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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC. AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02465A-09-0411
IN THE MATTER OF THE APPLICATION OF NORTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-20453A-09-0412
IN THE MATTER OF THE APPLICATION OF SOUTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-20454A-09-0413

EXHIBIT
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ADMITTED

IN THE MATTER OF THE JOINT APPLICATION OF BELLA VISTA WATER CO., INC., NORTHERN SUNRISE WATER COMPANY, INC., AND SOUTHERN SUNRISE WATER COMPANY, INC. FOR APPROVAL OF AUTHORITY TO CONSOLIDATE OPERATIONS, AND FOR THE TRANSFER OF UTILITY ASSETS TO BELLA VISTA WATER CO., INC. PURSUANT TO ARIZONA REVISED STATUTES 40-285.	DOCKET NO. W-02465A-09-0414 DOCKET NO. W-20453A-09-0414 DOCKET NO. W-20454A-09-0414

REJOINDER TESTIMONY OF

THOMAS J. BOURASSA

(COST OF CAPITAL)

BELLA VISTA WATER CO., INC.,
NORTHERN SUNRISE WATER COMPANY INC.
AND SOUTHERN SUNRISE WATER COMPANY INC

July 7, 2010

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I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND 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. I am testifying in this proceeding on behalf of the applicants, Bella Vista Water Company, Northern Sunrise Water Company, and Southern Sunrise Water Company, consolidated as Bella Vista Water Company ("BVWC" 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.

II. SUMMARY OF REJOINDER TESTIMONY AND THE PROPOSED COST OF CAPITAL FOR THE COMPANY

A. Summary of Company's Rebuttal Recommendation

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 May 25, 2010. The Company's proposed consolidated capital structure is 22.6 percent debt and 77.4 percent equity. I continue to recommend a cost of equity of 10.9 percent, which results in a weighted cost of capital ("WACC") of 9.85 percent.

As I explained in my rebuttal testimony, I believe that a return on equity of 10.9 percent is fair and reasonable, and properly takes into account BVWC'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 Commission in setting rates for numerous water and wastewater utilities, including affiliates of BVWC. The return produced by those models was then adjusted downward by 60 basis points to account for the absence of debt in the Company's capital structure, and then, finally, 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	9.1%	10.5%	9.8%
Range of CAPM Estimates	10.4%	13.9%	12.2%
Average of DCF and CAPM midpoint estimates	9.8%	12.2%	11.0%
Financial Risk Adjustment	-0.6%	-0.6%	-0.6%
Specific Company Risk Premium	0.5%	0.5%	0.5%
Indicated Cost of Equity	**9.7%**	**12.1%**	**10.9%**

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

Q. ON A STAND ALONE BASIS, WHAT ARE THE COMPANY'S RECOMMENDATIONS?

A. The Company's proposed capital structure for a stand-alone Bella Vista is 31.56

percent debt and 68.44 percent equity. I recommend a cost of equity of 11.0 percent, which results in a weighted cost of capital ("WACC") of 9.51 percent. The Company's proposed capital structure for Northern Sunrise and Southern Sunrise is 100 percent equity. I recommend a cost of equity of 11.1 percent, which results in a weighted cost of capital ("WACC") of 11.1 percent. The details of my cost of capital analysis on a stand-alone basis can be found in the respective stand-alone D schedules for Bella Vista, Northern Sunrise, and Southern Sunrise. From this point forward I will be testifying on the cost of capital as it relates to the consolidated Bella Vista Water Company.

B. Summary of the Recommendations of Staff and RUCO.

Q. PLEASE SUMMARIZE THE COMPANY'S RESPONSE REGARDING STAFF'S RECOMMENDED EQUITY RETURN AND WACC.

A. Staff's cost of capital witness, Mr. Chaves, continues to recommend a capital structure consisting of 18.7 percent debt and 81.3 percent equity.[1] He also recommends a return on equity of 9.3 percent. That return is based on the average cost of equity produced by its DCF and CAPM models – 10.3 percent – and a 100 basis-point downward adjustment for BVWC's financial risk.[2] Based on Staff's proposed capital structure, Mr. Chaves is proposing a WACC for BVWC of 8.8 percent.[3]

Q. HAS STAFF MADE COST OF EQUITY AND WEIGHTED COST OF CAPITAL RECOMMENDATIONS FOR BELLA VISTA, NORTHERN SUNRISE, AND SOUTHERN SUNRISE ON A STAND-ALONE BASIS?

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[1] Surrebuttal Testimony of Pedro M. Chaves ("Chaves Sb.") at 7.

[2] *Id.*

[3] *Id.*

A. Actually, Staff uses its 8.8 percent return for both its consolidated basis and stand-alone basis for all three utilities.

Q. PLEASE CONTINUE.

A. The most significant problems with Staff's recommendations are, in summary:

(1) Staff's downward adjustment for financial risk is significantly overstated. First, Mr. Chaves 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 BVWC, even though BVWC is much smaller and is riskier than the publicly traded utilities.

(2) Staff ignores the fact that BVWC is riskier than the publicly traded utilities in the sample group, despite BVWC's small size, lack of liquidity and Arizona's unfavorable regulatory climate. Empirical financial data demonstrate that there exists a relationship between firm size and return.[4] 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.

Q. PLEASE SUMMARIZE THE COMPANY'S RESPONSE REGARDING RUCO'S RECOMMENDED EQUITY RETURN AND WACC.

[4] Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook* ("*Ibbotson*") at 85 – 107.

A. RUCO's cost of capital witness, Mr. Rigsby, recommends a consolidated capital structure consisting of 21.08 percent debt and 78.92 percent debt.[5] He also recommends a return on equity of 9.0 and a cost of debt of 6.27 percent.[6] Based on RUCO's recommend capital structure, RUCO recommends a WACC of 8.42 percent.[7] As I discussed in my rebuttal testimony, RUCO's witness, Mr. Rigsby, estimated that the cost of equity for its sample utilities is only 7.93 percent, based on the results of his DCF and CAPM methods.[8] RUCO's cost of equity is driven by its extraordinarily low CAPM estimate, 5.95 percent, which is lower than the current yield on an investment grade bond and, moreover, lower than the cost of debt RUCO's recommends. Mr. Rigsby obviously utilized techniques that greatly bias downward his cost of equity estimates and, for this reason, he had to increase his own recommended cost of equity upwards by roughly 110 basis points to 9 percent. The most significant flaws in RUCO's cost of equity estimate, in summary, are:

(1) RUCO relies on a sample group of publicly traded gas utilities to estimate BVWC's cost of equity, and estimates that this industry's group's cost of equity is only 7.8 percent. In contrast, the Commission recently authorized a 9.5 percent return on equity for UNS Gas.[9] 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 9.5 percent.

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[5] Surrebuttal Testimony of William A. Rigsby ("Rigsby Sb.") at 4.

[6] *Id.* at 4 – 5.

[7] *Id.* at 5.

[8] Rebuttal Testimony of Thomas J. Bourassa – Consolidated Cost of Capital ("Bourassa COC Rb.") at 5.

[9] *UNS Gas, Inc.*, Decision No. 71623 (April 14, 2010).

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

(3) RUCO erroneously relies on geometric annual averages in its 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.

Q. WHAT ARE RUCO'S RECOMMENDATIONS FOR BELLA VISTA, NORTHERN SUNRISE AND SOUTHERN SUNRISE ON A STAND-ALONE BASIS?

A. For Bella Vista (stand-alone), RUCO recommends a capital structure consisting of 27.76 percent debt and 72.24 percent equity. RUCO recommends a cost of debt of 6.27 percent and 9.0 percent cost of equity, which produces an overall return on 8.24 percent.[10] RUCO recommends a hypothetical capital structure consisting of 40 percent debt and 60 percent equity for Northern Sunrise (stand-alone) and Southern Sunrise (stand-alone). RUCO recommends a cost of debt of 6.26 percent

[10] Rigsby Sb. at 3.

and 9.0 percent cost of equity, which produces an overall return on 7.90 percent.[11]

Q. EXCUSE ME, MR. BOURASSA, DID YOU JUST SAY THAT RUCO IS RECOMMENDING AN OVERALL RETURN FOR NORTHERN SUNRISE AND SOUTHERN SUNRISE THAT IS LESS THAN BELLA VISTA?

A. Yes. This is because RUCO recommends the same 9.0 percent return on equity, proposes a hypothetical capital structure of 40 percent debt and 60 percent equity, and uses the same cost of debt for Northern Sunrise (stand-alone) and Southern Sunrise (stand-alone) as it does for Bella Vista (stand-alone). In my view, Mr. Rigsby's recommendations are at the very least inconsistent. Even worse, they defy simple financial common sense. Let me give some examples.

Mr. Rigsby appears to find Bella Vista's (stand-alone) proportion of debt in its capital structure of nearly 28 percent acceptable at the same time he recommends a hypothetical debt level of 40 percent debt as appropriate for the much smaller Northern Sunrise and Southern Sunrise. This shows the overly subjective nature of his recommendation, a problem compounded by the fact that his hypothetical capital structures presume an optimal level of leverage in the capital structure for Northern Sunrise and Southern Sunrise, meaning Northern and Southern Sunrise (as stand-alone companies) could borrow at what is effectively the current rate for investment grade bonds, for which Mr. Rigsby provides no evidence. Further, the effective overall return on equity is **only 6.9 percent** when RUCO's fictitious income tax deduction is considered. How can anyone recommend a 6.9 percent return for the former McLain systems?

