. Interim cases, meanwhile, should add nearly $9 million annually.

**Nevertheless, we suspect that growth hit a speed bump in the September period . . .** (Results were not out when we went to press with this issue.) Although we look for demand to remain healthy, tough comparisons probably resulted in a modest share-net shortfall. Plus, we expect that operating costs did not abate.

**. . . and will remain moderate going forward.** Even though tough comps ought to subside a bit over the next few quarters, profitability will likely be limited by rising infrastructure costs. Maintenance expenses should continue to rise as many pipelines and wells are in need of serious attention. Meanwhile, the additional finance commitments that will have to be assumed, given CWT's weak balance sheet and high costs of doing business, are expected to limit bottom-line growth for the foreseeable future.

**This stock is not for everybody.** Its growth prospects are dull, given the growing infrastructure costs that we envision being required over the next couple of years. The issue may, however, interest those looking to take shelter from the economic uncertainty that has resulted in recent broad market volatility. Indeed, CWT's steady dividend growth makes an attractive component in today's market and may well appeal to risk-averse investors seeking a low-risk alternative.

*Andre J. Costanza* *October 23, 2009*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (7¢); '01, 4¢; '02, 8¢. Next earnings report due late February.
(B) Dividends historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. deferred charges. In '08: $3.9 mill., $.19/sh.
(D) In millions, adjusted for split.
(E) Excludes non-reg. rev.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 80 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 75 |

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# SOUTHWEST WATER NDQ-SWWC

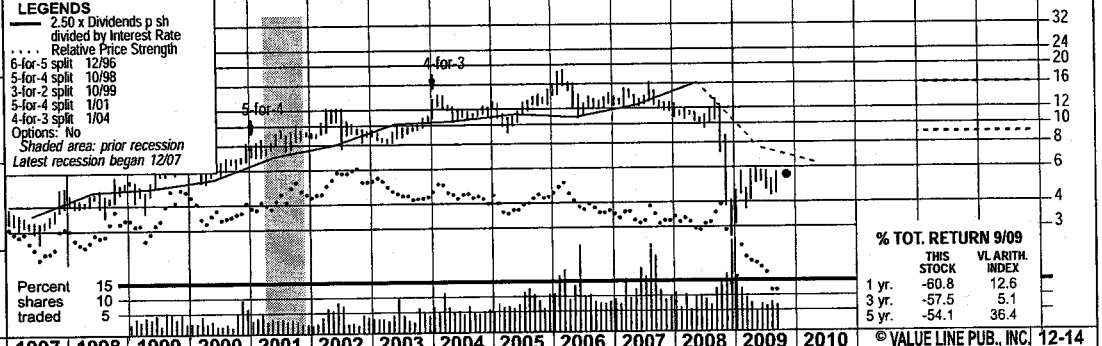
RECENT PRICE 5.50 | P/E RATIO 30.6 (Trailing: 50.0 Median: 29.0) | RELATIVE P/E RATIO 1.76 | DIV'D YLD 1.8% | VALUE LINE

TIMELINESS 4 New 10/23/09
SAFETY 4 New 10/23/09
TECHNICAL 2 Raised 9/25/09
BETA 1.10 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 5.6 | 9.2 | 8.3 | 10.2 | 12.4 | 11.2 | 14.3 | 15.2 | 19.1 | 16.4 | 13.4 | 5.9 |
| Low: | 3.5 | 3.6 | 5.1 | 6.9 | 7.6 | 8.1 | 10.3 | 9.0 | 10.8 | 11.5 | 2.7 | 3.1 |

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 2.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
6-for-5 split 12/96
5-for-4 split 10/98
3-for-2 split 10/99
5-for-4 split 1/01
4-for-3 split 1/04
Options: No
Shaded area: prior recession
Latest recession began 12/07




**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 16 | 190% | 31% |
| Low | 9 | 65% | 13% |

**Insider Decisions**

| | N | D | J | F | M | A | M | J | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 33 | 39 | 42 |
| to Sell | 42 | 38 | 39 |
| Hld's(000) | 11260 | 11007 | 11107 |

**% TOT. RETURN 9/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -60.8 | 12.6 |
| 3 yr. | -57.5 | 5.1 |
| 5 yr. | -54.1 | 36.4 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 4.03 | 4.20 | 4.84 | 5.31 | 5.61 | 5.63 | 6.16 | 7.49 | 8.15 | 9.12 | 10.70 | 9.23 | 9.10 | 9.42 | 8.96 | 8.87 | *8.60* | *8.80* | Revenues per sh | *10.40* |
| .38 | .38 | .44 | .46 | .53 | .59 | .65 | .76 | .87 | .86 | .91 | .67 | .78 | .85 | .69 | .66 | *1.00* | *1.20* | "Cash Flow" per sh | *1.55* |
| .08 | .09 | .12 | .15 | .21 | .25 | .31 | .38 | .42 | .39 | .44 | .23 | .34 | .40 | .31 | .04 | *.15* | *.30* | Earnings per sh A | *.50* |
| .14 | .08 | .08 | .09 | .09 | .10 | .11 | .13 | .14 | .15 | .16 | .18 | .20 | .21 | .23 | .24 | *.01* | *.01* | Div'd Decl'd per sh B | *.05* |
| .60 | .72 | .84 | .95 | .74 | .79 | .53 | .55 | 1.06 | 1.78 | 1.14 | 1.26 | 1.66 | 1.87 | 1.70 | 1.35 | *1.70* | *1.75* | Cap'l Spending per sh | *1.90* |
| 2.31 | 2.31 | 2.45 | 2.40 | 2.52 | 2.70 | 3.05 | 3.44 | 3.84 | 4.27 | 4.90 | 6.17 | 6.49 | 6.98 | 6.54 | 4.55 | *4.70* | *4.90* | Book Value per sh D | *6.05* |
| 11.97 | 12.13 | 11.74 | 12.45 | 12.65 | 12.83 | 13.12 | 13.99 | 14.17 | 14.35 | 16.17 | 20.36 | 22.33 | 23.80 | 24.27 | 24.90 | *25.00* | *25.50* | Common Shs Outst'g C | *26.50* |
| 35.8 | 22.3 | 14.6 | 16.5 | 16.9 | 17.2 | 19.6 | 17.0 | 19.8 | 24.8 | 21.2 | 51.6 | 35.5 | 34.8 | 42.1 | NMF | *Bold figures are* | | Avg Ann'l P/E Ratio | *25.0* |
| 2.11 | 1.46 | .98 | 1.03 | .97 | .89 | 1.12 | 1.11 | 1.01 | 1.35 | 1.21 | 2.73 | 1.89 | 1.88 | 2.23 | NMF | *Value Line* | | Relative P/E Ratio | *1.65* |
| 4.7% | 4.2% | 4.7% | 3.4% | 2.7% | 2.3% | 1.8% | 2.0% | 1.7% | 1.5% | 1.7% | 1.5% | 1.6% | 1.5% | 1.8% | 2.4% | *estimates* | | Avg Ann'l Div'd Yield | *1.2%* |

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 80.9 | 104.7 | 115.5 | 130.8 | 173.0 | 188.0 | 203.2 | 224.2 | 217.3 | 220.9 | *215* | *225* | Revenues ($mill) | *275* |
| 4.2 | 5.4 | 6.2 | 6.0 | 7.2 | 4.5 | 7.3 | 9.3 | 5.1 | 1.0 | *3.5* | *7.5* | Net Profit ($mill) | *13.0* |
| 39.0% | 37.0% | 36.0% | 34.9% | 35.9% | 36.1% | 36.0% | 35.0% | 56.0% | NMF | *NMF* | *NMF* | Income Tax Rate | *NMF* |
| -- | -- | 14.4% | 3.2% | -- | 11.0% | 9.5% | -- | 12.5% | 10.0% | *14.0%* | *13.5%* | AFUDC % to Net Profit | *12.0%* |
| 45.2% | 48.8% | 51.4% | 56.7% | 47.9% | 47.9% | 44.7% | 43.6% | 47.7% | 62.6% | *60.5%* | *57.5%* | Long-Term Debt Ratio | *48.5%* |
| 54.1% | 50.7% | 48.2% | 42.9% | 51.8% | 52.0% | 55.1% | 56.3% | 52.1% | 37.2% | *39.5%* | *42.5%* | Common Equity Ratio | *51.5%* |
| 73.9 | 95.0 | 113.0 | 142.8 | 152.8 | 242.0 | 262.9 | 295.2 | 304.5 | 304.4 | *300* | *295* | Total Capital ($mill) | *310* |
| 113.7 | 157.8 | 171.1 | 203.9 | 219.5 | 302.6 | 344.8 | 389.6 | 417.9 | 429.3 | *460* | *480* | Net Plant ($mill) | *525* |
| 7.6% | 7.6% | 7.6% | 5.8% | 6.2% | 3.1% | 4.1% | 4.5% | 2.9% | 1.8% | *2.5%* | *3.5%* | Return on Total Cap'l | *5.0%* |
| 10.3% | 11.1% | 11.4% | 9.7% | 9.0% | 3.6% | 5.0% | 5.6% | 3.2% | .9% | *3.0%* | *6.0%* | Return on Shr. Equity | *8.0%* |
| 10.4% | 11.1% | 11.4% | 9.7% | 9.1% | 3.6% | 5.0% | 5.6% | 3.2% | .8% | *3.0%* | *6.0%* | Return on Com Equity | *8.0%* |
| 7.0% | 7.8% | 7.8% | 6.3% | 5.8% | .8% | 2.1% | 2.6% | NMF | NMF | *1.0%* | *4.0%* | Retained to Com Eq | *6.5%* |
| 33% | 31% | 32% | 36% | 36% | 78% | 58% | 54% | 112% | NMF | *85%* | *42%* | All Div'ds to Net Prof | *31%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $152.0 mill. **Due in 5 Yrs** $149.8 mill.
**LT Debt** $149.8 mill. **LT Interest** $6.6 mill.
(Total interest coverage: 2.7x) (48% of Cap'l)

**Leases, Uncapitalized:** Annual rentals $5.5 mill.
**Pension Liability** None

**Pfd Stock** $.458 mill. **Pfd Div'd** $.020 mill.
**Common Stock** 24,888,745 shs.
as of 8/31/09

**MARKET CAP: $125 million (Small Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 2.9 | 1.1 | 1.6 |
| Receivables | 26.0 | 29.7 | 31.7 |
| Inventory (Avg Cst) | -- | -- | -- |
| Other | 32.7 | 26.9 | 24.5 |
| Current Assets | 61.6 | 57.7 | 57.8 |
| Accts Payable | 14.9 | 16.1 | 13.7 |
| Debt Due | 1.9 | 2.2 | 2.2 |
| Other | 29.4 | 28.4 | 18.6 |
| Current Liab. | 46.2 | 46.7 | 34.5 |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 5.0% | -0.5% | 2.5% |
| "Cash Flow" | 3.5% | -3.5% | 13.5% |
| Earnings | 2.0% | -10.0% | 12.0% |
| Dividends | 9.5% | 8.5% | -22.5% |
| Book Value | 9.0% | 7.0% | Nil |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 50.8 | 55.4 | 60.1 | 57.9 | 224.2 |
| 2007 | 48.1 | 55.0 | 57.4 | 56.8 | 217.3 |
| 2008 | 49.6 | 56.9 | 60.4 | 54.0 | 220.9 |
| 2009 | 50.1 | 52.4 | *57.0* | *55.5* | *215* |
| 2010 | *52.0* | *55.0* | *60.0* | *58.0* | *225* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun. 30 | Sep. 30 | Dec. 31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .03 | .08 | .16 | .13 | .40 |
| 2007 | .03 | .09 | .09 | .11 | .31E |
| 2008 | d.04 | .03 | d.02 | .07 | .04 |
| 2009 | .03 | .03 | *.04* | *.05* | *.15* |
| 2010 | *.06* | *.06* | *.08* | *.10* | *.30* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .048 | .048 | .048 | .052 | .20 |
| 2006 | .052 | .052 | .052 | .058 | .21 |
| 2007 | .058 | .058 | .058 | .058 | .23 |
| 2008 | .06 | .06 | .06 | .06 | .24 |
| 2009 | .025 | .025 | .025 | .025 | |

**BUSINESS:** SouthWest Water Company provides a broad range of services including water production, treatment and distribution; wastewater collection and treatment; utility billing and collection; and utility infrastructure. It operates four groups, Utility, 32% of 2008 revenues; Texas Utility, 16%; O&M Services, 18%; Texas MUD Services, 34%. Utility and Texas Utility own and manage rate-regulated public water utilities in California, Alabama, Oklahoma, and Texas. O&M and Texas MUD Services maintain projects on a contract and fee basis. Off./dir. own 6.4% of com. shs.; Stein Roe IC, 9.2% (4/08 proxy). CEO/Chrmn: Mark Swatek. Inc.: DE. Addr.: One Wilshire Building, 624 S. Grand Ave. Ste. 2900, Los Angeles, CA 90017. Tel.: 213-929-1800. Internet: www.swwc.com.

**SouthWest Water Company finally released its first- and second-quarter 10-Qs for 2009.** The company has been delinquent in filing a number of its reports over the past few quarters because of the discovery of mistakes made reporting depreciation rates of assets gained through acquisitions, and accounting issues for revenues and related costs associated with the installation of water and sewer taps. Also, year-over-year revenue and earnings comparisons for the first two quarters are skewed by SouthWest's restatement of its financial reports for those periods. Meanwhile, the company is poised to have a lackluster year as the slowdown in the economy has impacted business over the past few quarters, and should continue to do so.

**SouthWest's future growth will likely be achieved through acquisitions and rate increases.** To this extent, the company has put in for a number of rate increase cases in California, Texas, and Alabama. It is also positioning itself to make 2010 a "test year" to establish its position for future petitions. SWWC may look to buy a utility to replace the one lost because of an eminent domain lawsuit in New Mexico (sold for a net total of nearly $54 million during the June interim).

**This stock is untimely.** SouthWest will likely be burdened by a number of charges over the next few quarters related to the late filings. Also, the recession has weighed down housing starts and limits potential new customers.

**The recovery potential for this equity is offset by its risk.** While we expect the top and bottom lines to recover out to 2012-2014 as the economy picks up, there is a degree of risk associated with these advances. This is reflected by SWWC's low rank for Financial Strength (C++), as well as mediocre scores for Earnings Predictability and Stock Price Stability. Another mark against the appeal of this equity is the reduced dividend payout, lowered 60% from the prior year. Overall, investors should look elsewhere at this time.

*John D. Burke* *October 23, 2009*

| CASH POSITION | 5-Year Av'g | 6/30/09 |
|---|---|---|
| Current Assets to Current Liabilities: | 125% | 168% |
| Cash & Equiv's to Current Liabilities: | 10% | 5% |
| Working Capital to Sales: | 5% | 11% |

(A) Diluted earnings. Excludes nonrecurring gains (losses): '00, (3¢); '01, (5¢); '02, 1¢; '05, (23¢); '07, (54¢); '08, ($1.35); 1Q '09 (24¢); 2Q '09, (54¢). Next earnings report late November.
(B) Dividends historically paid in late January, April, July, and October.
(C) In millions, adjusted for splits.
(D) Includes intangibles. In 2008: $19.3 million, $0.83/share.
(E) Earnings may not add due to rounding.

| | |
|---|---|
| Company's Financial Strength | C++ |
| Stock's Price Stability | 45 |
| Price Growth Persistence | 40 |
| Earnings Predictability | 45 |

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# AQUA AMERICA NYSE-WTR

RECENT PRICE **16.65** | P/E RATIO **20.1** (Trailing: 22.2 / Median: 25.0) | RELATIVE P/E RATIO **1.16** | DIV'D YLD **3.5%** | VALUE LINE

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 11.5 | 11.5 | 12.0 | 14.8 | 15.0 | 16.8 | 18.5 | 29.2 | 29.8 | 26.6 | 22.0 | 21.5 |
| Low: | 7.2 | 7.6 | 6.3 | 9.4 | 9.6 | 11.8 | 14.2 | 17.5 | 20.1 | 18.9 | 12.2 | 16.1 |

**TIMELINESS** 3 Lowered 6/26/09
**SAFETY** 3 Lowered 8/1/03
**TECHNICAL** 4 Raised 10/16/09
**BETA** .65 (1.00 = Market)

**2012-14 PROJECTIONS**

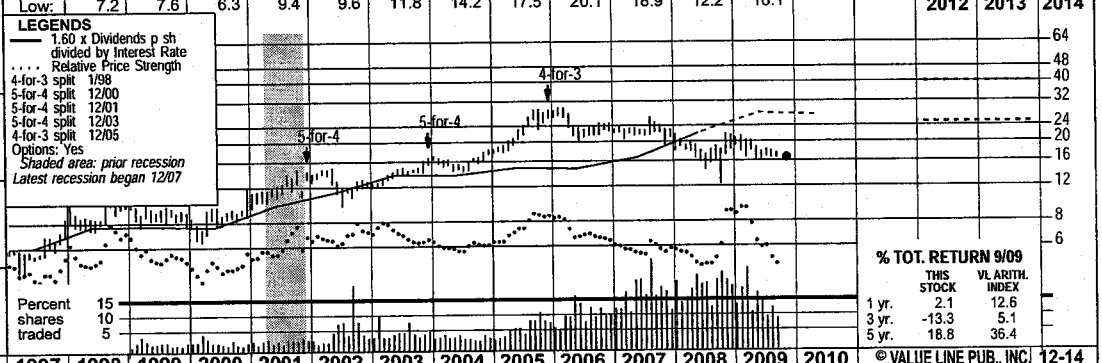
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+140%) | 26% |
| Low | 25 | (+50%) | 13% |

**Insider Decisions**

| | N | D | J | F | M | A | M | J | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 131 | 130 | 117 |
| to Sell | 131 | 134 | 136 |
| Hld's(000) | 60996 | 63551 | 61341 |




**Target Price Range**
2012 | 2013 | 2014

**% TOT. RETURN 9/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 2.1 | 12.6 |
| 3 yr. | -13.3 | 5.1 |
| 5 yr. | 18.8 | 36.4 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1.70 | 1.82 | 1.84 | 1.86 | 2.02 | 2.09 | 2.41 | 2.46 | 2.70 | 2.85 | 2.97 | 3.48 | 3.85 | 4.03 | 4.52 | 4.63 | *5.00* | *5.30* | Revenues per sh | *6.50* |
| .42 | .42 | .47 | .50 | .56 | .61 | .72 | .76 | .86 | .94 | .96 | 1.09 | 1.21 | 1.26 | 1.37 | 1.42 | *1.55* | *1.65* | "Cash Flow" per sh | *2.10* |
| .24 | .26 | .29 | .30 | .34 | .40 | .42 | .47 | .51 | .54 | .57 | .64 | .71 | .70 | .71 | .73 | *.82* | *.90* | Earnings per sh A | *1.25* |
| .21 | .21 | .22 | .23 | .24 | .26 | .27 | .28 | .30 | .32 | .35 | .37 | .40 | .44 | .48 | .51 | *.54* | *.56* | Div'd Decl'd per sh B■ | *.65* |
| .47 | .46 | .52 | .48 | .58 | .82 | .90 | 1.16 | 1.09 | 1.20 | 1.32 | 1.54 | 1.84 | 2.05 | 1.79 | 1.98 | *2.10* | *2.20* | Cap'l Spending per sh | *2.75* |
| 2.29 | 2.41 | 2.46 | 2.69 | 2.84 | 3.21 | 3.42 | 3.85 | 4.15 | 4.36 | 5.34 | 5.89 | 6.30 | 6.96 | 7.32 | 7.82 | *8.05* | *8.35* | Book Value per sh | *10.60* |
| 59.40 | 59.77 | 63.74 | 65.75 | 67.47 | 72.20 | 106.80 | 111.82 | 113.97 | 113.19 | 123.45 | 127.18 | 128.97 | 132.33 | 133.40 | 135.37 | *136.00* | *136.50* | Common Shs Outst'g C | *138.00* |
| 14.4 | 13.5 | 12.0 | 15.6 | 17.8 | 22.5 | 21.2 | 18.2 | 23.6 | 23.6 | 24.5 | 25.1 | 31.8 | 34.7 | 32.0 | 24.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | *25.0* |
| .85 | .89 | .80 | .98 | 1.03 | 1.17 | 1.21 | 1.18 | 1.21 | 1.29 | 1.40 | 1.33 | 1.69 | 1.87 | 1.70 | 1.50 | *Value Line* | | Relative P/E Ratio | *1.65* |
| 5.9% | 6.0% | 6.2% | 4.9% | 3.9% | 2.9% | 3.0% | 3.3% | 2.5% | 2.5% | 2.5% | 2.3% | 1.8% | 1.8% | 2.1% | 2.8% | *estimates* | | Avg Ann'l Div'd Yield | *2.0%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $1255.4 mill. **Due in 5 Yrs** $245.0 mill.
**LT Debt** $1227.7 mill. **LT Interest** $65.0 mill.
(LT interest earned: 3.4x; total interest coverage: 3.4x) (54% of Cap'l)

**Pension Assets-12/08** $112.2 mill. **Oblig.** $204.7 mill.

**Pfd Stock** None
**Common Stock** 135,917,740 shares as of 7/21/09

**MARKET CAP: $2.3 billion (Mid Cap)**

| 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 257.3 | 275.5 | 307.3 | 322.0 | 367.2 | 442.0 | 496.8 | 533.5 | 602.5 | 627.0 | *680* | *730* | Revenues ($mill) | *900* |
| 45.0 | 50.7 | 58.5 | 62.7 | 67.3 | 80.0 | 91.2 | 92.0 | 95.0 | 97.9 | *115* | *125* | Net Profit ($mill) | *170* |
| 38.4% | 38.9% | 39.3% | 38.5% | 39.3% | 39.4% | 38.4% | 39.6% | 38.9% | 39.7% | *39.0%* | *39.0%* | Income Tax Rate | *39.0%* |
| -- | -- | -- | -- | -- | -- | -- | -- | 2.9% | 3.1% | *3.5%* | *3.2%* | AFUDC % to Net Profit | *2.5%* |
| 52.9% | 52.0% | 52.2% | 54.2% | 51.4% | 50.0% | 52.0% | 51.6% | 55.4% | 54.1% | *54.0%* | *54.0%* | Long-Term Debt Ratio | *49.0%* |
| 46.7% | 47.8% | 47.7% | 45.8% | 48.6% | 50.0% | 48.0% | 48.4% | 44.6% | 45.9% | *46.0%* | *46.0%* | Common Equity Ratio | *51.0%* |
| 782.7 | 901.1 | 990.4 | 1076.2 | 1355.7 | 1497.3 | 1690.4 | 1904.4 | 2191.4 | 2306.6 | *2385* | *2470* | Total Capital ($mill) | *2865* |
| 1135.4 | 1251.4 | 1368.1 | 1490.8 | 1824.3 | 2069.8 | 2280.0 | 2506.0 | 2792.8 | 2997.4 | *3150* | *3300* | Net Plant ($mill) | *3600* |
| 7.6% | 7.4% | 7.8% | 7.6% | 6.4% | 6.7% | 6.9% | 6.4% | 5.9% | 5.7% | *6.5%* | *6.5%* | Return on Total Cap'l | *6.5%* |
| 12.2% | 11.7% | 12.3% | 12.7% | 10.2% | 10.7% | 11.2% | 10.0% | 9.7% | 9.3% | *10.5%* | *11.0%* | Return on Shr. Equity | *11.5%* |
| 12.3% | 11.7% | 12.4% | 12.7% | 10.2% | 10.7% | 11.2% | 10.0% | 9.7% | 9.3% | *10.5%* | *11.0%* | Return on Com Equity | *11.5%* |
| 4.3% | 4.7% | 5.1% | 5.2% | 4.2% | 4.6% | 4.9% | 3.7% | 3.2% | 2.8% | *4.0%* | *4.5%* | Retained to Com Eq D | *5.5%* |
| 65% | 60% | 59% | 59% | 59% | 57% | 56% | 63% | 67% | 70% | *64%* | *61%* | All Div'ds to Net Prof | *53%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 14.5 | 14.9 | 13.8 |
| Receivables | 82.9 | 84.5 | 84.9 |
| Inventory (AvgCst) | 8.8 | 9.8 | 9.7 |
| Other | 9.3 | 11.8 | 14.1 |
| Current Assets | 115.5 | 121.0 | 122.5 |
| Accts Payable | 45.8 | 50.0 | 29.5 |
| Debt Due | 80.8 | 87.9 | 27.7 |
| Other | 56.6 | 55.3 | 148.6 |
| Current Liab. | 183.2 | 193.2 | 205.8 |
| Fix. Chg. Cov. | 323% | 329% | 325% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 8.0% | 9.0% | *6.5%* |
| "Cash Flow" | 9.5% | 8.0% | *7.5%* |
| Earnings | 7.5% | 5.5% | *10.0%* |
| Dividends | 7.0% | 8.0% | *5.5%* |
| Book Value | 9.5% | 10.0% | *6.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 117.9 | 131.7 | 147.0 | 136.9 | 533.5 |
| 2007 | 137.3 | 150.6 | 165.5 | 149.1 | 602.5 |
| 2008 | 139.3 | 151.0 | 177.1 | 159.6 | 627.0 |
| 2009 | 154.5 | 167.3 | *185* | *173.2* | *680* |
| 2010 | *165* | *185* | *195* | *185* | *730* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .13 | .17 | .21 | .19 | .70 |
| 2007 | .13 | .17 | .22 | .19 | .71 |
| 2008 | .11 | .17 | .26 | .19 | .73 |
| 2009 | .14 | .19 | *.28* | *.21* | *.82* |
| 2010 | *.15* | *.22* | *.30* | *.23* | *.90* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .098 | .098 | .098 | .107 | .40 |
| 2006 | .107 | .107 | .115 | .115 | .44 |
| 2007 | .115 | .115 | .125 | .125 | .48 |
| 2008 | .125 | .125 | .125 | .135 | .51 |
| 2009 | .135 | .135 | .135 | | |

**BUSINESS:** Aqua America, Inc. is the holding company for water and wastewater utilities that serve approximately three million residents in Pennsylvania, Ohio, North Carolina, Illinois, Texas, New Jersey, Florida, Indiana, and five other states. Divested three of four non-water businesses in '91; telemarketing group in '93; and others. Acquired AquaSource, 7/03; Consumers Water, 4/99; and others. Water supply revenues '08: residential, 60%; commercial, 14%; industrial & other, 26%. Officers and directors own 1.3% of the common stock (4/09 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

**Aqua America completed the second quarter on a good note.** Despite unfavorable weather conditions and the slowdown in the home building market, the company registered revenue and earnings growth of nearly 11%. Also, a number of rate increases were approved by the courts, and the year-to-date approval of $27.2 million in upward rate adjustments should help bolster the top and bottom lines over the next few quarters.

**The company is likely to build on this momentum in 2010.** Indeed, several rate-relief cases should be decided in the latter half of this year, and the more than $9 million request this year would be accretive to revenues and earnings going into 2010, provided the cases are ruled in Aqua's favor. Additional rate increase petitions for upwards of $50 million will also be filed during the next few months, notably in Pennsylvania and New Jersey.

**Aqua America will likely remain active on the acquisition front.** One of the company's current growth strategies involves purchasing available utilities and making infrastructure improvements in order to procure rate relief judgments. This should benefit WTR's cost structure, as well as expand its customer base.

**A focus will also remain on procuring favorable rate increase judgments over the next few years.** As a portion of capital spending (currently planned to run up to about $315 million per annum), approximately 10% is earmarked for "compliance spending", which is used for adjustments mandated by regulating agencies. The remaining 90% will likely be used to make improvements to current facilities in order to petition for more rate increases.

**The board of directors approved a dividend increase.** During its annual strategy session, a 7.4% rise was instituted, and will bring the year-ahead dividend up to $0.58 a share.

**This neutrally ranked stock may appeal to conservative investors.** The probable steady dividend growth and the worthwhile appreciation potential over the 2012–2014 horizon support the appeal of these shares. Also of note are the high marks for Stock Price Stability and Earnings Predictability.

*John D. Burke* *October 23, 2009*

(A) Diluted shares. Excl. nonrec. gains (losses): '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢. Excl. gain from disc. operations: '96, 2¢. Next earnings report due early November.

(B) Dividends historically paid in early March, June, Sept. & Dec. ■ Div'd. reinvestment plan available (5% discount).

(C) In millions, adjusted for stock splits.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 95 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 100 |

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# ATTACHMENT B

**INDUSTRY TIMELINESS: 46 (of 98)**

**The Natural Gas Utility Industry has lost some ground since our June review. This group now ranks in the middle of our industry spectrum for Timeliness. The economy has shown signs of life in recent months, which has led most investors to look to more-risky plays as opposed to stable picks like natural gas utilities. However, investors should note that these equities typically offer attractive dividend yields that are backed by steady cash flows.**

### Economic Environment

No doubt, this sector has been pressured by the dour economic climate. The weakness in the housing market has particularly weighed on results for natural gas utilities. Usage has moderated as customers have curbed their consumption in an effort to rein in expenses. What's more, customer growth has been a concern in recent months. These businesses have also been having a tougher time collecting bills of late, which can also hurt results. Therefore, we suggest interested investors watch these trends in the months ahead as they will probably influence this group's performance.

### Regulation

Rate cases are a key theme for companies in this sector. These businesses are regulated by state commissions that determine the return on equity these utilities can achieve. As a result, the performance of these equities remains tied to the current rates these companies have in place. Numerous utilities, at any given time, often have cases pending where they seek better rates from these commissions. Positive or negative news regarding a rate case can have a notable impact on a stock's performance in this industry. Notably, the falling natural gas prices in recent months has helped companies seeking rate relief. Indeed, lower prices favor customers, which makes a new rate for these utilities more palatable. Still, regulatory bodies try to strike a balance between customer and shareholder interests when evaluating a rate case. Interested investors should keep a close eye on stocks that have cases pending when reading the following pages.

### Business Strategy

Weather is another element to consider when evaluating this industry's performance. Warmer or colder-than-expected weather can lead to volatile results. Thus, most of these utilities use weather-adjusted rate mechanisms to hedge against this risk. As such, we suggest conservative investors look for stocks that utilize this strategy. Many companies have also been increasingly investing in nonregulated businesses. These ventures are free from the regulatory bodies, and as a result, come with greater risk and reward tradeoff. On point, the utilities with nonregulated operations have generally been feeling the effects of the lower energy prices more so than these competitors without such operations. Also, of note, these nonregulated businesses provide another avenue for these utilities to diversify their income. All told, we expect these ventures to continue to be an important opportunity for this sector over the long term. Another strategy in this industry is conservation. Some governments have been offering these utilities incentives to participate in energy conservation programs. This approach allows these companies to adjust to market conditions without sacrificing profitability.

### Conclusion

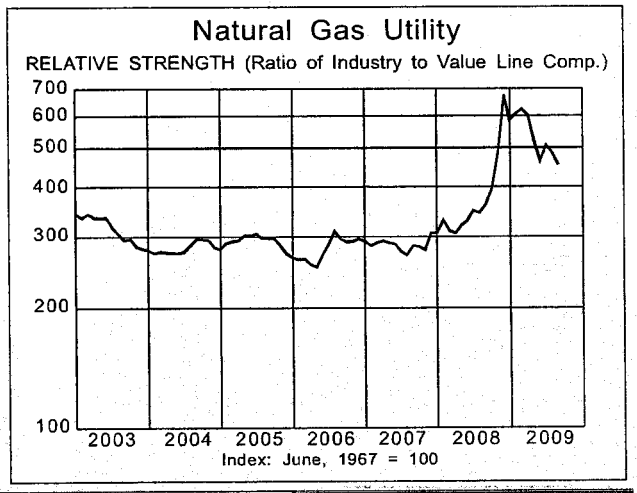
As a group, natural gas utilities will likely remain under pressure in the months ahead due to unfavorable gas prices. As a result, this industry is ranked near the midpoint of our Timeliness spectrum. Still, risk-averse investors may want to consider this group if the economic recovery stalls. Natural gas utilities tend to be a solid defensive play when the stock market is faltering. However, this sector's long-term prospects are uninspiring. Therefore, we recommend patient investors look elsewhere.

All told, investors should study these reports carefully and limit their investments to equities that appear well positioned to weather the difficult operating environment. Additionally, these utilities offer dividend yields that are above the *Value Line* median. Therefore, income-oriented accounts may find stocks with yields that are above the industry average (4.3%) of interest.

*Richard Gallagher*

Composite Statistics: Natural Gas Utility

| 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|
| 36075 | 38273 | 38528 | 44207 | *45500* | *47000* | Revenues ($mill) | *52750* |
| 1386.0 | 1553.3 | 1562.4 | 1694.2 | *1775* | *1850* | Net Profit ($mill) | *2150* |
| 36.0% | 35.3% | 33.9% | 35.7% | *36.0%* | *36.0%* | Income Tax Rate | *36.0%* |
| 3.8% | 4.0% | 4.1% | 3.8% | *3.9%* | *3.9%* | Net Profit Margin | *4.1%* |
| 51.3% | 51.2% | 50.4% | 50.6% | *51.0%* | *51.0%* | Long-Term Debt Ratio | *52.0%* |
| 48.4% | 48.7% | 49.5% | 49.4% | *48.0%* | *48.0%* | Common Equity Ratio | *46.0%* |
| 29218 | 30847 | 32263 | 32729 | *33250* | *34750* | Total Capital ($mill) | *40000* |
| 30894 | 32543 | 33936 | 35342 | *36750* | *38500* | Net Plant ($mill) | *46250* |
| 6.5% | 6.6% | 6.5% | 6.8% | *6.5%* | *6.5%* | Return on Total Cap'l | *7.0%* |
| 9.7% | 10.2% | 9.8% | 10.5% | *10.0%* | *10.5%* | Return on Shr. Equity | *11.0%* |
| 9.8% | 10.2% | 9.8% | 10.5% | *10.0%* | *10.5%* | Return on Com Equity | *11.0%* |
| 3.5% | 4.0% | 3.7% | 4.3% | *4.0%* | *4.5%* | Retained to Com Eq | *5.0%* |
| 65% | 61% | 62% | 59% | *60%* | *62%* | All Div'ds to Net Prof | *65%* |
| 17.1 | 15.6 | 16.6 | 13.9 | *Bold figures are Value Line estimates* | | Avg Ann'l P/E Ratio | *13.0* |
| .91 | .84 | .88 | .83 | | | Relative P/E Ratio | *.85* |
| 3.8% | 3.9% | 3.7% | 4.2% | | | Avg Ann'l Div'd Yield | *4.6%* |
| 315% | 327% | 336% | 358% | *375%* | *375%* | Fixed Charge Coverage | *400%* |

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# AGL RESOURCES NYSE-AGL

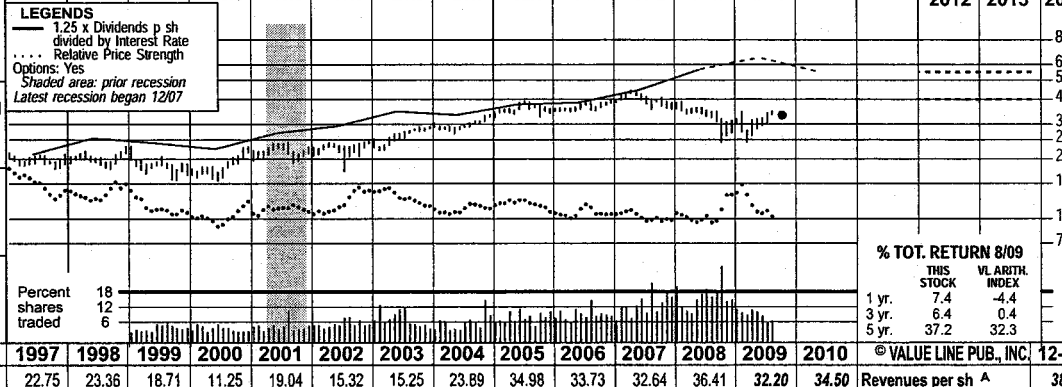
| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|---|
| 33.35 | 13.1 | (Trailing: 10.9 Median: 14.0) | 0.81 | 5.2% | VALUE LINE |

**TIMELINESS** 3 Lowered 6/12/09
**SAFETY** 2 New 7/27/90
**TECHNICAL** 5 Lowered 9/11/09
**BETA** .75 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 23.4 | 23.4 | 23.2 | 24.5 | 25.0 | 29.3 | 33.7 | 39.3 | 40.1 | 44.7 | 39.1 | 35.0 |
| Low: | 17.7 | 15.6 | 15.5 | 19.0 | 17.3 | 21.9 | 26.5 | 32.0 | 34.4 | 35.2 | 24.0 | 24.0 |

**Target Price Range** 2012 | 2013 | 2014

**LEGENDS**
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
*Shaded area: prior recession*
*Latest recession began 12/07*



**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 55 | (+65%) | 17% |
| Low | 40 | (+20%) | 10% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 2 | 1 | 0 | 2 | 0 | 0 | 1 | 0 |
| to Sell | 0 | 3 | 1 | 0 | 1 | 0 | 0 | 2 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 107 | 110 | 124 |
| to Sell | 111 | 107 | 96 |
| Hld's(000) | 46113 | 45714 | 45662 |

Percent shares traded 18 12 6

**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 7.4 | -4.4 |
| 3 yr. | 6.4 | 0.4 |
| 5 yr. | 37.2 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22.73 | 23.59 | 19.32 | 21.91 | 22.75 | 23.36 | 18.71 | 11.25 | 19.04 | 15.32 | 15.25 | 23.89 | 34.98 | 33.73 | 32.64 | 36.41 | *32.20* | *34.50* | Revenues per sh A | *38.80* |
| 2.25 | 2.24 | 2.33 | 2.49 | 2.42 | 2.65 | 2.29 | 2.86 | 3.31 | 3.39 | 3.47 | 3.29 | 4.20 | 4.50 | 4.65 | 4.68 | *4.70* | *4.95* | "Cash Flow" per sh | *5.40* |
| 1.08 | 1.17 | 1.33 | 1.37 | 1.37 | 1.41 | .91 | 1.29 | 1.50 | 1.82 | 2.08 | 2.28 | 2.48 | 2.72 | 2.72 | 2.71 | *2.70* | *2.90* | Earnings per sh A B | *3.30* |
| 1.04 | 1.04 | 1.04 | 1.06 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.08 | 1.11 | 1.15 | 1.30 | 1.48 | 1.64 | 1.68 | *1.72* | *1.76* | Div'ds Decl'd per sh C■ | *1.88* |
| 2.49 | 2.37 | 2.17 | 2.37 | 2.59 | 2.05 | 2.51 | 2.92 | 2.83 | 3.30 | 2.46 | 3.44 | 3.44 | 3.26 | 3.39 | 4.84 | *5.15* | *5.30* | Cap'l Spending per sh | *5.60* |
| 9.90 | 10.19 | 10.12 | 10.56 | 10.99 | 11.42 | 11.59 | 11.50 | 12.19 | 12.52 | 14.66 | 18.06 | 19.29 | 20.71 | 21.74 | 21.48 | *23.10* | *23.40* | Book Value per sh D | *23.55* |
| 49.72 | 50.86 | 55.02 | 55.70 | 56.60 | 57.30 | 57.10 | 54.00 | 55.10 | 56.70 | 64.50 | 76.70 | 77.70 | 77.70 | 76.40 | 76.90 | *78.00* | *79.00* | Common Shs Outst'g E | *85.00* |
| 17.9 | 15.1 | 12.6 | 13.8 | 14.7 | 13.9 | 21.4 | 13.6 | 14.6 | 12.5 | 12.5 | 13.1 | 14.3 | 13.5 | 14.7 | 12.3 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.0* |
| 1.06 | .99 | .84 | .86 | .85 | .72 | 1.22 | .88 | .75 | .68 | .71 | .69 | .76 | .73 | .78 | .74 | *Value Line* | | Relative P/E Ratio | *1.00* |
| 5.4% | 5.9% | 6.2% | 5.6% | 5.4% | 5.5% | 5.5% | 6.2% | 4.9% | 4.7% | 4.3% | 3.9% | 3.7% | 4.0% | 4.1% | 5.0% | *estimates* | | Avg Ann'l Div'd Yield | *3.8%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $2093.0 mill. **Due in 5 Yrs** $962.0 mill.
**LT Debt** $1675.0 mill. **LT Interest** $90.0 mill.
(Total interest coverage: 3.9x)