Q. MR. BOURASSA, STAFF AND RUCO BOTH HAVE RECOMMENDED A DISALLOWANCE OF VIRTUALLY THE ENTIRE AMOUNT OF

[11] *Id.* at 3 – 4.

CENTRAL OFFICE COSTS INCURRED BY APT AND ALLOCATED TO BVWC. IF ADOPTED BY THE COMMISSION, WOULD THAT DISALLOWANCE OF THE APT CENTRAL OFFICE COSTS HAVE ANY IMPACT ON THE COST OF EQUITY FOR BVWC?

A. Yes, a denial of the APT Central Office Costs would deprive BVWC 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 APUC, 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.

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 BVWC, Staff and RUCO would prevent BVWC from earning its authorized rate of return. In fact, I am aware that the California PUC has authorized recovery of these types of expenses.[12] It is arbitrary and unfair for Staff and RUCO to set BVWC's cost of equity based on net earnings of the sample companies, which reflect corporate expenses of being publicly traded, but disallow BVWC from recovering those costs in this case, and then also fail to account for the differences.

III. 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 and rebuttal testimony,[13] Staff's recommended surrebuttal financial risk adjustment of 100 basis points is overstated by at least 50 basis

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

[13] Direct Testimony of Thomas J. Bourassa – Cost of Capital ("Bourassa COC Dt.") at 35 – 36; Bourassa COC Rb. at 9.

points. Accordingly, Staff's cost of equity estimate would increase from 9.3 percent to at least 9.8 percent if market values rather than book values were used in the Hamada method.

The other problem with Staff's financial risk adjustment is that Staff assumes that the average beta of the publicly traded water utilities is the beta for BVWC. A basic assumption underlying the use of the Hamada method is that the publicly traded utility companies are comparable in every way except for capital structure. I have testified extensively that small companies like BVWC are not comparable,[14] consequently the beta for would be higher[15] and the results of any financial risk adjustment would be lower.[16]

Q. DO YOU USE THE AVERAGE BETA FOR THE SAMPLE WATER COMPANIES IN PERFORMING YOUR FINANCIAL RISK ADJUSTMENT?

A. Yes. But the important difference is that my cost of capital analysis includes a company specific risk premium (small company risk premium) which reflects the fact that the Company is more risky than the publicly traded water utilities – the risks of smaller firms not captured by the market beta of the larger water utility companies. Ignoring the additional risk of smaller firms and adjusting only for financial risk based on a proxy beta of much larger companies produces anomalous results.

Q. DO YOU HAVE AN EXAMPLE?

A. Yes. Staff recommended an 80 basis point financial risk adjustment in the pending

[14] Bourassa COC Dt. at 15 – 22; Bourassa COC Rb. at 11 – 13.

[15] Bourassa COC Dt. at 31 – 32; Bourassa COC Rb. at 8.

[16] *Id.*

Litchfield Park Service Company ("LPSCO") rate case.[17] LPSCO is a much larger utility than BVWC having over 15,000 water customers and nearly 15,000 wastewater customers compared to 9,600 water customers for BVWC. A rational investor would not view BVWC as having directly comparable business and operational risks as the much larger LPSCO. Despite recommending a similar capital structure for LPSCO,[18] Staff's financial risk adjustment is higher by 20 basis points for BVWC than for LPSCO.

Another example is the pending Black Mountain Sewer Company ("BMSC") rate case. In that case, Staff recommended a financial risk adjustment of 80 basis points using a capital structure very similar to BVWC.[19] Yet, BMSC has only 2,100 wastewater customers less than 1/6 the size of LPSCO. Again, a rational investor would not view BMSC as having directly comparable business and operational risks as the much larger LPSCO. Perhaps this is why Staff did not recommend a financial risk adjustment for BMSC in its prior rate case.[20] In fact, in the BMSC rate case, 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.*[21]

[17] *See* Surrebuttal Testimony of Juan C. Manrique, filed December 17, 2009 in Docket Nos. SW-01428A-09-0103 & W-01427A-09-0104, at Schedule JCM-3.

[18] In the LPSCO rate case Staff recommends a capital structure of 17.2 percent debt and 82.8 percent equity. *See id.* at Schedule JCM-4.

[19] In the BMSC, Staff recommends a capital structure consisting of 21.6 percent debt and 78.4 percent equity. *See* Surrebuttal Testimony of Juan C. Manrique, filed November 9, 2009 in Docket W-02361A-08-0609, at Schedules JCM-3 and JCM-4.

[20] *Black Mountain Sewer Corporation*, Decision 69164 (December 5, 2006).

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

Yet another example, in the pending Sahuarita Water Company ("SWC") rate case, Staff is recommending a very similar capital structure for SWC and yet is not recommending any financial risk adjustment.[22] Staff is recommending a 10.3 percent rate of return in that case. SWC has about 4,600 customers and is somewhat smaller than BVWC so this might justify a bit lower return than 10.3 percent. However, in the pending BMSC rate case, where BMSC has less than half the number of customers, Staff is recommending a 9.4 percent return.[23]

Q. WHAT REASON DOES STAFF PROVIDE FOR NOT MAKING ANY FINANCIAL RISK ADJUSTMENT IN THE SWC RATE CASE?

A. Staff states, "[It] does not use a financial risk adjustment because SWC is not a publicly traded company, and does not have access to the capital markets."[24]

Q. IS BVWC PUBLICLY TRADED?

A. No. So the same view should hold in this rate case. However, I suspect that Staff will make a distinction in the fact that BVWC's parent, APUC, is publicly traded whereas the owners of SWC are not publicly traded.

Q. IS THIS THE CORRECT VIEW?

A. No. None of the parties consider who the shareholders of the publicly traded utility companies are to make a determination on the cost of equity. And, neither should we. It is the investment, and not the investor, that is relevant to the cost of capital.

(emphasis supplied).

[22] In the SWC rate case (Docket W-03718A-09-0359), Staff recommends a capital structure consisting of 17.8 percent debt and 82.2 percent equity. Staff recommends its unadjusted cost of equity of 10.3 percent. *See* Direct and Surrebuttal Testimony of Juan C. Manrique, filed April 22, 2010 and June 21, 2010, respectively, in Docket W-03718A-09-0359, at Schedules JCM-3 and JCM-4.

[23] *See* Surrebuttal Testimony of Juan C. Manrique, filed November 9, 2009 in Docket W-02361A-08-0609, at Schedules JCM-3 and JCM-4. Staff recommendation is for a unadjusted return of 10.3% and a financial risk adjustment of 80 basis points.

[24] See Direct Testimony of Juan C. Manrique filed April 22, 2010 in Docket W-03718A-09-0359 at 33.

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

A. Staff simply claims that the use of book values is "prudent and reasonable in a regulatory environment."[25] This is hardly authoritative. In fact, 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?

A. If book values are used rather than stock prices, Staff's dividend yield increases to 7.0 percent and Staff's cost of equity estimate for the DCF constant growth method would increase from 8.9 percent to 12.3 percent. The average of Staff's DCF method would increase to 11.7 percent from 9.5 percent (average of 12.3 percent for DCF constant growth, and 10.0 percent for multi-stage DCF).

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.[26] Staff has not disputed this point.

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[25] Chaves Sb. at 3.

[26] Bourassa COC Dt. at 26.

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."[27] 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.[28] Over time, earnings will be insufficient to pay dividends and both earnings and book value will necessarily decline.

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.[29] 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 11.1 percent as k, the average M/B ratio of 1.8 for Staff sample group as M/B, and an implied growth rate of 7.5 percent[30] as g, the indicated book equity return for Staff's models using the equation above is 13.2 percent and is computed as follows:

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

[28] *Id.* at 434.

[29] *Id.* at 364.

[30] 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 11.1% and Staff's dividend yield is 3.6%, thus the implied growth rate in 11.1% less 3.6% or 7.5%.

13.98% = 1.8(11.1% - 7.5%) + 7.5%

Thus, Staff's CAPM estimate would increase to 13.98 percent from 11.1 percent.

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 percent from 10.3 percent. Applying Staff's book value based financial risk adjustment of 100 basis points to Staff's book value based cost of equity estimate would result in an indicated cost of equity of 11.8 percent as shown below:

DCF Method	D_1/B_0	+	g^1	=	k
Constant Growth DCF estimate (book value)	7.0%	+	5.7%	=	12.7%
Multi-stage DCF estimate (book value)					10.0%
Average of DCF estimates					11.7%

CAPM Method	k
CAPM (book value)	13.98%

Average	12.8%
Financial Risk Adjustment[1]	-1.0%
Total	11.7%

[1] From Staff Surrebuttal Schedule JCM-3

Q. WHAT'S THE AVERAGE PERCENTAGE PROJECTED RATE OF RETURN ON BOOK COMMON EQUITY FOR MR. CHAVES' WATER UTILITIES SAMPLE?

A. Based on Mr. Chaves' water industry, the average ROE is 11.8 percent. It is found as the average of Value Line's projected ROEs for American States of 10.5 percent, for Aqua America of 14.0 percent and California Water of 11.0 percent.[31]

[31] Value Line Investment Survey, April 23, 2010.

This compares favorably with the 11.7 percent estimate shown above and like the 11.7 percent, it is much higher than the 10.3 percent estimate of Staff.[32]

B. Firm Specific Risk

Q. HOW DO YOU RESPOND TO MR. CHAVES' ASSERTION THAT THE ARIZONA REGULATORY ENVIRONMENT IS NO LESS FAVORABLE THAN THE REGULATORY ENVIRONMENTS FACED BY THE SAMPLE UTILITIES?

A. I disagree with him. Mr. Chaves testifies that the regulatory environment in Arizona has many "attractive attributes," including the use of a fair value rate base ("FVRB"), the ability to seek accounting orders, the recognition of known and measurable changes, the wide use of hook-up fees, and regulatory responsiveness, such as the approval of arsenic recovery mechanisms and arsenic remedial surcharge mechanisms.[33] I will address each of the alleged "attractive attributes" Mr. Chaves has identified.

Q. PLEASE START WITH FAIR VALUE RATE BASE. DO INVESTORS CONSIDER ARIZONA'S USE OF FAIR VALUE RATE BASE AN ATTRACTIVE ATTRIBUTE OF INVESTING IN ARIZONA?

A. To my knowledge, investors do not. This is because the Commission does not recognize the increased value when the utility's FVRB is higher than the original cost rate base. If a higher FVRB does not generate higher returns then investors will not consider it an attractive attribute. Again, this is financial common sense.

Furthermore, the issue of FVRB has been significantly disputed in Arizona. The Court of Appeals in Chaparral City Water Co. v. Ariz. Corp. Comm'n 1 CA-

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[32] The unadjusted average of Staff's DCF and CAPM results as shown on Staff Surrebuttal Schedule PCM-2 is 10.3%.

[33] Chaves Sb. at 4:20 – 5:18.

CC-05-0002 (Ariz. App. Feb. 13, 2007) ("Chaparral City") issued a Memorandum Decision on the issue, which rejected the ACC's methodology for calculating FVRB, which led to a remand decision, (Decision No. 70441, July 28, 2008) which revised the ACC method, adjusting the equity component of FVRB downward to account for inflation. Then, the ACC adopted another decision (Decision No. 71308, October 21, 2009) which applied the inflation factor discount to both the equity and the debt components of FVRB.

In that case, the Commission itself stated:

> "The Constitution is silent as to how the Commission is to determine the rate of return, thereby leaving that duty to the Commission and allowing it to use its knowledge and expertise, with the caveat that resulting rates and charges must be just and reasonable." [Decision No. 70441, at 20]

To claim that investors would view that dispute, that transition from one method to another, to yet another, all in the light of the Commission stating that there is no Constitutional clarity as a positive, is to completely misunderstand investors' desire for certainty, transparency, and stability.

Q. ARE ACCOUNTING ORDERS AN "ATTRACTIVE ATTRIBUTE" OF REGULATION IN ARIZONA?

A. No. I am not aware that regulatory mechanisms similar to accounting orders are not available to any of the sample water utilities in the regulatory jurisdictions in which they operate. Therefore, accounting orders do not make Arizona attractive to investors relative to other investments. Besides, the nature of accounting orders limits their attractiveness.

Q. WHAT DO YOU MEAN?

A. In Arizona, accounting orders are narrowly tailored for specific circumstances and generally only allow utilities to track certain, specified costs. No rate recovery is authorized or assured. Rather, accounting orders issued by this Commission

postpone consideration of any cost recovery until a future rate case. In fact, the uncertainty inherent in an accounting order is illustrated in the pending rate case for BVWC's affiliate, LPSCO, where both Staff and RUCO oppose recovery of costs incurred pursuant to a recent Commission-issued accounting order.[34] This is yet another area where Staff misunderstands investors – having a potentially positive tool that is irregularly applied, and always disputed, does nothing to add stability, transparency, or certainty to the Arizona regulatory climate.

Q. WHAT ABOUT THE RECOGNITION OF "KNOWN AND MEASURABLE" CHANGES?

A. Again, this is not a regulatory attribute unique to Arizona. In fact, I am not aware of any jurisdictions that utilize an historic test year where adjustments based on known and measurable changes cannot be made to either the test year rate base or to test year revenue and expenses in order to make the test year a more "normal" representation of the costs of service during the period in which the rates will be in effect. Besides, the historical test year, with its inherent time lag, is not the most favorable base for regulation in the first place.

In contrast, California, in which three of the six sample water companies (American States, California Water, and SJW Corp.) primarily operate, uses future test years in setting rates. Under that state's rate making system, future expenses can be increased to reflect expected changes including projected inflation, revenues can be adjusted to reflect expected future erosion of revenues from water conservation, and future expected capital investment can be recognized in rate

[34] *See* Direct Testimony of Jeffery M. Michlik (water division), filed November 4, 2009 in Docket Nos. SW-01428A-09-0103 & W-01427A-09-0104, at 12 – 14. Staff and RUCO are recommending denial of recovery of costs related to the potential contamination of its water supply due to the proximity of a federally designated superfund site in the current rate case, although Staff has suggested consideration in a future rate case.

base. This regulatory approach is far more attractive to investors than the recognition of known and measurable changes, which is common.

Moreover, California allows adjuster mechanisms that permit utilities to recover increases in purchased power and purchased water costs due to increases in rates charged by power and water providers. More recently, in connection with implementing conservation-oriented rate structures, California has authorized water revenue adjustment mechanisms to be implemented in order to offset revenue erosion due to conservation. In some cases, California allows utilities to file for adjustment mechanisms when unexpected significant capital investment has to be made. By allowing revenues to change between rate cases to match known increases in investment and operating expenses, utilities are given a reasonable chance to earn their authorized return.

In contrast, in Arizona, adjuster mechanisms for purchased water and purchased power have been uniformly opposed by Staff and RUCO over the past decade, and they have been denied by the Commission.[35] And, I don't believe that I have ever seen a revenue conservation adjustment adopted by the Commission for an Arizona water utility with inverted-tier rates designed to encourage water conservation.

Q. DIDN'T THE COMMISSION PROVIDE ARSENIC COST RECOVERY MECHANISMS IN THE PAST?

A. To some extent. But generally these mechanisms have only been allowed for recovery of debt service costs not capital costs and depreciation. That was beneficial, particularly for utilities that could not cash flow the debt service without this mechanism in place. However, these mechanisms did not include recovery of

[35] *See, e.g. Chaparral City Water Company*, Decision 68176 (September 30, 2005); *Arizona Water Company (Eastern Group)*, Decision No. 66849 (March 19, 2004).

increases in operating and maintenance costs associated with the arsenic facilities. And the Commission has made it clear that such mechanisms were special cases intended to address extraordinary circumstances, and their approval did not establish a precedent for adjuster mechanisms in general. Thus, while approval of the ACRMs was certainly helpful to the water utilities that obtained them, they do not make Arizona's regulatory environment more attractive to investors than other jurisdictions, which routinely authorize cost recovery mechanisms.

Q. ARE THERE ANY OTHER "ATTRACTIVE ATTRIBUTES" OF OTHER JURISDICTIONS?

A. Yes. For instance, as I discussed in my direct testimony, in many states in which Aqua America operates, utilities are permitted to implement surcharges to recover additional depreciation and capital costs outside the context of a rate case.[36] Aqua America also operates in jurisdictions that allow utilities to implement rates before a final decision in a rate case.[37] In addition, in certain states in which Aqua America operates, utilities are allowed surcharges to reflect changes in certain costs until such time as the costs are incorporated into base rates. Pennsylvania allows water utilities to collect a distribution system improvement charge ("DISC") for the replacement of mains, storage tanks and other distribution system infrastructure. Similarly, Middlesex operates utilities in Delaware, which also allows for the implementation of a DISC for the recovery of depreciation and capital costs outside the context of a rate case. Delaware also allows plant expected to be constructed within three years from the end of the test period to be included in rate base. These attributes are attractive to investors, and none of them are available in Arizona.

[36] Bourassa COC Dt. at 21.

[37] *Id.*

Q. ARE YOU AWARE OF ANY STUDIES THAT SUPPORT YOUR TESTIMONY THAT ARIZONA IS NOT AN ATTRACTIVE REGULATORY ENVIRONMENT?

A. Yes. Standard and Poor's, for example, issued a report in November 2008 that ranked Arizona among the least credit supportive regulatory environments.[38] Investors do recognize the overall effect of the unfavorable regulatory environment here in Arizona. Again, this is why Liberty Water's utilities in Arizona are having a hard time competing for capital with utilities in other states.

Q. BUT LIBERTY WATER WASN'T FORCED TO BUY BVWC AND THE OTHER UTILITIES IT OWNS IN ARIZONA, WAS IT?

A. No, but that isn't the point. Not if we want to attract capital to Arizona, which we obviously do. The goal in this case and every rate case should be to develop a fair and reasonable return on invested capital and, ultimately, rate of return on rate base. The Commission has broad discretion, and may choose to use historic test years with limited out-of-period adjustments, refuse to approve adjuster mechanisms for water and wastewater utilities, and impose inverted-tier water rates without considering the impact on the utility's revenues. But if it chooses to adopt these policies, it cannot also ignore the impact on investment risk. The criteria established by the Supreme Court in decisions such as *Bluefield Water Works* apply in Arizona too.

Q. PLEASE RESPOND TO MR. CHAVES' TESTIMONY ON PAGE 5 THAT REGULATORY RISK IS A FIRM-SPECIFIC RISK AND INVESTORS CANNOT EXPECT TO BE COMPENSATED FOR FIRM-SPECIFIC RISKS.

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[38] Assessing U.S. Utility Regulatory Environments, Rating Directs, Standard and Poor's (November 7, 2008).