**Leases, Uncapitalized** Annual rentals $30.0 mill.
**Pension Assets-12/08** $242.0 mill. **Oblig.** $442.0 mill.

**Pfd Stock** None

**Common Stock** 77,278,942 shs. as of 7/24/09
**MARKET CAP: $2.6 billion (Mid Cap)**

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1068.6 | 607.4 | 1049.3 | 868.9 | 983.7 | 1832.0 | 2718.0 | 2621.0 | 2494.0 | 2800.0 | *2510* | *2725* | Revenues ($mill) A | *3300* |
| 52.1 | 71.1 | 82.3 | 103.0 | 132.4 | 153.0 | 193.0 | 212.0 | 211.0 | 207.6 | *155* | *160* | Net Profit ($mill) | *180* |
| 33.1% | 34.3% | 40.7% | 36.0% | 35.9% | 37.0% | 37.7% | 37.8% | 37.6% | 40.5% | *35.0%* | *38.0%* | Income Tax Rate | *38.0%* |
| 4.9% | 11.7% | 7.8% | 11.9% | 13.5% | 8.4% | 7.1% | 8.1% | 8.5% | 7.4% | *8.4%* | *8.4%* | Net Profit Margin | *8.5%* |
| 45.3% | 45.9% | 61.3% | 58.3% | 50.3% | 54.0% | 51.9% | 50.2% | 50.2% | 50.3% | *48.0%* | *45.0%* | Long-Term Debt Ratio | *43.0%* |
| 49.2% | 48.3% | 38.7% | 41.7% | 49.7% | 46.0% | 48.1% | 49.8% | 49.8% | 49.7% | *52.0%* | *55.0%* | Common Equity Ratio | *57.0%* |
| 1345.8 | 1286.2 | 1736.3 | 1704.3 | 1901.4 | 3008.0 | 3114.0 | 3231.0 | 3335.0 | 3327.0 | *3475* | *3350* | Total Capital ($mill) | *3500* |
| 1598.9 | 1637.5 | 2058.9 | 2194.2 | 2352.4 | 3178.0 | 3271.0 | 3436.0 | 3566.0 | 3816.0 | *4000* | *4150* | Net Plant ($mill) | *4400* |
| 5.7% | 7.4% | 6.5% | 8.1% | 8.9% | 6.3% | 7.9% | 8.0% | 7.7% | 7.4% | *7.5%* | *8.0%* | Return on Total Cap'l | *9.0%* |
| 7.1% | 10.2% | 12.3% | 14.5% | 14.0% | 11.0% | 12.9% | 13.2% | 12.7% | 12.6% | *11.5%* | *12.5%* | Return on Shr. Equity | *14.0%* |
| 7.9% | 11.5% | 12.3% | 14.5% | 14.0% | 11.0% | 12.9% | 13.2% | 12.7% | 12.6% | *11.5%* | *12.5%* | Return on Com Equity | *14.0%* |
| NMF | 3.2% | 4.2% | 7.0% | 6.6% | 5.6% | 6.2% | 6.3% | 5.3% | 5.1% | *4.0%* | *5.0%* | Retained to Com Eq | *6.0%* |
| 101% | 72% | 65% | 52% | 53% | 49% | 52% | 52% | 58% | 60% | *64%* | *60%* | All Div'ds to Net Prof | *57%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 21.0 | 16.0 | 12.0 |
| Other | 1790.0 | 2026.0 | 1304.0 |
| Current Assets | 1811.0 | 2042.0 | 1316.0 |
| Accts Payable | 172.0 | 202.0 | 167.0 |
| Debt Due | 580.0 | 866.0 | 418.0 |
| Other | 893.0 | 915.0 | 696.0 |
| Current Liab. | 1645.0 | 1983.0 | 1281.0 |
| Fix. Chg. Cov. | 391% | 416% | 527% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 4.0% | 15.5% | *2.0%* |
| "Cash Flow" | 6.0% | 6.5% | *2.5%* |
| Earnings | 7.0% | 8.5% | *3.5%* |
| Dividends | 4.0% | 8.0% | *2.5%* |
| Book Value | 7.0% | 10.0% | *1.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 1044 | 436 | 434 | 707 | 2621 |
| 2007 | 973 | 467 | 369 | 685 | 2494 |
| 2008 | 1012 | 444 | 539 | 805 | 2800 |
| 2009 | 995 | 377 | *440* | *698* | *2510* |
| 2010 | *1020* | *450* | *480* | *775* | *2725* |

| Cal-endar | EARNINGS PER SHARE B Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 1.41 | .25 | .46 | .60 | 2.72 |
| 2007 | 1.29 | .40 | .17 | .86 | 2.72 |
| 2008 | 1.16 | .30 | .28 | .97 | 2.71 |
| 2009 | 1.55 | .26 | *.20* | *.69* | *2.70* |
| 2010 | *1.40* | *.30* | *.30* | *.90* | *2.90* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .31 | .31 | .31 | .37 | 1.30 |
| 2006 | .37 | .37 | .37 | .37 | 1.48 |
| 2007 | .41 | .41 | .41 | .41 | 1.64 |
| 2008 | .42 | .42 | .42 | .42 | 1.68 |
| 2009 | .43 | .43 | .43 | | |

**BUSINESS:** AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas and Virginia Natural Gas. The utilities have more than 2.2 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Maryland. Engaged in non-regulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. Franklin Resources owns 7.7% of common stock; off./dir., less than 1.0% (3/09 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

**We do not expect 2009 to be a banner year for AGL Resources.** The company reported healthy results in the first quarter. However, performance was less favorable in the recent interim. The Wholesale services business posted an operating loss of $11 million, while the Retail Energy Operations and Energy Investments units reported lower earnings. On the bright side, the Distribution Operations business posted moderate growth in operating earnings. This was primarily due to higher fees to marketers in Georgia for the storage of natural gas inventory and greater pipeline replacement revenues at Atlanta Gas Light. Overall, revenues and share earnings declined in the June period. Looking forward, comparisons will likely also prove unfavorable for the second half of the year. Thus, we anticipate lower revenues and relatively flat share earnings for full-year 2009.

**Subsidiary Atlanta Gas Light has announced a system infrastructure investment project.** This $400 million program will be completed over a 10-year period. Infrastructure improvements include upgrading the utility's distribution system and its liquefied natural gas facilities. This project will improve system reliability, increase operational flexibility, and allow Atlanta Gas Light to meet its forecasted growth objectives.

**Elizabethtown Gas has modified its rate case filing.** It had originally requested a $25 million rate hike, but has since lowered this amount to $17 million. The proposed increase would become effective at the beginning of 2010. Meanwhile, Atlanta Gas Light has requested to postpone a rate case filing, which had originally been scheduled for November 1st of this year. However, it does plan to file sometime after that (June 1, 2010 at the latest). Virginia Natural Gas and Chattanooga Gas also intend to file rate cases in 2010.

**We anticipate higher revenues and share earnings at the company by 2012-2014,** on better operating conditions. Moreover, AGL has a healthy dividend yield and earns high marks for Safety, Price Stability, and Earnings Predictability. From the present quotation, **this issue features decent risk-adjusted total return potential.**

*Michael Napoli, CPA* *September 11, 2009*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses): '95, ($0.83); '99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late October. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2008: $418 million, $5.44/share.
(E) In millions.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 75 |
| Earnings Predictability | 90 |

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# ATMOS ENERGY CORP. NYSE-ATO

| RECENT PRICE | P/E RATIO | | RELATIVE P/E RATIO | DIV'D YLD | |
|---|---|---|---|---|---|
| 27.06 | 12.1 | (Trailing: 11.9 Median: 16.0) | 0.75 | 5.0% | VALUE LINE |

**TIMELINESS** 3 Lowered 9/11/09
**SAFETY** 2 Raised 12/16/05
**TECHNICAL** 4 Lowered 9/4/09
**BETA** .65 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 32.3 | 33.0 | 26.3 | 25.8 | 24.5 | 25.5 | 27.6 | 30.0 | 33.1 | 33.5 | 29.3 | 28.6 | |
| Low: | 24.8 | 19.6 | 14.3 | 19.5 | 17.6 | 20.8 | 23.4 | 25.0 | 25.5 | 23.9 | 19.7 | 20.1 | |

**Target Price Range** 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

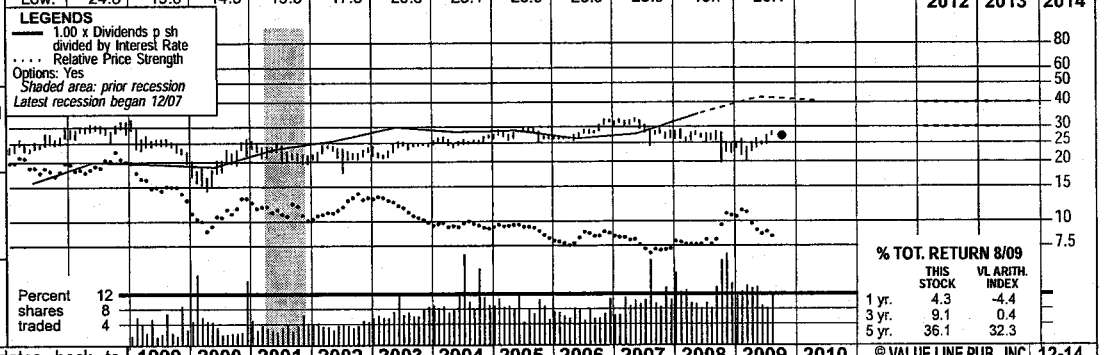
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+50%) | 14% |
| Low | 30 | (+10%) | 7% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 1 | 0 | 0 | 0 | 1 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 1 | 0 | 1 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 141 | 108 | 107 |
| to Sell | 103 | 122 | 115 |
| Hld's(000) | 53678 | 53874 | 54285 |




**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 4.3 | -4.4 |
| 3 yr. | 9.1 | 0.4 |
| 5 yr. | 36.1 | 32.3 |

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 22.09 | 26.61 | 35.36 | 22.82 | 54.39 | 46.50 | 61.75 | 75.27 | 66.03 | 79.52 | *54.25* | *68.45* | Revenues per sh A | *86.35* |
| 2.62 | 3.01 | 3.03 | 3.39 | 3.23 | 2.91 | 3.90 | 4.26 | 4.14 | 4.19 | *4.40* | *4.55* | "Cash Flow" per sh | *4.80* |
| .81 | 1.03 | 1.47 | 1.45 | 1.71 | 1.58 | 1.72 | 2.00 | 1.94 | 2.00 | *2.10* | *2.20* | Earnings per sh A B | *2.50* |
| 1.10 | 1.14 | 1.16 | 1.18 | 1.20 | 1.22 | 1.24 | 1.26 | 1.28 | 1.30 | *1.32* | *1.34* | Div'ds Decl'd per sh C■ | *1.40* |
| 3.53 | 2.36 | 2.77 | 3.17 | 3.10 | 3.03 | 4.14 | 5.20 | 4.39 | 5.20 | *5.50* | *5.75* | Cap'l Spending per sh | *6.60* |
| 12.09 | 12.28 | 14.31 | 13.75 | 16.66 | 18.05 | 19.90 | 20.16 | 22.01 | 22.60 | *24.10* | *24.40* | Book Value per sh | *26.90* |
| 31.25 | 31.95 | 40.79 | 41.68 | 51.48 | 62.80 | 80.54 | 81.74 | 89.33 | 90.81 | *92.50* | *93.50* | Common Shs Outst'g D | *110.00* |
| 33.0 | 18.9 | 15.6 | 15.2 | 13.4 | 15.9 | 16.1 | 13.5 | 15.9 | 13.6 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.0* |
| 1.88 | 1.23 | .80 | .83 | .76 | .84 | .86 | .73 | .84 | .84 | *Value Line* | | Relative P/E Ratio | *.95* |
| 4.1% | 5.9% | 5.1% | 5.4% | 5.2% | 4.9% | 4.5% | 4.7% | 4.2% | 4.8% | *estimates* | | Avg Ann'l Div'd Yield | *4.0%* |
| 690.2 | 850.2 | 1442.3 | 950.8 | 2799.9 | 2920.0 | 4973.3 | 6152.4 | 5898.4 | 7221.3 | *5020* | *6400* | Revenues ($mill) A | *9500* |
| 25.0 | 32.2 | 56.1 | 59.7 | 79.5 | 86.2 | 135.8 | 162.3 | 170.5 | 180.3 | *195* | *205* | Net Profit ($mill) | *275* |
| 35.0% | 36.1% | 37.3% | 37.1% | 37.1% | 37.4% | 37.7% | 37.6% | 35.8% | 38.4% | *35.0%* | *37.0%* | Income Tax Rate | *40.5%* |
| 3.6% | 3.8% | 3.9% | 6.3% | 2.8% | 3.0% | 2.7% | 2.6% | 2.9% | 2.5% | *3.9%* | *3.2%* | Net Profit Margin | *3.0%* |
| 50.0% | 48.1% | 54.3% | 53.9% | 50.2% | 43.2% | 57.7% | 57.0% | 52.0% | 50.8% | *50.0%* | *50.5%* | Long-Term Debt Ratio | *49.0%* |
| 50.0% | 51.9% | 45.7% | 46.1% | 49.8% | 56.8% | 42.3% | 43.0% | 48.0% | 49.2% | *50.0%* | *49.5%* | Common Equity Ratio | *51.0%* |
| 755.1 | 755.7 | 1276.3 | 1243.7 | 1721.4 | 1994.8 | 3785.5 | 3828.5 | 4092.1 | 4172.3 | *4430* | *4580* | Total Capital ($mill) | *5800* |
| 965.8 | 982.3 | 1335.4 | 1300.3 | 1516.0 | 1722.5 | 3374.4 | 3629.2 | 3836.8 | 4136.9 | *4365* | *4575* | Net Plant ($mill) | *5850* |
| 5.1% | 6.5% | 5.9% | 6.8% | 6.2% | 5.8% | 5.3% | 6.1% | 5.9% | 5.9% | *6.0%* | *6.0%* | Return on Total Cap'l | *6.0%* |
| 6.6% | 8.2% | 9.6% | 10.4% | 9.3% | 7.6% | 8.5% | 9.8% | 8.7% | 8.8% | *9.0%* | *9.0%* | Return on Shr. Equity | *9.5%* |
| 6.6% | 8.2% | 9.6% | 10.4% | 9.3% | 7.6% | 8.5% | 9.8% | 8.7% | 8.8% | *9.0%* | *9.0%* | Return on Com Equity | *9.5%* |
| NMF | NMF | 2.1% | 1.9% | 2.8% | 1.7% | 2.3% | 3.6% | 3.0% | 3.1% | *3.5%* | *3.5%* | Retained to Com Eq | *4.0%* |
| NMF | 112% | 79% | 82% | 70% | 77% | 73% | 63% | 65% | 65% | *63%* | *61%* | All Div'ds to Net Prof | *56%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $2169.5 mill. **Due in 5 Yrs** $1360.0 mill.
**LT Debt** $2169.4 mill. **LT Interest** $115.0 mill.
(LT interest earned: 2.9x; total interest coverage: 2.8x)
**Leases, Uncapitalized** Annual rentals $18.4 mill.
**Pfd Stock** None
**Pension Assets-9/08** $341.4 mill. **Oblig.** $337.6 mill.
**Common Stock** 92,272,478 shs. as of 7/31/09
**MARKET CAP: $2.5 billion (Mid Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 60.7 | 46.7 | 125.7 |
| Other | 1008.2 | 1238.4 | 670.3 |
| Current Assets | 1068.9 | 1285.1 | 796.0 |
| Accts Payable | 355.3 | 395.4 | 222.0 |
| Debt Due | 154.4 | 351.3 | .1 |
| Other | 410.0 | 460.4 | 422.2 |
| Current Liab. | 919.7 | 1207.1 | 644.3 |
| Fix. Chg. Cov. | 405% | 450% | 446% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 9.5% | 14.5% | *3.0%* |
| "Cash Flow" | 3.5% | 5.5% | *2.5%* |
| Earnings | 2.5% | 5.0% | *4.0%* |
| Dividends | 2.5% | 1.5% | *1.5%* |
| Book Value | 6.5% | 7.5% | *4.0%* |

| Fiscal Year Ends | QUARTERLY REVENUES ($ mill.) A Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | 2283.8 | 2033.8 | 863.2 | 971.6 | 6152.4 |
| 2007 | 1602.6 | 2075.6 | 1218.2 | 1002.0 | 5898.4 |
| 2008 | 1657.5 | 2484.0 | 1639.1 | 1440.7 | 7221.3 |
| 2009 | 1716.3 | 1821.4 | 780.8 | *701.5* | *5020* |
| 2010 | *1465* | *2435* | *1345* | *1155* | *6400* |

| Fiscal Year Ends | EARNINGS PER SHARE A B E Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | .88 | 1.10 | d.22 | .25 | 2.00 |
| 2007 | .97 | 1.20 | d.15 | d.05 | 1.94 |
| 2008 | .82 | 1.24 | d.07 | .02 | 2.00 |
| 2009 | .83 | 1.29 | .02 | *d.04* | *2.10* |
| 2010 | *.90* | *1.35* | *d.04* | *d.01* | *2.20* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .31 | .31 | .31 | .315 | 1.25 |
| 2006 | .315 | .315 | .315 | .32 | 1.27 |
| 2007 | .32 | .32 | .32 | .325 | 1.29 |
| 2008 | .325 | .325 | .325 | .33 | 1.31 |
| 2009 | .33 | .33 | .33 | | |

**BUSINESS:** Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to 3.2 million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2008 gas volumes: 293 MMcf. Breakdown: 56%, residential; 32%, commercial; 7%, industrial; and 5% other. 2008 depreciation rate 3.5%. Has around 4,560 employees. Officers and directors own approximately 1.9% of common stock (12/08 Proxy). Chairman and Chief Executive Officer: Robert W. Best. Incorporated: Texas. Address: P.O. Box 650205, Dallas, Texas 75265. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

**Atmos Energy's core natural gas utility has generated healthy earnings of late.** That is largely because of an increase in rates, primarily for the Mid-Tex, Louisiana, and West Texas divisions. But throughput is being constrained some by diminished consumption from residential and commercial customers (reflecting difficult economic conditions).

**The pipeline and storage, and regulated transmission and storage units are performing nicely, as well.** The former segment is enjoying expanded margins arising from gains from the settlement of financial positions associated with storage and trading activities. Meanwhile, results for the regulated transmission and storage operation are being boosted by higher transportation fees on through-system deliveries, due to favorable market conditions.

**It appears that consolidated share net will advance around 5%, to $2.10, in fiscal 2009** (which ends September 30th). Assuming further expansion in operating margins, the bottom line may increase at a similar rate, to $2.20 a share, the following fiscal year.

**Finances are in order.** An acquisition caused a mid-decade rise in the debt ratio. But the company has whittled that figure back to normal, if at the cost of some dilution from stock issuances. A reduced level of uncollectible accounts, owing to lower gas prices, is another plus these days.

**We believe that more steady, though unexciting, profit growth is in store for the company over the next 3 to 5 years.** The utility is one of the country's biggest natural gas-only distributors, currently serving customers across 12 states. What is more, the unregulated segments, especially pipelines, possess healthy overall prospects. Excluding future acquisitions, annual share-net gains may be in the mid-single-digit range over 2012-2014.

**On a risk-adjusted basis, these good-quality shares offer decent total return potential.** The dividend yield is appealing, compared to others in the *Value Line* Natural Gas Utility universe. Future hikes in the payout, though likely to be gradual, as in previous years, should be well covered by earnings. Meanwhile, the stock is ranked 3 (Average) for Timeliness.

*Frederick L. Harris, III September 11, 2009*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '99, d23¢; '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢; Q2 '09, 12¢. Next egs. rpt. due early Nov. (C) Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail. (D) In millions. (E) Qtrs may not add due to change in shrs outstanding.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 50 |
| Earnings Predictability | 85 |

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# LACLEDE GROUP NYSE-LG

| RECENT PRICE | 32.61 | P/E RATIO | 13.8 (Trailing: 10.9 / Median: 15.0) | RELATIVE P/E RATIO | 0.86 | DIV'D YLD | 4.8% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 3 Lowered 5/22/09
**SAFETY** 2 Raised 6/20/03
**TECHNICAL** 5 Lowered 9/4/09
**BETA** .60 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 27.9 | 27.0 | 24.8 | 25.5 | 25.0 | 30.0 | 32.5 | 34.3 | 37.5 | 36.0 | 55.8 | 48.3 |
| Low: | 22.4 | 20.0 | 17.5 | 21.3 | 19.0 | 21.8 | 26.0 | 26.9 | 29.1 | 28.8 | 31.9 | 29.3 |

**Target Price Range**
2012 | 2013 | 2014

**2012-14 PROJECTIONS**

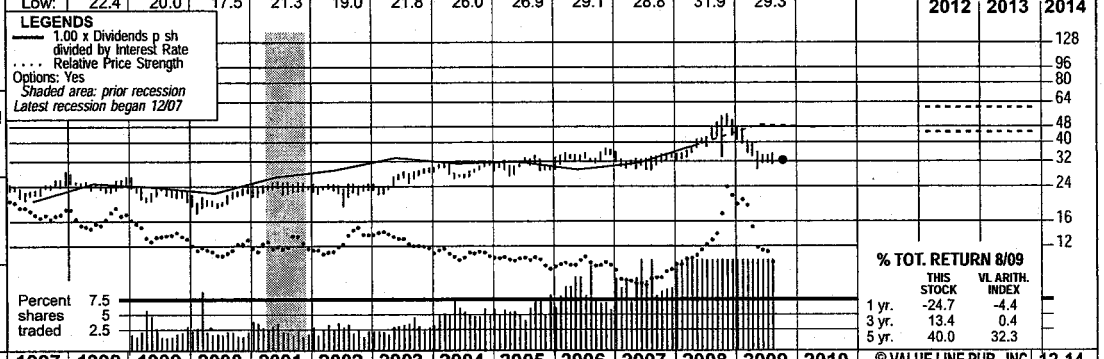
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+85%) | 19% |
| Low | 45 | (+40%) | 12% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 2 | 1 |
| Options | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 73 | 70 | 71 |
| to Sell | 86 | 81 | 81 |
| Hld's(000) | 11494 | 11043 | 10569 |




**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -24.7 | -4.4 |
| 3 yr. | 13.4 | 0.4 |
| 5 yr. | 40.0 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 32.33 | 33.43 | 24.79 | 31.03 | 34.33 | 31.04 | 26.04 | 29.99 | 53.08 | 39.84 | 54.95 | 59.59 | 75.43 | 93.51 | 93.40 | 100.44 | *88.90* | *91.30* | Revenues per sh | *111.55* |
| 2.81 | 2.65 | 2.55 | 3.29 | 3.32 | 3.02 | 2.56 | 2.68 | 3.00 | 2.56 | 3.15 | 2.79 | 2.98 | 3.81 | 3.87 | 4.22 | *4.90* | *4.50* | "Cash Flow" per sh | *5.40* |
| 1.61 | 1.42 | 1.27 | 1.87 | 1.84 | 1.58 | 1.47 | 1.37 | 1.61 | 1.18 | 1.82 | 1.82 | 1.90 | 2.37 | 2.31 | 2.64 | *2.95* | *2.60* | Earnings per sh A B | *3.00* |
| 1.22 | 1.22 | 1.24 | 1.26 | 1.30 | 1.32 | 1.34 | 1.34 | 1.34 | 1.34 | 1.34 | 1.35 | 1.37 | 1.40 | 1.45 | 1.49 | *1.53* | *1.57* | Div'ds Decl'd per sh C■ | *1.70* |
| 2.62 | 2.50 | 2.63 | 2.35 | 2.44 | 2.68 | 2.58 | 2.77 | 2.51 | 2.80 | 2.67 | 2.45 | 2.84 | 2.97 | 2.72 | 2.57 | *2.55* | *2.60* | Cap'l Spending per sh | *3.40* |
| 12.19 | 12.44 | 13.05 | 13.72 | 14.26 | 14.57 | 14.96 | 14.99 | 15.26 | 15.07 | 15.65 | 16.96 | 17.31 | 18.85 | 19.79 | 22.12 | *23.65* | *23.55* | Book Value per sh D | *28.05* |
| 15.59 | 15.67 | 17.42 | 17.56 | 17.56 | 17.63 | 18.88 | 18.88 | 18.88 | 18.96 | 19.11 | 20.98 | 21.17 | 21.36 | 21.65 | 21.99 | *22.50* | *23.00* | Common Shs Outst'g E | *26.00* |
| 13.5 | 16.4 | 15.5 | 11.9 | 12.5 | 15.5 | 15.8 | 14.9 | 14.5 | 20.0 | 13.6 | 15.7 | 16.2 | 13.6 | 14.2 | 14.3 | *Bold figures are* | | Avg Ann'l P/E Ratio | *17.5* |
| .80 | 1.08 | 1.04 | .75 | .72 | .81 | .90 | .97 | .74 | 1.09 | .78 | .83 | .86 | .73 | .75 | .89 | *Value Line* | | Relative P/E Ratio | *1.15* |
| 5.6% | 5.3% | 6.3% | 5.6% | 5.6% | 5.4% | 5.8% | 6.6% | 5.7% | 5.7% | 5.4% | 4.7% | 4.4% | 4.3% | 4.4% | 3.9% | *estimates* | | Avg Ann'l Div'd Yield | *3.2%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $522.2 mill. **Due in 5 Yrs** $90.0 mill.
**LT Debt** $389.2 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 3.0x)

**Leases, Uncapitalized** Annual rentals $.9 mill.
**Pension Assets-9/08** $248.3 mill. **Oblig.** $308.7 mill.
**Pfd Stock** None
**Common Stock** 22,167,303 shs. as of 7/31/09

**MARKET CAP: $725 million (Small Cap)**

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 491.6 | 566.1 | 1002.1 | 755.2 | 1050.3 | 1250.3 | 1597.0 | 1997.6 | 2021.6 | 2209.0 | *2000* | *2100* | Revenues ($mill) A | *2900* |
| 26.9 | 26.0 | 30.5 | 22.4 | 34.6 | 36.1 | 40.1 | 50.5 | 49.8 | 57.6 | *65.0* | *60.0* | Net Profit ($mill) | *80.0* |
| 35.5% | 35.2% | 32.7% | 35.4% | 35.0% | 34.8% | 34.1% | 32.5% | 33.4% | 31.3% | *35.5%* | *35.0%* | Income Tax Rate | *35.0%* |
| 5.5% | 4.6% | 3.0% | 3.0% | 3.3% | 2.9% | 2.5% | 2.5% | 2.5% | 2.6% | *3.3%* | *2.9%* | Net Profit Margin | *2.8%* |
| 41.8% | 45.2% | 49.5% | 47.5% | 50.4% | 51.6% | 48.1% | 49.5% | 45.3% | 44.4% | *42.5%* | *45.0%* | Long-Term Debt Ratio | *47.0%* |
| 57.8% | 54.5% | 50.2% | 52.3% | 49.4% | 48.3% | 51.8% | 50.4% | 54.6% | 55.5% | *57.5%* | *55.0%* | Common Equity Ratio | *53.0%* |
| 488.6 | 519.2 | 574.1 | 546.6 | 605.0 | 737.4 | 707.9 | 798.9 | 784.5 | 876.1 | *925* | *985* | Total Capital ($mill) | *1375* |
| 519.4 | 575.4 | 602.5 | 594.4 | 621.2 | 646.9 | 679.5 | 763.8 | 793.8 | 823.2 | *865* | *915* | Net Plant ($mill) | *1250* |
| 7.1% | 6.7% | 6.9% | 6.0% | 7.4% | 6.6% | 7.6% | 8.4% | 8.5% | 8.1% | *8.5%* | *7.5%* | Return on Total Cap'l | *7.0%* |
| 9.5% | 9.1% | 10.5% | 7.8% | 11.5% | 10.1% | 10.9% | 12.5% | 11.6% | 11.8% | *12.0%* | *11.0%* | Return on Shr. Equity | *11.0%* |
| 9.5% | 9.1% | 10.5% | 7.8% | 11.6% | 10.1% | 10.9% | 12.5% | 11.6% | 11.8% | *12.0%* | *11.0%* | Return on Com Equity | *11.0%* |
| 1.0% | .2% | 1.8% | NMF | 3.1% | 2.7% | 3.1% | 5.1% | 4.3% | 5.2% | *6.0%* | *4.5%* | Retained to Com Eq | *5.0%* |
| 89% | 98% | 83% | 113% | 74% | 73% | 72% | 59% | 63% | 56% | *53%* | *60%* | All Div'ds to Net Prof | *55%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 52.7 | 14.9 | 89.1 |
| Other | 414.6 | 547.0 | 283.6 |
| Current Assets | 467.3 | 561.9 | 372.7 |
| Accts Payable | 106.8 | 159.6 | 79.3 |
| Debt Due | 251.6 | 216.1 | 133.0 |
| Other | 115.3 | 103.5 | 87.8 |
| Current Liab. | 473.7 | 479.2 | 300.1 |
| Fix. Chg. Cov. | 282% | 377% | 370% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 11.5% | 14.0% | *2.5%* |
| "Cash Flow" | 2.0% | 6.5% | *5.5%* |
| Earnings | 3.5% | 9.5% | *3.5%* |
| Dividends | 1.0% | 1.5% | *2.5%* |
| Book Value | 3.5% | 5.5% | *5.5%* |

| Fiscal Year Ends | QUARTERLY REVENUES ($ mill.)A Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | 689.2 | 708.8 | 330.6 | 269.0 | 1997.6 |
| 2007 | 539.6 | 700.8 | 457.9 | 323.3 | 2021.6 |
| 2008 | 504.0 | 747.7 | 505.5 | 451.8 | 2209.0 |
| 2009 | 674.3 | 659.1 | 309.9 | *356.7* | *2000* |
| 2010 | *530* | *570* | *520* | *480* | *2100* |

| Fiscal Year Ends | EARNINGS PER SHARE A B F Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | 1.23 | 1.05 | .13 | d.04 | 2.37 |
| 2007 | .89 | .97 | .43 | .03 | 2.31 |
| 2008 | .99 | 1.39 | .41 | d.14 | 2.64 |
| 2009 | 1.42 | 1.40 | .31 | *d.18* | *2.95* |
| 2010 | *1.03* | *1.21* | *.38* | *d.02* | *2.60* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .34 | .345 | .345 | .345 | 1.38 |
| 2006 | .345 | .355 | .355 | .355 | 1.41 |
| 2007 | .365 | .365 | .365 | .365 | 1.46 |
| 2008 | .375 | .375 | .375 | .375 | 1.50 |
| 2009 | .385 | .385 | .385 | | |

**BUSINESS:** Laclede Group, Inc., is a holding company for Laclede Gas, which distributes natural gas in eastern Missouri, including the city of St. Louis, St. Louis County, and parts of 10 other counties. Has roughly 630,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Therms sold and transported in fiscal 2008: 1.08 mill. Revenue mix for regulated operations: residential, 62%; commercial and industrial, 24%; transportation, 1%; other, 13%. Has around 1,807 employees. Officers and directors own approximately 7.2% of common shares (1/09 proxy). Chairman, Chief Executive Officer, and President: Douglas H. Yaeger. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

**It appears that Laclede Group will generate record earnings in fiscal 2009**, which ends on September 30th. The non-regulated gas marketing unit, Laclede Energy Resources, is enjoying a healthy rise in volumes. That has been brought about by significantly increased pipeline capacity and expanded margins on sales of natural gas (reflecting a drop in natural gas prices). Unfortunately, the utility, Laclede Gas, has not performed up to par of late, stemming partly from a rise in operational expenses. Furthermore, last year's results included certain previously unrecognized tax benefits (which amounted to about $0.07 a share). Nevertheless, consolidated share net may well advance about 12%, to $2.95 a share, in fiscal 2009.

**But fiscal 2010 may be a down year**, when measured against the strong profits we anticipate for this year. Moreover, the benefit of sharply lower natural gas prices may not be repeatable.

**The company's 3- to 5-year prospects look unspectacular.** Annual customer growth for the natural gas distribution unit has been only around 1% for some time, and it appears that trend will continue. This is because the service territory, based in eastern Missouri, is in a mature phase. Laclede Energy Resources has promising expansion possibilities, given its proximity to existing and planned pipelines, as well as opportunities from shale development. But that segment has contributed just a small portion to total profits on a historical basis. A major acquisition could help to offset this, but it appears that such plans are not on management's agenda at this juncture. Consequently, annual earnings-per-share growth could range only between 4% and 5% out to 2012-2014.

**Income-oriented accounts may find the dividend yield modestly appealing.** Further increases in the payout will probably be gradual, however. That is largely because of Laclede Gas' unexciting expansion prospects.

**Total return potential over the 3- to 5-year horizon looks unexciting**, based on the stock's current quotation and assuming minimal growth in the distribution.

*Frederick L. Harris, III September 11, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Based on average shares outstanding thru. '97, then diluted. Excludes nonrecurring loss: '06, 7¢. Excludes gain from discontinued operations: '08, 94¢. Next earnings report due late Oct. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '08: $340.4 mill., $15.48/sh.
(E) In millions.
(F) Qtly. egs. may not sum due to rounding or change in shares outstanding.

| | |
|---|---|
| Company's Financial Strength | B+ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 60 |
| Earnings Predictability | 85 |

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# NEW JERSEY RES. NYSE-NJR

RECENT PRICE **36.60** | P/E RATIO **14.2** (Trailing: 17.3 / Median: 15.0) | RELATIVE P/E RATIO **0.88** | DIV'D YLD **3.4%** | VALUE LINE

**TIMELINESS** 3 Lowered 5/22/09
**SAFETY** 1 Raised 9/15/06
**TECHNICAL** 5 Lowered 9/11/09
**BETA** .65 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 17.9 | 18.3 | 19.8 | 21.7 | 22.4 | 26.4 | 29.7 | 32.9 | 35.4 | 37.6 | 41.1 | 42.4 |
| Low: | 14.0 | 14.9 | 16.1 | 16.6 | 16.2 | 20.0 | 24.3 | 27.1 | 27.7 | 30.3 | 24.6 | 30.0 |

**Target Price Range** 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

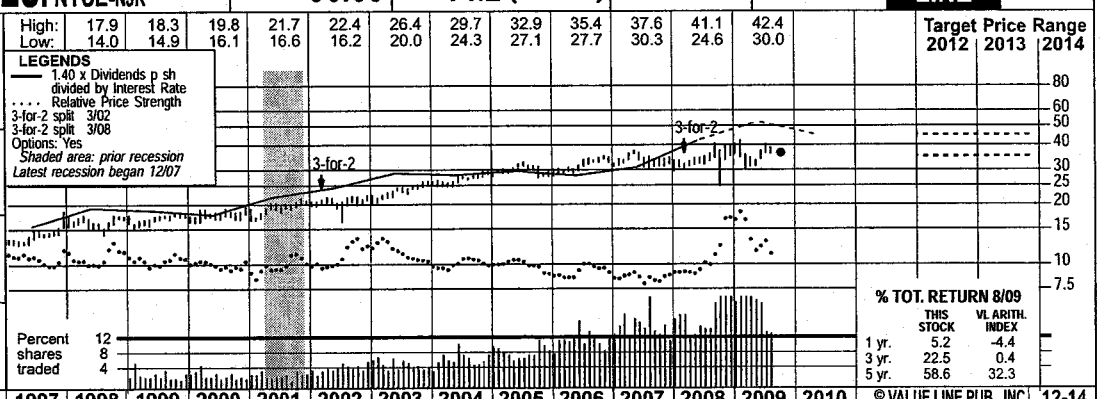
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 45 | (+25%) | 8% |
| Low | 35 | (-5%) | 2% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 0 |
| Options | 1 | 2 | 3 | 0 | 0 | 1 | 0 | 0 | 0 |
| to Sell | 0 | 1 | 4 | 0 | 1 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 93 | 87 | 89 |
| to Sell | 73 | 88 | 88 |
| Hld's(000) | 24319 | 23324 | 24695 |




**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 5.2 | -4.4 |
| 3 yr. | 22.5 | 0.4 |
| 5 yr. | 58.6 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 12.02 | 12.81 | 11.36 | 13.48 | 17.31 | 17.73 | 22.65 | 29.42 | 51.22 | 44.11 | 62.29 | 60.89 | 76.19 | 79.63 | 72.62 | 90.74 | *65.90* | *81.40* | Revenues per sh A | *85.00* |
| 1.42 | 1.54 | 1.42 | 1.48 | 1.63 | 1.74 | 1.86 | 1.99 | 2.12 | 2.14 | 2.38 | 2.50 | 2.62 | 2.73 | 2.44 | 3.62 | *3.35* | *3.60* | "Cash Flow" per sh | *3.70* |
| .76 | .84 | .86 | .92 | .99 | 1.04 | 1.11 | 1.20 | 1.30 | 1.39 | 1.59 | 1.70 | 1.77 | 1.87 | 1.55 | 2.70 | *2.45* | *2.70* | Earnings per sh B | *2.80* |
| .68 | .68 | .68 | .69 | .71 | .73 | .75 | .76 | .78 | .80 | .83 | .87 | .91 | .96 | 1.01 | 1.11 | *1.24* | *1.28* | Div'ds Decl'd per sh C■ | *1.40* |
| 1.54 | 1.40 | 1.18 | 1.19 | 1.15 | 1.07 | 1.21 | 1.23 | 1.10 | 1.02 | 1.14 | 1.45 | 1.28 | 1.28 | 1.46 | 1.72 | *1.75* | *1.75* | Cap'l Spending per sh | *1.80* |
| 6.54 | 6.43 | 6.47 | 6.73 | 6.92 | 7.26 | 7.57 | 8.29 | 8.80 | 8.71 | 10.26 | 11.25 | 10.60 | 15.00 | 15.50 | 17.28 | *18.80* | *20.75* | Book Value per sh D | *27.45* |
| 37.84 | 38.93 | 40.03 | 40.69 | 40.23 | 40.07 | 39.92 | 39.59 | 40.00 | 41.50 | 40.85 | 41.61 | 41.32 | 41.44 | 41.61 | 42.06 | *42.50* | *43.00* | Common Shs Outst'g E | *45.00* |
| 15.1 | 13.0 | 11.8 | 13.6 | 13.5 | 15.3 | 15.2 | 14.7 | 14.2 | 14.7 | 14.0 | 15.3 | 16.8 | 16.1 | 21.6 | 12.3 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.0* |
| .89 | .85 | .79 | .85 | .78 | .80 | .87 | .96 | .73 | .80 | .80 | .81 | .89 | .87 | 1.15 | .77 | *Value Line* | | Relative P/E Ratio | *.95* |
| 5.8% | 6.2% | 6.7% | 5.6% | 5.3% | 4.6% | 4.5% | 4.4% | 4.2% | 3.9% | 3.7% | 3.3% | 3.1% | 3.2% | 3.0% | 3.3% | *estimates* | | Avg Ann'l Div'd Yield | *3.6%* |

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 904.3 | 1164.5 | 2048.4 | 1830.8 | 2544.4 | 2533.6 | 3148.3 | 3299.6 | 3021.8 | 3816.2 | *2800* | *3500* | Revenues ($mill) A | *3825* |
| 44.9 | 47.9 | 52.3 | 56.8 | 65.4 | 71.6 | 74.4 | 78.5 | 65.3 | 113.9 | *80.0* | *105* | Net Profit ($mill) | *125* |
| 36.2% | 37.8% | 38.0% | 38.7% | 39.4% | 39.1% | 39.1% | 38.9% | 38.8% | 37.8% | *39.0%* | *39.0%* | Income Tax Rate | *40.0%* |
| 5.0% | 4.1% | 2.6% | 3.1% | 2.6% | 2.8% | 2.4% | 2.4% | 2.2% | 3.0% | *3.7%* | *3.3%* | Net Profit Margin | *3.3%* |
| 48.7% | 47.0% | 50.1% | 50.6% | 38.1% | 40.3% | 42.0% | 34.8% | 37.3% | 38.5% | *38.5%* | *37.0%* | Long-Term Debt Ratio | *32.0%* |
| 51.2% | 52.9% | 49.9% | 49.4% | 61.9% | 59.7% | 58.0% | 65.2% | 62.7% | 61.5% | *61.5%* | *63.0%* | Common Equity Ratio | *68.0%* |
| 590.4 | 620.1 | 706.2 | 732.4 | 676.8 | 783.8 | 755.3 | 954.0 | 1028.0 | 1182.1 | *1300* | *1415* | Total Capital ($mill) | *1815* |
| 705.4 | 730.6 | 743.9 | 756.4 | 852.6 | 880.4 | 905.1 | 934.9 | 970.9 | 1017.3 | *1040* | *1060* | Net Plant ($mill) | *1125* |
| 9.0% | 9.0% | 8.5% | 8.7% | 10.7% | 10.1% | 11.2% | 9.6% | 7.7% | 10.7% | *9.0%* | *9.0%* | Return on Total Cap'l | *8.0%* |
| 14.8% | 14.6% | 14.8% | 15.7% | 15.6% | 15.3% | 17.0% | 12.6% | 10.1% | 15.7% | *13.0%* | *13.0%* | Return on Shr. Equity | *10.0%* |
| 14.8% | 14.6% | 14.9% | 15.7% | 15.6% | 15.3% | 17.0% | 12.6% | 10.1% | 15.7% | *13.0%* | *13.0%* | Return on Com Equity | *10.0%* |
| 5.0% | 5.4% | 6.1% | 6.9% | 7.7% | 7.8% | 8.5% | 6.3% | 3.6% | 9.5% | *6.5%* | *7.0%* | Retained to Com Eq | *5.0%* |
| 67% | 63% | 59% | 56% | 51% | 49% | 50% | 50% | 64% | 40% | *50%* | *47%* | All Div'ds to Net Prof | *50* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $512.3 mill. **Due in 5 Yrs** $175.6 mill.
**LT Debt** $457.7 mill. **LT Interest** $16.9 mill.
Incl. $8.8 mill. capitalized leases.
(LT interest earned: 4.8x; total interest coverage: 4.8x)
**Pension Assets-9/08** $80.6 mill. **Oblig.** $102.4 mill.