A. I have three comments. First, Mr. Chaves' assertion is undermined by the fact that the *Bluefield* standard requires the return on equity be commensurate with returns on enterprises with 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 BVWC more risky and therefore not comparable to the large publicly traded water companies. Second, Mr. Chaves does not dispute my testimony that smaller companies tend to have higher betas than larger companies making smaller companies more risky.[39] It stands to reason that BVWC would have higher beta than the sample water companies.[40] Yet, Mr. Chaves blindly accepts that the average beta of the much larger publicly traded water utilities as the beta for BVWC.[41] Third, the firm size phenomenon is real and should not be ignored. As *Morningstar* states[42]:

> One of the most remarkable discoveries of modern finance is that of a relationship between firm size and return. The relationship cuts across the entire size spectrum but is most evident among smaller companies which have higher returns than larger ones. Many studies have looked at the effect of firm size and return...

And, the CAPM has been shown to be incomplete - not fully account for the higher returns of small company stocks. As *Morningstar* states[43]:

> The firm size phenomenon is remarkable in several ways. First, the greater risk of small stocks does not, in the context

[39] Bourassa COC Dt. at 15 – 22; Bourassa COC Rb. at 11 – 13.

[40] Bourassa COC Rb. at 8.

[41] Chaves Dt. at 30.

[42] *Ibbotson* at 85.

[43] *Id.* at 89.

of the capital asset pricing model (CAPM), fully account for their higher returns over the long term. In the CAPM only systematic, or beta risk, is rewarded; small company stocks have had returns in excess of those implied by their betas.

Q. DOES THE ANNIE WONG STUDY CITED BY MR. CHAVES DISPROVE THE EXISTENCE OF A SIZE PREMIUM FOR SMALL UTILITY STOCKS?

A. No. As Dr. Zepp concluded in his review of Ms. Wong's study, "[her] weak evidence provides little support for a small firm effect existing or not existing in either the industrial or utility sector."[44] In Dr. Zepp's study he concluded that there was a 99 basis point higher indicated return for smaller water utilities.[45]

Q. ARE THERE OTHER STUDIES WHICH DEMONSTRATE THAT SMALLER UTILITIES ARE RISKIER THAN LARGER UTILITIES?

A. Yes. A California PUC study, as mentioned by Dr. Zepp, showed smaller water utilities are more risky than larger ones.[46] Frankly, it seems to me indisputable that investors require higher returns on small company stocks as compared to large company stocks – this includes utility stocks. Yet again, one has to understand that investors seek certainty, transparency, and stability. Small water companies do not provide anything like the transparency of a publicly traded company; this is simply because of the more stringent oversight and reporting requirements on publicly traded companies and is not a criticism of small and private companies' commitment to accounting standards.

The only firm-specific risk Staff acknowledges is financial risk. Other risks

[44] Thomas M. Zepp, "Utility Stocks and the Size Effect – Revisited," The Quarterly Review Economics and Finance, Vol. 43, Issue 3, Autumn 2003, 578 – 582.

[45] *Id.* at 580.

[46] Staff Report on Issues Related to Small Water Utilities, June 10, 1991 and CPUC Decision 92-03-093.

that would obviously be considered by any rational investor are simply ignored. Would a rational investor really regard an equity investment in BVWC 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 BVWC's capital structure? The answer is a resounding "no."

Q. IS THERE A WAY TO ESTIMATE THE COST OF EQUITY FOR A NON-PUBLICLY TRADED COMPANY THAT DOES NOT HAVE A MARKET BETA?

A. Yes, it is called the Build-up Method.[47] This is a common and effective method used by appraisers and valuation experts.[48] The Build-up Method is an additive model in which the return on a security is the sum of a risk-free rate and more or more risk premia. Each premium represents the reward an investor receives for taking on a specific risk. The elegance of the Build-up Method is that it does not require an estimate of market beta which is problematic for non-publicly traded companies such as BVWC. The Build-up Method can be stated as follows:

[1] $k = R_f + RP_m + RP_s +/- RP_u$

where k = the expected return

R_f = risk-free rate

RP_m = equity risk premium for the market

RPs = equity risk premium for size

RP_u = risk premium attributed to the specific company or to the industry (often call the company specific risk premium)

[47] *Ibbotson*, Chapter 3.

[48] *Id.* at 27.

Alternatively the Build-up method can be stated as:

[2] $k = R_f + RP_{ms} +/- RP_u$

where k = the expected return

R_f = risk-free rate

RP_{m+s} = equity risk premium for the market and size

RP_u = risk premium attributed to the specific company or to the industry (often call the company specific risk premium)

The data for the equity risk premium for the market (RP_m), the equity risk premium for size (RP_s), and the company specific or industry risk premium (RP_u) can be ready obtained from *Morningstar* and/or other size premium studies such as the *Duff & Phelps* study.[49] *Morningstar* quantifies the size premium separate from the market risk premium by market capitalization as a measure of size whereas *Duff & Phelps* study quantifies the risk premium (RP_{m+s}) (market premium (RP_m) plus the size premium (RP_s)) by book value of common equity, 5 year average net income, market value of invested capital, total assets (as reported on balance sheet), 5-year average of earnings before interest, income taxes, depreciation and amortization (EBITDA), sales, and number of employees in addition to market capitalization – all of which have been shown to be highly correlated with market returns. I should note that the authors of the *Duff & Phelps* study concludes that, by whatever measures of size is used, the results are clear that there is an inverse relationship between size and historical equity returns – small companies have higher returns than larger companies.[50] They also explain, as I have previously, in

[49] Duff & Phelps LLC, Risk Premium Report 2010.

[50] Duff & Phelps at 10.

the context of the CAPM, the greater betas of smaller companies explain some, but not all of the higher average returns in their size-ranked portfolios.[51]

Q. HAVE YOU PREPARED AN ESTIMATE OF THE COST OF EQUITY USING THE BUILD-UP METHOD FOR BVWC USING DATA FROM MORNINGSTAR?

A. Yes. Using the Build-up Method, I estimate the cost of equity for BVWC to be 13.18 percent. This is based upon the data from Morningstar as contained Table C-1 (the risk-rate would be 4.6 percent,[52] the equity risk premium would be 6.7 percent,[53] the small company risk premium of 6.28 percent[54]) and data contained in Table 3-5 – Industry Premia Estimates (negative 4.40 for the water supply industry SIC code 494). The calculation is shown as follows:

[3] $k = R_f + RP_m + RP_s +/- RP_u$

[4] $k = 4.6\% + 6.7\% + 6.28\% - 4.4\%$

[5] $k = 13.18\%$

Q. HAVE YOU PREPARED A COST OF EQUITY ESTIMATE FOR BVWC USING THE DUFF & PHELPS STUDY?

A. Yes. Please *see* **Exhibit TJB-COC-RJ1**. I have included cost of equity estimates for the water sample companies. These estimates have been adjusted for leverage (financial risk) differences between the companies in the size portfolios contained in the study and the water sample companies and BVWC. Further, like the Build-up Method cost of equity estimate using the Morningstar data, the cost of equity

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[51] *Id.*

[52] Long-term (20 year) U.S. Treasury Bond Yield.

[53] Long-horizon historical equity risk premium.

[54] Decile 10 – smallest, market capitalization of 1 million to 214 million.

estimates includes a water industry risk premium adjustment. Based on various measures of size the results are as follows:

Stock Symbol	Company	Cost of Equity
AWR	American States Water Co.	11.90%
WTR	Aqua America	10.77%
CWT	California Water Services Group	11.75%
CTWS	Connecticut Water Services	11.47%
MSEX	Middlesex Water Company	12.88%
SJW	SJW Corp.	12.60%
	Average	11.90%
	Bella Vista Water (Consolidated)	12.64%

Q. WHAT DOES ALL THIS MEAN?

A. It means that my cost of equity estimate of 10.9 percent for BVWC is very conservative. It also shows that my size premium used in my cost of capital analysis of 50 basis points is likely far too low and should be on the order of 200 basis points or more. Even accounting for financial risk differences, the indicated cost of equity for BVWC based on the *Duff & Phelps* study is nearly 75 basis points higher than the sample water companies (12.64% minus 11.90%).

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

A. 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 directly 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. In addition, the gas sample provides 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 BVWC?

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.[55] Moreover, in April 2010, the Commission authorized a 9.5 percent return on equity for UNS Gas.[56] Based on these cases, we know that a return on equity of 9.5 percent to 10 percent is just and reasonable for an Arizona gas utility. We also know that Mr. Rigsby's water industry sample has a beta of 0.73, while his gas industry sample has a beta of just 0.66.[57] That means that the equity cost for a water utility is greater than a gas utility. Yet, Mr. Rigsby's artificially inflated 9.0 percent ROE is 100 basis points lower than Southwest Gas and 50 basis points lower than UNS Gas. If Mr. Rigsby is going to insist on using gas companies, he should follow his own logic and recommend a return of more than 10 percent. In my rebuttal testimony, I estimated that the cost of equity for the water industry sample should be 110 basis points greater than the gas industry sample.[58]

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

[56] Decision No. 71623.

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

[58] 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

Q. SO THE POINT IS NOT WHETHER IT 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 9.5 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 10.6 percent, not 7.9 percent, as Mr. Rigsby has estimated.

Q. AT PAGE 16 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.[59] I also attached an excerpt from Dr. Morin's textbook in my Exhibit TJB-COC-RB2 to that testimony to show why no weight should be given to geometric annual averages when computing the market risk premium ("MRP"). At page 16, lines 6-8, 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.

Schedules JMR-7 and JMR-18.

[59] Bourassa COC Rb. at 27.