**Pfd Stock** None

**Common Stock** 42,014,773 shs. as of 8/4/09
**MARKET CAP: $1.5 billion (Mid Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 5.1 | 42.6 | 77.0 |
| Other | 794.8 | 1067.1 | 636.5 |
| Current Assets | 799.9 | 1109.7 | 713.5 |
| Accts Payable | 64.4 | 61.7 | 49.2 |
| Debt Due | 260.8 | 238.3 | 54.6 |
| Other | 378.1 | 594.0 | 475.9 |
| Current Liab. | 703.3 | 894.0 | 579.7 |
| Fix. Chg. Cov. | 461% | 450% | 450% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 17.5% | 9.0% | *1.0%* |
| "Cash Flow" | 6.0% | 6.0% | *4.0%* |
| Earnings | 7.5% | 7.5% | *5.5%* |
| Dividends | 4.0% | 5.0% | *5.5%* |
| Book Value | 8.5% | 11.5% | *9.5%* |

| Fiscal Year Ends | QUARTERLY REVENUES ($ mill.) A Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | 1164 | 1064 | 536.1 | 535.5 | 3299.6 |
| 2007 | 737.4 | 1029 | 662.2 | 593.2 | 3021.8 |
| 2008 | 811.1 | 1178 | 1000 | 827.1 | 3816.2 |
| 2009 | 801.3 | 937.5 | 441.1 | *620.1* | *2800* |
| 2010 | *845* | *985* | *790* | *880* | *3500* |

| Fiscal Year Ends | EARNINGS PER SHARE A B Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | .82 | 1.43 | d.09 | d.29 | 1.87 |
| 2007 | .70 | .19 | .60 | .06 | 1.55F |
| 2008 | 1.31 | 1.86 | d.10 | d.39 | 2.70 |
| 2009 | .77 | 1.71 | .03 | *d.06* | *2.45* |
| 2010 | *.85* | *1.75* | *d.05* | *.15* | *2.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C E■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .227 | .227 | .227 | .227 | .91 |
| 2006 | .24 | .24 | .24 | .24 | .96 |
| 2007 | .253 | .253 | .253 | .253 | 1.01 |
| 2008 | .267 | .28 | .28 | .28 | 1.11 |
| 2009 | .31 | .31 | .31 | | |

**BUSINESS:** New Jersey Resources Corp. is a holding company providing retail/wholesale energy svcs. to customers in New Jersey, and in states from the Gulf Coast to New England, and Canada. New Jersey Natural Gas had about 484,000 customers at 9/30/08 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2008 volume: 99.6 bill. cu. ft. (59% firm, 6% interruptible industrial and electric utility, 35% off-system and capacity release). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2008 dep. rate: 2.9%. Has 854 empls. Off./dir. own about 1.7% of common (12/09 Proxy). Chrmn., CEO, & Pres. : Laurence M. Downes. Inc.: NJ Addr.: 1415 Wyckoff Road, Wall, NJ 07719. Tel.: 732-938-1480. Web: www.njresources.com.

**New Jersey Resources' bottom line has been improving despite weaker top-line results.** All of the company's operating segments registered lower volumes during the June period. The NJR Energy Services unit, which typically contributes the lion's share of revenues, was hit the hardest on both a dollar-value and percentage basis. Meantime, the Natural Gas Distribution and Retail segments also registered declines well into the double digits. The bulk of that downturn can be attributed to the lower commodity prices compared to last year, and conservation efforts, as consumers continue to real in spending. Still, the customer base continues to widen. The New Jersey Natural Gas division has added almost 4,200 new customer accounts thus far in 2009 and completed more than 450 natural gas heat conversions. All told, the company registered higher-than-expected earnings for the June interim. But,

**We do look for September's share net to fall into negative territory.** The anticipated loss during the fiscal fourth quarter is related to the seasonal nature of the natural gas business. Nonetheless, economic headwinds have prompted us to trim a nickel off our 2009 earnings estimate to $2.45 a share. This would represent a decline of about 9%. However, we view this largely as a technicality, due to last year's difficult comparison and the fact that NJR continues to improve the fundamentals of its business through the expansion of its mid-stream assets and an ever-widening customer base.

**Capital projects and infrastructure programs augur well for longer-term prospects.** The Steckman Ridge storage facility has begun accumulating natural gas inventories in preparation for the coming winter. That facility is expected to start making meaningful earnings contributions next year. And the other programs should provide needed jobs, while simultaneously boosting the safety and reliability of the distribution system.

**These high-quality shares may appeal to income-oriented accounts.** They don't stand out for appreciation potential for the pull to 2012-2014, compared to most utilities. The main appeal here comes from solid dividend growth prospects.

*Bryan J. Fong* *September 11, 2009*

(A) Fiscal year ends Sept. 30th.
(B) Diluted earnings. Qtly egs may not sum to total due to change in shares outstanding. Next earnings report due late Oct.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2008: $340.7 million, $8.09/share.
(E) In millions, adjusted for splits.
(F) Restated.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 65 |
| Earnings Predictability | 45 |

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# NICOR, INC. NYSE-GAS

| RECENT PRICE | 35.65 | P/E RATIO | 13.5 (Trailing: 14.0 / Median: 15.0) | RELATIVE P/E RATIO | 0.84 | DIV'D YLD | 5.2% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

**TIMELINESS** 3 Raised 12/7/07
**SAFETY** 3 Lowered 6/17/05
**TECHNICAL** 4 Lowered 9/4/09
**BETA** .70 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 44.4 | 42.9 | 43.9 | 42.4 | 49.0 | 39.3 | 39.7 | 43.0 | 49.9 | 53.7 | 52.0 | 38.1 |
| Low: | 37.1 | 31.2 | 29.4 | 34.0 | 17.3 | 23.7 | 32.0 | 35.5 | 38.7 | 37.8 | 32.3 | 27.5 |

**Target Price Range**
2012 | 2013 | 2014

**2012-14 PROJECTIONS**

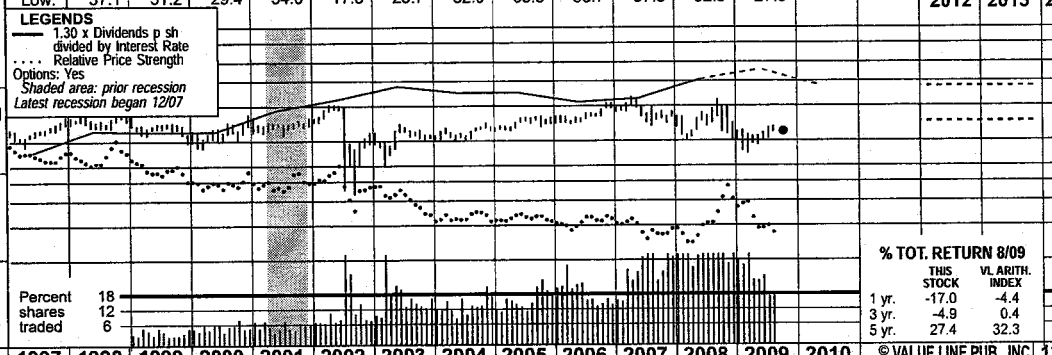
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 60 | (+70%) | 17% |
| Low | 40 | (+10%) | 7% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 1 | 2 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 114 | 92 | 105 |
| to Sell | 126 | 126 | 103 |
| Hld's(000) | 27287 | 25772 | 25968 |




**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -17.0 | -4.4 |
| 3 yr. | -4.9 | 0.4 |
| 5 yr. | 27.4 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 31.02 | 31.23 | 29.42 | 37.39 | 41.33 | 30.84 | 34.45 | 50.52 | 57.30 | 43.11 | 60.46 | 62.12 | 76.00 | 65.92 | 69.20 | 83.68 | *70.90* | *72.90* | Revenues per sh | *93.30* |
| 3.80 | 4.11 | 4.19 | 4.97 | 5.29 | 5.21 | 5.59 | 6.16 | 6.41 | 6.03 | 5.37 | 6.00 | 6.19 | 6.82 | 6.96 | 6.85 | *6.05* | *6.70* | "Cash Flow" per sh | *7.85* |
| 1.97 | 2.07 | 1.96 | 2.42 | 2.55 | 2.31 | 2.57 | 2.94 | 3.01 | 2.88 | 2.11 | 2.22 | 2.27 | 2.87 | 2.99 | 2.63 | *2.55* | *2.85* | Earnings per sh A | *3.25* |
| 1.22 | 1.25 | 1.28 | 1.32 | 1.40 | 1.48 | 1.54 | 1.66 | 1.76 | 1.84 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | 1.86 | *1.86* | *1.86* | Div'ds Decl'd per sh B■ | *1.86* |
| 2.62 | 3.34 | 3.12 | 2.42 | 2.34 | 2.87 | 3.28 | 3.48 | 4.18 | 4.37 | 4.12 | 4.32 | 4.57 | 4.17 | 3.77 | 5.54 | *5.95* | *6.35* | Cap'l Spending per sh | *6.80* |
| 13.05 | 13.26 | 13.67 | 14.74 | 15.43 | 15.97 | 16.80 | 15.56 | 16.39 | 16.55 | 17.13 | 16.99 | 18.36 | 19.43 | 20.58 | 21.55 | *22.10* | *23.10* | Book Value per sh | *26.80* |
| 53.96 | 51.54 | 50.30 | 49.49 | 48.22 | 47.51 | 46.89 | 45.49 | 44.40 | 44.01 | 44.04 | 44.10 | 44.18 | 44.90 | 45.90 | 45.13 | *45.50* | *45.50* | Common Shs Outst'g C | *45.50* |
| 14.1 | 12.5 | 13.1 | 12.5 | 14.2 | 17.6 | 14.6 | 11.9 | 12.8 | 13.1 | 15.8 | 15.9 | 17.3 | 15.0 | 15.0 | 15.1 | *Bold figures are* | | Avg Ann'l P/E Ratio | *16.0* |
| .83 | .82 | .88 | .78 | .82 | .92 | .83 | .77 | .66 | .72 | .90 | .84 | .92 | .81 | .80 | .93 | *Value Line* | | Relative P/E Ratio | *1.05* |
| 4.4% | 4.8% | 5.0% | 4.4% | 3.9% | 3.6% | 4.1% | 4.7% | 4.6% | 4.9% | 5.6% | 5.3% | 4.7% | 4.3% | 4.2% | 4.7% | *estimates* | | Avg Ann'l Div'd Yield | *3.9%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $725.7 mill. **Due in 5 Yrs** $914.9 mill.
**LT Debt** $498.7 mill. **LT Interest** $5.0 mill.
(Total interest coverage: 5.1x)

**Pension Assets-12/08** $306.6 mill. **Oblig.** $270.2 mill.

**Pfd Stock** $.6 mill. **Pfd Div'd** None

**Common Stock** 45,221,593 shares as of 7/24/09
**MARKET CAP: $1.6 billion (Mid Cap)**

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1615.2 | 2298.1 | 2544.1 | 1897.4 | 2662.7 | 2739.7 | 3357.8 | 2960.0 | 3176.3 | 3776.6 | *3225* | *3500* | Revenues ($mill) | *4200* |
| 121.9 | 136.4 | 136.3 | 128.0 | 93.1 | 98.1 | 101.1 | 128.3 | 135.2 | 119.5 | *115* | *130* | Net Profit ($mill) | *150* |
| 34.7% | 34.8% | 33.5% | 31.0% | 35.2% | 31.8% | 28.3% | 26.3% | 26.6% | 27.0% | *27.0%* | *27.0%* | Income Tax Rate | *27.0%* |
| 7.5% | 5.9% | 5.4% | 6.7% | 3.5% | 3.6% | 3.0% | 4.3% | 4.3% | 3.2% | *3.6%* | *3.7%* | Net Profit Margin | *3.5%* |
| 35.5% | 32.7% | 37.8% | 35.1% | 39.6% | 39.8% | 37.4% | 36.3% | 30.9% | 31.5% | *33%* | *30%* | Long-Term Debt Ratio | *26%* |
| 64.0% | 66.7% | 61.7% | 64.5% | 60.3% | 60.1% | 62.5% | 63.7% | 69.0% | 68.4% | *67%* | *70%* | Common Equity Ratio | *74%* |
| 1230.1 | 1061.2 | 1180.1 | 1128.9 | 1251.5 | 1246.0 | 1297.7 | 1370.7 | 1368.0 | 1421.1 | *1500* | *1500* | Total Capital ($mill) | *1650* |
| 1735.2 | 1729.6 | 1768.6 | 1796.8 | 2484.2 | 2549.8 | 2659.1 | 2714.1 | 2757.3 | 2858.6 | *3000* | *3150* | Net Plant ($mill) | *3600* |
| 10.9% | 13.7% | 12.3% | 12.2% | 8.3% | 8.8% | 9.4% | 10.9% | 11.2% | 9.7% | *9.0%* | *10.0%* | Return on Total Cap'l | *10.0%* |
| 15.4% | 19.1% | 18.6% | 17.5% | 12.3% | 13.1% | 12.5% | 14.7% | 14.3% | 12.3% | *11.5%* | *12.5%* | Return on Shr. Equity | *12.0%* |
| 15.4% | 19.2% | 18.7% | 17.5% | 12.3% | 13.1% | 12.5% | 14.7% | 14.3% | 12.3% | *11.5%* | *12.5%* | Return on Com Equity | *12.0%* |
| 6.2% | 8.5% | 7.9% | 6.5% | 1.5% | 2.1% | 2.3% | 5.2% | 5.4% | 3.6% | *3.0%* | *4.5%* | Retained to Com Eq | *5.5%* |
| 60% | 56% | 58% | 63% | 88% | 84% | 81% | 65% | 62% | 71% | *70%* | *65%* | All Div'ds to Net Prof | *57%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 91.9 | 95.5 | 116.3 |
| Other | 931.9 | 1243.4 | 627.0 |
| Current Assets | 1023.8 | 1338.9 | 743.3 |
| Accts Payable | 564.5 | 411.3 | 266.1 |
| Debt Due | 350.0 | 789.9 | 227.0 |
| Other | 227.9 | 466.8 | 482.9 |
| Current Liab. | 1142.4 | 1668.0 | 976.0 |
| Fix. Chg. Cov. | 543% | 461% | 449% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 7.0% | 6.5% | *4.0%* |
| "Cash Flow" | 3.0% | 3.0% | *2.0%* |
| Earnings | 1.5% | 1.0% | *2.5%* |
| Dividends | 3.0% | 0.5% | *Nil* |
| Book Value | 3.0% | 4.0% | *4.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 1319.4 | 451.3 | 351.1 | 838.2 | 2960.0 |
| 2007 | 1334.7 | 556.9 | 365.2 | 919.5 | 3176.3 |
| 2008 | 1595.7 | 699.8 | 440.3 | 1040.8 | 3776.6 |
| 2009 | 1110.8 | 447.6 | *375* | *1291.6* | *3225* |
| 2010 | *1150* | *625* | *425* | *1300* | *3500* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | .99 | .19 | .39 | 1.30 | 2.87 |
| 2007 | 1.04 | .40 | .32 | 1.22 | 2.98 |
| 2008 | .91 | .64 | .03 | 1.05 | 2.63 |
| 2009 | .96 | .50 | *.05* | *1.04* | *2.55* |
| 2010 | *1.05* | *.50* | *.30* | *1.00* | *2.85* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .465 | .465 | .465 | .465 | 1.86 |
| 2006 | .465 | .465 | .465 | .465 | 1.86 |
| 2007 | .465 | .465 | .465 | .465 | 1.86 |
| 2008 | .465 | .465 | .465 | .465 | 1.86 |
| 2009 | .465 | .465 | .465 | | |

**BUSINESS:** Nicor Inc. is a holding company with gas distribution as its primary business. Serves over 2.2 million customers in northern and western Illinois. 2008 gas delivered: 498.1 Bcf, incl. 222.6 Bcf from transportation. 2008 gas sales (275.5 bcf): residential, 93%; commercial, 6%; industrial, 1%. Principal supplying pipelines: Natural Gas Pipeline, Horizon Pipeline, and TGPC. Current operations include Tropical Shipping subsidiary and several energy related ventures. Divested oil and gas E&P, 6/93. Has about 3,900 employees. Officers/directors own about 2.2% of common stock (3/09 proxy). Chairman and Chief Executive Officer: Russ Strobel. Incorporated: Illinois. Address: 1844 Ferry Road, Naperville, Illinois 60563. Telephone: 630-305-9500. Internet: www.nicor.com.

**Nicor posted mixed results in the second quarter.** Both the top and bottom lines fell short of 2008's results due to the challenging macroeconomic environment and lower energy prices. Furthermore, sales of $447.6 million missed our estimate in June ($600 million). However, earnings of $0.50 a share topped our number, thanks to new rates in the natural gas distribution business (discussed below), which offset unfavorable pricing and a weak showing in the shipping operations.

**We have lowered our bottom-line estimate for 2009 by a dime, to $2.55 a share.** Management reaffirmed its share-net guidance range of $2.54 to $2.74. However, we have pared our target to the low end of management's range, given the tough market conditions for natural gas producers. Most notably, lower usage, coupled with unfavorable pricing, will probably continue to pressure these utilities over the coming months. Therefore, we look for the top line to decline 15% to $3.2 million.

**The company requested a rehearing on its rate case.** Nicor was approved for a $69 million increase in base revenues at the end of the March period. However, the company is awaiting a decision from the Illinois Commerce Commission regarding a rehearing. Nicor is seeking greater relief than what was approved.

**This equity offers a yield that is above average for a natural gas utility.** Nicor continues to pay a hearty dividend despite the challenging operating environment. What's more, we think the payout is safe, thanks to the company's strong balance sheet. Thus, income-oriented investors may find this equity's attractive yield (5.2%) of interest.

**Shares of Nicor are ranked to mirror the broader market averages over the next six to 12 months,** as near-term prospects appear to be limited. Moreover, at the current quotation, this issue has below-average total return potential over the 3- to 5-year pull. Therefore, we recommend most investors look elsewhere. However, risk-averse investors should note this equity is well positioned to weather any volatility (Beta: 70) over the coming years, given its strong finances and stable business (Financial Strength: A).

*Richard Gallagher* *September 11, 2009*

(A) Based on primary earnings thru. '96, then diluted. Excl. nonrecurring gains/(loss): '97, 6¢; '98, 11¢; '99, 5¢; '00, ($1.96); '01, 16¢; '03, (27¢); '04, (52¢); '05, 80¢; '06, (17¢); '07 (13¢). Excl. items from discontinued ops.: '93, 4¢; '96, 30¢. Next egs. report due early November. (B) Dividends historically paid mid February, May, August, November. ■ Dividend reinvestment plan available. (C) In millions.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 45 |
| Earnings Predictability | 80 |

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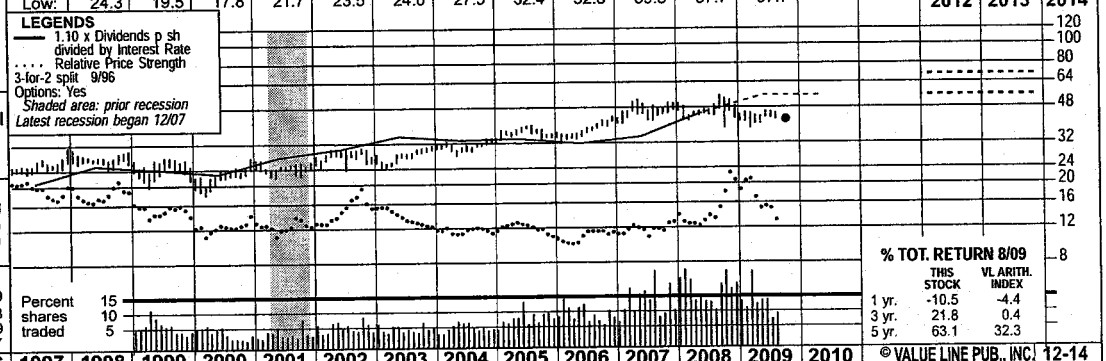
# N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **41.94** | P/E RATIO **14.7** (Trailing: 15.5 Median: 16.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS **3** Lowered 7/24/09
SAFETY **1** Raised 3/18/05
TECHNICAL **4** Lowered 9/4/09
BETA .60 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 30.8 | 27.9 | 27.5 | 26.8 | 30.7 | 31.3 | 34.1 | 39.6 | 43.7 | 52.8 | 55.2 | 46.1 |
| Low: | 24.3 | 19.5 | 17.8 | 21.7 | 23.5 | 24.0 | 27.5 | 32.4 | 32.8 | 39.8 | 37.7 | 37.7 |

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/96
Options: Yes
*Shaded area: prior recession*
*Latest recession began 12/07*



Target Price Range 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 70 | (+65%) | 16% |
| Low | 55 | (+30%) | 10% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 2 | 0 | 0 | 0 |
| Options | 0 | 1 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 2 | 0 | 1 | 0 | 0 | 0 | 1 | 1 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 82 | 67 | 78 |
| to Sell | 83 | 93 | 69 |
| Hld's(000) | 14907 | 15126 | 15387 |

Percent shares traded 15 10 5

**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -10.5 | -4.4 |
| 3 yr. | 21.8 | 0.4 |
| 5 yr. | 63.1 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 18.15 | 18.30 | 16.02 | 16.86 | 15.82 | 16.77 | 18.17 | 21.09 | 25.78 | 25.07 | 23.57 | 25.69 | 33.01 | 37.20 | 39.13 | 39.16 | *39.60* | *41.50* | Revenues per sh | *48.20* |
| 3.74 | 3.50 | 3.41 | 3.86 | 3.72 | 3.24 | 3.72 | 3.68 | 3.86 | 3.65 | 3.85 | 3.92 | 4.34 | 4.76 | 5.41 | 5.31 | *5.60* | *5.85* | "Cash Flow" per sh | *6.75* |
| 1.74 | 1.63 | 1.61 | 1.97 | 1.76 | 1.02 | 1.70 | 1.79 | 1.88 | 1.62 | 1.76 | 1.86 | 2.11 | 2.35 | 2.76 | 2.57 | *2.85* | *2.85* | Earnings per sh A | *3.45* |
| 1.17 | 1.17 | 1.18 | 1.20 | 1.21 | 1.22 | 1.23 | 1.24 | 1.25 | 1.26 | 1.27 | 1.30 | 1.32 | 1.39 | 1.44 | 1.52 | *1.60* | *1.68* | Div'ds Decl'd per sh B■ | *2.00* |
| 3.61 | 4.23 | 3.02 | 3.70 | 5.07 | 4.02 | 4.78 | 3.46 | 3.23 | 3.11 | 4.90 | 5.52 | 3.48 | 3.56 | 4.48 | 3.92 | *4.50* | *4.50* | Cap'l Spending per sh | *4.50* |
| 13.08 | 13.63 | 14.55 | 15.37 | 16.02 | 16.59 | 17.12 | 17.93 | 18.56 | 18.88 | 19.52 | 20.64 | 21.28 | 22.01 | 22.52 | 23.71 | *24.90* | *26.10* | Book Value per sh | *30.50* |
| 19.77 | 20.13 | 22.24 | 22.56 | 22.86 | 24.85 | 25.09 | 25.23 | 25.23 | 25.59 | 25.94 | 27.55 | 27.58 | 27.24 | 26.41 | 26.50 | *26.50* | *26.50* | Common Shs Outst'g C | *28.00* |
| 12.9 | 13.0 | 12.9 | 11.7 | 14.4 | 26.7 | 14.5 | 12.4 | 12.9 | 17.2 | 15.8 | 16.7 | 17.0 | 15.9 | 16.7 | 18.1 | *Bold figures are* | | Avg Ann'l P/E Ratio | *18.0* |
| .76 | .85 | .86 | .73 | .83 | 1.39 | .83 | .81 | .66 | .94 | .90 | .88 | .91 | .86 | .89 | 1.11 | *Value Line* | | Relative P/E Ratio | *1.20* |
| 5.2% | 5.5% | 5.7% | 5.2% | 4.8% | 4.5% | 5.0% | 5.6% | 5.1% | 4.5% | 4.6% | 4.2% | 3.7% | 3.7% | 3.1% | 3.3% | *estimates* | | Avg Ann'l Div'd Yield | *3.2%* |

**CAPITAL STRUCTURE as of 6/30/09**
Total Debt $677.6 mill. Due in 5 Yrs $173.8 mill.
LT Debt $587.0 mill. LT Interest $37.0 mill.

(Total interest coverage: 4.0x)

Pension Assets-12/08 $163 mill.
Oblig. $281 mill.
Pfd Stock None

Common Stock 26,513,188 shares as of 7/31/09
MARKET CAP $1.1 billion (Mid Cap)

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 455.8 | 532.1 | 650.3 | 641.4 | 611.3 | 707.6 | 910.5 | 1013.2 | 1033.2 | 1037.9 | *1025* | *1125* | Revenues ($mill) | *1350* |
| 44.9 | 47.8 | 50.2 | 43.8 | 46.0 | 50.6 | 58.1 | 65.2 | 74.5 | 68.5 | *75.5* | *75.5* | Net Profit ($mill) | *96.5* |
| 35.4% | 35.9% | 35.4% | 34.9% | 33.7% | 34.4% | 36.0% | 36.3% | 37.2% | 36.9% | *37.0%* | *37.0%* | Income Tax Rate | *37.0%* |
| 9.9% | 9.0% | 7.7% | 6.8% | 7.5% | 7.1% | 6.4% | 6.4% | 7.2% | 6.6% | *7.3%* | *6.7%* | Net Profit Margin | *7.2%* |
| 46.0% | 45.1% | 43.0% | 47.6% | 49.7% | 46.0% | 47.0% | 46.3% | 46.3% | 44.9% | *47%* | *47%* | Long-Term Debt Ratio | *47%* |
| 49.9% | 50.9% | 53.2% | 51.5% | 50.3% | 54.0% | 53.0% | 53.7% | 53.7% | 55.1% | *53%* | *53%* | Common Equity Ratio | *53%* |
| 861.5 | 887.8 | 880.5 | 937.3 | 1006.6 | 1052.5 | 1108.4 | 1116.5 | 1106.8 | 1140.4 | *1180* | *1225* | Total Capital ($mill) | *1400* |
| 895.9 | 934.0 | 965.0 | 995.6 | 1205.9 | 1318.4 | 1373.4 | 1425.1 | 1495.9 | 1549.1 | *1600* | *1660* | Net Plant ($mill) | *1900* |
| 6.8% | 6.7% | 6.9% | 5.9% | 5.7% | 5.9% | 6.5% | 7.1% | 8.5% | 7.7% | *8.0%* | *8.0%* | Return on Total Cap'l | *8.0%* |
| 9.7% | 9.8% | 10.0% | 8.9% | 9.1% | 8.9% | 9.9% | 10.9% | 12.5% | 10.9% | *11.0%* | *11.0%* | Return on Shr. Equity | *11.0%* |
| 9.9% | 10.0% | 10.2% | 8.5% | 9.0% | 8.9% | 9.9% | 10.9% | 12.5% | 10.9% | *11.0%* | *11.0%* | Return on Com Equity | *11.0%* |
| 2.8% | 3.1% | 3.5% | 1.9% | 2.6% | 2.7% | 3.7% | 4.5% | 6.0% | 4.5% | *4.5%* | *4.5%* | Retained to Com Eq | *4.5%* |
| 74% | 70% | 67% | 79% | 72% | 69% | 63% | 59% | 52% | 59% | *56%* | *59%* | All Div'ds to Net Prof | *58%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 6.1 | 6.9 | 31.1 |
| Other | 268.8 | 474.1 | 241.3 |
| Current Assets | 274.9 | 481.0 | 272.4 |
| Accts Payable | 119.7 | 94.4 | 50.1 |
| Debt Due | 148.1 | 248.0 | 90.6 |
| Other | 122.1 | 208.9 | 148.8 |
| Current Liab. | 389.9 | 551.3 | 289.5 |
| Fx. Chg. Cov. | 408% | 393% | NMF |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 9.0% | 9.0% | *4.0%* |
| "Cash Flow" | 3.5% | 6.5% | *4.5%* |
| Earnings | 5.0% | 8.0% | *5.0%* |
| Dividends | 2.0% | 3.0% | *5.5%* |
| Book Value | 3.5% | 3.5% | *5.0%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 390.4 | 171.0 | 114.9 | 336.9 | 1013.2 |
| 2007 | 394.1 | 183.2 | 124.2 | 331.7 | 1033.2 |
| 2008 | 387.7 | 191.3 | 109.7 | 349.2 | 1037.9 |
| 2009 | 437.4 | 149.4 | *100* | *338.2* | *1025* |
| 2010 | *420* | *215* | *125* | *365* | *1125* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 1.48 | .07 | d.35 | 1.15 | 2.35 |
| 2007 | 1.77 | .10 | d.22 | 1.11 | 2.76 |
| 2008 | 1.62 | .08 | d.38 | 1.25 | 2.57 |
| 2009 | 1.72 | .12 | *d.31* | *1.32* | *2.85* |
| 2010 | *1.72* | *.11* | *d.33* | *1.35* | *2.85* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .325 | .325 | .325 | .345 | 1.32 |
| 2006 | .345 | .345 | .345 | .355 | 1.39 |
| 2007 | .355 | .355 | .355 | .375 | 1.44 |
| 2008 | .375 | .375 | .375 | .395 | 1.52 |
| 2009 | .395 | .395 | .395 | | |

**BUSINESS:** Northwest Natural Gas Co. distributes natural gas to 90 communities, 662,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 55%; commercial, 28%; industrial, gas transportation, and other, 17%. Employs 1,106. Barclays Global owns 6.6% of shares; officers and directors, 1.4% (4/09 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

**Northwest Natural's normal-looking first-half results contained some unusual elements.** The company shares in either 20% or 10% of the difference between forecast natural gas costs and the actual outlays in Oregon. In this year's first half, very low gas prices led to an $11 million profit from the cost-sharing mechanism, versus a $6 million loss in the prior-year period. The profit, however, was partially offset by considerably higher operating and maintenance expenses, due partly to higher pension expense related to the decline in the stock market and bonuses due to the earnings gain. Meanwhile, the recession cost Northwest 3,000 customers in the June period, dropping its year-to-year customer increase to 0.8%.

**Thus, we look for little earnings change through 2010.** With natural gas prices likely to rise at least a bit next year, Northwest has opted to share in 10% of the difference between forecast and actual gas costs, likely reducing commodity cost effects. As gas prices are down, however, the company expects that residential rates will drop 15%-20% next year, raising the incentive to convert to gas heat. Moreover, the company plans to pare 50 to 100 jobs, adding to the 175 it eliminated in the last two years.

**Northwest should benefit from a new union contract.** Under the new five-year agreement, union members (about 60% of the workforce) received a 2.3% raise but will get just 1% more per year for years two through five, plus up to 2% for inflation. The company gains extra flexibility, and new hires will not be eligible for the defined benefit pension plan.

**New projects could significantly boost earnings by the end of our time horizon.** Northwest owns 75% of the Gill Ranch, CA gas storage project and will invest about $160 million in the project; it should contribute to the bottom line by 2011. The proposed Palomar pipeline would bring a second source of gas to the Portland area; its eastern section could come on line by 2013. NWN's investment would be around $200 million, plus an equal sum if the western half is built.

**These top-quality shares offer decent total-return potential, suitable for conservative accounts.**

*Sigourney B. Romaine September 11, 2009*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); 1Q '09, 6¢. Next earnings report due early November.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions, adjusted for stock split.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 70 |
| Earnings Predictability | 90 |

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# PIEDMONT NAT'L. GAS NYSE-PNY

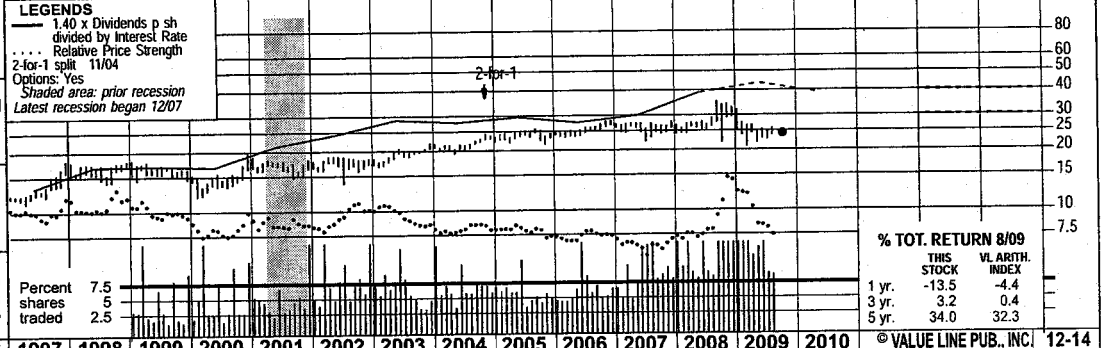
| RECENT PRICE | 24.24 | P/E RATIO | 14.8 (Trailing: 15.6 Median: 18.0) | RELATIVE P/E RATIO | 0.92 | DIV'D YLD | 4.5% | VALUE LINE |
|---|---|---|---|---|---|---|---|---|

TIMELINESS **3** Raised 6/15/07
SAFETY **2** New 7/27/90
TECHNICAL **4** Raised 7/17/09
BETA .65 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 18.1 | 18.3 | 19.7 | 19.0 | 19.0 | 22.0 | 24.3 | 25.8 | 28.4 | 28.0 | 35.3 | 32.0 |
| Low: | 13.9 | 14.3 | 11.8 | 14.6 | 13.7 | 16.6 | 19.2 | 21.3 | 23.2 | 22.0 | 21.7 | 20.7 |

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.40 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 11/04
Options: Yes
*Shaded area: prior recession*
*Latest recession began 12/07*




**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+65%) | 17% |
| Low | 30 | (+25%) | 10% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 1 | 0 | 1 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 1 | 1 | 0 | 0 | 0 | 0 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 112 | 75 | 78 |
| to Sell | 93 | 123 | 96 |
| Hld's(000) | 33160 | 34611 | 33567 |

**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -13.5 | -4.4 |
| 3 yr. | 3.2 | 0.4 |
| 5 yr. | 34.0 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 10.57 | 10.82 | 8.76 | 11.59 | 12.84 | 12.45 | 10.97 | 13.01 | 17.06 | 12.57 | 18.14 | 19.95 | 22.96 | 25.80 | 23.37 | 28.52 | *26.45* | *27.25* | Revenues per sh A | *30.00* |
| 1.14 | 1.13 | 1.25 | 1.49 | 1.62 | 1.72 | 1.70 | 1.77 | 1.81 | 1.81 | 2.04 | 2.31 | 2.43 | 2.51 | 2.64 | 2.77 | *2.85* | *2.95* | "Cash Flow" per sh | *3.15* |
| .73 | .68 | .73 | .84 | .93 | .98 | .93 | 1.01 | 1.01 | .95 | 1.11 | 1.27 | 1.32 | 1.27 | 1.40 | 1.49 | *1.60* | *1.70* | Earnings per sh B | *1.90* |
| .48 | .51 | .54 | .57 | .61 | .64 | .68 | .72 | .76 | .80 | .82 | .85 | .91 | .95 | .99 | 1.03 | *1.07* | *1.11* | Div'ds Decl'd per sh C■ | *1.23* |
| 1.58 | 1.95 | 1.72 | 1.64 | 1.52 | 1.48 | 1.58 | 1.65 | 1.29 | 1.21 | 1.16 | 1.85 | 2.50 | 2.74 | 1.85 | 2.47 | *2.40* | *2.10* | Cap'l Spending per sh | *2.25* |
| 5.45 | 5.68 | 6.16 | 6.53 | 6.95 | 7.45 | 7.86 | 8.26 | 8.63 | 8.91 | 9.36 | 11.15 | 11.53 | 11.83 | 11.99 | 12.11 | *12.70* | *13.25* | Book Value per sh D | *15.05* |
| 52.30 | 53.15 | 57.67 | 59.10 | 60.39 | 61.48 | 62.59 | 63.83 | 64.93 | 66.18 | 67.31 | 76.67 | 76.70 | 74.61 | 73.23 | 73.26 | *73.50* | *73.50* | Common Shs Outst'g E | *73.00* |
| 15.4 | 15.7 | 13.8 | 13.9 | 13.6 | 16.3 | 17.7 | 14.3 | 16.7 | 18.4 | 16.7 | 16.6 | 17.9 | 19.2 | 18.7 | 18.2 | *Bold figures are* | | Avg Ann'l P/E Ratio | *18.0* |
| .91 | 1.03 | .92 | .87 | .78 | .85 | 1.01 | .93 | .86 | 1.01 | .95 | .88 | .95 | 1.04 | .99 | 1.15 | *Value Line* | | Relative P/E Ratio | *1.50* |
| 4.3% | 4.8% | 5.4% | 4.9% | 4.8% | 4.0% | 4.1% | 5.0% | 4.5% | 4.6% | 4.4% | 4.1% | 3.8% | 3.9% | 3.8% | 3.8% | *estimates* | | Avg Ann'l Div'd Yield | *3.6%* |

**CAPITAL STRUCTURE as of 4/30/09**
Total Debt $1029.0 mill. Due in 5 Yrs $150.0 mill.
LT Debt $793.5 mill. LT Interest $55.5 mill.
(LT interest earned: 4.0x; total interest coverage: 3.7x)

Pension Assets-10/08 $150.3 mill. Oblig. $143.5 mill.

Pfd Stock None

Common Stock 72,959,779 shs. as of 6/2/09
MARKET CAP: $1.8 billion (Mid Cap)

| 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|
| 686.5 | 830.4 | 1107.9 | 832.0 | 1220.8 | 1529.7 | 1761.1 | 1924.7 | 1711.3 | 2089.1 | *1945* | *2005* | Revenues ($mill) A | *2190* |
| 58.2 | 64.0 | 65.5 | 62.2 | 74.4 | 95.2 | 101.3 | 97.2 | 104.4 | 110.0 | *115* | *125* | Net Profit ($mill) | *140* |
| 39.7% | 34.7% | 34.6% | 33.1% | 34.8% | 35.1% | 33.7% | 34.2% | 33.0% | 36.4% | *35.0%* | *35.0%* | Income Tax Rate | *35.0%* |
| 8.5% | 7.7% | 5.9% | 7.5% | 6.1% | 6.2% | 5.8% | 5.0% | 6.1% | 5.3% | *6.1%* | *6.3%* | Net Profit Margin | *6.4%* |
| 46.2% | 46.1% | 47.6% | 43.9% | 42.2% | 43.6% | 41.4% | 48.3% | 48.4% | 47.2% | *47.5%* | *48.0%* | Long-Term Debt Ratio | *47.0%* |
| 53.8% | 53.9% | 52.4% | 56.1% | 57.8% | 56.4% | 58.6% | 51.7% | 51.6% | 52.8% | *52.5%* | *52.0%* | Common Equity Ratio | *53.0%* |
| 914.7 | 978.4 | 1069.4 | 1051.6 | 1090.2 | 1514.9 | 1509.2 | 1707.9 | 1703.3 | 1681.5 | *1775* | *1875* | Total Capital ($mill) | *2075* |
| 1047.0 | 1072.0 | 1114.7 | 1158.5 | 1812.3 | 1849.8 | 1939.1 | 2075.3 | 2141.5 | 2240.8 | *2250* | *2300* | Net Plant ($mill) | *2450* |
| 8.1% | 8.3% | 7.9% | 7.8% | 8.6% | 7.8% | 8.2% | 7.2% | 7.8% | 8.2% | *8.0%* | *8.0%* | Return on Total Cap'l | *8.0%* |
| 11.8% | 12.1% | 11.7% | 10.6% | 11.8% | 11.1% | 11.5% | 11.0% | 11.9% | 12.4% | *12.5%* | *13.0%* | Return on Shr. Equity | *12.5%* |
| 11.8% | 12.1% | 11.7% | 10.6% | 11.8% | 11.1% | 11.5% | 11.0% | 11.9% | 12.4% | *12.5%* | *13.0%* | Return on Com Equity | *12.5%* |
| 3.3% | 3.5% | 3.0% | 1.7% | 3.1% | 3.7% | 3.6% | 2.8% | 3.5% | 3.9% | *4.0%* | *4.5%* | Retained to Com Eq | *4.5%* |
| 72% | 71% | 75% | 83% | 74% | 66% | 68% | 74% | 70% | 69% | *67%* | *65%* | All Div'ds to Net Prof | *65%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 4/30/09 |
|---|---|---|---|
| Cash Assets | 7.5 | 7.0 | 20.7 |
| Other | 427.8 | 593.8 | 528.0 |
| Current Assets | 435.3 | 600.8 | 548.7 |
| Accts Payable | 143.6 | 132.3 | 94.0 |
| Debt Due | 195.0 | 436.5 | 235.5 |
| Other | 75.9 | 112.7 | 182.3 |
| Current Liab. | 424.5 | 681.5 | 511.8 |
| Fix. Chg. Cov. | 309% | 341% | 350% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 7.5% | 10.0% | *2.5%* |
| "Cash Flow" | 5.0% | 7.0% | *3.0%* |
| Earnings | 4.5% | 6.5% | *5.5%* |
| Dividends | 5.0% | 4.5% | *3.5%* |
| Book Value | 5.5% | 6.0% | *4.0%* |

| Fiscal Year Ends | QUARTERLY REVENUES ($ mill.) A Jan.31 | Apr.30 | Jul.31 | Oct.31 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | 921.4 | 483.2 | 237.9 | 282.2 | 1924.7 |
| 2007 | 677.2 | 531.5 | 224.4 | 278.2 | 1711.3 |
| 2008 | 788.5 | 634.2 | 354.7 | 311.7 | 2089.1 |
| 2009 | 779.6 | 455.4 | *372* | *338* | *1945* |
| 2010 | *790* | *470* | *390* | *355* | *2005* |

| Fiscal Year Ends | EARNINGS PER SHARE A B Jan.31 | Apr.30 | Jul.31 | Oct.31 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | .94 | .57 | d.16 | d.08 | 1.27 |
| 2007 | .94 | .69 | d.12 | d.11 | 1.40 |
| 2008 | 1.12 | .66 | d.10 | d.18 | 1.49 |
| 2009 | 1.10 | .73 | *d.10* | *d.13* | *1.60* |
| 2010 | *1.12* | *.75* | *d.08* | *d.09* | *1.70* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .215 | .23 | .23 | .23 | .91 |
| 2006 | .23 | .24 | .24 | .24 | .95 |
| 2007 | .24 | .25 | .25 | .25 | .99 |
| 2008 | .25 | .26 | .26 | .26 | 1.03 |
| 2009 | .26 | .27 | .27 | | |

**BUSINESS:** Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 935,724 customers in North Carolina, South Carolina, and Tennessee. 2008 revenue mix: residential (39%), commercial (24%), industrial (12%), other (25%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 73.5% of revenues. '08 deprec. rate: 3.2%. Estimated plant age: 8.7 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,833 employees. Officers & directors own about 1.1% of common stock (1/09 proxy). Chairman, CEO, & President: Thomas E. Skains. Inc.: NC. Address: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

**Piedmont Natural Gas has posted a mixed bag of financial results thus far in 2009.** Quarterly sales in the first half declined, year over year, as the weakened economy continued to weigh on both residential and commercial new construction activities. As a result, PNY's regulated utility segment has been experiencing declining customer growth compounded by rising conservation practices at existing accounts. Nonetheless, margins have been widening, thanks largely to lower natural gas costs, which have more than offset the rise in operating expenses. These trends resulted in a 10.6% hike in the April-period bottom line.

**Meantime, slumping demand has put the brakes on many of the company's capital projects.** Management has opted to defer its pipeline infrastructure enhancement plans that were scheduled to serve the new gas-fired power generation markets of North Carolina. Moreover, construction of the liquid natural gas storage facility in Robeson County, NC has also been put off. Current customer growth projections in that region indicate this facility may not be necessary for a few more years. As a result, PNY is holding off on construction until 2012, with a potential in-service date of 2015. These moves ought to help the company conserve cash at a time when rising accounts receivable and higher delinquencies are a distinct possibility.

**Still, we have raised our earnings estimates for this year and next by a nickel.** The main culprit for the disappointing 2009 revenues can be attributed to the slumping commodity prices. This trend masks Piedmont's continued customer growth, a figure that should register at about 1%-1.5% this year. Meantime, lower gas costs should continue to offset the margin tightening associated with diminished volumes. Consequently, annual earnings gains should persist.

**These neutrally ranked shares have some appeal as an income vehicle.** Recovery potential for the pull to 2012-2014 is about average for a utility. But the recent dividend hike, and relative stability provided by an ever-increasing customer base, shines a positive light on this good-quality stock.

*Bryan J. Fong* *September 11, 2009*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early Nov. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid mid-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2008: $16.3 million, 22¢/share.
(E) In millions, adjusted for stock split.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 60 |
| Earnings Predictability | 90 |

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# SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE **34.29** | P/E RATIO **14.3** (Trailing: 14.8 Median: 14.0) | RELATIVE P/E RATIO **0.89** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS **3** Lowered 8/14/09
SAFETY **2** Lowered 1/4/91
TECHNICAL **5** Lowered 9/11/09
BETA .65 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 15.4 | 15.4 | 15.1 | 17.0 | 18.3 | 20.3 | 26.5 | 32.4 | 34.3 | 41.3 | 40.6 | 40.8 |
| Low: | 11.0 | 10.8 | 12.3 | 13.8 | 14.1 | 15.3 | 19.7 | 24.9 | 25.6 | 31.2 | 25.2 | 32.0 |

Target Price Range 2012 | 2013 | 2014

**2012-14 PROJECTIONS**

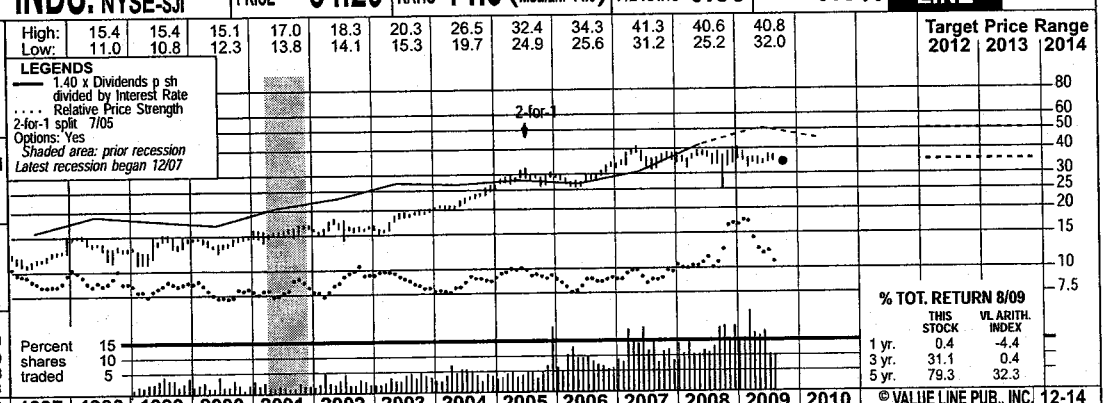
| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 50 | (+45%) | 13% |
| Low | 35 | (Nil) | 5% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 1 | 0 | 0 | 1 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 2 | 0 | 0 | 0 | 4 | 0 | 1 | 2 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 75 | 73 | 70 |
| to Sell | 69 | 70 | 78 |
| Hld's(000) | 16545 | 16545 | 15858 |




**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 0.4 | -4.4 |
| 3 yr. | 31.1 | 0.4 |
| 5 yr. | 79.3 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 17.03 | 17.45 | 16.50 | 16.52 | 16.18 | 20.89 | 17.60 | 22.43 | 35.30 | 20.69 | 26.34 | 29.51 | 31.78 | 31.76 | 32.30 | 32.36 | *30.85* | *31.60* | Revenues per sh | *36.35* |
| 1.54 | 1.35 | 1.65 | 1.54 | 1.60 | 1.44 | 1.84 | 1.95 | 1.90 | 2.12 | 2.24 | 2.44 | 2.51 | 3.51 | 3.20 | 3.48 | *3.35* | *3.60* | "Cash Flow" per sh | *4.20* |
| .78 | .61 | .83 | .85 | .86 | .64 | 1.01 | 1.08 | 1.15 | 1.22 | 1.37 | 1.58 | 1.71 | 2.46 | 2.09 | 2.27 | *2.40* | *2.65* | Earnings per sh A | *3.10* |
| .72 | .72 | .72 | .72 | .72 | .72 | .72 | .73 | .74 | .75 | .78 | .82 | .86 | .92 | 1.01 | 1.11 | *1.20* | *1.28* | Div'ds Decl'd per sh B ■ | *1.50* |
| 1.87 | 1.93 | 2.08 | 2.01 | 2.30 | 3.06 | 2.19 | 2.21 | 2.82 | 3.47 | 2.36 | 2.67 | 3.21 | 2.51 | 1.88 | 2.08 | *2.35* | *2.40* | Cap'l Spending per sh | *2.90* |
| 7.17 | 7.23 | 7.34 | 8.03 | 6.43 | 6.23 | 6.74 | 7.25 | 7.81 | 9.67 | 11.26 | 12.41 | 13.50 | 15.11 | 16.25 | 17.33 | *18.65* | *19.35* | Book Value per sh C | *22.75* |
| 19.61 | 21.43 | 21.44 | 21.51 | 21.54 | 21.56 | 22.30 | 23.00 | 23.72 | 24.41 | 26.46 | 27.76 | 28.98 | 29.33 | 29.61 | 29.73 | *30.00* | *31.00* | Common Shs Outst'g D | *33.00* |
| 15.8 | 16.1 | 12.2 | 13.3 | 13.8 | 21.2 | 13.3 | 13.0 | 13.6 | 13.5 | 13.3 | 14.1 | 16.6 | 11.9 | 17.2 | 15.9 | *Bold figures are* | | Avg Ann'l P/E Ratio | *14.0* |
| .93 | 1.06 | .82 | .83 | .80 | 1.10 | .76 | .85 | .70 | .74 | .76 | .74 | .88 | .64 | .91 | .95 | *Value Line* | | Relative P/E Ratio | *.95* |
| 5.9% | 7.4% | 7.2% | 6.4% | 6.1% | 5.3% | 5.4% | 5.2% | 4.7% | 4.6% | 4.3% | 3.7% | 3.0% | 3.2% | 2.8% | 3.1% | *estimates* | | Avg Ann'l Div'd Yield | *3.5%* |

**CAPITAL STRUCTURE as of 6/30/09**
Total Debt $496.4 mill. Due in 5 Yrs $228.8 mill.
LT Debt $332.7 mill. LT Interest $16.0 mill.
(Total interest coverage: 8.4x)

Pension Assets-12/08 $88.3 mill. Oblig. $142.7 mill.

Pfd Stock none

Common Stock 29,796,232 common shs. as of 8/3/09

MARKET CAP: $1.0 billion (Mid Cap)

| 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 392.5 | 515.9 | 837.3 | 505.1 | 696.8 | 819.1 | 921.0 | 931.4 | 956.4 | 962.0 | *925* | *980* | Revenues ($mill) | *1200* |
| 22.0 | 24.7 | 26.8 | 29.4 | 34.6 | 43.0 | 48.6 | 72.0 | 61.8 | 67.7 | *70.0* | *80.0* | Net Profit ($mill) | *100* |
| 42.8% | 43.1% | 42.2% | 41.4% | 40.6% | 40.9% | 41.5% | 41.3% | 41.9% | 47.7% | *38.0%* | *40.0%* | Income Tax Rate | *40.0%* |
| 5.6% | 4.8% | 3.2% | 5.8% | 5.0% | 5.2% | 5.3% | 7.7% | 6.5% | 7.0% | *7.6%* | *8.2%* | Net Profit Margin | *8.3%* |
| 53.8% | 54.1% | 57.0% | 53.6% | 50.8% | 48.7% | 44.9% | 44.7% | 42.7% | 39.2% | *38.5%* | *40.0%* | Long-Term Debt Ratio | *38.0%* |
| 37.0% | 37.6% | 35.9% | 46.1% | 49.0% | 51.0% | 55.1% | 55.3% | 57.3% | 60.8% | *61.5%* | *60.0%* | Common Equity Ratio | *62.0%* |
| 405.9 | 443.5 | 516.2 | 512.5 | 608.4 | 675.0 | 710.3 | 801.1 | 839.0 | 848.0 | *910* | *1000* | Total Capital ($mill) | *1210* |
| 533.3 | 562.2 | 607.0 | 666.6 | 748.3 | 799.9 | 877.3 | 920.0 | 948.9 | 982.6 | *1030* | *1075* | Net Plant ($mill) | *1250* |
| 7.4% | 7.4% | 6.9% | 7.6% | 7.3% | 7.9% | 8.3% | 10.1% | 8.6% | 8.5% | *8.5%* | *9.0%* | Return on Total Cap'l | *9.0%* |
| 11.7% | 12.1% | 12.1% | 12.4% | 11.5% | 12.4% | 12.4% | 16.3% | 12.8% | 13.1% | *12.5%* | *13.5%* | Return on Shr. Equity | *13.5%* |
| 14.6% | 14.8% | 12.8% | 12.5% | 11.6% | 12.5% | 12.4% | 16.3% | 12.8% | 13.1% | *12.5%* | *13.5%* | Return on Com Equity | *13.5%* |
| 4.2% | 4.8% | 3.5% | 4.7% | 5.0% | 5.9% | 6.2% | 10.2% | 6.7% | 6.7% | *6.0%* | *6.5%* | Retained to Com Eq | *6.5%* |
| 72% | 67% | 76% | 62% | 57% | 52% | 50% | 37% | 48% | 49% | *51%* | *50%* | All Div'ds to Net Prof | *50%* |

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 11.7 | 5.8 | 6.0 |
| Other | 316.6 | 429.3 | 351.4 |
| Current Assets | 328.3 | 435.1 | 357.4 |
| Accts Payable | 101.2 | 120.2 | 87.9 |
| Debt Due | 118.4 | 237.6 | 163.7 |
| Other | 108.7 | 142.1 | 135.7 |
| Current Liab. | 328.3 | 499.9 | 387.3 |
| Fix. Chg. Cov. | 476% | 598% | 834% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 6.0% | 3.0% | 2.0% |
| "Cash Flow" | 8.5% | 10.0% | 3.5% |
| Earnings | 11.5% | 13.0% | 5.5% |
| Dividends | 3.5% | 6.0% | 7.0% |
| Book Value | 9.0% | 11.0% | 6.0% |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 372.6 | 153.8 | 154.7 | 250.3 | 931.4 |
| 2007 | 368.4 | 171.7 | 156.2 | 260.1 | 956.4 |
| 2008 | 348.1 | 135.8 | 210.4 | 267.7 | 962.0 |
| 2009 | 362.2 | 134.5 | *150* | *278.3* | *925* |
| 2010 | *365* | *160* | *170* | *285* | *980* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 1.06 | .20 | .51 | .69 | 2.46 |
| 2007 | 1.30 | .21 | d.05 | .63 | 2.09 |
| 2008 | 1.32 | .26 | .04 | .67 | 2.27 |
| 2009 | 1.46 | .15 | *.05* | *.74* | *2.40* |
| 2010 | *1.45* | *.25* | *.10* | *.85* | *2.65* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B ■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | -- | .213 | .213 | .438 | .86 |
| 2006 | -- | .225 | .225 | .470 | .92 |
| 2007 | -- | .245 | .245 | .515 | 1.01 |
| 2008 | -- | .270 | .270 | .568 | 1.11 |
| 2009 | -- | .298 | .298 | | |

**BUSINESS:** South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 340,136 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '08: residential, 46%; commercial, 23%; cogeneration and electric generation, 6%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 602 employees. Off./dir. control 1.0% of com. shares; Barclays, 7.5%; Keeley Asset Management, 5.6% (3/09 proxy). Chrmn. & CEO: Edward Graham. Incorp.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Tel.: 609-561-9000. Internet: www.sjindustries.com.

**South Jersey Industries posted a flat top-line comparison and lower share earnings for the second quarter.** Earnings declined moderately at subsidiary South Jersey Gas in the recent interim. Lower interest payments were more than offset by higher pension expense and an increase in other operating costs at this business. Meanwhile, significantly cooler temperatures during the period resulted in lower air conditioning demand and reduced earnings at the on-site energy production business, Marina Energy. The Asset Management and Marketing business also posted an earnings decline for the quarter.

**The company has attractive prospects for the coming years.** Customer growth at South Jersey Gas has continued at a steady clip, despite weakness in the broader economy. Natural gas remains the fuel of choice in the markets served by the utility, and SJG continues to see significant interest in conversions from other fuel sources to natural gas. Its recent gas main extension project, along with aggressive marketing efforts, should benefit the utility going forward. We anticipate solid results from the nonutility operations, as well.

**South Jersey Gas has filed with the New Jersey Board of Public Utilities to reduce rates by 20.2%.** The approval of the Basic Gas Supply Service (BGSS) petition would allow customers to realize significant savings, and provide an incentive for homeowners to switch from oil to natural gas. The BGSS clause allows South Jersey to pass along increases and decreases in gas costs directly to consumers. The company's ability to secure lower-priced gas has allowed it to provide customers with the lower rates.

**Shares of South Jersey Industries have slipped one notch in Timeliness,** and are now neutrally ranked for year-ahead performance. Looking further out, we anticipate higher revenues and share earnings at the company by 2012-2014. Moreover, SJI scores high marks for Safety, Price Stability, and Earnings Predictability. But from the present quotation, this issue has below-average, though reasonably well-defined, total return potential for the coming years.

*Michael Napoli, CPA* *September 11, 2009*

(A) Based on GAAP EPS through 2006, economic earnings thereafter. GAAP EPS: '07, $2.10; '08, $2.58. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31. Excl gain (losses) from discont. ops.: '99, ($0.02); '00, ($0.04); '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Earnings may not sum due to rounding. Next egs. report due in November. (B) Div'ds paid early Apr., Jul., Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. regulatory assets. In 2008: $270.4 mill., $9.10 per shr. (D) In millions, adj. for split.

| | |
|---|---|
| Company's Financial Strength | B++ |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 90 |
| Earnings Predictability | 80 |

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# SOUTHWEST GAS NYSE-SWX

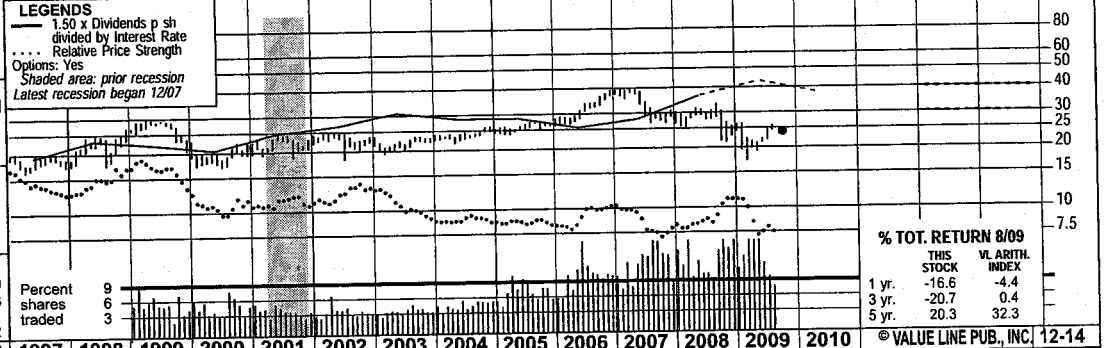
RECENT PRICE **23.98** | P/E RATIO **13.5** (Trailing: 16.3 / Median: 19.0) | RELATIVE P/E RATIO **0.84** | DIV'D YLD **4.1%** | VALUE LINE

**TIMELINESS** 3 Raised 5/23/08
**SAFETY** 3 Lowered 1/4/91
**TECHNICAL** 4 Lowered 7/24/09
**BETA** .75 (1.00 = Market)

| | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 26.9 | 29.5 | 23.0 | 24.7 | 25.3 | 23.6 | 26.2 | 28.1 | 39.4 | 39.9 | 33.3 | 26.4 | |
| Low: | 17.3 | 20.4 | 16.9 | 18.6 | 18.1 | 19.3 | 21.5 | 23.5 | 26.0 | 26.5 | 21.1 | 17.1 | |

**Target Price Range** 2012 | 2013 | 2014

**LEGENDS**
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
*Shaded area: prior recession*
*Latest recession began 12/07*



**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 40 | (+65%) | 17% |
| Low | 30 | (+25%) | 10% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 1 | 1 | 0 | 0 | 0 | 3 | 0 | 0 | 0 |
| Options | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 1 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 83 | 83 | 86 |
| to Sell | 75 | 71 | 71 |
| Hld's(000) | 32362 | 32859 | 32802 |

Percent shares traded 9 6 3

**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | -16.6 | -4.4 |
| 3 yr. | -20.7 | 0.4 |
| 5 yr. | 20.3 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 25.68 | 28.16 | 23.03 | 24.09 | 26.73 | 30.17 | 30.24 | 32.61 | 42.98 | 39.68 | 35.96 | 40.14 | 43.59 | 48.47 | 50.28 | 48.53 | *39.55* | *41.50* | Revenues per sh | *52.00* |
| 3.24 | 5.09 | 2.65 | 3.00 | 3.85 | 4.48 | 4.45 | 4.57 | 4.79 | 5.07 | 5.11 | 5.57 | 5.20 | 5.97 | 6.21 | 5.76 | *5.95* | *6.15* | "Cash Flow" per sh | *7.30* |
| .63 | 1.22 | .10 | .25 | .77 | 1.65 | 1.27 | 1.21 | 1.15 | 1.16 | 1.13 | 1.66 | 1.25 | 1.98 | 1.95 | 1.39 | *1.75* | *1.90* | Earnings per sh A | *2.30* |
| .74 | .80 | .82 | .82 | .82 | .82 | .82 | .82 | .82 | .82 | .82 | .82 | .82 | .82 | .86 | .90 | *.95* | *1.00* | Div'ds Decl'd per sh B■† | *1.15* |
| 5.43 | 6.64 | 6.79 | 8.19 | 6.19 | 6.40 | 7.41 | 7.04 | 8.17 | 8.50 | 7.03 | 8.23 | 7.49 | 8.27 | 7.96 | 6.79 | *5.50* | *5.95* | Cap'l Spending per sh | *7.20* |
| 15.96 | 16.38 | 14.55 | 14.20 | 14.09 | 15.67 | 16.31 | 16.82 | 17.27 | 17.91 | 18.42 | 19.18 | 19.10 | 21.58 | 22.98 | 23.49 | *25.25* | *26.05* | Book Value per sh | *28.00* |
| 21.00 | 21.28 | 24.47 | 26.73 | 27.39 | 30.41 | 30.99 | 31.71 | 32.49 | 33.29 | 34.23 | 36.79 | 39.33 | 41.77 | 42.81 | 44.19 | *45.50* | *47.00* | Common Shs Outst'g C | *50.00* |
| 26.5 | 14.0 | NMF | 69.3 | 24.1 | 13.2 | 21.1 | 16.0 | 19.0 | 19.9 | 19.2 | 14.3 | 20.6 | 15.9 | 17.3 | 20.3 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.0* |
| 1.57 | .92 | NMF | 4.34 | 1.39 | .69 | 1.20 | 1.04 | .97 | 1.09 | 1.09 | .76 | 1.10 | .86 | .92 | 1.22 | *Value Line* | | Relative P/E Ratio | *1.00* |
| 4.4% | 4.7% | 5.4% | 4.7% | 4.4% | 3.8% | 3.1% | 4.2% | 3.8% | 3.6% | 3.8% | 3.5% | 3.2% | 2.6% | 2.6% | 3.2% | *estimates* | | Avg Ann'l Div'd Yield | *3.3%* |
| | | | | | | 936.9 | 1034.1 | 1396.7 | 1320.9 | 1231.0 | 1477.1 | 1714.3 | 2024.7 | 2152.1 | 2144.7 | *1800* | *1950* | Revenues ($mill) | *2600* |
| | | | | | | 39.3 | 38.3 | 37.2 | 38.6 | 38.5 | 58.9 | 48.1 | 80.5 | 83.2 | 61.0 | *80.0* | *90.0* | Net Profit ($mill) | *115* |
| | | | | | | 35.5% | 26.2% | 34.5% | 32.8% | 30.5% | 34.8% | 29.7% | 37.3% | 36.5% | 40.1% | *38.0%* | *38.0%* | Income Tax Rate | *36.0%* |
| | | | | | | 4.2% | 3.7% | 2.7% | 2.9% | 3.1% | 4.0% | 2.8% | 4.0% | 3.9% | 2.8% | *4.4%* | *4.6%* | Net Profit Margin | *4.4%* |
| | | | | | | 60.3% | 60.2% | 56.2% | 62.5% | 66.0% | 64.2% | 63.8% | 60.6% | 58.1% | 55.3% | *51.0%* | *50.5%* | Long-Term Debt Ratio | *49.0%* |
| | | | | | | 35.5% | 35.8% | 39.6% | 34.1% | 34.0% | 35.8% | 36.2% | 39.4% | 41.9% | 44.7% | *49.0%* | *49.5%* | Common Equity Ratio | *51.0%* |
| | | | | | | 1424.7 | 1489.9 | 1417.6 | 1748.3 | 1851.6 | 1968.6 | 2076.0 | 2287.8 | 2349.7 | 2323.3 | *2350* | *2475* | Total Capital ($mill) | *2750* |
| | | | | | | 1581.1 | 1686.1 | 1825.6 | 1979.5 | 2175.7 | 2336.0 | 2489.1 | 2668.1 | 2845.3 | 2983.3 | *3050* | *3150* | Net Plant ($mill) | *3600* |
| | | | | | | 4.8% | 4.6% | 5.1% | 4.3% | 4.2% | 5.0% | 4.3% | 5.5% | 5.5% | 4.5% | *5.0%* | *5.5%* | Return on Total Cap'l | *6.0%* |
| | | | | | | 7.0% | 6.5% | 6.0% | 5.9% | 6.1% | 8.3% | 6.4% | 8.9% | 8.5% | 5.9% | *7.0%* | *7.5%* | Return on Shr. Equity | *8.0%* |
| | | | | | | 7.8% | 7.2% | 6.6% | 6.5% | 6.1% | 8.3% | 6.4% | 8.9% | 8.5% | 5.9% | *7.0%* | *7.5%* | Return on Com Equity | *8.0%* |
| | | | | | | 2.8% | 2.4% | 1.9% | 1.9% | 1.7% | 4.3% | 2.2% | 5.2% | 4.8% | 2.1% | *3.0%* | *3.5%* | Retained to Com Eq | *4.0%* |
| | | | | | | 64% | 67% | 71% | 70% | 72% | 49% | 65% | 42% | 44% | 63% | *54%* | *52%* | All Div'ds to Net Prof | *50%* |

**CAPITAL STRUCTURE as of 6/30/09**

**Total Debt** $1228.0 mill. **Due in 5 Yrs** $566.1 mill.
**LT Debt** $1222.9 mill. **LT Interest** $85.0 mill.
(Total interest coverage: 2.2x)
**Leases, Uncapitalized** Annual rentals $6.0 mill.
**Pension Assets-12/08** $342.9 mill.
**Oblig.** $558.9 mill.

**Pfd Stock** None

**Common Stock** 44,822,466 shs.
as of 7/30/09

**MARKET CAP: $1.1 billion (Mid Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 32.0 | 26.4 | 26.8 |
| Other | 470.5 | 411.7 | 232.5 |
| Current Assets | 502.5 | 438.1 | 259.3 |
| Accts Payable | 220.7 | 191.4 | 68.0 |
| Debt Due | 47.1 | 62.8 | 5.1 |
| Other | 260.1 | 255.7 | 303.0 |
| Current Liab. | 527.9 | 509.9 | 376.1 |
| Fix. Chg. Cov. | 229% | 224% | 233% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 6.0% | 4.5% | *1.0%* |
| "Cash Flow" | 4.5% | 3.5% | *3.5%* |
| Earnings | 7.0% | 9.0% | *4.5%* |
| Dividends | 0.5% | 1.0% | *5.0%* |
| Book Value | 4.5% | 5.0% | *3.5%* |

| Cal-endar | QUARTERLY REVENUES ($ mill.) Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 676.9 | 430.9 | 351.8 | 565.1 | 2024.7 |
| 2007 | 793.7 | 426.6 | 371.5 | 560.3 | 2152.1 |
| 2008 | 813.6 | 447.3 | 374.4 | 509.4 | 2144.7 |
| 2009 | 689.9 | 387.6 | *275* | *447.5* | *1800* |
| 2010 | *730* | *410* | *310* | *500* | *1950* |

| Cal-endar | EARNINGS PER SHARE A Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2006 | 1.11 | .02 | d.26 | 1.11 | 1.98 |
| 2007 | 1.17 | d.01 | d.22 | 1.01 | 1.95 |
| 2008 | 1.14 | d.06 | d.38 | .71 | 1.39 |
| 2009 | 1.12 | d.01 | *d.35* | *.99* | *1.75* |
| 2010 | *1.15* | *Nil* | *d.30* | *1.05* | *1.90* |

| Cal-endar | QUARTERLY DIVIDENDS PAID B■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .205 | .205 | .205 | .205 | .82 |
| 2006 | .205 | .205 | .205 | .205 | .82 |
| 2007 | .205 | .215 | .215 | .215 | .85 |
| 2008 | .215 | .225 | .225 | .225 | .89 |
| 2009 | .225 | .238 | .238 | | |

**BUSINESS:** Southwest Gas Corporation is a regulated gas distributor serving approximately 1.8 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2008 margin mix: residential and small commercial, 86%; large commercial and industrial, 5%; transportation, 9%. Total throughput: 2.4 billion therms. Sold PriMerit Bank, 7/96. Has 4,732 employees. Off. & Dir. own 2.0% of common stock; T. Rowe Price Associates, Inc., 7.0%; Barclays Global Investors, 6.8%; GAMCO Investors, Inc., 6.4% (3/09 Proxy). Chairman: James J. Kropid. CEO: Jeffrey W. Shaw. Inc.: CA. Address: 5241 Spring Mountain Road, Las Vegas, Nevada 89146. Telephone: 702-876-7237. Internet: www.swgas.com.

**Southwest Gas reported unfavorable top-line performance for the second quarter.** The recent recession stymied customer growth and resulted in lower usage. On the bright side, rate relief in Arizona and California (discussed below) supported results. Consequently, the company's share loss of $0.01 compared favorably with the prior-year tally. Losses are common during the second and third quarters, owing to the seasonal nature of the business. Looking forward, we expect lower revenue and a normal-sized share loss for the third quarter. Earnings comparisons ought to improve in the fourth quarter, assuming a better operating environment and greater cost control. Overall, we anticipate lower revenue and higher share earnings for Southwest in full-year 2009. Bottom-line growth may well continue next year.

**The company is awaiting a rate case decision from the state of Nevada.** Southwest is seeking a $30.5 million rate increase to compensate it for higher operating costs in that state. The request asks that the new rates take effect at the beginning of November. The company is also seeking an improvement in rate design. Specifically, SWX wants to implement a decoupled rate structure that would allow it more freedom in pursuing customer conservation opportunities. This follows recent prior rate case settlements in California and Arizona.

**Investors should be mindful of several caveats.** Warmer-than-normal temperatures during the winter months can hurt performance at Southwest Gas. In addition, the company will probably incur greater operating costs as it continues to expand, and profitability may suffer if rate relief cannot keep up with rising expenses.

**The pace of customer growth should pick up in the future.** That's assuming economic conditions in Southwest's service areas improve in the coming years. As a result, we anticipate higher revenues and share earnings at the company by 2012-2014. Moreover, income-oriented investors may find the stock's prospects for dividend growth attractive. But from the present quotation, this neutrally ranked equity features about-average total return potential for a utility.