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-RB2, which compares the historical returns of two stocks calculated using arithmetic and geometric averages.

Q. DOES MR. RIGSBY'S EXAMPLE ON PAGES 16 AND 17 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. The problem is that it's our goal 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. PLEASE RESPOND TO MR. RIGSBY'S TESTIMONY THAT THE USE OF GEOMETRIC MEANS AND INCOME RETURNS ARE APPROPRIATE BECAUSE THIS INFORMATION IS AVAILABLE TO INVESTORS.

A. Rather than focusing on what method is conceptually correct,[60] Mr. Rigsby contends that if an investor has information available, such information should be used to determine the Company's cost of equity, even if its use is improper.[61] If the test is simply whether investors have information available, and not whether its use is conceptually correct, then the Commission's prior rejection of methods such

[60] Bourassa COC Rb. at 28.

[61] Rigsby Sb. at 18.

as the risk premium method and the comparable earnings method in past cases was improper.[62] The Commission has stated that the risk premium methodology is based on a "comparable earnings" method that "has long been discredited."[63] Even if true, however, an investor may still rely on that method and, under the logic of Mr. Rigsby, the Commission should have considered it.

Moreover, there are types of information and methods that the Commission should also consider if it were to accept the arguments of Mr. Rigsby. For example, Value Line reports projected returns on equity (2013 through 2015) for the water utility group and the gas utility group used by Mr. Rigsby in his cost of capital analysis have projected returns of 11.9 percent and 11.9 percent, respectively.

The project Value Line returns are shown below.

RUCO Water Utility Sample Group

Stock Symbol	Company	Value Line Projected Book Return on Equity[64]
AWR	American States Water Co.	10.5%
WTR	Aqua America	11.0%
CWT	California Water Services Group	14.0%
	Average	11.9%

[62] *See Arizona Water Company (Western Group)*, Decision No. 68302 (November 14, 2005) at 37 – 38.
[63] *Id.* at 37.
[64] Value Line Investment Survey April 23, 2010.

RUCO Gas Utility Sample Group

Stock Symbol	Company	Value Line Projected Book Return on Equity[65]
AGL	AGL Resources, Inc.	11.5%
ATO	Atmos Energy Corp.	10.0%
LG	Laclede Group, Inc.	11.0%
NJR	New Jersey Resources Corp.	16.5%
GAS	Nicor, Inc.	11.0%
NWN	Northwest Natural Gas	11.5%
PNY	Piedmont Natural Gas Company	13.0%
SJI	South Jersey Industry	14.5%
SWX	Southwest Gas Corp.	9.0%
WGL	WGL Holdings, Inc.	10.5%
	Average	11.9%

Value Line's forecasts are widely available and would be considered by investors in evaluating an investment in those utilities. In fact, Mr. Rigsby specifically selected the three water utilities for his proxy group for BVWC because Value Line provides long-term estimates of those utilities' return on common equity.[66] Therefore, if the principal criterion for deciding whether to consider a particular equity cost estimate is its "availability to investors," the Commission should use Value Line's projected average return of 11.9 percent to estimate BVWC's cost of equity.

There's more. The market-to-book ("M/B") ratios of the sample water utilities are widely available to the investment community, along with the book

[65] Value Line Investment Survey June 11, 2010.

[66] *See* Direct Testimony of William A. Rigsby ("Rigsby Dt.") at 21.

values of those utilities' stocks. Some authorities believe that it is improper to use a market-based equity return derived by means of the DCF model with an original cost (i.e., net book value) rate base when a utility's stock is trading above book value.[67] Instead, when an original cost rate base is used, the book value of the sample water utilities' stocks should be used to calculate the dividend yield to ensure methodological consistency.[68] The average M/B ratio of the sample water utilities used by Mr. Rigsby is over 1.9,[69] i.e., the average market price of those utilities' stocks is nearly two times their book value. This means that the dividend yield calculations made by the parties are understated by nearly 50 percent! Thus, instead of being in 3.0 percent to 3.4 percent range for the sample water utility group, the dividend yield should be 300 to 340 basis points higher, and the parties' DCF model estimates should likewise be 300 to 340 basis points higher.

The bottom line, and the point I am going to extremes to make, is that investors may well use data from investment sources such as Value Line and Ibbotson incorrectly. Investors undoubtedly use (and misuse) a variety of information in deciding whether to invest in securities. But that does not mean the Commission should make the same mistakes in determining the cost of capital for water utilities. For the reasons stated, there is no conceptual basis for using geometric averages to estimate expected returns on equity. Therefore, the cost of equity estimates of Mr. Rigsby should be rejected.

Q. AT PAGE 19, LINES 9-13, MR. RIGSBY ALSO CLAIMS THE CKM BOOK SHOWS THAT YEAR-TO-YEAR RETURNS ARE NOT INDEPENDENT,

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[67] *See, e.g.*, Win Whittaker, *The Discounted Cash Flow Methodology: Its Use in Estimating a Utility's Cost of Equity*, 12 Energy L.J. 265 (1991).

[68] *Id.* at 281 – 283 (citing *Farmers Union Cent. Exch., Inc. v. FERC*, 734 F.2d 1486 (D.C.Cir. 1984)).

[69] *See* RUCO Direct Schedule WAR-4, page 2 of 2.

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.[70] 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 19, to compute arithmetic averages.

Q. AT PAGE 20 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 IS IN THE RANGE OF 4.0 PERCENT TO 5.5 PERCENT. DO YOU AGREE?

A. No. CKM, in part, justifies its range of 4.0 percent to 5.5 percent based on an analysis of historical data from 1962 to 2002 (40 years of data). The *Morningstar* long-horizon equity risk premium for this time period is 4.0 percent and is not inconsistent with CKM for this time period.[71] However, the estimate of the equity risk premium depends on the length of the data series studied. A longer historical time period shows that the long-horizon equity risk premium is 7.0 percent (1926 to 2002 or 74 years of data).[72] As Morningstar states[73]:

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[70] *Ibbotson* at 60.

[71] *Id.* at Table A-1 (page 4 of 6).

[72] *Id.* at Table A-1 (page 2 of 6).

> A proper estimate of the equity risk premium requires a data series long enough to give a reliable average without being unduly influenced by very good and very poor short-term returns. When calculated using a long data series, the historical equity risk premium is relatively stable. Furthermore, because an average of the realized equity risk premium is quite volatile when calculated using a short history, using a long series makes it less likely the analyst can justify a number he or she wants.

Morningstar also shows the average stock market return and average realized long-horizon equity risk premium over various time periods.[74] This data show that using a longer historical period provides a more stable estimate of the equity risk premium. The reason is that any unique period will not be weighted heavily in an average covering a longer time period.[75]

An additional problem with CKM's analysis besides subjectively using a shorter time horizon, is that CKM arbitrarily substitutes an average based on 10-year periods, 5.5 percent (Exhibit 10-5),[76] and combines that average with a negative adjustment of 1.0 percent to 2.0 percent 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. 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 is 7.0 percent if we do not apply CKM's subjective downward adjustment. Mr. Rigsby should have relied upon the 7.0 percent MRP in his CAPM estimate.

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[73] *Id. at* 59.

[74] *Id.*

[75] *Id.*

[76] CKM admits that the downside to using 10-year holding periods is that they have very few observations. *See* page 302.

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. ON PAGE 20 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.

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.[77] Thus, income returns rather than total returns should be used in the estimation of the equity risk premium.[78] 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.[79]

Q. DOES THE FACT THAT UTILITY RATES ARE NOT SET EVERY THIRTY YEARS HAVE ANYTHING TO DO WITH THE PROPER

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[77] Bourassa COC Rb. at 27 – 29.

[78] *Id.* at 38.

[79] Chaves Dt. at 30 – 31. Staff uses historical market risk premium calculated from Ibbotson Associates SBBI 2009 Yearbook data.

CHOICE OF THE LENGTH OF THE TREASURY THAT SHOULD BE USED IN THE CAPM AS SUGGESTED BY MR. RIGSBY ON PAGE 21 OF HIS TESTIMONY?

A. No. This is simply incorrect. 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.[80] Moreover, short term rates are volatile, fluctuate widely, and are subject to more random disturbances leading to volatile and unreliable equity returns.[81]

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 considering current economic conditions.[82] 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.[83] And, the current market risk premium has had impact on the cost of equity in both directions over the years.[84] My current market equity risk premium of 11.2 percent 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.[85] In fact, my current market risk premium estimate is 80 basis points lower than Staff's 12.0 percent estimate.[86] Further, while

[80] Bourassa COC Rb. at 38 – 39.

[81] *Id.* at 39.

[82] Rigsby Dt. at 38 – 39.

[83] Bourassa COC Rb. at 41 – 42.

[84] *Id.* at 42.

[85] *Id.* at 40.

[86] *See* Staff Surrebuttal Schedule PMC-2.

economic conditions have improved since the start of the recession in 2008, unemployment remains high and the economic outlook is still very uncertain. Value Line recently commented that "the strength and sustainability of the economic recovery are open questions at this time."[87]

Q. ON PAGE 22 AND 23, 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 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

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

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 Damodaran, 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 percent, which was much lower than earlier estimates which over 13 percent.[88] The 5.7 percent 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 23 BY MR. RIGSBY?

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 percent or the 5 percent 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 5.28 percent and 6.01 percent are reasonable when the cost of Baa bonds was 6.28 percent.[89] A reasonable estimate of the cost of equity must be higher than the cost of Baa bonds.