*Michael Napoli, CPA* *September 11, 2009*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '93, 8¢; '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Incl. asset writedown: '93, 44¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due early November. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

| | |
|---|---|
| Company's Financial Strength | B |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 65 |
| Earnings Predictability | 70 |

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# WGL HOLDINGS NYSE-WGL

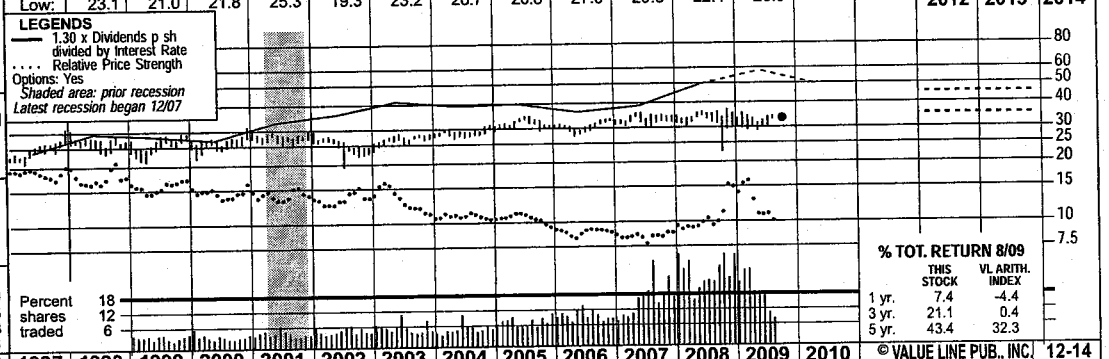
RECENT PRICE 33.30 | P/E RATIO 13.2 (Trailing: 13.1 Median: 15.0) | RELATIVE P/E RATIO 0.82 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Lowered 6/5/09
SAFETY 1 Raised 4/2/93
TECHNICAL 5 Lowered 9/11/09
BETA .65 (1.00 = Market)

| | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| High: | 30.8 | 29.4 | 31.5 | 30.5 | 29.5 | 28.8 | 31.4 | 34.8 | 33.6 | 35.9 | 37.1 | 35.5 |
| Low: | 23.1 | 21.0 | 21.8 | 25.3 | 19.3 | 23.2 | 26.7 | 28.8 | 27.0 | 29.8 | 22.4 | 28.6 |

Target Price Range 2012 | 2013 | 2014

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07




**2012-14 PROJECTIONS**

| | Price | Gain | Ann'l Total Return |
|---|---|---|---|
| High | 45 | (+35%) | 12% |
| Low | 35 | (+5%) | 6% |

**Insider Decisions**

| | O | N | D | J | F | M | A | M | J |
|---|---|---|---|---|---|---|---|---|---|
| to Buy | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Options | 0 | 4 | 0 | 0 | 1 | 0 | 0 | 0 | 0 |
| to Sell | 0 | 4 | 0 | 0 | 4 | 1 | 0 | 2 | 0 |

**Institutional Decisions**

| | 4Q2008 | 1Q2009 | 2Q2009 |
|---|---|---|---|
| to Buy | 94 | 97 | 85 |
| to Sell | 95 | 96 | 98 |
| Hld's(000) | 31580 | 30919 | 31333 |

**% TOT. RETURN 8/09**

| | THIS STOCK | VL ARITH. INDEX |
|---|---|---|
| 1 yr. | 7.4 | -4.4 |
| 3 yr. | 21.1 | 0.4 |
| 5 yr. | 43.4 | 32.3 |

| 1993 | 1994 | 1995 | 1996 | 1997 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | 2008 | 2009 | 2010 | © VALUE LINE PUB., INC. | 12-14 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 21.55 | 21.69 | 19.30 | 22.19 | 24.16 | 23.74 | 20.92 | 22.19 | 29.80 | 32.63 | 42.45 | 42.93 | 44.94 | 53.96 | 53.51 | 52.65 | *53.20* | *54.25* | Revenues per sh A | *57.60* |
| 2.25 | 2.43 | 2.51 | 2.93 | 3.02 | 2.79 | 2.74 | 3.20 | 3.24 | 2.63 | 4.00 | 3.87 | 3.97 | 3.89 | 3.89 | 4.34 | *4.40* | *4.45* | "Cash Flow" per sh | *4.70* |
| 1.31 | 1.42 | 1.45 | 1.85 | 1.85 | 1.54 | 1.47 | 1.79 | 1.88 | 1.14 | 2.30 | 1.98 | 2.13 | 1.94 | 2.10 | 2.44 | *2.50* | *2.55* | Earnings per sh B | *2.70* |
| 1.09 | 1.11 | 1.12 | 1.14 | 1.17 | 1.20 | 1.22 | 1.24 | 1.26 | 1.27 | 1.28 | 1.30 | 1.32 | 1.35 | 1.37 | 1.41 | *1.47* | *1.51* | Div'ds Decl'd per sh C■ | *1.63* |
| 2.43 | 2.84 | 2.63 | 2.85 | 3.20 | 3.62 | 3.42 | 2.67 | 2.68 | 3.34 | 2.65 | 2.33 | 2.32 | 3.27 | 3.33 | 2.70 | *3.00* | *3.00* | Cap'l Spending per sh | *2.50* |
| 11.04 | 11.51 | 11.95 | 12.79 | 13.48 | 13.86 | 14.72 | 15.31 | 16.24 | 15.78 | 16.25 | 16.95 | 17.80 | 18.86 | 19.83 | 20.99 | *22.00* | *23.05* | Book Value per sh D | *26.20* |
| 41.50 | 42.19 | 42.93 | 43.70 | 43.70 | 43.84 | 46.47 | 46.47 | 48.54 | 48.56 | 48.63 | 48.67 | 48.65 | 48.89 | 49.45 | 49.92 | *50.00* | *50.00* | Common Shs Outst'g E | *50.00* |
| 15.6 | 14.0 | 12.7 | 11.5 | 12.7 | 17.2 | 17.3 | 14.6 | 14.7 | 23.1 | 11.1 | 14.2 | 14.7 | 15.5 | 15.6 | 13.7 | *Bold figures are* | | Avg Ann'l P/E Ratio | *15.0* |
| .92 | .92 | .85 | .72 | .73 | .89 | .99 | .95 | .75 | 1.26 | .63 | .75 | .78 | .84 | .82 | .85 | *Value Line* | | Relative P/E Ratio | *1.00* |
| 5.3% | 5.6% | 6.1% | 5.4% | 5.0% | 4.5% | 4.8% | 4.8% | 4.6% | 4.8% | 5.0% | 4.6% | 4.2% | 4.5% | 4.2% | 4.2% | *estimates* | | Avg Ann'l Div'd Yield | *4.0%* |
| | | | | | | 972.1 | 1031.1 | 1446.5 | 1584.8 | 2064.2 | 2089.6 | 2186.3 | 2637.9 | 2646.0 | 2628.2 | *2660* | *2715* | Revenues ($mill) A | *2880* |
| | | | | | | 68.8 | 84.6 | 89.9 | 55.7 | 112.3 | 98.0 | 104.8 | 96.0 | 102.9 | 122.9 | *125* | *130* | Net Profit ($mill) | *135* |
| | | | | | | 36.0% | 36.1% | 39.6% | 34.0% | 38.0% | 38.2% | 37.4% | 39.0% | 39.1% | 37.1% | *37.0%* | *37.0%* | Income Tax Rate | *38.0%* |
| | | | | | | 7.1% | 8.2% | 6.2% | 3.5% | 5.4% | 4.7% | 4.8% | 3.6% | 3.9% | 4.7% | *4.7%* | *4.8%* | Net Profit Margin | *4.7%* |
| | | | | | | 41.5% | 43.1% | 41.7% | 45.7% | 43.8% | 40.9% | 39.5% | 37.8% | 37.9% | 35.9% | *36.5%* | *35.5%* | Long-Term Debt Ratio | *34.0%* |
| | | | | | | 56.1% | 54.8% | 56.3% | 52.4% | 54.3% | 57.2% | 58.6% | 60.4% | 60.3% | 62.4% | *62.0%* | *63.0%* | Common Equity Ratio | *64.5%* |
| | | | | | | 1218.5 | 1299.2 | 1400.8 | 1462.5 | 1454.9 | 1443.6 | 1478.1 | 1526.1 | 1625.4 | 1679.5 | *1780* | *1830* | Total Capital ($mill) | *2040* |
| | | | | | | 1402.7 | 1460.3 | 1519.7 | 1606.8 | 1874.9 | 1915.6 | 1969.7 | 2067.9 | 2150.4 | 2208.3 | *2325* | *2420* | Net Plant ($mill) | *2720* |
| | | | | | | 7.1% | 7.9% | 7.9% | 5.3% | 9.1% | 8.2% | 8.5% | 7.6% | 7.6% | 8.5% | *8.0%* | *8.0%* | Return on Total Cap'l | *8.0%* |
| | | | | | | 9.7% | 11.4% | 11.0% | 7.0% | 13.7% | 11.5% | 11.7% | 10.1% | 10.2% | 11.4% | *11.5%* | *11.0%* | Return on Shr. Equity | *10.5%* |
| | | | | | | 9.9% | 11.7% | 11.2% | 7.2% | 14.0% | 11.7% | 12.0% | 10.3% | 10.4% | 11.6% | *12.0%* | *11.5%* | Return on Com Equity | *11.0%* |
| | | | | | | 1.8% | 3.7% | 3.8% | NMF | 6.2% | 4.1% | 4.6% | 3.2% | 3.5% | 5.0% | *4.5%* | *4.5%* | Retained to Com Eq | *4.0%* |
| | | | | | | 82% | 69% | 67% | 112% | 56% | 65% | 62% | 69% | 66% | 57% | *59%* | *59%* | All Div'ds to Net Prof | *60%* |

**CAPITAL STRUCTURE as of 6/30/09**
**Total Debt** $728.7 mill. **Due in 5 Yrs** $264.5 mill.
**LT Debt** $624.1 mill. **LT Interest** $37.4 mill.
(LT interest earned: 5.9x; total interest coverage: 5.2x)
**Pension Assets-9/08** $588.2 mill. **Oblig.** $590.5 mill.
**Preferred Stock** $28.2 mill. **Pfd. Div'd** $1.3 mill.

**Common Stock** 50,141,229 shs. as of 7/31/09

**MARKET CAP: $1.7 billion (Mid Cap)**

| CURRENT POSITION ($MILL.) | 2007 | 2008 | 6/30/09 |
|---|---|---|---|
| Cash Assets | 4.9 | 6.2 | 41.6 |
| Other | 568.8 | 736.1 | 553.2 |
| Current Assets | 573.7 | 742.3 | 594.8 |
| Accts Payable | 216.9 | 243.1 | 202.8 |
| Debt Due | 205.4 | 347.0 | 104.6 |
| Other | 134.8 | 158.4 | 202.1 |
| Current Liab. | 557.1 | 748.5 | 509.5 |
| Fix. Chg. Cov. | 432% | 490% | 500% |

| ANNUAL RATES of change (per sh) | Past 10 Yrs. | Past 5 Yrs. | Est'd '06-'08 to '12-'14 |
|---|---|---|---|
| Revenues | 8.5% | 9.0% | *1.5%* |
| "Cash Flow" | 3.5% | 4.0% | *2.5%* |
| Earnings | 2.0% | 4.0% | *4.0%* |
| Dividends | 1.5% | 1.5% | *3.0%* |
| Book Value | 4.0% | 4.5% | *4.5%* |

| Fiscal Year Ends | QUARTERLY REVENUES ($ mill.) A Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | 902.9 | 1064.5 | 346.9 | 323.6 | 2637.9 |
| 2007 | 732.9 | 1119.9 | 467.5 | 325.7 | 2646.0 |
| 2008 | 751.6 | 1020.0 | 464.7 | 391.9 | 2628.2 |
| 2009 | 821.5 | 1040.9 | 427.0 | *370.6* | *2660* |
| 2010 | *830* | *1050* | *445* | *390* | *2715* |

| Fiscal Year Ends | EARNINGS PER SHARE A B Dec.31 | Mar.31 | Jun.30 | Sep.30 | Full Fiscal Year |
|---|---|---|---|---|---|
| 2006 | .93 | 1.17 | d.01 | d.15 | 1.94 |
| 2007 | .92 | 1.27 | .22 | d.31 | 2.10 |
| 2008 | .96 | 1.66 | .06 | d.24 | 2.44 |
| 2009 | 1.03 | 1.65 | .11 | *d.29* | *2.50* |
| 2010 | *1.04* | *1.66* | *.12* | *d.27* | *2.55* |

| Cal-endar | QUARTERLY DIVIDENDS PAID C■ Mar.31 | Jun.30 | Sep.30 | Dec.31 | Full Year |
|---|---|---|---|---|---|
| 2005 | .325 | .333 | .333 | .333 | 1.32 |
| 2006 | .333 | .338 | .338 | .338 | 1.34 |
| 2007 | .34 | .34 | .34 | .34 | 1.36 |
| 2008 | .34 | .36 | .36 | .36 | 1.42 |
| 2009 | .36 | .37 | .37 | | |

**BUSINESS:** WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,053,032 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. American Century Inv. own 7.1% of common stock; Off./dir. less than 1% (1/09 proxy). Chrmn. & CEO: J.H. DeGraffenreidt. Inc.: D.C. and VA. Addr.: 1100 H St., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

**WGL Holdings posted a mixed bag of financial results for the off-peak June period.** Top-line volumes fell approximately 8% over that time frame. This stemmed from weakness at the regulated utility segment, which has been dealing with lower natural gas consumption and some equipment cost issues. On a brighter note, the retail energy marketing division got a boost to its revenues and earnings contributions from higher natural gas and electricity margins. On the efficiency front, management has been performing well. Operating expenses declined 90 basis points versus the year-ago period. This stemmed from lower labor and benefits expenses. All told, the bottom line advanced nicely.

**We look for the company to register a mid-single-digit earnings hike this year.** The decent gains experienced earlier in 2009 will probably be offset by a larger share deficit in the fiscal fourth quarter. Despite the widening margins and solid performance from the retail energy and design build segments, demand at the mainstay regulated utility business may be soft. Also, the September period is historically and seasonally slow for WGL. Nonetheless, considering all that happened in the past year, the company appears to be in solid shape.

**The LNG peaking facility is going to take longer than expected to be completed and put into service.** That project will be used to support customer growth and maintain the pressure requirements of the distribution system in Chillum, MD. It was planned to be in service by the 2012-2013 winter heating season, but due to regulatory and legal issues, the following year is more likely.

**These top-quality shares may appeal to income-oriented accounts**, as they offer an attractive dividend yield. Typically, too, they proved much less volatile than the broader market during the recent turmoil. This partly stems from WGL's large government business in the DC metro area, which has been less affected by the economic downturn. These benefits are evident in the equity's top-notch Safety rank, and high mark for Price Stability. But appreciation potential is subpar for the pull to 2012-2014.

*Bryan J. Fong* *September 11, 2009*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late Oct.
(C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '08: $291.3 million, $5.81/sh.
(E) In millions, adjusted for stock split.

| | |
|---|---|
| Company's Financial Strength | A |
| Stock's Price Stability | 100 |
| Price Growth Persistence | 50 |
| Earnings Predictability | 80 |

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# ATTACHMENT C

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## AMERICAN STS WTR CO (NYSE)

Scottrade

| AWR | 32.47 | ▲0.35 | (1.09%) | Vol. 66,855 | 12:58 ET |
|---|---|---|---|---|---|

American States is a public utility company engaged principally in thepurchase, production, distribution and sale of water. The company alsodistributes electricity in some communities. In the customer service areas for both water and electric, rates and operations are subject to the jurisdiction of the California Public Utilities Commission.

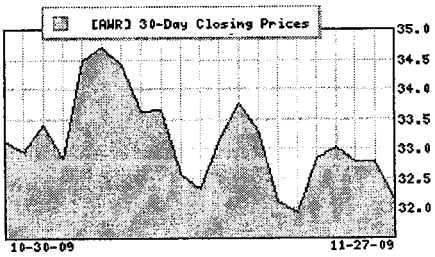
### General Information

AMER STATES WTR
630 East Foothill Boulevard
San Dimas, CA 91773-1212
Phone: 909 394-3600
Fax: 909 394-0711
Web: www.gswater.com
Email: investorinfo@aswater.com

| | |
|---|---|
| Industry | UTIL-WATER SPLY |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 03/11/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 32.12 |
| 52 Week High | 38.79 |
| 52 Week Low | 27.56 |
| Beta | 0.37 |
| 20 Day Moving Average | 58,586.95 |
| Target Price Consensus | 42 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -3.11 | 4 Week | -8.02 |
| 12 Week | -1.02 | 12 Week | -7.83 |
| YTD | -2.61 | YTD | -19.40 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 18.50 | Dividend Yield | 3.24% |
| | | Annual Dividend | $1.04 |
| Market Capitalization (millions) | 594.19 | Payout Ratio | 0.54 |
| Short Ratio | 7.63 | Change in Payout Ratio | -0.12 |
| Last Split Date | 06/10/2002 | Last Dividend Payout / Amount | 11/09/2009 / $0.26 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.40 | Current (1=Strong Buy, 5=Strong Sell) | 1.67 |
| Current Year EPS Consensus Estimate | 1.78 | 30 Days Ago | 1.67 |
| Estimated Long-Term EPS Growth Rate | 4.00 | 60 Days Ago | 1.67 |
| Next EPS Report Date | 03/11/2010 | 90 Days Ago | 2.33 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 18.02 | vs. Previous Year | 38.46% | vs. Previous Year | 19.05% |
| Trailing 12 Months: | 17.27 | vs. Previous Quarter | -15.62% | vs. Previous Quarter: | 8.50% |
| PEG Ratio | 4.51 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.65 | 09/30/09 | 10.03 | 09/30/09 | 3.06 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 8.54 | 06/30/09 | 9.40 | 06/30/09 | 2.83 |
| Price / Sales | 1.66 | 03/31/09 | 9.02 | 03/31/09 | 2.68 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.01 | 09/30/09 | 0.99 | 09/30/09 | 9.34 |
| 06/30/09 | 1.10 | 06/30/09 | 1.08 | 06/30/09 | 8.83 |
| 03/31/09 | 0.82 | 03/31/09 | 0.80 | 03/31/09 | 8.51 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 12.57 | 09/30/09 | 12.57 | 09/30/09 | 19.45 |
| 06/30/09 | 10.59 | 06/30/09 | 10.59 | 06/30/09 | 19.31 |
| 03/31/09 | 9.75 | 03/31/09 | 9.75 | 03/31/09 | 18.01 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 49.80 | 09/30/09 | 0.85 | 09/30/09 | 45.99 |
| 06/30/09 | 51.08 | 06/30/09 | 0.87 | 06/30/09 | 46.39 |
| 03/31/09 | 52.72 | 03/31/09 | 0.98 | 03/31/09 | 49.56 |

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## CALIFORNIA WTR SVC GROUP (NYSE)

Scottrade

| CWT | 36.09 | ▼-0.17 | (-0.47%) | Vol. 35,069 | 13:01 ET |
|---|---|---|---|---|---|

California Water Service Company's business, which is carried on through its operating subsidiaries, consists of the production, purchase, storage, purification, distribution and sale of water for domestic, industrial, public and irrigation uses, and for fire protection. It also provides water related services under agreements with municipalities and other private companies. The nonregulated services include full water system operation, and billing and meter reading services.

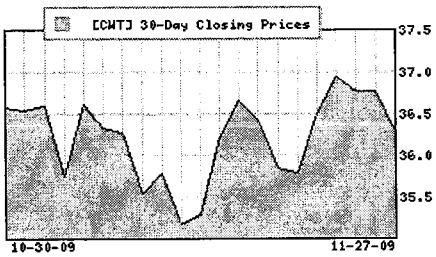
### General Information

CALIF WATER SVC
1720 North First Street
San Jose, CA 95112
Phone: 408 367-8200
Fax: 408 437-9185
Web: www.calwatergroup.com
Email: klichtenberg@calwater.com

| | |
|---|---|
| Industry | UTIL-WATER SPLY |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/24/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | 2 |
| Yesterday's Close | 36.26 |
| 52 Week High | 48.28 |
| 52 Week Low | 33.49 |
| Beta | 0.48 |
| 20 Day Moving Average | 101,620.85 |
| Target Price Consensus | 45.67 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -0.85 | 4 Week | -5.87 |
| 12 Week | 0.08 | 12 Week | -6.80 |
| YTD | -21.90 | YTD | -35.37 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 20.75 | Dividend Yield | 3.25% |
| | | Annual Dividend | $1.18 |
| Market Capitalization (millions) | 752.21 | Payout Ratio | 0.59 |
| Short Ratio | 4.37 | Change in Payout Ratio | -0.16 |
| Last Split Date | 01/26/1998 | Last Dividend Payout / Amount | 11/05/2009 / $0.29 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.35 | Current (1=Strong Buy, 5=Strong Sell) | 1.67 |
| Current Year EPS Consensus Estimate | 1.99 | 30 Days Ago | 2.00 |
| Estimated Long-Term EPS Growth Rate | 6.70 | 60 Days Ago | 2.00 |
| Next EPS Report Date | 02/24/2010 | 90 Days Ago | 2.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 18.26 | vs. Previous Year | -11.32% | vs. Previous Year | 5.67% |
| Trailing 12 Months: | 18.22 | vs. Previous Quarter | 62.07% | vs. Previous Quarter: | 19.29% |
| PEG Ratio | 2.74 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.79 | 09/30/09 | 10.18 | 09/30/09 | 2.81 |
| Price/Cash Flow | 9.40 | 06/30/09 | 10.94 | 06/30/09 | 3.12 |
| Price / Sales | 1.70 | 03/31/09 | 10.58 | 03/31/09 | 3.14 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.07 | 09/30/09 | 1.03 | 09/30/09 | 9.36 |
| 06/30/09 | 1.23 | 06/30/09 | 1.18 | 06/30/09 | 10.12 |
| 03/31/09 | 0.56 | 03/31/09 | 0.52 | 03/31/09 | 9.92 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 15.31 | 09/30/09 | 15.31 | 09/30/09 | 20.22 |
| 06/30/09 | 16.26 | 06/30/09 | 16.26 | 06/30/09 | 19.56 |
| 03/31/09 | 15.95 | 03/31/09 | 15.95 | 03/31/09 | 19.28 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 38.77 | 09/30/09 | 0.89 | 09/30/09 | 47.10 |
| 06/30/09 | 38.87 | 06/30/09 | 0.95 | 06/30/09 | 48.59 |
| 03/31/09 | 36.94 | 03/31/09 | 0.72 | 03/31/09 | 41.82 |

Zacks.com Quotes and Research

## SOUTHWEST WATER CO (NASD)

Scottrade

| SWWC | 5.84 | -0.06 | (-1.02%) | Vol. 47,244 | 12:58 ET |
|---|---|---|---|---|---|

Southwest Water Company provides a broad range of utility and utility management services and serves people from coast to coast. Through its various subsidiaries, Southwest operates and manages water and wastewater treatment facilities along with providing utility submetering and billing and collection services.

### General Information

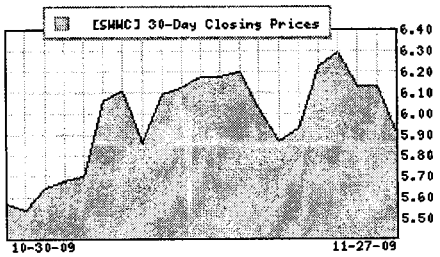
SOUTHWEST WATER
One Wilshire Building 624 South Grand Avenue
Suite 2900
Los Angeles, CA 90017-3782
Phone: 213 929-1800
Fax: 626-915-1558
Web: www.southwestwater.com
Email: swwc@swwc.com

| | |
|---|---|
| Industry | UTIL-WATER SPLY |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 07/08/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 5.90 |
| 52 Week High | 6.32 |
| 52 Week Low | 2.67 |
| Beta | 0.57 |
| 20 Day Moving Average | 138,595.30 |
| Target Price Consensus | 8.25 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 5.92 | 4 Week | 0.56 |
| 12 Week | 21.90 | 12 Week | 13.52 |
| YTD | 83.23 | YTD | 51.63 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 24.88 | Dividend Yield | 3.39% |
| | | Annual Dividend | $0.20 |
| Market Capitalization (millions) | 146.78 | Payout Ratio | 0.00 |
| Short Ratio | 2.64 | Change in Payout Ratio | 0.00 |
| Last Split Date | 12/28/2005 | Last Dividend Payout / Amount | 11/02/2009 / $0.05 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.05 | Current (1=Strong Buy, 5=Strong Sell) | 2.00 |
| Current Year EPS Consensus Estimate | 0.16 | 30 Days Ago | 2.20 |
| Estimated Long-Term EPS Growth Rate | - | 60 Days Ago | 2.50 |
| Next EPS Report Date | 07/08/2010 | 90 Days Ago | 2.50 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 38.06 | vs. Previous Year | -% | vs. Previous Year | -2.28% |
| Trailing 12 Months: | - | vs. Previous Quarter | 100.00% | vs. Previous Quarter: | 12.53% |
| PEG Ratio | - | | | | |

**Price Ratios** **ROE** **ROA**

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.32 | 09/30/09 | -28.88 | 09/30/09 | -6.11 |
| Price/Cash Flow | 3.35 | 06/30/09 | -27.86 | 06/30/09 | -6.36 |
| Price / Sales | 0.68 | 03/31/09 | -25.95 | 03/31/09 | -6.30 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | - | 09/30/09 | - | 09/30/09 | -14.90 |
| 06/30/09 | - | 06/30/09 | - | 06/30/09 | -15.64 |
| 03/31/09 | 1.33 | 03/31/09 | 1.33 | 03/31/09 | -15.27 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | - | 09/30/09 | - | 09/30/09 | - |
| 06/30/09 | - | 06/30/09 | - | 06/30/09 | - |
| 03/31/09 | -20.42 | 03/31/09 | -20.42 | 03/31/09 | 4.48 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | - | 09/30/09 | - | 09/30/09 | - |
| 06/30/09 | - | 06/30/09 | - | 06/30/09 | - |
| 03/31/09 | - | 03/31/09 | 1.78 | 03/31/09 | 63.88 |

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## AQUA AMERICA INC (NYSE)

Scottrade

| WTR | 16.17 | ▲0.08 | (0.50%) | Vol. 705,037 | 13:02 ET |
|---|---|---|---|---|---|

Aqua America is the largest publicly-traded U.S.-based water utility serving residents in Pennsylvania, Ohio, Illinois, Texas, New Jersey, Indiana, Virginia, Florida, North Carolina, Maine, Missouri, New York, South Carolina and Kentucky. The company has been committed to the preservation and improvement of the environment throughout its history, which spans more than 100 years.

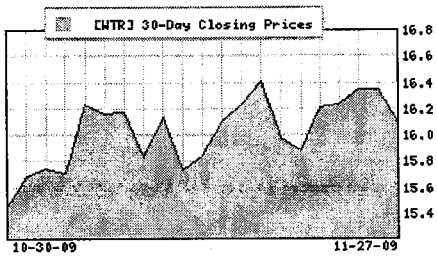
### General Information

AQUA AMER INC
762 W Lancaster Avenue
Bryn Mawr, PA 19010-3489
Phone: 610 527-8000
Fax: 610-645-1061
Web: www.suburbanwater.com
Email: ir.aquaamerica.com

| | |
|---|---|
| Industry | UTIL-WATER SPLY |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/25/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 16.09 |
| 52 Week High | 21.65 |
| 52 Week Low | 15.39 |
| Beta | 0.17 |
| 20 Day Moving Average | 1,535,791.75 |
| Target Price Consensus | 22.13 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 4.14 | 4 Week | -1.13 |
| 12 Week | -4.00 | 12 Week | -10.60 |
| YTD | -21.85 | YTD | -35.33 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 135.92 | Dividend Yield | 3.60% |
| | | Annual Dividend | $0.58 |
| Market Capitalization (millions) | 2,186.92 | Payout Ratio | 0.70 |
| Short Ratio | 14.13 | Change in Payout Ratio | 0.04 |
| Last Split Date | 12/02/2005 | Last Dividend Payout / Amount | 11/12/2009 / $0.14 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.22 | Current (1=Strong Buy, 5=Strong Sell) | 1.60 |
| Current Year EPS Consensus Estimate | 0.79 | 30 Days Ago | 1.73 |
| Estimated Long-Term EPS Growth Rate | 7.70 | 60 Days Ago | 1.80 |
| Next EPS Report Date | 02/25/2010 | 90 Days Ago | 1.80 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 20.27 | vs. Previous Year | -3.85% | vs. Previous Year | 2.11% |
| Trailing 12 Months: | 20.90 | vs. Previous Quarter | 31.58% | vs. Previous Quarter: | 8.06% |
| PEG Ratio | 2.64 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 2.03 | 09/30/09 | 9.66 | 09/30/09 | 2.93 |
| Price/Cash Flow | 11.29 | 06/30/09 | 9.95 | 06/30/09 | 3.04 |
| Price / Sales | 3.30 | 03/31/09 | 9.77 | 03/31/09 | 2.99 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 0.54 | 09/30/09 | 0.50 | 09/30/09 | 15.60 |
| 06/30/09 | 0.60 | 06/30/09 | 0.55 | 06/30/09 | 15.97 |
| 03/31/09 | 0.60 | 03/31/09 | 0.55 | 03/31/09 | 15.87 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 25.72 | 09/30/09 | 25.72 | 09/30/09 | 7.93 |
| 06/30/09 | 26.47 | 06/30/09 | 26.47 | 06/30/09 | 7.94 |
| 03/31/09 | 26.37 | 03/31/09 | 26.37 | 03/31/09 | 7.86 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 40.79 | 09/30/09 | 1.17 | 09/30/09 | 54.00 |
| 06/30/09 | 39.75 | 06/30/09 | 1.14 | 06/30/09 | 53.25 |
| 03/31/09 | 31.95 | 03/31/09 | 1.15 | 03/31/09 | 53.52 |

Zacks.com Quotes and Research

## AGL RESOURCES INC (NYSE)

Scottrade

| AGL | 34.19 | ▼-0.41 | (-1.18%) | Vol. 97,297 | 13:02 ET |
|---|---|---|---|---|---|

AGL Resources principal business is the distribution of natural gas to customers in central, northwest, northeast and southeast Georgia and the Chattanooga, Tennessee area through its natural gas distribution subsidiary. AGL's major service area is the ten county metropolitan Atlanta area.

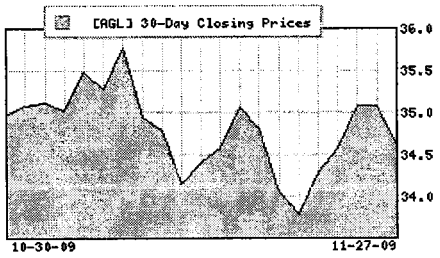
### General Information

AGL RESOURCES
Ten Peachtree Place NE
Atlanta, GA 30309
Phone: 404 584-4000
Fax: 404 584-3945
Web: www.aglresources.com
Email: scave@aglresources.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/04/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 34.60 |
| 52 Week High | 37.47 |
| 52 Week Low | 24.02 |
| Beta | 0.41 |
| 20 Day Moving Average | 285,124.59 |
| Target Price Consensus | 37.43 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -1.03 | 4 Week | -6.04 |
| 12 Week | 3.41 | 12 Week | -3.71 |
| YTD | 10.37 | YTD | -8.67 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 77.28 | Dividend Yield | 4.97% |
| | | Annual Dividend | $1.72 |
| Market Capitalization (millions) | 2,673.85 | Payout Ratio | 0.59 |
| Short Ratio | 4.19 | Change in Payout Ratio | 0.01 |
| Last Split Date | 12/04/1995 | Last Dividend Payout / Amount | 11/10/2009 / $0.43 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.84 | Current (1=Strong Buy, 5=Strong Sell) | 2.20 |
| Current Year EPS Consensus Estimate | 2.74 | 30 Days Ago | 2.20 |
| Estimated Long-Term EPS Growth Rate | 4.50 | 60 Days Ago | 2.20 |
| Next EPS Report Date | 02/04/2010 | 90 Days Ago | 2.20 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 12.63 | vs. Previous Year | -42.86% | vs. Previous Year | -43.04% |
| Trailing 12 Months: | 11.77 | vs. Previous Quarter | -38.46% | vs. Previous Quarter: | -18.57% |
| PEG Ratio | 2.81 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.53 | 09/30/09 | 13.05 | 09/30/09 | 3.56 |
| Price/Cash Flow | | 06/30/09 | | 06/30/09 | |

| | | | | | |
|---|---|---|---|---|---|
| | 7.39 | | 13.60 | | 3.68 |
| Price / Sales | 1.08 | 03/31/09 | 13.92 | 03/31/09 | 3.66 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.26 | 09/30/09 | 0.64 | 09/30/09 | 9.06 |
| 06/30/09 | 1.03 | 06/30/09 | 0.61 | 06/30/09 | 8.63 |
| 03/31/09 | 1.06 | 03/31/09 | 0.80 | 03/31/09 | 8.53 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 15.30 | 09/30/09 | 15.30 | 09/30/09 | 22.61 |
| 06/30/09 | 17.12 | 06/30/09 | 17.12 | 06/30/09 | 22.79 |
| 03/31/09 | 14.84 | 03/31/09 | 14.84 | 03/31/09 | 22.87 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 3.70 | 09/30/09 | 1.13 | 09/30/09 | 53.06 |
| 06/30/09 | 3.70 | 06/30/09 | 0.95 | 06/30/09 | 48.78 |
| 03/31/09 | 3.45 | 03/31/09 | 0.95 | 03/31/09 | 48.72 |

Zacks.com Quotes and Research

## ATMOS ENERGY CORP (NYSE)

Scottrade

| ATO | 27.40 | ▼-0.45 | (-1.62%) | Vol. 284,174 | 13:03 ET |
|---|---|---|---|---|---|

Atmos Energy Corporation distributes and sells natural gas to residential, commercial, industrial, agricultural and other customers. Atmos operates through five divisions in cities, towns and communities in service areas located in Colorado, Georgia, Illinois, Iowa, Kansas, Kentucky, Louisiana, Missouri, South Carolina, Tennessee, Texas and Virginia. The Company has entered into an agreement to sell all of its natural gas utility operations in South Carolina. The Company also transports natural gas for others through its distribution system.

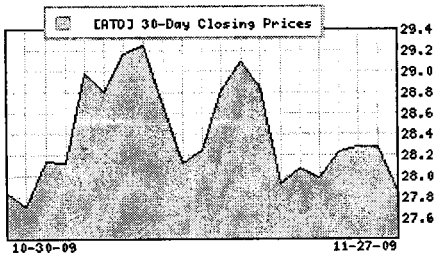
### General Information

ATMOS ENERGY CP
Three Lincoln Centre 5430 Lbj Freeway
Suite 1800
Dallas, TX 75240
Phone: 972-934-9227
Fax: 972-855-3040
Web: www.atmosenergy.com
Email: InvestorRelations@atmosenergy.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | September |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/09/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 27.85 |
| 52 Week High | 29.53 |
| 52 Week Low | 20.07 |
| Beta | 0.52 |
| 20 Day Moving Average | 514,786.56 |
| Target Price Consensus | 29.33 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 0.00 | 4 Week | -5.07 |
| 12 Week | 2.28 | 12 Week | -4.76 |
| YTD | 17.51 | YTD | -2.76 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 92.27 | Dividend Yield | 4.81% |
| | | Annual Dividend | $1.34 |
| Market Capitalization (millions) | 2,569.77 | Payout Ratio | 0.65 |
| Short Ratio | 1.76 | Change in Payout Ratio | 0.00 |
| Last Split Date | 05/17/1994 | Last Dividend Payout / Amount | 11/23/2009 / $0.34 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.90 | Current (1=Strong Buy, 5=Strong Sell) | 2.83 |
| Current Year EPS Consensus Estimate | 2.19 | 30 Days Ago | 2.83 |
| Estimated Long-Term EPS Growth Rate | 5.00 | 60 Days Ago | 2.83 |
| Next EPS Report Date | 02/09/2010 | 90 Days Ago | 2.57 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 12.69 | vs. Previous Year | -500.00% | vs. Previous Year | -54.84% |
| Trailing 12 Months: | 13.79 | vs. Previous Quarter | -33.33% | vs. Previous Quarter: | -16.67% |
| PEG Ratio | 2.54 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.18 | 09/30/09 | 8.58 | 09/30/09 | 2.85 |
| Price/Cash Flow | 6.24 | 06/30/09 | 9.14 | 06/30/09 | 2.99 |
| Price / Sales | 0.52 | 03/31/09 | 9.16 | 03/31/09 | 2.93 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.12 | 09/30/09 | 0.65 | 09/30/09 | 3.72 |
| 06/30/09 | 1.24 | 06/30/09 | 0.74 | 06/30/09 | 3.37 |
| 03/31/09 | 1.15 | 03/31/09 | 0.90 | 03/31/09 | 2.91 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 5.86 | 09/30/09 | 5.86 | 09/30/09 | 23.59 |
| 06/30/09 | 5.55 | 06/30/09 | 5.55 | 06/30/09 | 23.82 |
| 03/31/09 | 4.61 | 03/31/09 | 4.61 | 03/31/09 | 23.70 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 10.42 | 09/30/09 | 1.00 | 09/30/09 | 49.92 |
| 06/30/09 | 11.62 | 06/30/09 | 0.99 | 06/30/09 | 49.75 |
| 03/31/09 | 11.66 | 03/31/09 | 1.00 | 03/31/09 | 49.89 |

ZACKS INVESTMENT RESEARCH
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**Zacks.com Quotes and Research**

## LACLEDE GROUP INC (NYSE)

Scottrade

| LG | 31.30 | -0.21 | (-0.67%) | Vol. 66,740 | 13:04 ET |
|---|---|---|---|---|---|

The Laclede Group, Inc. is a public utility engaged in the retail distribution and transportation of natural gas. The Company, which is subject to the jurisdiction of the Missouri Public Service Commission, serves the City of St. Louis, St. Louis County, the City of St. Charles, St. Charles County, the town of Arnold, and parts of Franklin, Jefferson, St. Francois, Ste. Genevieve, Iron, Madison and Butler Counties, all in Missouri.

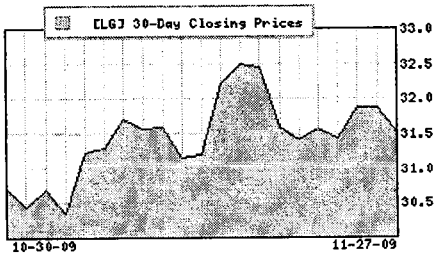
### General Information

LACLEDE GRP INC
720 Olive Street
St. Louis, MO 63101
Phone: 314-342-0500
Fax: 314-421-1979
Web: www.thelacledegroup.com
Email: mkullman@lacledegas.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | September |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 01/28/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 31.50 |
| 52 Week High | 52.17 |
| 52 Week Low | 29.26 |
| Beta | 0.03 |
| 20 Day Moving Average | 113,136.90 |
| Target Price Consensus | 35 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 2.57 | 4 Week | -2.62 |
| 12 Week | -4.23 | 12 Week | -10.81 |
| YTD | -32.75 | YTD | -44.35 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 22.17 | Dividend Yield | 4.89% |
| | | Annual Dividend | $1.54 |
| Market Capitalization (millions) | 698.26 | Payout Ratio | 0.53 |
| Short Ratio | 3.34 | Change in Payout Ratio | -0.10 |
| Last Split Date | 03/08/1994 | Last Dividend Payout / Amount | 09/09/2009 / $0.38 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 1.02 | Current (1=Strong Buy, 5=Strong Sell) | 3.25 |
| Current Year EPS Consensus Estimate | 2.52 | 30 Days Ago | 3.25 |
| Estimated Long-Term EPS Growth Rate | 3.00 | 60 Days Ago | 3.25 |
| Next EPS Report Date | 01/28/2010 | 90 Days Ago | 3.25 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 12.50 | vs. Previous Year | -57.14% | vs. Previous Year | -44.24% |
| Trailing 12 Months: | 10.82 | vs. Previous Quarter | -170.97% | vs. Previous Quarter: | -18.72% |
| PEG Ratio | 4.17 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.35 | 09/30/09 | 12.30 | 09/30/09 | 3.63 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 6.89 | 06/30/09 | 12.78 | 06/30/09 | 3.71 |
| Price / Sales | 0.37 | 03/31/09 | 13.53 | 03/31/09 | 3.89 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.23 | 09/30/09 | 0.84 | 09/30/09 | 3.39 |
| 06/30/09 | 1.24 | 06/30/09 | 0.98 | 06/30/09 | 3.14 |
| 03/31/09 | 1.17 | 03/31/09 | 0.95 | 03/31/09 | 2.97 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 5.11 | 09/30/09 | 5.11 | 09/30/09 | 23.32 |
| 06/30/09 | 4.81 | 06/30/09 | 4.81 | 06/30/09 | 23.97 |
| 03/31/09 | 4.46 | 03/31/09 | 4.46 | 03/31/09 | 24.11 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 11.80 | 09/30/09 | 0.75 | 09/30/09 | 42.95 |
| 06/30/09 | 10.65 | 06/30/09 | 0.73 | 06/30/09 | 42.30 |
| 03/31/09 | 11.30 | 03/31/09 | 0.73 | 03/31/09 | 42.17 |

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## NEW JERSEY RES (NYSE)

Scottrade

| NJR | 34.84 | ▼-0.47 | (-1.33%) | Vol. 80,231 | 13:04 ET |
|---|---|---|---|---|---|

NJ RESOURCES is an exempt energy svcs holding company providing retail & wholesale natural gas & related energy services to customers from the Gulf Coast to New England. Subsidiaries include: (1) N J Natural Gas Co, a natural gas distribution company that provides regulated energy & appliance services to residential, commercial & industrial customers in central & northern N J. (2) NJR Energy Holdings Corp formerly NJR Energy Svcs Corp & (3) NJR Development Corp, a sub-holding company of NJR, which includes the Company's remaining unregulated operating subsidiaries.

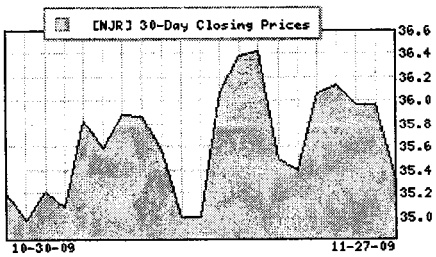
### General Information

NJ RESOURCES
1415 Wyckoff Road
Wall, NJ 07719
Phone: 732-938-1489
Fax: 732 938-3154
Web: www.njresources.com
Email: investcont@njresources.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | September |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 11/30/2009 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 35.31 |
| 52 Week High | 42.37 |
| 52 Week Low | 29.95 |
| Beta | 0.14 |
| 20 Day Moving Average | 141,417.66 |
| Target Price Consensus | 42 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 0.31 | 4 Week | -4.77 |
| 12 Week | -2.75 | 12 Week | -9.44 |
| YTD | -10.27 | YTD | -25.74 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 42.01 | Dividend Yield | 3.51% |
| | | Annual Dividend | $1.24 |
| Market Capitalization (millions) | 1,483.55 | Payout Ratio | 0.00 |
| Short Ratio | 9.56 | Change in Payout Ratio | 0.00 |
| Last Split Date | 03/04/2008 | Last Dividend Payout / Amount | 09/11/2009 / $0.31 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | -0.12 | Current (1=Strong Buy, 5=Strong Sell) | 1.50 |
| Current Year EPS Consensus Estimate | 2.39 | 30 Days Ago | 1.50 |
| Estimated Long-Term EPS Growth Rate | 7.00 | 60 Days Ago | 1.50 |
| Next EPS Report Date | 11/30/2009 | 90 Days Ago | 1.67 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.82 | vs. Previous Year | 130.00% | vs. Previous Year | -55.91% |
| Trailing 12 Months: | 16.81 | vs. Previous Quarter | -98.24% | vs. Previous Quarter: | -52.96% |
| PEG Ratio | 1.97 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 2.06 | 09/30/09 | - | 09/30/09 | - |
| Price/Cash Flow | 11.15 | 06/30/09 | 12.20 | 06/30/09 | 3.58 |
| Price / Sales | - | 03/31/09 | 11.73 | 03/31/09 | 3.25 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | - | 09/30/09 | - | 09/30/09 | - |
| 06/30/09 | 1.23 | 06/30/09 | 0.88 | 06/30/09 | 2.98 |
| 03/31/09 | 1.17 | 03/31/09 | 1.07 | 03/31/09 | 2.37 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | - | 09/30/09 | - | 09/30/09 | - |
| 06/30/09 | 5.66 | 06/30/09 | 5.66 | 06/30/09 | 17.11 |
| 03/31/09 | 5.26 | 03/31/09 | 5.26 | 03/31/09 | 17.90 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | - | 09/30/09 | - | 09/30/09 | - |
| 06/30/09 | 9.78 | 06/30/09 | 0.63 | 06/30/09 | 38.82 |
| 03/31/09 | 10.09 | 03/31/09 | 0.61 | 03/31/09 | 37.74 |

Zacks.com Quotes and Research

## NICOR INC (NYSE)

Scottrade

| GAS | 38.89 | ▼-0.22 | (-0.56%) | Vol. 141,460 | 13:05 ET |
|---|---|---|---|---|---|

Nicor Inc. is a holding company and is a member of the Standard & Poor's 500 Index. Its primary business is Nicor Gas, one of the nation's largest natural gas distribution companies. Nicor owns Tropical Shipping, a containerized shipping business serving the Caribbean region and the Bahamas. In addition, the company owns and has an equity interest in several energy-related businesses.

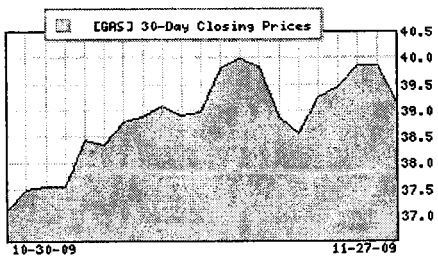
### General Information

NICOR INC
1844 Ferry Road
Naperville, IL 60563-9600
Phone: 630-305-9500
Fax: 630-983-9328
Web: www.nicor.com
Email: None

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/24/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 39.11 |
| 52 Week High | 40.21 |
| 52 Week Low | 27.50 |
| Beta | 0.33 |
| 20 Day Moving Average | 414,910.16 |
| Target Price Consensus | 40.75 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 5.47 | 4 Week | 0.13 |
| 12 Week | 9.15 | 12 Week | 1.64 |
| YTD | 12.58 | YTD | -6.84 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 45.22 | Dividend Yield | 4.76% |
| | | Annual Dividend | $1.86 |
| Market Capitalization (millions) | 1,768.63 | Payout Ratio | 0.66 |
| Short Ratio | 5.35 | Change in Payout Ratio | -0.06 |
| Last Split Date | 04/27/1993 | Last Dividend Payout / Amount | 09/28/2009 / $0.47 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 1.01 | Current (1=Strong Buy, 5=Strong Sell) | 2.67 |
| Current Year EPS Consensus Estimate | 2.68 | 30 Days Ago | 2.67 |
| Estimated Long-Term EPS Growth Rate | 4.20 | 60 Days Ago | 2.67 |
| Next EPS Report Date | 02/24/2010 | 90 Days Ago | 3.00 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.60 | vs. Previous Year | 900.00% | vs. Previous Year | -26.05% |
| Trailing 12 Months: | 13.92 | vs. Previous Quarter | -40.00% | vs. Previous Quarter: | -27.26% |
| PEG Ratio | 3.45 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.77 | 09/30/09 | 12.88 | 09/30/09 | 2.88 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 5.71 | 06/30/09 | 11.78 | 06/30/09 | 2.59 |
| Price / Sales | 0.60 | 03/31/09 | 12.46 | 03/31/09 | 2.67 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 0.81 | 09/30/09 | 0.62 | 09/30/09 | 4.38 |
| 06/30/09 | 0.76 | 06/30/09 | 0.73 | 06/30/09 | 3.81 |
| 03/31/09 | 0.78 | 03/31/09 | 0.77 | 03/31/09 | 3.70 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 6.32 | 09/30/09 | 6.32 | 09/30/09 | 22.13 |
| 06/30/09 | 5.46 | 06/30/09 | 5.46 | 06/30/09 | 22.25 |
| 03/31/09 | 5.21 | 03/31/09 | 5.21 | 03/31/09 | 22.16 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 15.60 | 09/30/09 | 0.50 | 09/30/09 | 33.24 |
| 06/30/09 | 14.05 | 06/30/09 | 0.50 | 06/30/09 | 33.12 |
| 03/31/09 | 15.05 | 03/31/09 | 0.45 | 03/31/09 | 30.91 |

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## NORTHWEST NAT GAS CO (NYSE)

Scottrade

| NWN | 42.36 | ▼-0.43 | (-1.00%) | Vol. 76,933 | 13:03 ET |
|---|---|---|---|---|---|

NW Natural is principally engaged in the distribution of natural gas.The Oregon Public Utility Commission (OPUC) has allocated to NW Natural as its exclusive service area a major portion of western Oregon, including the Portland metropolitan area, most of the fertile Willamette Valley and the coastal area from Astoria to Coos Bay. NW Natural also holds certificates from the Washington Utilities and Transportation Commission (WUTC) granting it exclusive rights to serve portions of three Washington counties bordering the Columbia River.

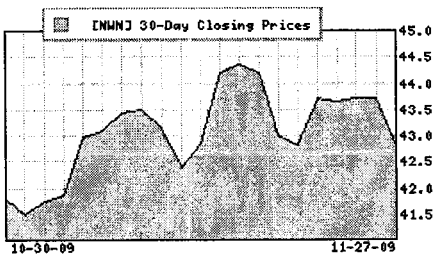
### General Information

NORTHWEST NAT G
220 NW Second Avenue
Portland, OR 97209
Phone: 503 226-4211
Fax: 503 273-4824
Web: www.nwnatural.com
Email: Bob.Hess@nwnatural.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/11/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 42.79 |
| 52 Week High | 49.26 |
| 52 Week Low | 37.71 |
| Beta | 0.25 |
| 20 Day Moving Average | 99,669.00 |
| Target Price Consensus | 49.86 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 2.34 | 4 Week | -2.84 |
| 12 Week | 2.27 | 12 Week | -4.77 |
| YTD | -3.26 | YTD | -19.94 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 26.51 | Dividend Yield | 3.88% |
| | | Annual Dividend | $1.66 |
| Market Capitalization (millions) | 1,134.49 | Payout Ratio | 0.54 |
| Short Ratio | 10.64 | Change in Payout Ratio | -0.05 |
| Last Split Date | 09/09/1996 | Last Dividend Payout / Amount | 10/28/2009 / $0.41 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 1.19 | Current (1=Strong Buy, 5=Strong Sell) | 1.86 |
| Current Year EPS Consensus Estimate | 2.80 | 30 Days Ago | 1.67 |
| Estimated Long-Term EPS Growth Rate | 5.80 | 60 Days Ago | 1.50 |
| Next EPS Report Date | 02/11/2010 | 90 Days Ago | 1.50 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 15.30 | vs. Previous Year | 34.21% | vs. Previous Year | 6.52% |
| Trailing 12 Months: | 14.70 | vs. Previous Quarter | -308.33% | vs. Previous Quarter: | -21.61% |
| PEG Ratio | 2.66 | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.77 | 09/30/09 | 11.87 | 09/30/09 | 3.33 |
| Price/Cash Flow | 7.98 | 06/30/09 | 11.51 | 06/30/09 | 3.26 |
| Price / Sales | 1.08 | 03/31/09 | 11.69 | 03/31/09 | 3.37 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.03 | 09/30/09 | 0.69 | 09/30/09 | 7.31 |
| 06/30/09 | 0.94 | 06/30/09 | 0.67 | 06/30/09 | 7.03 |
| 03/31/09 | 1.03 | 03/31/09 | 0.80 | 03/31/09 | 6.78 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 11.71 | 09/30/09 | 11.71 | 09/30/09 | 24.17 |
| 06/30/09 | 11.19 | 06/30/09 | 11.19 | 06/30/09 | 24.80 |
| 03/31/09 | 10.81 | 03/31/09 | 10.81 | 03/31/09 | 25.05 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 9.12 | 09/30/09 | 0.99 | 09/30/09 | 49.85 |
| 06/30/09 | 8.96 | 06/30/09 | 0.89 | 06/30/09 | 47.18 |
| 03/31/09 | 10.10 | 03/31/09 | 0.88 | 03/31/09 | 46.93 |

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## PIEDMONT NAT GAS INC (NYSE)

Scottrade

| PNY | 23.34 | ▼-0.28 | (-1.19%) | Vol. 229,417 | 13:06 ET |
|---|---|---|---|---|---|

Piedmont Natural Gas Co, Inc., is an energy and services company engaged in the transportation and sale of natural gas and the sale of propane to residential, commercial and industrial customers in North Carolina, South Carolina and Tennessee. The Company is the second-largest natural gas utility in the southeast. The Company and its non-utility subsidiaries and divisions are also engaged in acquiring, marketing and arranging for the transportation and storage of natural gas for large-volume purchasers, and in the sale of propane to customers in the Company's three-state service area.

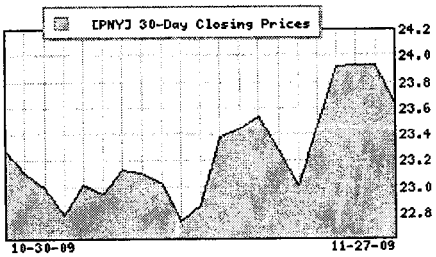
### General Information

PIEDMONT NAT GA
4720 Piedmont Row Drive
Charlotte, NC 28210
Phone: 704 364-3120
Fax: 704-365-3849
Web: www.piedmontng.com
Email: investorrelations@piedmontng.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | October |
| Last Reported Quarter | 10/31/09 |
| Next EPS Date | 01/04/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 23.62 |
| 52 Week High | 32.94 |
| 52 Week Low | 20.68 |
| Beta | 0.18 |
| 20 Day Moving Average | 430,196.31 |
| Target Price Consensus | 26.61 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 1.46 | 4 Week | -3.68 |
| 12 Week | -1.67 | 12 Week | -8.43 |
| YTD | -25.42 | YTD | -38.28 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 73.11 | Dividend Yield | 4.57% |
| | | Annual Dividend | $1.08 |
| Market Capitalization (millions) | 1,726.88 | Payout Ratio | 0.00 |
| Short Ratio | 7.24 | Change in Payout Ratio | 0.00 |
| Last Split Date | 11/01/2004 | Last Dividend Payout / Amount | 09/22/2009 / $0.27 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | -0.14 | Current (1=Strong Buy, 5=Strong Sell) | 2.00 |
| Current Year EPS Consensus Estimate | 1.58 | 30 Days Ago | 1.75 |
| Estimated Long-Term EPS Growth Rate | 7.00 | 60 Days Ago | 2.20 |
| Next EPS Report Date | 01/04/2010 | 90 Days Ago | 2.33 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.36 | vs. Previous Year | 0.00% | vs. Previous Year | -49.20% |
| Trailing 12 Months: | - | vs. Previous Quarter | -113.70% | vs. Previous Quarter: | -60.43% |
| PEG Ratio | 2.05 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.82 | 10/31/09 | - | 10/31/09 | - |
| Price/Cash Flow | 8.35 | 07/31/09 | 12.13 | 07/31/09 | 3.64 |
| Price / Sales | - | 04/30/09 | 12.17 | 04/30/09 | 3.66 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 10/31/09 | - | 10/31/09 | - | 10/31/09 | - |
| 07/31/09 | 0.99 | 07/31/09 | 0.76 | 07/31/09 | 6.59 |
| 04/30/09 | 1.07 | 04/30/09 | 0.88 | 04/30/09 | 5.97 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 10/31/09 | - | 10/31/09 | - | 10/31/09 | - |
| 07/31/09 | 12.89 | 07/31/09 | 12.89 | 07/31/09 | 12.99 |
| 04/30/09 | 11.58 | 04/30/09 | 11.58 | 04/30/09 | 13.20 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 10/31/09 | - | 10/31/09 | - | 10/31/09 | - |
| 07/31/09 | 10.20 | 07/31/09 | 0.84 | 07/31/09 | 45.54 |
| 04/30/09 | 10.05 | 04/30/09 | 0.82 | 04/30/09 | 45.00 |

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## SOUTH JERSEY INDS INC (NYSE)

Scottrade

| SJI | 35.78 | -0.02 | (-0.06%) | Vol. 62,834 | 13:03 ET |
|---|---|---|---|---|---|

South Jersey Inds Inc. is engaged in the business of operating, through subsidiaries, various business enterprises. The company's most significant subsidiary is South Jersey Gas Company (SJG). SJG is a public utility company engaged in the purchase, transmission and sale of natural gas for residential, commercial and industrial use. SJG also makes off-system sales of natural gas on a wholesale basis to various customers on the interstate pipeline system and transports natural gas.

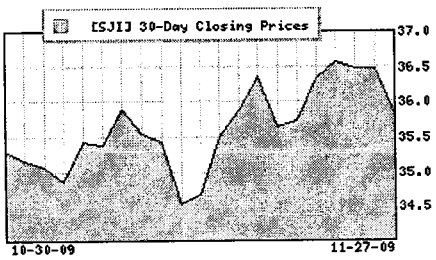
### General Information

SOUTH JERSEY IN
1 South Jersey Plaza
Folsom, NJ 08037
Phone: 609 561-9000
Fax: 609 561-8225
Web: www.sjindustries.com
Email: investorrelations@sjindustries.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/25/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 35.80 |
| 52 Week High | 40.78 |
| 52 Week Low | 31.98 |
| Beta | 0.22 |
| 20 Day Moving Average | 147,675.00 |
| Target Price Consensus | 46.5 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 1.45 | 4 Week | -3.69 |
| 12 Week | 6.07 | 12 Week | -1.22 |
| YTD | -10.16 | YTD | -25.66 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 29.80 | Dividend Yield | 3.32% |
| | | Annual Dividend | $1.19 |
| Market Capitalization (millions) | 1,066.70 | Payout Ratio | 0.54 |
| Short Ratio | 4.97 | Change in Payout Ratio | 0.00 |
| Last Split Date | 07/01/2005 | Last Dividend Payout / Amount | 09/08/2009 / $0.30 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.82 | Current (1=Strong Buy, 5=Strong Sell) | 1.50 |
| Current Year EPS Consensus Estimate | 2.39 | 30 Days Ago | 1.50 |
| Estimated Long-Term EPS Growth Rate | 11.10 | 60 Days Ago | 1.60 |
| Next EPS Report Date | 02/25/2010 | 90 Days Ago | 1.75 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 14.99 | vs. Previous Year | -250.00% | vs. Previous Year | -39.60% |
| Trailing 12 Months: | 16.13 | vs. Previous Quarter | -140.00% | vs. Previous Quarter: | -5.50% |
| PEG Ratio | 1.35 | | | | |

**Price Ratios** **ROE** **ROA**

| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 2.02 | 09/30/09 | 12.53 | 09/30/09 | 3.86 |
| Price/Cash Flow | 10.30 | 06/30/09 | 13.17 | 06/30/09 | 4.06 |
| Price / Sales | 1.20 | 03/31/09 | 14.14 | 03/31/09 | 4.30 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 0.88 | 09/30/09 | 0.54 | 09/30/09 | 7.47 |
| 06/30/09 | 0.92 | 06/30/09 | 0.64 | 06/30/09 | 7.13 |
| 03/31/09 | 0.93 | 03/31/09 | 0.74 | 03/31/09 | 7.43 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 10.32 | 09/30/09 | 10.32 | 09/30/09 | 17.74 |
| 06/30/09 | 17.54 | 06/30/09 | 17.54 | 06/30/09 | 18.11 |
| 03/31/09 | 14.51 | 03/31/09 | 14.51 | 03/31/09 | 18.20 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 6.37 | 09/30/09 | 0.63 | 09/30/09 | 38.63 |
| 06/30/09 | 5.74 | 06/30/09 | 0.62 | 06/30/09 | 38.14 |
| 03/31/09 | 5.73 | 03/31/09 | 0.61 | 03/31/09 | 38.07 |

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## SOUTHWEST GAS CORP (NYSE)

Scottrade

| SWX | 25.96 | ▼-0.46 | (-1.74%) | Vol. 191,336 | 13:07 ET |
|---|---|---|---|---|---|

SOUTHWEST GAS CORP. is principally engaged in the business of purchasing,transporting, and distributing natural gas in portions of Arizona, Nevada,and California. The Company also engaged in financial services activities,through PriMerit Bank, Federal Savings Bank (PriMerit or the Bank), a wholly owned subsidiary.

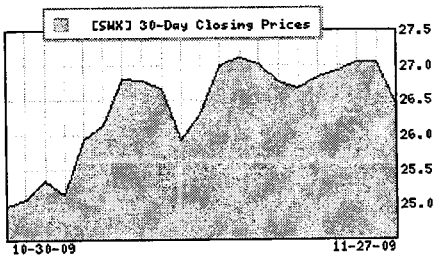
### General Information

SOUTHWEST GAS
5241 Spring Mountain Road
P.O. Box 98510
Las Vegas, NV 89193-8510
Phone: 702 876-7237
Fax: 702-876-7037
Web: www.swgas.com
Email: None

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |
| Fiscal Year End | December |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/25/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 26.42 |
| 52 Week High | 27.42 |
| 52 Week Low | 17.08 |
| Beta | 0.70 |
| 20 Day Moving Average | 201,690.80 |
| Target Price Consensus | 29 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | 5.72 | 4 Week | 0.37 |
| 12 Week | 9.04 | 12 Week | 1.54 |
| YTD | 4.76 | YTD | -13.31 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 44.82 | Dividend Yield | 3.60% |
| | | Annual Dividend | $0.95 |
| Market Capitalization (millions) | 1,184.20 | Payout Ratio | 0.47 |
| Short Ratio | 4.47 | Change in Payout Ratio | 0.00 |
| Last Split Date | N/A | Last Dividend Payout / Amount | 11/12/2009 / $0.24 |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 1.08 | Current (1=Strong Buy, 5=Strong Sell) | 2.50 |
| Current Year EPS Consensus Estimate | 1.92 | 30 Days Ago | 2.60 |
| Estimated Long-Term EPS Growth Rate | 7.00 | 60 Days Ago | 2.60 |
| Next EPS Report Date | 02/25/2010 | 90 Days Ago | 2.60 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.74 | vs. Previous Year | 147.37% | vs. Previous Year | -15.20% |
| Trailing 12 Months: | 13.08 | vs. Previous Quarter | 1,700.00% | vs. Previous Quarter: | -18.09% |
| PEG Ratio | 1.96 | | | | |

| Price Ratios | | ROE | | ROA | |
|---|---|---|---|---|---|
| Price/Book | 1.11 | 09/30/09 | 7.97 | 09/30/09 | 2.28 |

| | | | | | |
|---|---|---|---|---|---|
| Price/Cash Flow | 4.48 | 06/30/09 | 5.70 | 06/30/09 | 1.63 |
| Price / Sales | 0.62 | 03/31/09 | 5.45 | 03/31/09 | 1.56 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 0.72 | 09/30/09 | 0.72 | 09/30/09 | 4.47 |
| 06/30/09 | 0.69 | 06/30/09 | 0.69 | 06/30/09 | 3.07 |
| 03/31/09 | 0.82 | 03/31/09 | 0.82 | 03/31/09 | 2.81 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 5.93 | 09/30/09 | 5.93 | 09/30/09 | 23.76 |
| 06/30/09 | 5.35 | 06/30/09 | 5.35 | 06/30/09 | 24.16 |
| 03/31/09 | 5.09 | 03/31/09 | 5.09 | 03/31/09 | 24.40 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | - | 09/30/09 | 1.06 | 09/30/09 | 49.16 |
| 06/30/09 | - | 06/30/09 | 1.04 | 06/30/09 | 50.97 |
| 03/31/09 | - | 03/31/09 | 1.05 | 03/31/09 | 51.33 |

*Proven Ratings, Research & Recommendations*

**Zacks.com Quotes and Research**

## WGL HLDGS INC (NYSE)

Scottrade

| WGL | 31.06 | ▼-0.40 | (-1.27%) | Vol. 172,292 | 13:08 ET |
|---|---|---|---|---|---|

WASHINGTON GAS LIGHT CO is a public utility that delivers and sells natural gas to metropolitan Washington, D.C. and adjoining areas in Maryland and Virginia. A distribution subsidiary serves portions of Virginia and West Virginia. The Company has four wholly-owned active subsidiaries that include: Shenandoah Gas Company (Shenandoah) is engaged in the delivery and sale of natural gas at retail in the Shenandoah Valley, including Winchester, Middletown, Strasburg, Stephens City and New Market, Virginia, and Martinsburg, West Virginia.

### General Information

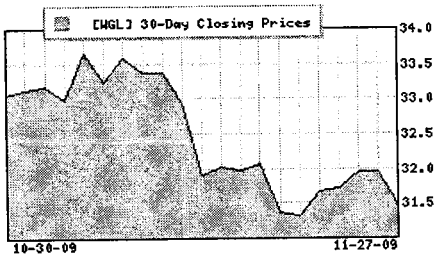
WGL HLDGS INC
101 Constitution Avenue NW
Washington, DC 20080
Phone: 703 750-2000
Fax: 703 750-4828
Web: www.wglholdings.com
Email: madams@washgas.com

| | |
|---|---|
| Industry | UTIL-GAS DISTR |
| Sector: | Utilities |

| | |
|---|---|
| Fiscal Year End | September |
| Last Reported Quarter | 09/30/09 |
| Next EPS Date | 02/10/2010 |

### Price and Volume Information

| | |
|---|---|
| Zacks Rank | |
| Yesterday's Close | 31.46 |
| 52 Week High | 35.52 |
| 52 Week Low | 28.59 |
| Beta | 0.20 |
| 20 Day Moving Average | 303,701.59 |
| Target Price Consensus | 34.67 |




| % Price Change | | % Price Change Relative to S&P 500 | |
|---|---|---|---|
| 4 Week | -4.84 | 4 Week | -9.66 |
| 12 Week | -4.95 | 12 Week | -11.49 |
| YTD | -3.76 | YTD | -20.36 |

| Share Information | | Dividend Information | |
|---|---|---|---|
| Shares Outstanding (millions) | 50.14 | Dividend Yield | 4.67% |
| | | Annual Dividend | $1.47 |
| Market Capitalization (millions) | 1,577.44 | Payout Ratio | 0.58 |
| | | Change in Payout Ratio | 0.00 |
| Short Ratio | 10.63 | Last Dividend Payout / Amount | 10/07/2009 / $0.37 |
| Last Split Date | 05/02/1995 | | |

| EPS Information | | Consensus Recommendations | |
|---|---|---|---|
| Current Quarter EPS Consensus Estimate | 0.98 | Current (1=Strong Buy, 5=Strong Sell) | 2.50 |
| Current Year EPS Consensus Estimate | 2.27 | 30 Days Ago | 2.50 |
| Estimated Long-Term EPS Growth Rate | - | 60 Days Ago | 2.50 |
| Next EPS Report Date | 02/10/2010 | 90 Days Ago | 2.50 |

### Fundamental Ratios

| P/E | | EPS Growth | | Sales Growth | |
|---|---|---|---|---|---|
| Current FY Estimate: | 13.85 | vs. Previous Year | -13.64% | vs. Previous Year | 155.45% |
| Trailing 12 Months: | 12.39 | vs. Previous Quarter | -327.27% | vs. Previous Quarter: | -3.32% |
| PEG Ratio | - | | | | |

| Price Ratios | ROE | ROA |
|---|---|---|

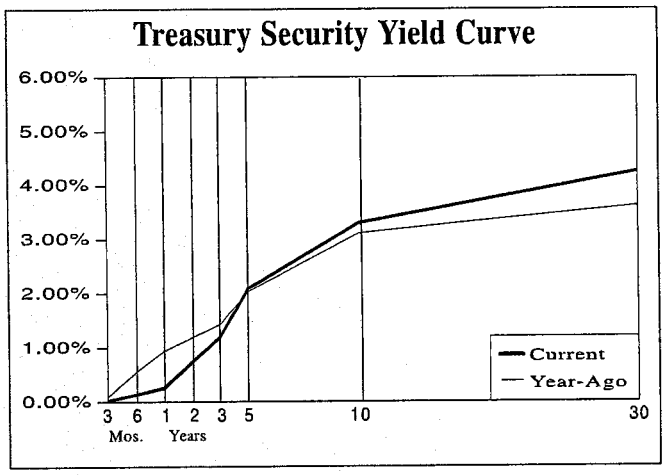
| | | | | | |
|---|---|---|---|---|---|
| Price/Book | 1.44 | 09/30/09 | 11.44 | 09/30/09 | 3.78 |
| Price/Cash Flow | 7.07 | 06/30/09 | 11.67 | 06/30/09 | 3.84 |
| Price / Sales | 0.58 | 03/31/09 | 11.60 | 03/31/09 | 3.75 |
| **Current Ratio** | | **Quick Ratio** | | **Operating Margin** | |
| 09/30/09 | 1.08 | 09/30/09 | 0.70 | 09/30/09 | 4.72 |
| 06/30/09 | 1.17 | 06/30/09 | 0.82 | 06/30/09 | 5.26 |
| 03/31/09 | 1.20 | 03/31/09 | 1.04 | 03/31/09 | 5.08 |
| **Net Margin** | | **Pre-Tax Margin** | | **Book Value** | |
| 09/30/09 | 7.30 | 09/30/09 | 7.30 | 09/30/09 | 21.89 |
| 06/30/09 | 7.81 | 06/30/09 | 7.81 | 06/30/09 | 22.56 |
| 03/31/09 | 7.58 | 03/31/09 | 7.58 | 03/31/09 | 22.89 |
| **Inventory Turnover** | | **Debt-to-Equity** | | **Debt to Capital** | |
| 09/30/09 | 8.81 | 09/30/09 | 0.51 | 09/30/09 | 33.29 |
| 06/30/09 | 9.10 | 06/30/09 | 0.55 | 06/30/09 | 34.99 |
| 03/31/09 | 8.22 | 03/31/09 | 0.57 | 03/31/09 | 35.81 |

# ATTACHMENT D

# Selected Yields

| | Recent (11/24/09) | 3 Months Ago (8/26/09) | Year Ago (11/25/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.25 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.00 |
| Prime Rate | 3.25 | 3.25 | 4.00 |
| 30-day CP (A1/P1) | 0.11 | 0.24 | 1.95 |
| 3-month LIBOR | 0.26 | 0.37 | 2.20 |
| **Bank CDs** | | | |
| 6-month | 0.34 | 0.48 | 1.59 |
| 1-year | 0.57 | 0.72 | 1.95 |
| 5-year | 2.21 | 2.25 | 3.32 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.03 | 0.15 | 0.10 |
| 6-month | 0.13 | 0.25 | 0.54 |
| 1-year | 0.26 | 0.45 | 0.94 |
| 5-year | 2.09 | 2.44 | 2.03 |
| 10-year | 3.30 | 3.43 | 3.11 |
| 10-year (inflation-protected) | 1.14 | 1.70 | 3.64 |
| 30-year | 4.25 | 4.20 | 3.62 |
| 30-year Zero | 4.43 | 4.29 | 3.52 |

| | Recent (11/24/09) | 3 Months Ago (8/26/09) | Year Ago (11/25/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 2.97 | 3.95 | 5.66 |
| FHLMC 6.5% (Gold) | 1.82 | 2.95 | 5.46 |
| FNMA 6.5% | 1.80 | 2.73 | 5.33 |
| FNMA ARM | 2.42 | 2.75 | 3.90 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.19 | 6.13 | 8.59 |
| Industrial (25/30-year) A | 5.52 | 5.52 | 7.17 |
| Utility (25/30-year) A | 5.52 | 5.53 | 7.20 |
| Utility (25/30-year) Baa/BBB | 6.22 | 6.17 | 7.95 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.29 | 3.40 | 3.40 |
| Germany | 3.25 | 3.24 | 3.35 |
| Japan | 1.30 | 1.32 | 1.41 |
| United Kingdom | 3.66 | 3.55 | 3.87 |
| **Preferred Stocks** | | | |
| Utility A | 6.02 | 6.34 | 7.06 |
| Financial A | 6.90 | 5.99 | 8.58 |
| Financial Adjustable A | 5.52 | 5.52 | 5.52 |




| | Recent (11/24/09) | 3 Months Ago (8/26/09) | Year Ago (11/25/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.35 | 4.58 | 5.13 |
| 25-Bond Index (Revs) | 5.04 | 5.62 | 5.98 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.35 | 0.40 | 1.05 |
| 1-year A | 1.32 | 1.10 | 1.15 |
| 5-year Aaa | 1.65 | 1.81 | 2.92 |
| 5-year A | 2.86 | 3.21 | 2.97 |
| 10-year Aaa | 3.18 | 2.96 | 4.00 |
| 10-year A | 4.10 | 4.48 | 4.20 |
| 25/30-year Aaa | 4.49 | 4.54 | 5.36 |
| 25/30-year A | 5.48 | 6.05 | 5.74 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.79 | 5.80 | 5.55 |
| Electric AA | 4.77 | 5.85 | 5.50 |
| Housing AA | 5.72 | 6.35 | 6.15 |
| Hospital AA | 5.19 | 6.35 | 6.20 |
| Toll Road Aaa | 4.84 | 5.80 | 5.55 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | 11/18/09 | 11/4/09 | Change | 12 Wks. | 26 Wks. | 52 Wks. |
| Excess Reserves | 1046180 | 1059253 | -13073 | 926142 | 847097 | 792057 |
| Borrowed Reserves | 217690 | 248364 | -30674 | 282156 | 354676 | 475956 |
| Net Free/Borrowed Reserves | 828490 | 810889 | 17601 | 643987 | 492420 | 316101 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | 11/9/09 | 11/2/09 | Change | 3 Mos. | 6 Mos. | 12 Mos. |
| M1 (Currency+demand deposits) | 1718.8 | 1695.9 | 22.9 | 14.0% | 16.0% | 12.7% |
| M2 (M1+savings+small time deposits) | 8388.9 | 8387.3 | 1.6 | 3.1% | 1.5% | 5.6% |

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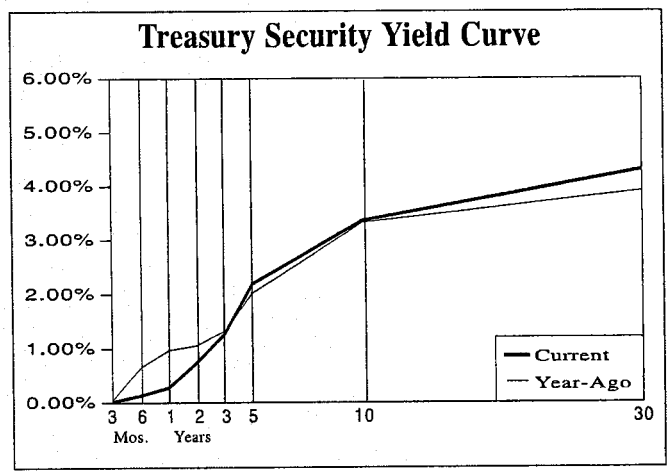
# Selected Yields

| | Recent (11/18/09) | 3 Months Ago (8/19/09) | Year Ago (11/19/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.25 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.00 |
| Prime Rate | 3.25 | 3.25 | 4.00 |
| 30-day CP (A1/P1) | 0.14 | 0.23 | 2.60 |
| 3-month LIBOR | 0.27 | 0.42 | 2.17 |
| **Bank CDs** | | | |
| 6-month | 0.34 | 0.48 | 1.59 |
| 1-year | 0.58 | 0.72 | 1.95 |
| 5-year | 2.23 | 1.90 | 3.32 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.02 | 0.16 | 0.06 |
| 6-month | 0.14 | 0.25 | 0.65 |
| 1-year | 0.28 | 0.39 | 0.97 |
| 5-year | 2.19 | 2.41 | 2.02 |
| 10-year | 3.36 | 3.45 | 3.32 |
| 10-year (inflation-protected) | 1.15 | 1.69 | 3.51 |
| 30-year | 4.30 | 4.29 | 3.91 |
| 30-year Zero | 4.47 | 4.42 | 3.92 |

| | Recent (11/18/09) | 3 Months Ago (8/19/09) | Year Ago (11/19/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.03 | 3.85 | 5.82 |
| FHLMC 6.5% (Gold) | 2.03 | 2.95 | 5.73 |
| FNMA 6.5% | 1.99 | 2.73 | 5.67 |
| FNMA ARM | 2.42 | 2.75 | 3.90 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.21 | 6.23 | 8.73 |
| Industrial (25/30-year) A | 5.52 | 5.60 | 7.23 |
| Utility (25/30-year) A | 5.51 | 5.64 | 7.34 |
| Utility (25/30-year) Baa/BBB | 6.24 | 6.23 | 8.20 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.41 | 3.40 | 3.51 |
| Germany | 3.29 | 3.25 | 3.54 |
| Japan | 1.31 | 1.35 | 1.48 |
| United Kingdom | 3.68 | 3.59 | 4.04 |
| **Preferred Stocks** | | | |
| Utility A | 5.68 | 6.02 | 7.10 |
| Financial A | 7.14 | 7.10 | 7.94 |
| Financial Adjustable A | 5.52 | 5.52 | 5.52 |




| | Recent (11/18/09) | 3 Months Ago (8/19/09) | Year Ago (11/19/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.40 | 4.65 | 5.14 |
| 25-Bond Index (Revs) | 5.02 | 5.66 | 5.98 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.42 | 0.40 | 1.10 |
| 1-year A | 1.38 | 0.90 | 1.20 |
| 5-year Aaa | 1.82 | 1.73 | 2.84 |
| 5-year A | 3.00 | 2.17 | 2.94 |
| 10-year Aaa | 3.27 | 2.94 | 3.83 |
| 10-year A | 4.18 | 3.30 | 4.03 |
| 25/30-year Aaa | 4.49 | 4.54 | 5.20 |
| 25/30-year A | 5.48 | 5.00 | 5.60 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.78 | 5.50 | 5.85 |
| Electric AA | 4.79 | 5.60 | 5.90 |
| Housing AA | 5.72 | 5.75 | 6.00 |
| Hospital AA | 5.19 | 5.85 | 6.10 |
| Toll Road Aaa | 4.91 | 5.55 | 5.95 |

# Federal Reserve Data

**BANK RESERVES**
*(Two-Week Period; in Millions, Seasonally Adjusted)*

| | Recent Levels 11/4/09 | 10/21/09 | Change | Average Levels Over the Last... 12 Wks. | 26 Wks. | 52 Wks. |
|---|---|---|---|---|---|---|
| Excess Reserves | 1059253 | 986798 | 72455 | 877903 | 827902 | 766778 |
| Borrowed Reserves | 248364 | 265229 | -16865 | 299705 | 375407 | 492904 |
| Net Free/Borrowed Reserves | 810889 | 721569 | 89320 | 578198 | 452495 | 273875 |

**MONEY SUPPLY**
*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels 11/2/09 | 10/26/09 | Change | Growth Rates Over the Last... 3 Mos. | 6 Mos. | 12 Mos. |
|---|---|---|---|---|---|---|
| M1 (Currency+demand deposits) | 1695.9 | 1668.0 | 27.9 | 4.2% | 11.1% | 11.2% |
| M2 (M1+savings+small time deposits) | 8387.3 | 8393.8 | -6.5 | 2.6% | 1.7% | 5.7% |