[88] Bourassa COC Rb. at 40.

[89] Federal Reserve at 3/26/2010.

B. RUCO's Hypothetical Capital Structure for Northern Sunrise and Southern Sunrise on Stand-Alone Basis

Q. PLEASE SUMMARIZE THE FINAL POSITIONS OF THE PARTIES CONCERNING THE CAPITAL STRUCTURE FOR NORTHERN SUNRISE AND SOUTHERN SUNRISE ON A STAND-ALONE BASIS, AND WHAT, IF ANY ADJUSTMENTS TO THAT CAPITAL STRUCTURE ARE APPROPRIATE.

A. Northern Sunrise and Southern Sunrise on a stand-alone basis have an actual capital structure consisting of 100 percent equity. The Company proposes the use of the Company's actual capital structure[90] to develop the WACC and required rate of return on rate base, which is consistent with other water and wastewater utility rate cases in this jurisdiction. Both Staff and the Company propose direct downward adjustments to account for lower financial risk of BVWC compared to the publicly traded water utilities. On a consolidated basis, Staff proposes a direct, downward adjustment to the cost of equity of 100 basis points, calculated using the Hamada formula.[91] I also propose such a downward financial risk adjustment both on a consolidated basis, but also on a stand-alone basis. On a consolidated basis, I recommend a smaller financial risk adjustment of 60 basis points. On a stand-alone basis, I recommend a downward adjustment of 50 basis points and 100 basis points for Bella Vista (stand-alone) and Northern Sunrise (stand-alone) and Southern Sunrise (stand-alone), respectively. Staff does not propose a separate WACC and financial risk adjustments on a stand-alone basis. And, as I have explained, Staff's adjustment is incorrectly calculated and erroneously assumes that BVWC would have the same beta as the water utility sample.

[90] As adjusted for Company proposed changes to PIS, CIAC, and ADIT.

[91] Chaves Sb. at 2.

RUCO, however, has taken a much different tack for Northern Sunrise and Southern Sunrise (stand-alone), and argues that a hypothetical capital structure should be imputed to these utilities, containing 40 percent hypothetical debt at a hypothetical interest rate of 6.26 percent. This produces a WACC of 7.9 percent (which happens to equal the cost of equity produced by Mr. Rigsby's DCF and CAPM models). 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 Northern Sunrise's and Southern Sunrise's test year operating expenses by nearly $20,000. That reduction reduces the actual rate of return on rate base on a stand-alone basis 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. SINCE WE ARE DEALING IN HYPOTHETICALS, IF A FICTITIOUS CAPITAL STRUCTURE WITH FICTITIOUS DEBT WERE IMPUTED TO NORTHERN SUNRISE AND SOUTHERN SUNRISE, DOES THAT MEAN THAT THEIR INCOME TAX EXPENSE SHOULD BE REDUCED?

A. Absolutely not. As Mr. Rigsby explained in his direct testimony, the purpose of using a hypothetical capital structure is to account for imprudent capital structures.[92] Presumably, this is to account for reduced financial risk. However, besides converting 40 percent of the Company's equity to lower cost debt, RUCO further reduces the effective return on equity by interest synchronization which lowers the Company's operating expenses.

[92] Rigsby Dt. at 55.

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. Northern Sunrise and Southern Sunrise, however, have no debt in their capital structure and thus have 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 RUCO is actually using its recommended hypothetical structure to lower operating expenses, not to develop an appropriate cost of equity. They are using an income statement adjustment to change the balance sheet. In effect, Northern Sunrise and Southern Sunrise and its shareholders are being punished because they have financed their plant with equity. The penalty being imposed is the loss of almost $20,000 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 neither Northern Sunrise nor Southern Sunrise will earn a reasonable return on their invested capital.

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.

C. RUCO's Unrealistic Cost of Debt

Q. PLEASE COMMENT ON MR. RIGSBY'S HYPOTHETICAL COST OF DEBT FOR NORTHERN SUNRISE AND SOUTHERN SUNRISE ON A STAND-ALONE BASIS.

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 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 – that significantly reduces their cost of debt – that is why companies seek bond ratings to reduce the cost of debt. Mr. Rigsby assumes that Northern Sunrise or Southern Sunrise could raise debt capital at the same cost as these entities. No one could believe that is true, in fact even Mr. Rigsby does not appear to believe that's true.[93]

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

[93] Rigsby Sb. at 10 – 12.

markets, these utilities have published bond ratings. They are much different from Northern Sunrise and Southern Sunrise 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 Northern Sunrise and Southern Sunrise could not borrow the equivalent of 40 percent of their capitalization – about $1 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 THE COMPANY?

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 Northern and Southern Sunrise, 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. Although my silence on any issue does not constitute agreement with the other parties.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Thomas J. Bourassa
Rejoinder Testimony
(Cost of Capital)
July 7, 2010

Exhibit
TB-RJ1

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

TABLE 1

	Company	Symbol	Measures of size (Millions) MV Equity[1]	Book Equity[1]	MVIC[1]	Total Assets[2]	5 Yr Avg. EBITDA[3]
1.	American States	AWR	$ 659	$ 336	$ 965	$ 1,113	$ 92
2.	Aqua America	WTR	$ 2,501	$ 1,101	$ 3,887	$ 3,763	$ 304
3.	California Water	CWT	$ 805	$ 419	$ 1,180	$ 1,526	$ 100
4.	Connecticut Water	CTWS	$ 204	$ 108	$ 316	$ 415	$ 20
5.	Middlesex	MSEX	$ 243	$ 138	$ 368	$ 458	$ 29
6.	SJW Corp.	SJW	$ 496	$ 249	$ 743	$ 878	$ 73
	Bella Vista Water Company (Consolidated)		$ 11.4 (Estimate)	$ 6	$ 13.1 (Estimate)	$ 17.6	$ 1.5

[1] From Value Line data (12/31/2009)
[2] From Zacks Investment Research. From E-1 for subject utility.
[3] Earnings before Interest, Taxes, Depreciation and Amortization (EBITDA). From Zacks Investment Research and Company ACC reports

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

MRP_{m+s} Estimates Using Duff & Phelps Study (Levered) **TABLE 2**

Data Smoothing with Regression Analysis ***Smoothed Premium = Constant + X Coefficients * Log(Relevent Metric)***	MV Equity (Table A-1)	Book Equity (Table A-2)	MVIC (Table A-4)	Total Assets (Table A-5)	5 Yr Avg. EBITDA (Table A-6)
Constant	17.357%	15.190%	17.375%	15.804%	13.723%
X Coefficient(s)	-2.924%	-2.296%	-2.154%	-2.230%	-2.141%

			MRP_{m+s} Estimates (Levered)					
	Company	Symbol	MV Equity	Book Equity	MVIC	Total Assets	5 Yr Avg. EBITDA	Average
1.	American States	AWR	9.11%	9.39%	10.95%	9.01%	9.52%	9.60%
2.	Aqua America	WTR	7.42%	8.21%	9.64%	7.83%	8.41%	8.30%
3.	California Water	CWT	8.86%	9.17%	10.76%	8.70%	9.44%	9.39%
4.	Connecticut Water	CTWS	10.61%	10.52%	11.99%	9.97%	10.96%	10.81%
5.	Middlesex	MSEX	10.38%	10.27%	11.85%	9.87%	10.58%	10.59%
6.	SJW Corp.	SJW	9.47%	9.69%	11.19%	9.24%	9.73%	9.86%
	Average (Unlevered)		9.31%	9.54%	11.06%	9.10%	9.77%	9.76%
	Bella Vista Water Company (Consolidated)		14.26%	13.44%	14.97%	13.03%	13.36%	13.81%

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

Average Debt to Market Value of Equity for MRP_{m+s} for Portfilios used in Duff & Phelps RP Study **TABLE 3**
(from Duff & Phelps RP Study (W_d/W_e) for use in un-levering MRP_{m+s} . See Table 4)

	Company	Symbol	W_d/W_e (Table C-1)	(Table C-2)	(Table C-4)	(Table C-5)	(Table C-6)	Average
1.	American States	AWR	34.10%	32.60%	36.10%	37.10%	35.50%	35.08%
2.	Aqua America	WTR	30.90%	33.30%	36.70%	41.50%	34.40%	35.36%
3.	California Water	CWT	32.40%	33.40%	34.90%	35.90%	35.50%	34.42%
4.	Connecticut Water	CTWS	36.60%	32.90%	35.30%	31.60%	30.70%	33.42%
5.	Middlesex	MSEX	35.70%	32.90%	34.80%	32.10%	34.40%	33.98%
6.	SJW Corp.	SJW	35.00%	34.60%	35.60%	35.60%	34.50%	35.06%
	Average		34.12%	33.28%	35.57%	35.63%	34.17%	34.55%

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

MRP Estimates Using Duff & Phelps Study (Un-levered) **TABLE 4**

Un-levered realized risk premium = {[Levered realized risk preium * 100) + $(W_d/W_e)*b_d/[1+W_d/W_e]$}/100

			MRP_{m+s} (Un-levered)					
	Company	Symbol	MV Equity	Book Equity	MVIC	Total Assets	5 Yr Avg. EBITDA	Average
1.	American States	AWR	6.85%	7.13%	8.10%	6.63%	7.08%	7.16%
2.	Aqua America	WTR	5.72%	6.21%	7.11%	5.59%	6.31%	6.19%
3.	California Water	CWT	6.74%	6.92%	8.03%	6.46%	7.02%	7.03%
4.	Connecticut Water	CTWS	7.82%	7.97%	8.92%	7.62%	8.43%	8.15%
5.	Middlesex	MSEX	7.70%	7.78%	8.84%	7.52%	7.93%	7.95%
6.	SJW Corp.	SJW	7.07%	7.25%	8.31%	6.87%	7.29%	7.36%
	Average MRP (Unlevered)		6.98%	7.21%	8.22%	6.78%	7.34%	7.31%
	Bella Vista Water Company (Consolidated)		10.64%	10.08%	11.04%	9.60%	9.96%	10.26%
	Implied small company risk premium over sample publicly traded water utilities							2.96%

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

MRP Estimates Using Duff & Phelps Study (Relevered)
(using W_d/W_e data from Table 4)

TABLE 5

				MRP_{m+s} (Relevered)					
	Company	Symbol	W_d/W_e	MV Equity	Book Equity	MVIC	Total Assets	5 Yr Avg. EBITDA	Average
1.	American States	AWR	55.3%	10.53%	10.97%	12.47%	10.18%	10.88%	11.00%
2.	Aqua America	WTR	61.2%	9.09%	9.88%	11.34%	8.89%	10.05%	9.85%
3.	California Water	CWT	55.6%	10.38%	10.66%	12.38%	9.94%	10.81%	10.83%
4.	Connecticut Water	CTWS	30.2%	10.12%	10.31%	11.54%	9.86%	10.92%	10.55%
5.	Middlesex	MSEX	51.6%	11.58%	11.69%	13.30%	11.30%	11.92%	11.96%
6.	SJW Corp.	SJW	60.5%	11.22%	11.51%	13.21%	10.90%	11.57%	11.68%
	Average MRP (Relevered)		52.41%	10.49%	10.84%	12.37%	10.18%	11.02%	10.98%
	Bella Vista Water Company (Consolidated)		14.81%	12.18%	11.54%	12.65%	11.00%	11.40%	11.75%

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

Equity Risk Premium Adjustment and Other meterics used in Build-up Method

TABLE 6

[1] Estimate of Current Market Risk Premium	4.25%
[2] Risk Premium Assumed in Duff & Phelps Study (1963-2009)	4.25%
[3] Equity Risk Premium Adjustment ([1] - [2])	0.00%
[4] Average MRP (relevered) for publicly traded water companies (from Table 5)	10.98%
[5] MRP (relevered) for publicly traded water companies (R_{m+s}) ([3] + [4])	10.98%
[6] Equity Risk Premium Adjustment ([3])	0.00%
[7] Average MRP (relevered) for subject utlity company (from Table 5)	11.75%
[8] MRP (relevered) for subject utility company (R_{m+s}) ([6] + [7])	11.75%
[9] Industry Risk Premium (From *Ibbotson* for SIC 494 Water Supply Industry Table 3-5)	-4.40%
[10] Adjustment Factor to Industry Risk Premium ([2] / 6.7%[1])	0.6343
[11] Adjusted Industry Risk Premium (R_i) ([9] x [10])	-2.79%
[12] Risk Free Rate (Ibbotson LT U.S. Treasury Yield) (R_f)[2]	3.71%

[1] From *Ibbotson SBBI 2010 Valuation Edition Yearbook*. Long-Horison Equity Risk Premium (1926-2009)
[2] 20 year U.S. Treasury Bond Yield at July 1, 2010

Bella Vista Water Company (Consolidated)
COST OF EQUITY (COE) USING BUILD-UP METHOD

Cost of Equity (COE) Estimate using Build-up Method **TABLE 7**

$E(R_i) = R_f + RP_{m+s} + R_i + R_u$

	Sample Publicly Traded Water Utilities	Bella Vista
Where:		
$E(R_i)$ =Expected rate of return		
R_f = Risk-free rate of return. See Table 6.	3.71%	3.71%
RP_{m+s} = Market risk premium including size premium. See Table 5	See Table 5	See Table 5
R_i = Industry risk premium (adjusted) See Table 6	-2.79%	-2.79%
R_u = Company-specific risk premium	0.00%	0.00%

			Indicated COE					
	Company	Symbol	MV Equity	Book Equity	MVIC	Total Assets	5 Yr Avg. EBITDA	Average
1.	American States	AWR	11.44%	11.89%	13.38%	11.10%	11.80%	11.92%
2.	Aqua America	WTR	10.01%	10.80%	12.26%	9.81%	10.97%	10.77%
3.	California Water	CWT	11.30%	11.58%	13.30%	10.86%	11.73%	11.75%
4.	Connecticut Water	CTWS	11.04%	11.23%	12.46%	10.78%	11.83%	11.47%
5.	Middlesex	MSEX	12.50%	12.61%	14.22%	12.22%	12.83%	12.88%
6.	SJW Corp.	SJW	12.14%	12.43%	14.13%	11.82%	12.49%	12.60%
	Average COE estimate		11.40%	11.76%	13.29%	11.10%	11.94%	11.90%
	Bella Vista Water Company (Consolidated)		13.10%	12.46%	13.56%	11.92%	12.32%	12.67%

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Thomas J. Bourassa
Rejoinder Testimony
(Cost of Capital)
July 7, 2010

Bella Vista Water Company
Consolidated Schedules

Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
Summary of Cost of Capital

Exhibit
Rejoinder Schedule D-1
Page 1
Witness: Bourassa

Line No.	Item of Capital	End of Test Year Dollar Amount	Percent of Total	Cost Rate	Weighted Cost	End of Projected Year Dollar Amount	Percent of Total	Cost Rate	Weighted Cost
1	Long-Term Debt	1,697,323	22.60%	6.28%	1.42%	1,584,033	19.66%	6.27%	1.23%
2									
3	Stockholder's Equity[1]	5,812,207	77.40%	10.90%	8.44%	6,474,728	80.34%	10.90%	8.76%
4									
5	Totals	$ 7,509,530	100.00%		9.85%	$ 8,058,761	100.00%		9.99%
6									
7									
8	[1] Adjustments to equity								
9	Acumm. depreciation adjustment		$ 205,167						
10	CIAC adjustment		$ (417)						
11	Deferred Income Tax Adjustment		$ (745,335)						
12									
13									
14									
15									
16	SUPPORTING SCHEDULES:								
17	Rejoinder D-1								
18	Rejoinder D-2								
19	Rejoinder D-3								
20	Rejoinder D-4								
21	Consolidated E-1								
22									
23									
24									
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30									
31									
32									
33									

RECAP SCHEDULES:

Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
Cost of Long Term Debt

Exhibit
Rejoinder Schedule D-2
Page 1
Witness: Bourassa

Line No.	Description of Debt	End of Test Year Amount Outstanding[1]	Annual Interest	Interest Rate	Weighted Cost	End of Projected Year Amount Outstanding	Annual Interest	Interest Rate	Weighted Cost
1	WIFA #1	108,754	6,634	6.10%	0.39%	108,754	6,634	6.10%	0.39%
2	WIFA #2	1,545,436	96,744	6.26%	5.70%	1,545,436	96,744	6.26%	5.70%
3	K-Mart	6,140	526	8.56%	0.03%	6,140	526	8.56%	0.03%
4	BVR/RC-3	13,849	1,011	7.30%	0.06%	13,849	1,011	7.30%	0.06%
5	BVR/RC-4	16,109	1,113	6.91%	0.07%	16,109	1,113	6.91%	0.07%
6	BVR-CCCII	7,035	504	7.16%	0.03%	7,035	504	7.16%	0.03%
7			-	0.00%	0.00%	-	-	0.00%	0.00%
8			-	0.00%	0.00%	-	-	0.00%	0.00%
9			-	0.00%	0.00%	-	-	0.00%	0.00%
10			-	0.00%	0.00%	-	-	0.00%	0.00%
11			-	0.00%	0.00%	-	-	0.00%	0.00%
12									
13	Totals	$ 1,697,323	$ 106,532		6.28%	$ 1,697,323	106,532		6.28%
14									
15	SUPPORTING SCHEDULES:					RECAP SCHEDULES:			
16						Rejoinder D-1			
17									
18									
19									
20									

Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
Cost of Preferred Stock

Exhibit
Rejoinder Schedule D-3
Page 1
Witness: Bourassa

Line No.	Description of Issue	End of Test Year Shares Outstanding	Amount	Dividend Requirement	End of Projected Year Shares Outstanding	Amount	Dividend Requirement
1							
2							
3	NOT APPLICABLE, NO PREFERRED STOCK ISSUED OR OUTSTANDING						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17	SUPPORTING SCHEDULES:			RECAP SCHEDULES:			
18				Rejoinder D-1			
19							
20							

Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
Cost of Common Equity

Exhibit
Rejoinder Schedule D-4
Page 1
Witness: Bourassa

Line No.		
1		
2	The Company is proposing a cost of common equity of	10.90% .
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	SUPPORTING SCHEDULES:	RECAP SCHEDULES:
18	Rejoinder D-4.1 to D-4.16	Rejoinder D-1
19		
20		

Bella Vista Water Company (Consolidated)
Summary of Results

Exhibit
Rejoinder Schedule D-4.1

Line No.	Method	Low	High	Midpoint
6	Range DCF Constant Growth Estimates[1]	9.1%	10.5%	9.8%
8	Range of CAPM Estimates[2]	10.4%	13.9%	12.2%
11	Average of DCF and CAPM midpoint estimates	9.8%	12.2%	11.0%
14	Financial Risk Adjustment[3]	-0.6%	-0.6%	-0.6%
16	Specific Company Risk Premium[4]	0.5%	0.5%	0.5%
18	Indicated Cost of Equity	9.7%	12.1%	10.9%
22	Recommended Cost of Equity			10.9%

[1] See Rejoinder Schedule D-4-8
[2] See Rejoinder Schedule D-4.12
[3] See Rejoinder Schedule D-4.16
[4] See testimony.