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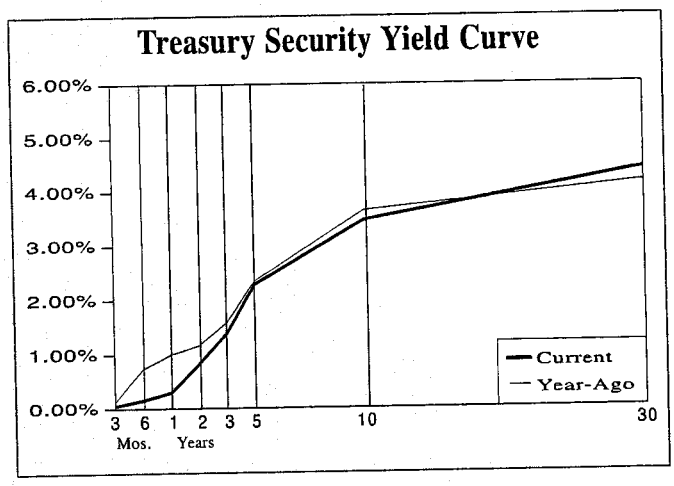
# Selected Yields

| | Recent (11/10/09) | 3 Months Ago (8/12/09) | Year Ago (11/12/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.25 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.00 |
| Prime Rate | 3.25 | 3.25 | 4.00 |
| 30-day CP (A1/P1) | 0.13 | 0.25 | 2.15 |
| 3-month LIBOR | 0.28 | 0.45 | 2.13 |
| **Bank CDs** | | | |
| 6-month | 0.38 | 0.50 | 1.72 |
| 1-year | 0.62 | 0.73 | 2.16 |
| 5-year | 2.22 | 1.90 | 3.40 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.06 | 0.17 | 0.14 |
| 6-month | 0.16 | 0.26 | 0.73 |
| 1-year | 0.30 | 0.43 | 1.00 |
| 5-year | 2.29 | 2.68 | 2.35 |
| 10-year | 3.47 | 3.72 | 3.65 |
| 10-year (inflation-protected) | 1.25 | 1.83 | 3.39 |
| 30-year | 4.41 | 4.54 | 4.17 |
| 30-year Zero | 4.58 | 4.65 | 4.04 |




| | Recent (11/10/09) | 3 Months Ago (8/12/09) | Year Ago (11/12/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.43 | 3.83 | 5.87 |
| FHLMC 6.5% (Gold) | 2.28 | 3.19 | 5.84 |
| FNMA 6.5% | 2.43 | 2.91 | 5.73 |
| FNMA ARM | 2.42 | 2.75 | 3.90 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.26 | 6.45 | 9.34 |
| Industrial (25/30-year) A | 5.58 | 5.85 | 7.42 |
| Utility (25/30-year) A | 5.64 | 5.79 | 7.62 |
| Utility (25/30-year) Baa/BBB | 6.32 | 6.62 | 8.07 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.50 | 3.52 | 3.66 |
| Germany | 3.34 | 3.46 | 3.63 |
| Japan | 1.44 | 1.43 | 1.51 |
| United Kingdom | 3.76 | 3.79 | 4.11 |
| **Preferred Stocks** | | | |
| Utility A | 5.74 | 5.66 | 6.95 |
| Financial A | 6.86 | 7.27 | 7.88 |
| Financial Adjustable A | 5.51 | 5.51 | 5.51 |
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.41 | 4.65 | 5.24 |
| 25-Bond Index (Revs) | 5.01 | 5.68 | 6.02 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.42 | 0.40 | 1.28 |
| 1-year A | 1.37 | 1.10 | 1.38 |
| 5-year Aaa | 1.93 | 1.69 | 3.10 |
| 5-year A | 3.10 | 3.09 | 3.15 |
| 10-year Aaa | 3.35 | 2.98 | 4.10 |
| 10-year A | 4.24 | 4.50 | 4.30 |
| 25/30-year Aaa | 4.49 | 4.66 | 5.26 |
| 25/30-year A | 5.53 | 6.17 | 5.64 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.80 | 5.90 | 5.45 |
| Electric AA | 4.78 | 5.95 | 5.40 |
| Housing AA | 5.78 | 6.45 | 6.05 |
| Hospital AA | 5.19 | 6.45 | 6.10 |
| Toll Road Aaa | 4.80 | 5.90 | 5.45 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | 11/4/09 | 10/21/09 | Change | 12 Wks. | 26 Wks. | 52 Wks. |
| Excess Reserves | 1059256 | 986806 | 72450 | 877905 | 827903 | 766779 |
| Borrowed Reserves | 248364 | 265229 | -16865 | 299705 | 375407 | 492904 |
| Net Free/Borrowed Reserves | 810892 | 721577 | 89315 | 578200 | 452496 | 273875 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | 10/26/09 | 10/19/09 | Change | 3 Mos. | 6 Mos. | 12 Mos. |
| M1 (Currency+demand deposits) | 1668.0 | 1678.7 | -10.7 | 5.2% | 11.9% | 12.3% |
| M2 (M1+savings+small time deposits) | 8393.8 | 8358.0 | 35.8 | 1.0% | 2.4% | 5.6% |

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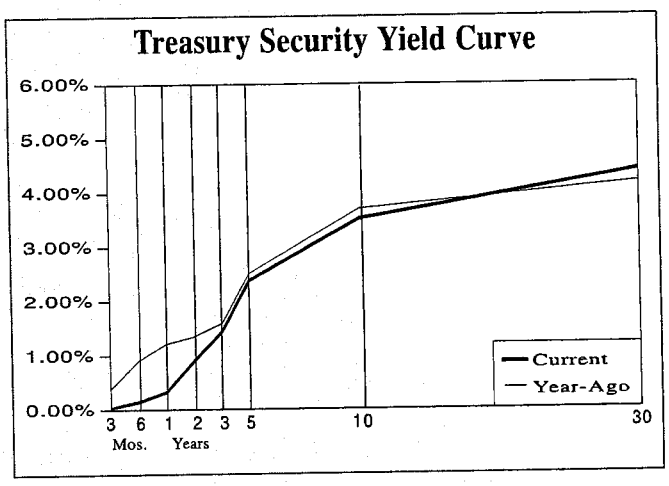
# Selected Yields

| | Recent (11/04/09) | 3 Months Ago (8/05/09) | Year Ago (11/05/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.25 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.00 |
| Prime Rate | 3.25 | 3.25 | 4.00 |
| 30-day CP (A1/P1) | 0.16 | 0.28 | 1.95 |
| 3-month LIBOR | 0.28 | 0.47 | 2.51 |
| **Bank CDs** | | | |
| 6-month | 0.38 | 0.50 | 1.84 |
| 1-year | 0.62 | 0.73 | 2.26 |
| 5-year | 2.22 | 1.90 | 3.40 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.04 | 0.18 | 0.39 |
| 6-month | 0.15 | 0.27 | 0.91 |
| 1-year | 0.33 | 0.47 | 1.22 |
| 5-year | 2.38 | 2.72 | 2.51 |
| 10-year | 3.52 | 3.75 | 3.70 |
| 10-year (inflation-protected) | 1.39 | 1.82 | 3.29 |
| 30-year | 4.40 | 4.55 | 4.18 |
| 30-year Zero | 4.55 | 4.65 | 3.94 |

| | Recent (11/04/09) | 3 Months Ago (8/05/09) | Year Ago (11/05/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.52 | 3.74 | 5.99 |
| FHLMC 6.5% (Gold) | 2.31 | 3.13 | 5.92 |
| FNMA 6.5% | 2.43 | 2.91 | 5.85 |
| FNMA ARM | 2.42 | 2.75 | 3.90 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.35 | 6.85 | 9.32 |
| Industrial (25/30-year) A | 5.59 | 5.96 | 7.41 |
| Utility (25/30-year) A | 5.71 | 5.70 | 7.25 |
| Utility (25/30-year) Baa/BBB | 6.39 | 6.70 | 7.45 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.48 | 3.58 | 3.75 |
| Germany | 3.32 | 3.34 | 3.77 |
| Japan | 1.41 | 1.44 | 1.54 |
| United Kingdom | 3.79 | 3.83 | 4.42 |
| **Preferred Stocks** | | | |
| Utility A | 5.59 | 6.04 | 6.76 |
| Financial A | 7.12 | 7.47 | 7.04 |
| Financial Adjustable A | 5.51 | 5.51 | 5.51 |




| | Recent (11/04/09) | 3 Months Ago (8/05/09) | Year Ago (11/05/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.39 | 4.69 | 5.35 |
| 25-Bond Index (Revs) | 4.95 | 5.66 | 6.09 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.43 | 0.42 | 1.50 |
| 1-year A | 1.45 | 0.92 | 1.60 |
| 5-year Aaa | 1.98 | 1.72 | 3.25 |
| 5-year A | 3.13 | 2.16 | 3.35 |
| 10-year Aaa | 3.36 | 2.99 | 4.20 |
| 10-year A | 4.30 | 3.35 | 4.40 |
| 25/30-year Aaa | 4.51 | 4.69 | 5.30 |
| 25/30-year A | 5.56 | 5.15 | 5.70 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.71 | 5.65 | 5.95 |
| Electric AA | 4.76 | 5.75 | 6.00 |
| Housing AA | 5.83 | 5.90 | 6.10 |
| Hospital AA | 5.17 | 6.00 | 6.20 |
| Toll Road Aaa | 4.80 | 5.70 | 6.05 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels 10/21/09 | 10/7/09 | Change | Average Levels Over the Last... 12 Wks. | 26 Wks. | 52 Wks. |
|---|---|---|---|---|---|---|
| Excess Reserves | 986806 | 918428 | 68378 | 830709 | 813841 | 737981 |
| Borrowed Reserves | 265229 | 288565 | -23336 | 313827 | 398049 | 509303 |
| Net Free/Borrowed Reserves | 721577 | 629863 | 91714 | 516882 | 415792 | 228678 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels 10/19/09 | 10/12/09 | Change | Growth Rates Over the Last... 3 Mos. | 6 Mos. | 12 Mos. |
|---|---|---|---|---|---|---|
| M1 (Currency+demand deposits) | 1679.6 | 1667.6 | 12.0 | 9.1% | 16.0% | 14.9% |
| M2 (M1+savings+small time deposits) | 8357.9 | 8331.5 | 26.4 | 0.4% | 2.6% | 4.9% |

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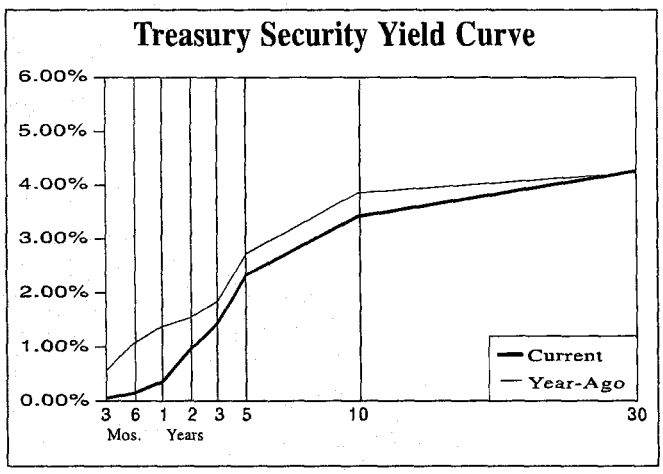
# Selected Yields

| | Recent (10/21/09) | 3 Months Ago (7/29/09) | Year Ago (10/29/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.25 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.00 |
| Prime Rate | 3.25 | 3.25 | 4.00 |
| 30-day CP (A1/P1) | 0.17 | 0.27 | 3.73 |
| 3-month LIBOR | 0.28 | 0.49 | 3.42 |
| **Bank CDs** | | | |
| 6-month | 0.38 | 0.56 | 1.85 |
| 1-year | 0.62 | 0.83 | 2.26 |
| 5-year | 2.22 | 1.90 | 3.42 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.06 | 0.18 | 0.58 |
| 6-month | 0.15 | 0.25 | 1.07 |
| 1-year | 0.36 | 0.48 | 1.38 |
| 5-year | 2.33 | 2.63 | 2.72 |
| 10-year | 3.42 | 3.66 | 3.86 |
| 10-year (inflation-protected) | 1.44 | 1.84 | 3.50 |
| 30-year | 4.26 | 4.51 | 4.23 |
| 30-year Zero | 4.39 | 4.61 | 4.04 |

| | Recent (10/21/09) | 3 Months Ago (7/29/09) | Year Ago (10/29/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.69 | 3.70 | 6.27 |
| FHLMC 6.5% (Gold) | 2.26 | 2.82 | 6.20 |
| FNMA 6.5% | 2.44 | 2.64 | 6.11 |
| FNMA ARM | 2.56 | 2.98 | 3.84 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.45 | 6.95 | 8.95 |
| Industrial (25/30-year) A | 5.44 | 6.02 | 7.57 |
| Utility (25/30-year) A | 5.53 | 5.79 | 7.27 |
| Utility (25/30-year) Baa/BBB | 6.20 | 7.14 | 7.29 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.46 | 3.53 | 3.74 |
| Germany | 3.26 | 3.42 | 3.79 |
| Japan | 1.43 | 1.38 | 1.50 |
| United Kingdom | 3.61 | 3.97 | 4.40 |
| **Preferred Stocks** | | | |
| Utility A | 5.58 | 5.71 | 6.86 |
| Financial A | 7.12 | 6.30 | 7.54 |
| Financial Adjustable A | 5.50 | 5.50 | 5.50 |




| | Recent (10/21/09) | 3 Months Ago (7/29/09) | Year Ago (10/29/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.31 | 4.69 | 5.32 |
| 25-Bond Index (Revs) | 4.87 | 5.67 | 6.06 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.45 | 0.42 | 1.68 |
| 1-year A | 1.45 | 1.12 | 1.78 |
| 5-year Aaa | 2.07 | 1.77 | 3.48 |
| 5-year A | 3.18 | 3.17 | 3.53 |
| 10-year Aaa | 3.35 | 3.03 | 4.35 |
| 10-year A | 4.33 | 4.55 | 4.55 |
| 25/30-year Aaa | 4.50 | 4.72 | 5.32 |
| 25/30-year A | 5.55 | 6.23 | 5.70 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.69 | 6.10 | 5.55 |
| Electric AA | 4.77 | 6.15 | 5.05 |
| Housing AA | 5.85 | 6.55 | 6.00 |
| Hospital AA | 5.15 | 6.50 | 6.05 |
| Toll Road Aaa | 4.80 | 6.10 | 5.10 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | 10/21/09 | 10/7/09 | Change | 12 Wks. | 26 Wks. | 52 Wks. |
| Excess Reserves | 986805 | 918428 | 68377 | 830708 | 813841 | 737980 |
| Borrowed Reserves | 265229 | 288565 | -23336 | 313827 | 398049 | 509303 |
| Net Free/Borrowed Reserves | 721576 | 629863 | 91713 | 516882 | 415792 | 228678 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | 10/12/09 | 10/5/09 | Change | 3 Mos. | 6 Mos. | 12 Mos. |
| M1 (Currency+demand deposits) | 1668.0 | 1667.2 | 0.8 | 2.9% | 11.9% | 13.7% |
| M2 (M1+savings+small time deposits) | 8331.6 | 8340.7 | -9.1 | -0.5% | 1.9% | 5.2% |

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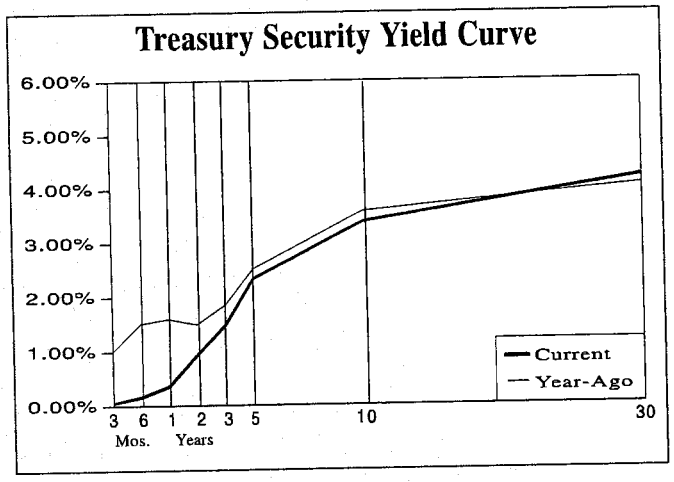
# Selected Yields

| | Recent (10/21/09) | 3 Months Ago (7/22/09) | Year Ago (10/22/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.75 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.50 |
| Prime Rate | 3.25 | 3.25 | 4.50 |
| 30-day CP (A1/P1) | 0.18 | 0.31 | 3.51 |
| 3-month LIBOR | 0.28 | 0.50 | 3.54 |
| **Bank CDs** | | | |
| 6-month | 0.38 | 0.56 | 1.72 |
| 1-year | 0.62 | 0.83 | 2.27 |
| 5-year | 2.22 | 1.90 | 3.42 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.06 | 0.18 | 1.01 |
| 6-month | 0.17 | 0.27 | 1.52 |
| 1-year | 0.37 | 0.43 | 1.60 |
| 5-year | 2.34 | 2.40 | 2.52 |
| 10-year | 3.39 | 3.54 | 3.59 |
| 10-year (inflation-protected) | 1.38 | 1.74 | 2.84 |
| 30-year | 4.21 | 4.45 | 4.06 |
| 30-year Zero | 4.32 | 4.56 | 3.90 |

| | Recent (10/21/09) | 3 Months Ago (7/22/09) | Year Ago (10/22/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.69 | 3.61 | 5.77 |
| FHLMC 6.5% (Gold) | 2.35 | 2.80 | 5.80 |
| FNMA 6.5% | 2.47 | 2.62 | 5.70 |
| FNMA ARM | 2.56 | 2.98 | 3.84 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.48 | 6.58 | 8.48 |
| Industrial (25/30-year) A | 5.42 | 5.98 | 7.16 |
| Utility (25/30-year) A | 5.53 | 5.81 | 6.54 |
| Utility (25/30-year) Baa/BBB | 6.16 | 6.97 | 6.59 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.45 | 3.45 | 3.60 |
| Germany | 3.32 | 3.38 | 3.81 |
| Japan | 1.36 | 1.39 | 1.55 |
| United Kingdom | 3.71 | 3.84 | 4.48 |
| **Preferred Stocks** | | | |
| Utility A | 6.29 | 5.97 | 6.87 |
| Financial A | 7.01 | 7.46 | 7.51 |
| Financial Adjustable A | 5.49 | 5.50 | 5.50 |




| | Recent (10/21/09) | 3 Months Ago (7/22/09) | Year Ago (10/22/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.32 | 4.68 | 6.01 |
| 25-Bond Index (Revs) | 4.86 | 5.66 | 6.48 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.37 | 0.42 | 1.80 |
| 1-year A | 0.87 | 0.92 | 1.90 |
| 5-year Aaa | 1.88 | 1.78 | 3.63 |
| 5-year A | 3.08 | 2.22 | 3.73 |
| 10-year Aaa | 3.03 | 2.99 | 4.56 |
| 10-year A | 4.23 | 3.35 | 4.76 |
| 25/30-year Aaa | 4.08 | 4.64 | 5.37 |
| 25/30-year A | 5.28 | 5.10 | 5.75 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 5.10 | 5.60 | 5.85 |
| Electric AA | 5.15 | 5.70 | 5.95 |
| Housing AA | 5.50 | 5.85 | 6.05 |
| Hospital AA | 5.50 | 5.95 | 6.25 |
| Toll Road Aaa | 5.10 | 5.65 | 6.00 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels 10/7/09 | 9/23/09 | Change | Average Levels Over the Last... 12 Wks. | 26 Wks. | 52 Wks. |
|---|---|---|---|---|---|---|
| Excess Reserves | 918431 | 854614 | 63817 | 796004 | 800840 | 706471 |
| Borrowed Reserves | 288565 | 307300 | -18735 | 331341 | 421671 | 519593 |
| Net Free/Borrowed Reserves | 629866 | 547314 | 82552 | 464663 | 379169 | 186879 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels 10/5/09 | 9/28/09 | Change | Growth Rates Over the Last... 3 Mos. | 6 Mos. | 12 Mos. |
|---|---|---|---|---|---|---|
| M1 (Currency+demand deposits) | 1672.2 | 1655.3 | 16.9 | 4.9% | 3.3% | 14.7% |
| M2 (M1+savings+small time deposits) | 8340.7 | 8364.0 | -23.3 | -0.8% | 2.2% | 5.9% |

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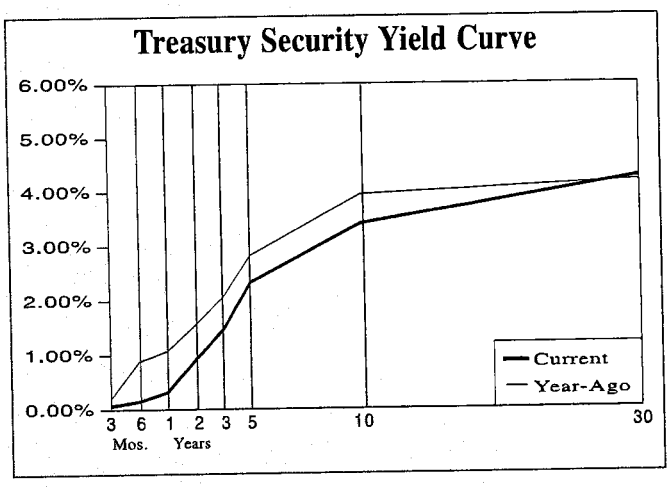
# Selected Yields

| | Recent (10/14/09) | 3 Months Ago (7/15/09) | Year Ago (10/15/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.75 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.50 |
| Prime Rate | 3.25 | 3.25 | 4.50 |
| 30-day CP (A1/P1) | 0.16 | 0.33 | 4.47 |
| 3-month LIBOR | 0.28 | 0.51 | 4.55 |
| **Bank CDs** | | | |
| 6-month | 0.39 | 0.58 | 1.73 |
| 1-year | 0.63 | 0.85 | 2.27 |
| 5-year | 2.24 | 1.92 | 3.48 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.07 | 0.18 | 0.21 |
| 6-month | 0.15 | 0.27 | 0.88 |
| 1-year | 0.32 | 0.47 | 1.07 |
| 5-year | 2.33 | 2.51 | 2.82 |
| 10-year | 3.41 | 3.60 | 3.95 |
| 10-year (inflation-protected) | 1.46 | 1.85 | 3.07 |
| 30-year | 4.26 | 4.49 | 4.19 |
| 30-year Zero | 4.39 | 4.60 | 4.04 |

| | Recent (10/14/09) | 3 Months Ago (7/15/09) | Year Ago (10/15/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.65 | 3.41 | 6.06 |
| FHLMC 6.5% (Gold) | 2.47 | 2.75 | 5.96 |
| FNMA 6.5% | 2.21 | 2.59 | 5.91 |
| FNMA ARM | 2.56 | 2.98 | 3.87 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.45 | 6.62 | 8.19 |
| Industrial (25/30-year) A | 5.48 | 6.12 | 7.03 |
| Utility (25/30-year) A | 5.65 | 5.97 | 6.67 |
| Utility (25/30-year) Baa/BBB | 6.22 | 7.19 | 7.03 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.53 | 3.49 | 3.76 |
| Germany | 3.23 | 3.37 | 4.12 |
| Japan | 1.31 | 1.34 | 1.59 |
| United Kingdom | 3.50 | 3.80 | 4.71 |
| **Preferred Stocks** | | | |
| Utility A | 5.96 | 5.95 | 6.57 |
| Financial A | 7.00 | 7.67 | 7.33 |
| Financial Adjustable A | 5.49 | 5.49 | 5.49 |




| | Recent (10/14/09) | 3 Months Ago (7/15/09) | Year Ago (10/15/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 4.06 | 4.71 | 5.47 |
| 25-Bond Index (Revs) | 4.69 | 5.70 | 5.97 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.37 | 0.40 | 2.15 |
| 1-year A | 0.80 | 1.10 | 2.25 |
| 5-year Aaa | 1.90 | 2.07 | 3.70 |
| 5-year A | 2.10 | 3.47 | 3.75 |
| 10-year Aaa | 3.05 | 2.98 | 4.86 |
| 10-year A | 3.45 | 4.50 | 5.06 |
| 25/30-year Aaa | 4.10 | 4.59 | 5.99 |
| 25/30-year A | 4.65 | 6.10 | 6.37 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.90 | 5.95 | 6.17 |
| Electric AA | 4.95 | 6.00 | 6.12 |
| Housing AA | 5.40 | 6.40 | 6.60 |
| Hospital AA | 5.60 | 6.35 | 6.65 |
| Toll Road Aaa | 5.00 | 5.95 | 6.15 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels 10/7/09 | 9/23/09 | Change | Average Levels Over the Last... 12 Wks. | 26 Wks. | 52 Wks. |
|---|---|---|---|---|---|---|
| Excess Reserves | 918434 | 854614 | 63820 | 796002 | 800839 | 706471 |
| Borrowed Reserves | 288565 | 307300 | -18735 | 331341 | 421671 | 519593 |
| Net Free/Borrowed Reserves | 629869 | 547314 | 82555 | 464661 | 379168 | 186878 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels 9/28/09 | 9/21/09 | Change | Growth Rates Over the Last... 3 Mos. | 6 Mos. | 12 Mos. |
|---|---|---|---|---|---|---|
| M1 (Currency+demand deposits) | 1653.6 | 1639.8 | 13.8 | 0.2% | 13.0% | 10.9% |
| M2 (M1+savings+small time deposits) | 8357.3 | 8309.8 | 47.5 | 0.4% | 0.7% | 5.5% |

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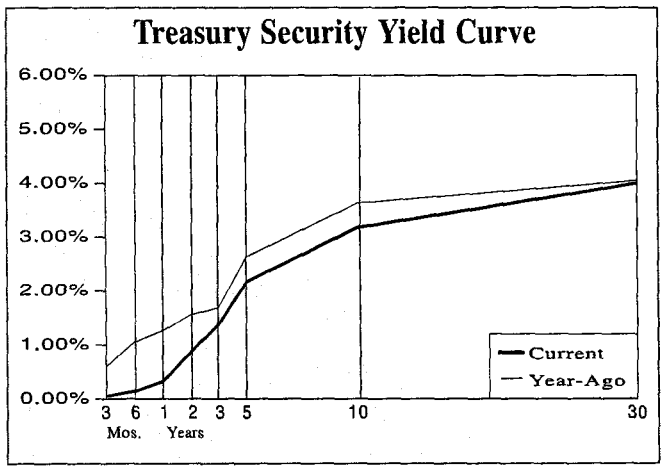
# Selected Yields

| | Recent (10/07/09) | 3 Months Ago (7/08/09) | Year Ago (10/08/08) |
|---|---|---|---|
| **TAXABLE** | | | |
| **Market Rates** | | | |
| Discount Rate | 0.50 | 0.50 | 1.75 |
| Federal Funds | 0.00-0.25 | 0.00-0.25 | 1.50 |
| Prime Rate | 3.25 | 3.25 | 4.50 |
| 30-day CP (A1/P1) | 0.16 | 0.36 | 4.55 |
| 3-month LIBOR | 0.28 | 0.53 | 4.52 |
| **Bank CDs** | | | |
| 6-month | 0.40 | 0.65 | 1.73 |
| 1-year | 0.64 | 0.86 | 2.27 |
| 5-year | 2.24 | 1.94 | 3.48 |
| **U.S. Treasury Securities** | | | |
| 3-month | 0.06 | 0.18 | 0.61 |
| 6-month | 0.14 | 0.25 | 1.05 |
| 1-year | 0.32 | 0.44 | 1.26 |
| 5-year | 2.17 | 2.23 | 2.63 |
| 10-year | 3.18 | 3.31 | 3.64 |
| 10-year (inflation-protected) | 1.42 | 1.76 | 2.66 |
| 30-year | 4.00 | 4.19 | 4.05 |
| 30-year Zero | 4.10 | 4.31 | 3.97 |

| | Recent (10/07/09) | 3 Months Ago (7/08/09) | Year Ago (10/08/08) |
|---|---|---|---|
| **Mortgage-Backed Securities** | | | |
| GNMA 6.5% | 3.44 | 3.71 | 5.82 |
| FHLMC 6.5% (Gold) | 2.38 | 2.99 | 5.70 |
| FNMA 6.5% | 2.33 | 2.83 | 5.62 |
| FNMA ARM | 2.56 | 2.98 | 3.84 |
| **Corporate Bonds** | | | |
| Financial (10-year) A | 5.46 | 6.53 | 7.34 |
| Industrial (25/30-year) A | 5.28 | 5.82 | 6.66 |
| Utility (25/30-year) A | 5.44 | 5.71 | 6.58 |
| Utility (25/30-year) Baa/BBB | 5.95 | 6.85 | 6.93 |
| **Foreign Bonds (10-Year)** | | | |
| Canada | 3.29 | 3.28 | 3.59 |
| Germany | 3.12 | 3.28 | 3.80 |
| Japan | 1.27 | 1.30 | 1.39 |
| United Kingdom | 3.39 | 3.62 | 4.30 |
| **Preferred Stocks** | | | |
| Utility A | 6.29 | 7.59 | 6.99 |
| Financial A | 6.89 | 6.57 | 8.54 |
| Financial Adjustable A | 5.48 | 5.48 | 5.48 |




| | Recent (10/07/09) | 3 Months Ago (7/08/09) | Year Ago (10/08/08) |
|---|---|---|---|
| **TAX-EXEMPT** | | | |
| **Bond Buyer Indexes** | | | |
| 20-Bond Index (GOs) | 3.94 | 4.83 | 5.36 |
| 25-Bond Index (Revs) | 4.69 | 5.75 | 5.69 |
| **General Obligation Bonds (GOs)** | | | |
| 1-year Aaa | 0.37 | 0.43 | 2.18 |
| 1-year A | 0.87 | 0.93 | 2.25 |
| 5-year Aaa | 1.57 | 1.96 | 3.34 |
| 5-year A | 2.77 | 2.40 | 3.44 |
| 10-year Aaa | 2.57 | 3.09 | 4.31 |
| 10-year A | 3.77 | 3.45 | 4.51 |
| 25/30-year Aaa | 3.81 | 4.59 | 5.35 |
| 25/30-year A | 5.01 | 5.05 | 5.70 |
| **Revenue Bonds (Revs) (25/30-Year)** | | | |
| Education AA | 4.85 | 5.55 | 5.80 |
| Electric AA | 4.90 | 5.65 | 5.90 |
| Housing AA | 5.20 | 5.80 | 6.00 |
| Hospital AA | 5.20 | 5.90 | 6.10 |
| Toll Road Aaa | 4.85 | 5.60 | 5.95 |

# Federal Reserve Data

**BANK RESERVES**

*(Two-Week Period; in Millions, Not Seasonally Adjusted)*

| | Recent Levels | | | Average Levels Over the Last... | | |
|---|---|---|---|---|---|---|
| | 9/9/09 | 8/26/09 | Change | 12 Wks. | 26 Wks. | 52 Wks. |
| Excess Reserves | 823187 | 794531 | 28656 | 754073 | 773681 | 643433 |
| Borrowed Reserves | 320295 | 327647 | -7352 | 369408 | 467326 | 513721 |
| Net Free/Borrowed Reserves | 502892 | 466884 | 36008 | 384665 | 306355 | 129711 |

**MONEY SUPPLY**

*(One-Week Period; in Billions, Seasonally Adjusted)*

| | Recent Levels | | | Growth Rates Over the Last... | | |
|---|---|---|---|---|---|---|
| | 9/21/09 | 9/14/09 | Change | 3 Mos. | 6 Mos. | 12 Mos. |
| M1 (Currency+demand deposits) | 1639.8 | 1670.9 | -31.1 | -6.8% | 11.4% | 11.3% |
| M2 (M1+savings+small time deposits) | 8310.3 | 8318.3 | -8.0 | -3.5% | -1.1% | 5.2% |

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**RIO RICO UTILITIES, INC.**
**DOCKET NO. WS-02676A-09-0257**
**TABLE OF CONTENTS TO SCHEDULES WAR**


| SCHEDULE # | |
|---|---|
| WAR - 1 | COST OF CAPITAL SUMMARY |
| WAR - 2 | DCF COST OF EQUITY CAPITAL |
| WAR - 3 | DIVIDEND YIELD CALCULATION |
| WAR - 4 | DIVIDEND GROWTH RATE CALCULATION |
| WAR - 5 | DIVIDEND GROWTH COMPONENTS |
| WAR - 6 | GROWTH RATE COMPARISON |
| WAR - 7 | CAPM COST OF EQUITY CAPITAL |
| WAR - 8 | ECONOMIC INDICATORS - 1990 TO PRESENT |
| WAR - 9 | CAPITAL STRUCTURES OF SAMPLE COMPANIES |

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL SUMMARY

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 1


## WEIGHTED AVERAGE COST OF CAPITAL - WATER AND WASTEWATER DIVISIONS

| LINE NO. | DESCRIPTION | (A) CAPITAL RATIO | (B) COST RATE | (C) WEIGHTED COST RATE |
|---|---|---|---|---|
| 1 | Long-Term Debt | 40.00% | 6.26% | 2.50% |
| 2 | Common Equity | 60.00% | 9.00% | 5.40% |
| 3 | Total Capitalization | 100.00% | | |
| 4 | **WEIGHTED AVERAGE COST OF CAPITAL** | | | **7.90%** |

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): TESTIMONY, WAR - SCHEDULE WAR-1, PAGE 2
COLUMN (C): COLUMN (A) x COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL SUMMARY

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 1


## SAMPLE COMPANIES APPROXIMATE WEIGHTED COSTS OF DEBT

| LINE NO. | STOCK SYMBOL | COMPANY | WEIGHTED COSTS | | |
|---|---|---|---|---|---|
| 1 | AWR | AMERICAN STATES WATER CO. | 7.13% | | |
| 2 | CWT | CALIFORNIA WATER SERVICE GROUP | 6.43% | | |
| 3 | WTR | AQUA AMERICA, INC. | 6.03% | | |
| 4 | CTWS | CONNECTICUT WATER SERVICES, INC. | 4.95% | | |
| 5 | MSEX | MIDDLESEX WATER COMPANY | 5.52% | | |
| 6 | SJW | SJW CORP. | 6.81% | | |
| 7 | YORW | YORK WATER COMPANY | 6.92% | | |
| 8 | AVERAGE OF APPROXIMATE WEIGHTED COSTS OF DEBT (a) | | | 6.26% | AVERAGE OF LINES 1 THRU 8 |
| 9 | **RUCO RECOMMENDED COST OF DEBT** | | | 6.26% | |

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

NOTE:
(a) COSTS ARE APPROXIMATE AND DO NOT INCLUDE THE FOLLOWING:
DEBT ISSUES THAT DID NOT HAVE STATED YIELDS; AND
DEBT ISSUES WITH ZERO RATES OF INTEREST.
IN THE CASE OF ISSUES WITH VARIABLE RATES OF INTEREST THE HIGH END OF THE VARIABLE RANGE WAS US

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
COST OF CAPITAL SUMMARY

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR-1, PAGE 3 OF 3

## COST OF COMMON EQUITY CALCULATION

| LINE NO. | | | |
|---|---|---|---|
| 1 | **DCF METHODOLOGY** | | |
| 2 | DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE | 9.94% | SCHEDULE WAR-2, COLUMN (C), LINE 5 |
| 3 | DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE | 9.48% | SCHEDULE WAR-2, COLUMN (C), LINE 13 |
| 4 | **AVERAGE OF DCF ESTIMATES** | **9.71%** | ( LINE 2 + LINE 3 ) ÷ 2 |
| 5 | **CAPM METHODOLOGY** | | |
| 6 | CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE | 5.72% | SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5 |
| 7 | CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE | 5.05% | SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13 |
| 8 | CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE | 7.29% | SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5 |
| 9 | CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE | 6.32% | SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13 |
| 10 | **AVERAGE OF CAPM ESTIMATES** | **6.10%** | ( SUM OF LINES 6 THRU 9 ) ÷ 4 |
| 11 | **AVERAGE OF DCF AND CAPM ESTIMATES** | **7.90%** | ( SUM OF LINES 4 AND 10 ) ÷ 2 |
| 12 | **FINAL COST OF COMMON EQUITY ESTIMATE** | **9.00%** | TESTIMONY WAR |

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DCF COST OF EQUITY CAPITAL

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 2

| LINE NO. | STOCK SYMBOL | COMPANY | (A) DIVIDEND YIELD | + | (B) GROWTH RATE (g) | = | (C) DCF COST OF EQUITY CAPITAL |
|---|---|---|---|---|---|---|---|
| 1 | AWR | AMERICAN STATES WATER CO. | 2.92% | + | 8.86% | = | 11.79% |
| 2 | CWT | CALIFORNIA WATER SERVICE GROUP | 3.15% | + | 6.67% | = | 9.82% |
| 3 | SWWC | SOUTHWEST WATER COMPANY | 1.76% | + | 7.27% | = | 9.02% |
| 4 | WTR | AQUA AMERICA, INC. | 3.36% | + | 5.75% | = | 9.11% |
| 5 | **WATER COMPANY AVERAGE** | | | | | | **9.94%** |
| 6 | AGL | AGL RESOURCES, INC. | 4.88% | + | 5.96% | = | 10.84% |
| 7 | ATO | ATMOS ENERGY CORP. | 4.66% | + | 4.43% | = | 9.09% |
| 8 | LG | LACLEDE GROUP, INC. | 4.86% | + | 5.05% | = | 9.91% |
| 9 | NJR | NEW JERSEY RESOURCES CORPORATION | 3.46% | + | 5.67% | = | 9.12% |
| 10 | GAS | NICOR, INC. | 4.87% | + | 5.19% | = | 10.06% |
| 11 | NWN | NORTHWEST NATURAL GAS CO. | 3.69% | + | 4.96% | = | 8.65% |
| 12 | PNY | PIEDMONT NATURAL GAS COMPANY | 4.58% | + | 4.75% | = | 9.34% |
| 13 | SJI | SOUTH JERSEY INDUSTIES, INC. | 3.32% | + | 7.92% | = | 11.25% |
| 14 | SWX | SOUTHWEST GAS CORPORATION | 3.69% | + | 4.03% | = | 7.72% |
| 15 | WGL | WGL HOLDINGS, INC. | 4.47% | + | 4.38% | = | 8.85% |
| 16 | **NATURAL GAS LDC AVERAGE** | | | | | | **9.48%** |

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND YIELD CALCULATION

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 3

| LINE NO. | STOCK SYMBOL | COMPANY | (A) ESTIMATED DIVIDEND (PER SHARE) | ÷ | (B) AVERAGE STOCK PRICE (PER SHARE) | = | (C) DIVIDEND YIELD |
|---|---|---|---|---|---|---|---|
| 1 | AWR | AMERICAN STATES WATER CO. | $1.00 | ÷ | $34.19 | = | 2.92% |
| 2 | CWT | CALIFORNIA WATER SERVICE GROUP | 1.18 | ÷ | 37.45 | = | 3.15% |
| 3 | SWWC | SOUTHWEST WATER COMPANY | 0.10 | ÷ | 5.69 | = | 1.76% |
| 4 | WTR | AQUA AMERICA, INC. | 0.54 | ÷ | 16.09 | = | 3.36% |
| 5 | **WATER COMPANY AVERAGE** | | | | | | **2.80%** |
| 6 | AGL | AGL RESOURCES, INC. | $1.72 | ÷ | $35.27 | = | 4.88% |
| 7 | ATO | ATMOS ENERGY CORP. | 1.32 | ÷ | 28.34 | = | 4.66% |
| 8 | LG | LACLEDE GROUP, INC. | 1.54 | ÷ | 31.71 | = | 4.86% |
| 9 | NJR | NEW JERSEY RESOURCES CORPORATION | 1.24 | ÷ | 35.88 | = | 3.46% |
| 10 | GAS | NICOR, INC. | 1.86 | ÷ | 38.16 | = | 4.87% |
| 11 | NWN | NORTHWEST NATURAL GAS CO. | 1.58 | ÷ | 42.78 | = | 3.69% |
| 12 | PNY | PIEDMONT NATURAL GAS COMPANY | 1.08 | ÷ | 23.56 | = | 4.58% |
| 13 | SJI | SOUTH JERSEY INDUSTIES, INC. | 1.19 | ÷ | 35.90 | = | 3.32% |
| 14 | SWX | SOUTHWEST GAS CORPORATION | 0.95 | ÷ | 25.77 | = | 3.69% |
| 15 | WGL | WGL HOLDINGS, INC. | 1.48 | ÷ | 33.09 | = | 4.47% |
| 16 | **NATURAL GAS LDC AVERAGE** | | | | | | **4.25%** |