Bella Vista Water Company (Consolidated)
Selected Characteristics of Sample Group of Water Utilities

Exhibit
Rejoinder Schedule D-4.2

Line No.	Company[1]	% Water Revenues	Operating Revenues (millions)	Net Plant (millions)	S&P Bond Rating	Moody's Bond Rating
1	1. American States	76%	$ 361.0	$ 962.1	A	A2
2	2. Aqua America	90%	$ 670.5	$ 2,790.5	AA-	NR
3	3. California Water	99%	$ 449.4	$ 1,079.9	AA-	NR
4	4. Connecticut Water	90%	$ 67.5	$ 273.1	A	NR
5	5. Middlesex	89%	$ 91.2	$ 329.7	A	NR
6	6. SJW Corp.	96%	$ 216.1	$ 523.7	NR	NR
7						
8	Average	90%	$ 309.3	$ 993.2		
9						
10	Bella Vista Water Company (Consolidated) (as of December 31, 2008)	100%	$ 4.2	$ 16.1	NR	NR

[1]AUS Utility Reports (May 2010).

Bella Vista Water Company (Consolidated)
Capital Structures

Exhibit
Rejoinder Schedule D-4.3

No.		Book Value[1]		Market Value[1]	
		Long-Term Debt	Common Equity	Long-Term Debt	Common Equity
	Company				
1.	American States	47.7%	52.3%	31.7%	68.3%
2.	Aqua America	55.7%	44.3%	35.7%	64.3%
3.	California Water	47.2%	52.8%	31.7%	68.3%
4.	Connecticut Water	51.0%	49.0%	35.5%	64.5%
5.	Middlesex	47.4%	52.6%	34.0%	66.0%
6.	SJW Corp.	49.8%	50.2%	33.2%	66.8%
	Average	49.8%	50.2%	33.6%	66.4%
	Bella Vista Water Company (Consolidated)[2] (Adjusted as of December 31, 2008)	22.6%	77.4%	N/A	N/A

[1] Value Line Analyzer Data (April 23, 2010)
[2] Adjusted Per Rejoinder Schedule D-1

Bella Vista Water Company (Consolidated)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.4

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Five-year historical average annual changes					Average of Future and Historical Growth
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1	American States	8.76%	4.98%	9.69%	2.88%	6.58%	5.38%	5.98%
2	Aqua America	NMF	6.20%	3.85%	8.81%	6.29%	9.02%	7.65%
3	California Water	4.93%	4.92%	6.62%	0.88%	4.34%	5.88%	5.11%
4	Connecticut Water	3.15%	2.88%	1.72%	1.39%	2.29%	7.25%	4.77%
5	Middlesex	2.61%	4.00%	0.41%	1.49%	2.13%	7.25%	4.69%
6	SJW Corp.	6.79%	5.68%	0.25%	5.53%	4.56%	7.25%	5.91%
	GROUP AVERAGE	5.25%	4.78%	3.76%	3.50%	4.36%	7.01%	5.68%
	GROUP MEDIAN	4.93%	4.95%	2.79%	2.18%	4.45%	7.25%	5.51%

[1] Average of changes in annual stock prices ending on April 23, 2010. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2005 to 2010.

[3] See Rejoinder Schedule D-4.6.

Bella Vista Water Company (Consolidated)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.5

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
								Average of Future and Historical Growth
		Ten-year historical average annual changes					Average Future	
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Growth[3]	Col 5-6
1.	American States	8.60%	4.80%	5.36%	1.79%	5.14%	5.38%	5.26%
2.	Aqua America	7.94%	8.19%	6.34%	7.67%	7.53%	9.02%	8.28%
3.	California Water	7.79%	3.91%	4.09%	0.80%	4.15%	5.88%	5.01%
4.	Connecticut Water	4.73%	3.77%	2.08%	1.31%	2.97%	7.25%	5.11%
5.	Middlesex	4.64%	3.81%	1.24%	1.71%	2.85%	7.25%	5.05%
6.	SJW Corp.	3.01%	5.25%	1.44%	5.53%	3.81%	7.25%	5.53%
	GROUP AVERAGE	6.12%	4.96%	3.42%	3.13%	4.41%	7.01%	5.71%
	GROUP MEDIAN	6.26%	4.36%	3.08%	1.75%	3.98%	7.25%	5.18%

[1] Average of changes in annual stock prices ending in 2009. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2000 to 2009.

[3] See Rejoinder Schedule D-4.6.

Bella Vista Water Company (Consolidated)
Analysts Forecasts of Earnings Per Share Growth

Exhibit
Rejoinder Schedule D-4.6

Line No.		[1]	[2]	[3]	[4]	[5]
		ESTIMATES OF EARNINGS GROWTH				Average
	Company	Zacks[1]	Reuters[1]	Yahoo[1]	Value Line[1]	Growth (G) (Cols 1-4)[2]
1	1. American States	4.00%	4.00%	7.00%	6.50%	5.38%
2	2. Aqua America	8.00%	8.25%	8.33%	11.50%	9.02%
3	3. California Water	7.00%	4.00%	6.00%	6.50%	5.88%
4	4. Connecticut Water			15.00%		7.25%
5	5. Middlesex			8.00%		7.25%
6	6. SJW Corp.			10.00%		7.25%
7						
8	GROUP AVERAGE	6.33%	5.42%	9.06%	8.17%	7.01%
9	GROUP MEDIAN					7.25%

[1] Data as of April 23, 2010

[2] Where no data available or single estimate, average of other utilities assumed to estimate for utility.

Bella Vista Water Company (Consolidated)
Current Dividend Yields for Water Utility Sample Group

Exhibit
Rejoinder Schedule D-4.7

Line No.	Company	Curent Stock Price (P_0)[1]	Current Dividend (D_0)[1]	Current Dividend Yield (D_0/P_0)[1]	Average Annual Dividend Yield (D_0/P_0)[1,2]
1	1. American States	$ 38.09	$ 1.04	2.73%	2.86%
2	2. Aqua America	$ 18.47	$ 0.60	3.25%	2.80%
3	3. California Water	$ 38.90	$ 1.19	3.06%	3.12%
4	4. Connecticut Water	$ 23.95	$ 0.91	3.81%	3.58%
5	5. Middlesex	$ 18.12	$ 0.72	3.98%	3.99%
6	6. SJW Corp.	$ 27.28	$ 0.70	2.55%	2.27%
7					
8	Average			3.23%	3.10%
9	Median			3.15%	2.99%

[1] Value Line Analyzer Data. Stock prices as of April 23, 2010.

[2] Average Annual Dividend is dividends declared per share for a year divided by the average annual price of the stock in the same year, expressed as a percentage. For comparison purposes only.

Bella Vista Water Company (Consolidated)
Discounted Cash Flow Analysis
DCF Constant Growth

Exhibit
Rejoinder Schedule D-4.8

Line No.		[1]	[2]	[3]		[4]
		Average Spot Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	Growth (g)		Indicated Cost of Equity k=Div Yld + g (Cols 2+3)
8	DCF - Past and Future Growth	3.23%	3.41%	5.68%	[3]	9.1%
10	DCF - Future Growth	3.23%	3.46%	7.01%	[4]	10.5%
13		3.23%	3.43%	6.34%		9.8%

[1] Spot Dividend Yield = D_0/P_0. See Rejoinder Schedule D-4.7.

[2] Expected Dividend Yield = $D_1/P_0 = D_0/P_0 * (1+g)$.

[3] Growth rate (g). Average of Past and Future Growth. See Rejoinder Schedule D-4.4, column 7

[4] Growth rate (g). Average of Analyst Estimates Future Growth. See Rejoinder Schedule D-4.6.

Bella Vista Water Company (Consolidated)
Market Betas

Exhibit
Rejoinder Schedule D-4.9

Line No.	Company	Beta (β)[1]
1	1. American States	0.80
2	2. Aqua America	0.65
3	3. California Water	0.75
4	4. Connecticut Water	0.80
5	5. Middlesex	0.75
6	6. SJW Corp.	0.95
7		
8	Average	**0.78**

[1] Value Line Investment Analyzer data (April 23, 2010)

Note: Beta is a relative measure of the historical sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percent-age changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00.

Bella Vista Water Company (Consolidated)
Forecasts of Long-Term Interest Rates
2011-2012

Exhibit
Rejoinder Schedule D-4.10

Line No.	Description	2011	2012	Average
6	Blue Chip Consensus Forecasts[1]	5.1%	5.5%	5.3%
8	Value Line[2]	4.9%	5.3%	5.1%
10	Average			5.2%

[1] December 2009 Blue Chip Financial Forecasts consensus forecast of 30 Year U.S.Treasury

[2] Value Line Quarterly forecast, dated February 26, 2010, Long-term Treasury

Bella Vista Water Company (Consolidated)
Computation of Current Market Risk Premium

Exhibit
Rejoinder Schedule D-4.11

Line No.	Month	Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	+	Growth (g)[3]	=	Expected Market Return (k)	-	Monthly Average 30 Year Treasury Rate[4]	=	Market Risk Premium (MRP)
1											
2											
3											
4	Jan 2009	4.86%	6.32%	+	30.02%	=	36.