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 10/23/2009 (WATER COMPANIES) AND 09/11/2009 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 08/24/2009 TO 10/16/2009 STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) / COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH RATE CALCULATION



| LINE NO. | STOCK SYMBOL | COMPANY | (A) INTERNAL GROWTH ( br ) | + | (B) EXTERNAL GROWTH (sv) | = | (C) DIVIDEND GROWTH (g) |
|---|---|---|---|---|---|---|---|
| 1 | AWR | AMERICAN STATES WATER CO. | 6.20% | + | 2.66% | = | 8.86% |
| 2 | CWT | CALIFORNIA WATER SERVICE GROUP | 6.00% | + | 0.67% | = | 6.67% |
| 3 | SWWC | SOUTHWEST WATER COMPANY | 7.15% | + | 0.12% | = | 7.27% |
| 4 | WTR | AQUA AMERICA, INC. | 5.50% | + | 0.25% | = | 5.75% |
| 5 | **WATER COMPANY AVERAGE** | | | | | | **7.14%** |
| 6 | AGL | AGL RESOURCES, INC. | 5.50% | + | 0.46% | = | 5.96% |
| 7 | ATO | ATMOS ENERGY CORP. | 4.10% | + | 0.33% | = | 4.43% |
| 8 | LG | LACLEDE GROUP, INC. | 4.50% | + | 0.55% | = | 5.05% |
| 9 | NJR | NEW JERSEY RESOURCES CORPORATION | 5.10% | + | 0.57% | = | 5.67% |
| 10 | GAS | NICOR, INC. | 5.10% | + | 0.09% | = | 5.19% |
| 11 | NWN | NORTHWEST NATURAL GAS CO. | 4.60% | + | 0.36% | = | 4.96% |
| 12 | PNY | PIEDMONT NATURAL GAS COMPANY | 4.75% | + | 0.00% | = | 4.75% |
| 13 | SJI | SOUTH JERSEY INDUSTIES, INC. | 7.00% | + | 0.92% | = | 7.92% |
| 14 | SWX | SOUTHWEST GAS CORPORATION | 4.00% | + | 0.03% | = | 4.03% |
| 15 | WGL | WGL HOLDINGS, INC. | 4.35% | + | 0.03% | = | 4.38% |
| 16 | **NATURAL GAS LDC AVERAGE** | | | | | | **5.23%** |

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH RATE CALCULATION



| LINE NO. | STOCK SYMBOL | COMPANY | (A) SHARE GROWTH | x | (B) { [ ( ( M+B ) + 1 ) ÷ 2 ] - 1 } | = | (C) EXTERNAL GROWTH ( sv ) |
|---|---|---|---|---|---|---|---|
| 1 | AWR | AMERICAN STATES WATER CO. | 5.00% | x | { [ ( ( 2.07 ) + 1 ) ÷ 2 ] - 1 } | = | 2.66% |
| 2 | CWT | CALIFORNIA WATER SERVICE GROUP | 1.50% | x | { [ ( ( 1.90 ) + 1 ) ÷ 2 ] - 1 } | = | 0.67% |
| 3 | SWWC | SOUTHWEST WATER COMPANY | 1.10% | x | { [ ( ( 1.21 ) + 1 ) ÷ 2 ] - 1 } | = | 0.12% |
| 4 | WTR | AQUA AMERICA, INC. | 0.50% | x | { [ ( ( 2.00 ) + 1 ) ÷ 2 ] - 1 } | = | 0.25% |
| 5 | **WATER COMPANY AVERAGE** | | | | | | **0.93%** |
| 6 | AGL | AGL RESOURCES, INC. | 1.75% | x | { [ ( ( 1.53 ) + 1 ) ÷ 2 ] - 1 } | = | 0.46% |
| 7 | ATO | ATMOS ENERGY CORP. | 3.75% | x | { [ ( ( 1.18 ) + 1 ) ÷ 2 ] - 1 } | = | 0.33% |
| 8 | LG | LACLEDE GROUP, INC. | 3.25% | x | { [ ( ( 1.34 ) + 1 ) ÷ 2 ] - 1 } | = | 0.55% |
| 9 | NJR | NEW JERSEY RESOURCES CORPORATION | 1.25% | x | { [ ( ( 1.91 ) + 1 ) ÷ 2 ] - 1 } | = | 0.57% |
| 10 | GAS | NICOR, INC. | 0.25% | x | { [ ( ( 1.73 ) + 1 ) ÷ 2 ] - 1 } | = | 0.09% |
| 11 | NWN | NORTHWEST NATURAL GAS CO. | 1.00% | x | { [ ( ( 1.72 ) + 1 ) ÷ 2 ] - 1 } | = | 0.36% |
| 12 | PNY | PIEDMONT NATURAL GAS COMPANY | 0.01% | x | { [ ( ( 1.86 ) + 1 ) ÷ 2 ] - 1 } | = | 0.00% |
| 13 | SJI | SOUTH JERSEY INDUSTIES, INC. | 2.00% | x | { [ ( ( 1.92 ) + 1 ) ÷ 2 ] - 1 } | = | 0.92% |
| 14 | SWX | SOUTHWEST GAS CORPORATION | 2.50% | x | { [ ( ( 1.02 ) + 1 ) ÷ 2 ] - 1 } | = | 0.03% |
| 15 | WGL | WGL HOLDINGS, INC. | 0.10% | x | { [ ( ( 1.50 ) + 1 ) ÷ 2 ] - 1 } | = | 0.03% |
| 16 | **NATURAL GAS LDC AVERAGE** | | | | | | **0.33%** |

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 10/23/2009 (WATER COMPANIES) AND 09/11/2009 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | WATER COMPANY NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AWR | AMERICAN STATES WATER CO. | 2004 | 0.1524 | | 6.60% | | 1.01% | 15.01 | 16.75 | |
| 2 | | | 2005 | 0.3182 | | 8.50% | | 2.70% | 15.72 | 16.80 | |
| 3 | | | 2006 | 0.3158 | | 8.10% | | 2.56% | 16.64 | 17.05 | |
| 4 | | | 2007 | 0.4074 | | 9.30% | | 3.79% | 17.53 | 17.23 | |
| 5 | | | 2008 | 0.3548 | | 8.60% | | 3.05% | 17.95 | 17.30 | |
| 6 | | | GROWTH 2004 - 2008 | | | | | 2.62% | 5.00% | | 0.81% |
| 7 | | | 2009 | 0.4632 | | 10.00% | | 4.63% | | 18.50 | 6.94% |
| 8 | | | 2010 | 0.4732 | | 10.50% | | 4.97% | | 18.75 | 4.11% |
| 9 | | | 2012-14 | 0.5192 | | 12.00% | | 6.23% | 4.00% | 20.00 | 2.94% |
| 10 | | | | | | | | | | | |
| 11 | CWT | CALIFORNIA WATER SERVICE GROUP | 2004 | 0.2260 | | 9.00% | | 2.03% | 15.66 | 18.37 | |
| 12 | | | 2005 | 0.2245 | | 9.30% | | 2.09% | 15.79 | 18.39 | |
| 13 | | | 2006 | 0.1418 | | 6.80% | | 0.96% | 18.15 | 20.66 | |
| 14 | | | 2007 | 0.2267 | | 8.10% | | 1.84% | 18.50 | 20.67 | |
| 15 | | | 2008 | 0.3842 | | 9.90% | | 3.80% | 19.44 | 20.72 | |
| 16 | | | GROWTH 2004 - 2008 | | | | | 2.15% | 6.50% | | 3.06% |
| 17 | | | 2009 | 0.4381 | | 11.50% | | 5.04% | | 21.00 | 1.35% |
| 18 | | | 2010 | 0.4591 | | 10.50% | | 4.82% | | 21.50 | 1.86% |
| 19 | | | 2012-14 | 0.4943 | | 12.00% | | 5.93% | 3.00% | 22.50 | 1.66% |
| 20 | | | | | | | | | | | |
| 21 | SWWC | SOUTHWEST WATER COMPANY | 2004 | 0.2174 | | 3.60% | | 0.78% | 6.17 | 20.36 | |
| 22 | | | 2005 | 0.4118 | | 5.00% | | 2.06% | 6.49 | 22.33 | |
| 23 | | | 2006 | 0.4750 | | 5.60% | | 2.66% | 6.98 | 23.80 | |
| 24 | | | 2007 | 0.2581 | | 3.20% | | 0.83% | 6.54 | 24.27 | |
| 25 | | | 2008 | -5.0000 | | 0.80% | | NMF | 4.55 | 24.90 | |
| 26 | | | GROWTH 2004 - 2008 | | | | | 1.58% | 7.00% | | 5.16% |
| 27 | | | 2009 | 0.9333 | | 3.00% | | 2.80% | | 25.00 | 0.40% |
| 28 | | | 2010 | 0.9667 | | 6.00% | | 5.80% | | 25.50 | 1.20% |
| 29 | | | 2012-14 | 0.9000 | | 8.00% | | 7.20% | - | 26.50 | 1.25% |
| 30 | | | | | | | | | | | |
| 31 | WTR | AQUA AMERICA, INC. | 2004 | 0.4219 | | 10.70% | | 4.51% | 5.89 | 127.18 | |
| 32 | | | 2005 | 0.4366 | | 11.20% | | 4.89% | 6.30 | 128.97 | |
| 33 | | | 2006 | 0.3714 | | 10.00% | | 3.71% | 6.96 | 132.33 | |
| 34 | | | 2007 | 0.3239 | | 9.70% | | 3.14% | 7.32 | 133.40 | |
| 35 | | | 2008 | 0.3014 | | 9.30% | | 2.80% | 7.82 | 135.37 | |
| 36 | | | GROWTH 2004 - 2008 | | | | | 3.81% | 10.00% | | 1.57% |
| 37 | | | 2009 | 0.3415 | | 10.50% | | 3.59% | | 136.00 | 0.47% |
| 38 | | | 2010 | 0.3778 | | 11.00% | | 4.16% | | 136.50 | 0.42% |
| 39 | | | 2012-14 | 0.4800 | | 11.50% | | 5.52% | 6.50% | 138.00 | 0.39% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 10/23/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | NATURAL GAS LDC NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AGL | AGL RESOURCES, INC. | 2004 | 0.4956 | | 11.00% | | 5.45% | 18.06 | 76.70 | |
| 2 | | | 2005 | 0.4758 | | 12.90% | | 6.14% | 19.29 | 77.70 | |
| 3 | | | 2006 | 0.4559 | | 13.20% | | 6.02% | 20.71 | 77.70 | |
| 4 | | | 2007 | 0.3971 | | 12.70% | | 5.04% | 21.74 | 76.40 | |
| 5 | | | 2008 | 0.3801 | | 12.60% | | 4.79% | 21.48 | 76.90 | |
| 6 | | | GROWTH 2004 - 2008 | | | | | 5.49% | 10.00% | | 0.07% |
| 7 | | | 2009 | 0.3630 | | 11.50% | | 4.17% | | 78.00 | 1.43% |
| 8 | | | 2010 | 0.3931 | | 12.50% | | 4.91% | | 79.00 | 1.36% |
| 9 | | | 2012-14 | 0.4303 | | 14.00% | | 6.02% | 1.50% | 85.00 | 2.02% |
| 10 | | | | | | | | | | | |
| 11 | ATO | ATMOS ENERGY CORP. | 2004 | 0.2278 | | 7.60% | | 1.73% | 18.05 | 62.80 | |
| 12 | | | 2005 | 0.2791 | | 8.50% | | 2.37% | 19.90 | 80.54 | |
| 13 | | | 2006 | 0.3700 | | 9.80% | | 3.63% | 20.16 | 81.74 | |
| 14 | | | 2007 | 0.3402 | | 8.70% | | 2.96% | 22.01 | 89.33 | |
| 15 | | | 2008 | 0.3500 | | 8.80% | | 3.08% | 22.60 | 90.81 | |
| 16 | | | GROWTH 2004 - 2008 | | | | | 2.75% | 7.50% | | 9.66% |
| 17 | | | 2009 | 0.3714 | | 9.00% | | 3.34% | | 92.50 | 1.86% |
| 18 | | | 2010 | 0.3909 | | 9.00% | | 3.52% | | 93.50 | 1.47% |
| 19 | | | 2012-14 | 0.4400 | | 9.50% | | 4.18% | 4.00% | 110.00 | 3.91% |
| 20 | | | | | | | | | | | |
| 21 | LG | LACLEDE GROUP, INC. | 2004 | 0.2582 | | 10.10% | | 2.61% | 16.96 | 20.98 | |
| 22 | | | 2005 | 0.2789 | | 10.90% | | 3.04% | 17.31 | 21.17 | |
| 23 | | | 2006 | 0.4093 | | 12.50% | | 5.12% | 18.85 | 21.36 | |
| 24 | | | 2007 | 0.3723 | | 11.60% | | 4.32% | 19.79 | 21.65 | |
| 25 | | | 2008 | 0.4356 | | 11.80% | | 5.14% | 22.12 | 21.99 | |
| 26 | | | GROWTH 2004 - 2008 | | | | | 4.04% | 5.50% | | 1.18% |
| 27 | | | 2009 | 0.4814 | | 12.00% | | 5.78% | | 22.50 | 2.32% |
| 28 | | | 2010 | 0.3962 | | 11.00% | | 4.36% | | 23.00 | 2.27% |
| 29 | | | 2012-14 | 0.4333 | | 11.00% | | 4.77% | 5.50% | 26.00 | 3.41% |
| 30 | | | | | | | | | | | |
| 31 | NJR | NEW JERSEY RESOURCES CORPORATION | 2004 | 0.4882 | | 15.30% | | 7.47% | 11.25 | 41.61 | |
| 32 | | | 2005 | 0.4859 | | 17.00% | | 8.26% | 10.60 | 41.32 | |
| 33 | | | 2006 | 0.4866 | | 12.60% | | 6.13% | 15.00 | 41.44 | |
| 34 | | | 2007 | 0.3484 | | 10.10% | | 3.52% | 15.50 | 41.61 | |
| 35 | | | 2008 | 0.5889 | | 15.70% | | 9.25% | 17.28 | 42.06 | |
| 36 | | | GROWTH 2004 - 2008 | | | | | 6.93% | 11.50% | | 0.27% |
| 37 | | | 2009 | 0.4939 | | 13.00% | | 6.42% | | 42.50 | 1.05% |
| 38 | | | 2010 | 0.5259 | | 13.00% | | 6.84% | | 43.00 | 1.11% |
| 39 | | | 2012-14 | 0.5000 | | 10.00% | | 5.00% | 9.50% | 45.00 | 1.36% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 09/11/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | NATURAL GAS LDC NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | GAS | NICOR, INC. | 2004 | 0.1622 | | 13.10% | | 2.12% | 16.99 | 44.10 | |
| 2 | | | 2005 | 0.1806 | | 12.50% | | 2.26% | 18.36 | 44.18 | |
| 3 | | | 2006 | 0.3519 | | 14.70% | | 5.17% | 19.43 | 44.90 | |
| 4 | | | 2007 | 0.3779 | | 14.30% | | 5.40% | 20.58 | 45.90 | |
| 5 | | | 2008 | 0.2928 | | 12.30% | | 3.60% | 21.55 | 45.13 | |
| 6 | | | GROWTH 2004 - 2008 | | | | | 3.71% | 4.00% | | 0.58% |
| 7 | | | 2009 | 0.2706 | | 11.50% | | 3.11% | | 45.50 | 0.82% |
| 8 | | | 2010 | 0.3474 | | 12.50% | | 4.34% | | 45.50 | 0.41% |
| 9 | | | 2012-14 | 0.4277 | | 12.00% | | 5.13% | 4.50% | 45.50 | 0.16% |
| 10 | | | | | | | | | | | |
| 11 | NWN | NORTHWEST NATURAL GAS CO. | 2004 | 0.3011 | | 8.90% | | 2.68% | 20.64 | 27.55 | |
| 12 | | | 2005 | 0.3744 | | 9.90% | | 3.71% | 21.28 | 27.58 | |
| 13 | | | 2006 | 0.4085 | | 10.90% | | 4.45% | 22.01 | 27.24 | |
| 14 | | | 2007 | 0.4783 | | 12.50% | | 5.98% | 22.52 | 26.41 | |
| 15 | | | 2008 | 0.4086 | | 10.90% | | 4.45% | 23.71 | 26.50 | |
| 16 | | | GROWTH 2004 - 2008 | | | | | 4.25% | 3.50% | | -0.97% |
| 17 | | | 2009 | 0.4386 | | 11.00% | | 4.82% | | 26.50 | 0.00% |
| 18 | | | 2010 | 0.4105 | | 11.00% | | 4.52% | | 26.50 | 0.00% |
| 19 | | | 2012-14 | 0.4203 | | 11.00% | | 4.62% | 5.00% | 28.00 | 1.11% |
| 20 | | | | | | | | | | | |
| 21 | PNY | PIEDMONT NATURAL GAS COMPANY | 2004 | 0.3307 | | 11.10% | | 3.67% | 11.15 | 76.67 | |
| 22 | | | 2005 | 0.3106 | | 11.50% | | 3.57% | 11.53 | 76.70 | |
| 23 | | | 2006 | 0.2520 | | 11.00% | | 2.77% | 11.83 | 74.61 | |
| 24 | | | 2007 | 0.2929 | | 11.90% | | 3.49% | 11.99 | 73.23 | |
| 25 | | | 2008 | 0.3087 | | 12.40% | | 3.83% | 12.11 | 73.26 | |
| 26 | | | GROWTH 2004 - 2008 | | | | | 3.47% | 6.00% | | -1.13% |
| 27 | | | 2009 | 0.3313 | | 12.50% | | 4.14% | | 73.50 | 0.33% |
| 28 | | | 2010 | 0.3471 | | 13.00% | | 4.51% | | 73.50 | 0.16% |
| 29 | | | 2012-14 | 0.3526 | | 12.50% | | 4.41% | 4.00% | 73.00 | -0.07% |
| 30 | | | | | | | | | | | |
| 31 | SJI | SOUTH JERSEY INDUSTIES, INC. | 2004 | 0.4810 | | 12.50% | | 6.01% | 12.41 | 27.76 | |
| 32 | | | 2005 | 0.4971 | | 12.40% | | 6.16% | 13.50 | 28.98 | |
| 33 | | | 2006 | 0.6260 | | 16.30% | | 10.20% | 15.11 | 29.33 | |
| 34 | | | 2007 | 0.5167 | | 12.80% | | 6.61% | 16.25 | 29.61 | |
| 35 | | | 2008 | 0.5110 | | 13.10% | | 6.69% | 17.33 | 29.73 | |
| 36 | | | GROWTH 2004 - 2008 | | | | | 7.14% | 11.00% | | 1.73% |
| 37 | | | 2009 | 0.5000 | | 12.50% | | 6.25% | | 30.00 | 0.91% |
| 38 | | | 2010 | 0.5170 | | 13.50% | | 6.98% | | 31.00 | 2.11% |
| 39 | | | 2012-14 | 0.5161 | | 13.50% | | 6.97% | 6.00% | 33.00 | 2.11% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 09/11/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2004 - 2008

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16 & 26, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
DIVIDEND GROWTH COMPONENTS



| LINE NO. | STOCK SYMBOL | NATURAL GAS LDC NAME | OPERATING PERIOD | (A) RETENTION RATIO (b) | x | (B) RETURN ON BOOK EQUITY (r) | = | (C) DIVIDEND GROWTH (g) | (D) BOOK VALUE ($/SHARE) | (E) SHARES OUTST. (MILLIONS) | (F) SHARE GROWTH |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | SWX | SOUTHWEST GAS CORPORATION | 2004 | 0.5060 | | 8.30% | | 4.20% | 19.18 | 36.79 | |
| 2 | | | 2005 | 0.3440 | | 6.40% | | 2.20% | 19.10 | 39.33 | |
| 3 | | | 2006 | 0.5859 | | 8.90% | | 5.21% | 21.58 | 41.77 | |
| 4 | | | 2007 | 0.5590 | | 8.50% | | 4.75% | 22.98 | 42.81 | |
| 5 | | | 2008 | 0.3525 | | 5.90% | | 2.08% | 23.49 | 44.19 | |
| 6 | | | GROWTH 2004 - 2008 | | | | | 3.69% | 5.00% | | 4.69% |
| 7 | | | 2009 | 0.4571 | | 7.00% | | 3.20% | | 45.50 | 2.96% |
| 8 | | | 2010 | 0.4737 | | 7.50% | | 3.55% | | 47.00 | 3.13% |
| 9 | | | 2012-14 | 0.5000 | | 8.00% | | 4.00% | 3.50% | 50.00 | 2.50% |
| 10 | | | | | | | | | | | |
| 11 | WGL | WGL HOLDINGS, INC. | 2004 | 0.3434 | | 11.70% | | 4.02% | 16.95 | 48.67 | |
| 12 | | | 2005 | 0.3803 | | 11.70% | | 4.45% | 17.80 | 48.65 | |
| 13 | | | 2006 | 0.3041 | | 10.30% | | 3.13% | 18.86 | 48.89 | |
| 14 | | | 2007 | 0.3476 | | 10.40% | | 3.62% | 19.83 | 49.45 | |
| 15 | | | 2008 | 0.4221 | | 11.60% | | 4.90% | 20.99 | 49.92 | |
| 16 | | | GROWTH 2004 - 2008 | | | | | 4.02% | 4.50% | | 0.64% |
| 17 | | | 2009 | 0.4120 | | 12.00% | | 4.94% | | 50.00 | 0.16% |
| 18 | | | 2010 | 0.4078 | | 11.50% | | 4.69% | | 50.00 | 0.08% |
| 19 | | | 2012-14 | 0.3963 | | 11.00% | | 4.36% | 4.50% | 50.00 | 0.03% |

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 09/11/2009
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2004 - 2008

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
GROWTH RATE COMPARISON

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 6

**WATER COMPANY SAMPLE:**

| LINE NO. | STOCK SYMBOL | (A) ( br ) + ( sv ) | (B) ZACKS EPS | (C) VALUE LINE PROJECTED EPS | (C) DPS | (C) BVPS | (D) VALUE LINE HISTORIC EPS | (D) DPS | (D) BVPS | (E) VALUE LINE & ZACKS AVGS. | (F) 5 - YEAR COMPOUND HISTORY EPS | (F) DPS | (F) BVPS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AWR | 8.86% | 4.00% | 9.50% | 4.50% | 4.00% | 5.50% | 2.00% | 5.00% | 4.93% | 10.23% | 2.96% | 4.57% |
| 2 | CWT | 6.67% | 6.70% | 4.75% | 2.50% | 3.50% | 7.00% | 0.50% | 6.50% | 4.49% | 6.81% | 0.87% | 5.55% |
| 3 | SWWC | 7.27% | - | 12.00% | -22.50% | - | -10.00% | 8.50% | 7.00% | -1.00% | -35.42% | 7.46% | -7.33% |
| 4 | WTR | 5.75% | 7.70% | 10.00% | 5.50% | 6.50% | 5.50% | 8.00% | 10.00% | 7.60% | 3.34% | 8.35% | 7.34% |
| 5 | | | | 9.06% | -2.50% | 4.67% | 2.00% | 4.75% | 7.13% | | -3.76% | 4.91% | 2.53% |
| 6 | AVERAGES | 7.14% | 6.13% | | 3.74% | | | 4.63% | | 4.01% | | 1.23% | |

**NATURAL GAS LDC SAMPLE:**

| LINE NO. | STOCK SYMBOL | (A) ( br ) + ( sv ) | (B) ZACKS EPS | (C) VALUE LINE PROJECTED EPS | (C) DPS | (C) BVPS | (D) VALUE LINE HISTORIC EPS | (D) DPS | (D) BVPS | (E) VALUE LINE & ZACKS AVGS. | (F) 5 - YEAR COMPOUND HISTORY EPS | (F) DPS | (F) BVPS |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AGL | 5.96% | 4.50% | 3.50% | 2.50% | 1.50% | 8.50% | 8.00% | 10.00% | 5.50% | 4.41% | 9.94% | 4.43% |
| 2 | ATO | 4.43% | 5.00% | 4.00% | 1.50% | 4.00% | 5.00% | 1.50% | 7.50% | 4.07% | 6.07% | 1.60% | 5.78% |
| 3 | LG | 5.05% | 3.00% | 3.50% | 2.50% | 5.50% | 9.50% | 1.50% | 5.50% | 4.43% | 9.74% | 2.50% | 6.87% |
| 4 | NJR | 5.67% | 7.00% | 5.50% | 5.50% | 9.50% | 7.50% | 5.00% | 11.50% | 7.36% | 12.26% | 6.28% | 11.33% |
| 5 | GAS | 5.19% | 4.20% | 2.50% | - | 4.50% | 1.00% | 0.50% | 4.00% | 2.78% | 4.33% | 0.00% | 6.12% |
| 6 | NWN | 4.96% | 5.80% | 5.00% | 5.50% | 5.00% | 8.00% | 3.00% | 3.50% | 5.11% | 8.42% | 3.99% | 3.53% |
| 7 | PNY | 4.75% | 7.00% | 5.50% | 3.50% | 4.00% | 6.50% | 4.50% | 6.00% | 5.29% | 4.07% | 4.92% | 2.09% |
| 8 | SJI | 7.92% | 11.10% | 5.50% | 7.00% | 6.00% | 13.00% | 6.00% | 11.00% | 8.51% | 9.48% | 7.86% | 8.71% |
| 9 | SWX | 4.03% | 7.00% | 4.50% | 5.00% | 3.50% | 9.00% | 1.00% | 5.00% | 5.00% | -4.34% | 2.35% | 5.20% |
| 10 | WGL | 4.38% | - | 4.00% | 3.00% | 4.50% | 4.00% | 1.50% | 4.50% | 3.58% | 5.36% | 2.05% | 5.49% |
| 11 | | | | 4.35% | 4.00% | 4.80% | 7.20% | 3.25% | 6.85% | | 5.98% | 4.15% | 5.95% |
| 12 | AVERAGES | 5.23% | 6.07% | | 4.38% | | | 5.77% | | 5.16% | | 5.36% | |

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 10/23/2009 (WATER COMPANIES) AND 09/11/2009 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 10/23/2009 (WATER COMPANIES) AND 09/11/2009 (NATURAL GAS LDC's)
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 3 (WATER) AND 1 THRU 10 (NATURAL GAS)
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 10/23/2009 (WATER COMPANIES) AND 09/11/2009 (NATURAL GAS LDC's)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPM COST OF EQUITY CAPITAL

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 7, PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

| LINE NO. | STOCK SYMBOL | k | = | $r_f$ | + [ | (A) ß | x | ( | $r_m$ | - | $r_f$ | ) ] | = | (B) EXPECTED RETURN |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AWR | k | = | 2.26% | + [ | 0.80 | x | ( | 9.60% | - | 5.40% | ) ] | = | 5.62% |
| 2 | CWT | k | = | 2.26% | + [ | 0.75 | x | ( | 9.60% | - | 5.40% | ) ] | = | 5.41% |
| 3 | SWWC | k | = | 2.26% | + [ | 1.10 | x | ( | 9.60% | - | 5.40% | ) ] | = | 6.88% |
| 4 | WTR | k | = | 2.26% | + [ | 0.65 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.99% |
| 5 | **WATER COMPANY AVERAGE** | | | | | 0.83 | | | | | | | | 5.72% |
| 6 | AGL | k | = | 2.26% | + [ | 0.75 | x | ( | 9.60% | - | 5.40% | ) ] | = | 5.41% |
| 7 | ATO | k | = | 2.26% | + [ | 0.65 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.99% |
| 8 | LG | k | = | 2.26% | + [ | 0.60 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.78% |
| 9 | NJR | k | = | 2.26% | + [ | 0.65 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.99% |
| 10 | GAS | k | = | 2.26% | + [ | 0.70 | x | ( | 9.60% | - | 5.40% | ) ] | = | 5.20% |
| 11 | NWN | k | = | 2.26% | + [ | 0.60 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.78% |
| 12 | PNY | k | = | 2.26% | + [ | 0.65 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.99% |
| 13 | SJI | k | = | 2.26% | + [ | 0.65 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.99% |
| 14 | SWX | k | = | 2.26% | + [ | 0.75 | x | ( | 9.60% | - | 5.40% | ) ] | = | 5.41% |
| 15 | WGL | k | = | 2.26% | + [ | 0.65 | x | ( | 9.60% | - | 5.40% | ) ] | = | 4.99% |
| 16 | **NATURAL GAS LDC AVERAGE** | | | | | 0.67 | | | | | | | | 5.05% |

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ ß (r_m - r_f ) ]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
$r_f$ = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
$r_m$ = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 10/16/2009 THROUGH 12/04/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PEI THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK.

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPM COST OF EQUITY CAPITAL

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 7, PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

| LINE NO. | STOCK SYMBOL | k | = | $r_f$ | + [ | (A) ß | x | ( | $r_m$ | - | $r_f$ | ) ] | = | (B) EXPECTED RETURN |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | AWR | k | = | 2.26% | + [ | 0.80 | x | ( | 11.70% | - | 5.60% | ) ] | = | 7.14% |
| 2 | CWT | k | = | 2.26% | + [ | 0.75 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.83% |
| 3 | SWWC | k | = | 2.26% | + [ | 1.10 | x | ( | 11.70% | - | 5.60% | ) ] | = | 8.97% |
| 4 | WTR | k | = | 2.26% | + [ | 0.65 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.22% |
| 5 | **WATER COMPANY AVERAGE** | | | | | 0.83 | | | | | | | | 7.29% |
| 6 | AGL | k | = | 2.26% | + [ | 0.75 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.83% |
| 7 | ATO | k | = | 2.26% | + [ | 0.65 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.22% |
| 8 | LG | k | = | 2.26% | + [ | 0.60 | x | ( | 11.70% | - | 5.60% | ) ] | = | 5.92% |
| 9 | NJR | k | = | 2.26% | + [ | 0.65 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.22% |
| 10 | GAS | k | = | 2.26% | + [ | 0.70 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.53% |
| 11 | NWN | k | = | 2.26% | + [ | 0.60 | x | ( | 11.70% | - | 5.60% | ) ] | = | 5.92% |
| 12 | PNY | k | = | 2.26% | + [ | 0.65 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.22% |
| 13 | SJI | k | = | 2.26% | + [ | 0.65 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.22% |
| 14 | SWX | k | = | 2.26% | + [ | 0.75 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.83% |
| 15 | WGL | k | = | 2.26% | + [ | 0.65 | x | ( | 11.70% | - | 5.60% | ) ] | = | 6.22% |
| 16 | **NATURAL GAS LDC AVERAGE** | | | | | 0.67 | | | | | | | | 6.32% |

REFERENCES:
COLUMN (A): SHARPE LITNER CAPITAL ASSET PRICING MODEL ("CAPM") FORMULA

$$k = r_f + [ß (r_m - r_f)]$$

WHERE: k = THE EXPECTED RETURN ON A GIVEN SECURITY
$r_f$ = RATE OF RETURN ON A RISK FREE ASSET PROXY (a)
ß = THE BETA COEFFICIENT OF A GIVEN SECURITY
$r_m$ = PROXY FOR THE MARKET RATE OF RETURN (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 5-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 10/16/2009 THROUGH 12/04/2009 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE GEOMETRIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAME PER THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK.

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 8

| LINE NO. | YEAR | (A) CHANGE IN CPI | (B) CHANGE IN GDP (1996 $) | (C) PRIME RATE | (D) FED. DISC. RATE | (E) FED. FUNDS RATE | (F) 91-DAY T-BILLS | (G) 30-YR T-BONDS | (H) A-RATED UTIL. BOND YIELD | (I) Baa-RATED UTIL. BOND YIELD |
|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 1990 | 5.39% | 1.90% | 10.01% | 6.98% | 8.10% | 7.50% | 7.49% | 9.86% | 10.06% |
| 2 | 1991 | 4.25% | -0.20% | 8.46% | 5.45% | 5.69% | 5.38% | 5.38% | 9.36% | 9.55% |
| 3 | 1992 | 3.03% | 3.30% | 6.25% | 3.25% | 3.52% | 3.43% | 3.43% | 8.69% | 8.86% |
| 4 | 1993 | 2.96% | 2.70% | 6.00% | 3.00% | 3.02% | 3.00% | 3.00% | 7.59% | 7.91% |
| 5 | 1994 | 2.61% | 4.00% | 7.14% | 3.60% | 4.21% | 4.25% | 4.25% | 8.31% | 8.63% |
| 6 | 1995 | 2.81% | 2.50% | 8.83% | 5.21% | 5.83% | 5.49% | 5.49% | 7.89% | 8.29% |
| 7 | 1996 | 2.93% | 3.70% | 8.27% | 5.02% | 5.30% | 5.01% | 5.01% | 7.75% | 8.17% |
| 8 | 1997 | 2.34% | 4.50% | 8.44% | 5.00% | 5.46% | 5.06% | 5.06% | 7.60% | 8.12% |
| 9 | 1998 | 1.55% | 4.20% | 8.35% | 4.92% | 5.35% | 4.78% | 4.78% | 7.04% | 7.27% |
| 10 | 1999 | 2.19% | 4.50% | 7.99% | 4.62% | 4.97% | 4.64% | 4.64% | 7.62% | 7.88% |
| 11 | 2000 | 3.38% | 3.70% | 9.23% | 5.73% | 6.24% | 5.82% | 5.82% | 8.24% | 8.36% |
| 12 | 2001 | 2.83% | 0.80% | 6.92% | 3.41% | 3.88% | 3.40% | 5.95% | 7.59% | 8.02% |
| 13 | 2002 | 1.59% | 1.60% | 4.67% | 1.17% | 1.67% | 1.61% | 5.38% | 7.41% | 7.98% |
| 14 | 2003 | 2.27% | 2.50% | 4.12% | 2.03% | 1.13% | 1.01% | 4.92% | 6.18% | 6.64% |
| 15 | 2004 | 2.68% | 3.60% | 4.34% | 2.34% | 1.35% | 1.37% | 5.03% | 5.77% | 6.20% |
| 16 | 2005 | 3.39% | 2.90% | 6.16% | 4.19% | 3.22% | 3.15% | 4.57% | 5.38% | 5.78% |
| 17 | 2006 | 3.24% | 2.80% | 7.97% | 5.96% | 4.97% | 4.73% | 4.91% | 5.94% | 6.30% |
| 18 | 2007 | 2.85% | 2.00% | 8.05% | 5.86% | 5.02% | 4.36% | 4.84% | 6.07% | 6.24% |
| 19 | 2008 | 3.58% | 1.30% | 5.09% | 2.39% | 1.92% | 1.37% | 4.28% | 6.34% | 6.64% |
| 20 | CURRENT | -0.20% | 2.80% | 3.25% | 0.50% | 0.00% - 0.25% | 0.03% | 4.25% | 5.52% | 6.22% |

REFERENCES:
COLUMN (A): 1990 - CURRENT, U.S. DEPARTMENT OF LABOR, BUREAU OF LABOR STATISTICS WEB SITE
COLUMN (B): 1990 - CURRENT, U.S. DEPARTMENT OF COMMERCE, BUREAU OF ECONOMIC ANALYSIS WEB SITE
COLUMN (C) THROUGH (G): 1990 - 2003, FEDERAL RESERVE BANK OF ST. LOUIS WEB SITE
COLUMN (C) THROUGH (D): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 12/04/2009
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 12/04/2009
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

RIO RICO UTILITIES, INC.
TEST YEAR ENDED DECEMBER 31, 2008
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. WS-02676A-09-0257
SCHEDULE WAR - 9

## AVERAGE CAPITAL STRUCTURES OF SAMPLE WATER COMPANIES

| LINE NO. | | AWR | PCT. | CWT | PCT. | SWWC | PCT. | WTR | PCT. | WATER COMPANY AVERAGE | PCT. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | DEBT | $ 266.5 | 46.2% | $ 287.5 | 41.6% | $ 190.6 | 62.6% | $ 1,248.1 | 54.1% | $ 498.2 | 51.4% |
| 2 | | | | | | | | | | | |
| 3 | PREFERRED STOCK | 0.0 | 0.0% | 0.0 | 0.0% | 0.5 | 0.2% | 0.0 | 0.0% | 0.1 | 0.0% |
| 4 | | | | | | | | | | | |
| 5 | COMMON EQUITY | 310.5 | 53.8% | 402.9 | 58.4% | 113.3 | 37.2% | 1,058.4 | 45.9% | 471.3 | 48.6% |
| 6 | | | | | | | | | | | |
| 7 | TOTALS | $ 577.0 | 100% | $ 690.4 | 100% | $ 304.4 | 100% | $ 2,306.5 | 100% | $ 969.6 | 100% |

## AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES

| LINE NO. | | AGL | PCT. | ATO | PCT. | LG | PCT. | NJR | PCT. | GAS | PCT. |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | | | | | | | | | | | |
| 2 | | | | | | | | | | | |
| 3 | DEBT | $ 1,675.0 | 50.3% | $ 2,119.8 | 50.8% | $ 389.2 | 44.4% | $ 455.1 | 38.5% | $ 448.0 | 31.5% |
| 4 | | | | | | | | | | | |
| 5 | PREFERRED STOCK | 0.0 | 0.0% | 0.0 | 0.0% | 0.5 | 0.1% | 0.0 | 0.0% | 0.6 | 0.0% |
| 6 | | | | | | | | | | | |
| 7 | COMMON EQUITY | 1,652.0 | 49.7% | 2,052.5 | 49.2% | 486.5 | 55.5% | 727.0 | 61.5% | 973.1 | 68.4% |
| 8 | | | | | | | | | | | |
| 9 | TOTALS | $ 3,327.0 | 100% | $ 4,172.3 | 100% | $ 876.2 | 100% | $ 1,182.1 | 100% | $ 1,421.7 | 100% |
| 10 | | | | | | | | | | | |
| 11 | | | | | | | | | | | |
| 12 | | NWN | PCT. | PNY | PCT. | SJI | PCT. | SWX | PCT. | WGL | PCT. |
| 13 | | | | | | | | | | | |
| 14 | DEBT | $ 512.0 | 44.9% | $ 794.3 | 47.2% | $ 332.8 | 39.2% | $ 1,185.5 | 51.0% | $ 603.7 | 38.5% |
| 15 | | | | | | | | | | | |
| 16 | PREFERRED STOCK | 0.0 | 0.0% | 0.0 | 0.0% | 0.0 | 0.0% | 100.0 | 4.3% | 28.2 | 1.8% |
| 17 | | | | | | | | | | | |
| 18 | COMMON EQUITY | 628.4 | 55.1% | 887.2 | 52.8% | 515.3 | 60.8% | 1,037.8 | 44.7% | 935.1 | 59.7% |
| 19 | | | | | | | | | | | |
| 20 | TOTALS | $ 1,140.4 | 100% | $ 1,681.5 | 100% | $ 848.1 | 100% | $ 2,323.3 | 100% | $1,567.0 | 100% |
| 21 | | | | | | | | | | | |
| 22 | | | | | | | | | | | |
| 23 | | NATURAL GAS LDC | | | | WATER & LDC | | | | | |
| 24 | | AVERAGE | PCT. | | | AVERAGE | PCT. | | | | |
| 25 | | | | | | | | | | | |
| 26 | DEBT | $ 851.5 | 45.9% | | | $ 674.9 | 47.8% | | | | |
| 27 | | | | | | | | | | | |
| 28 | PREFERRED STOCK | 12.9 | 0.7% | | | 6.5 | 0.5% | | | | |
| 29 | | | | | | | | | | | |
| 30 | COMMON EQUITY | 989.5 | 53.4% | | | 730.4 | 51.7% | | | | |
| 31 | | | | | | | | | | | |
| 32 | TOTALS | $ 1,854.0 | 100% | | | $ 1,411.7 | 100% | | | | |

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS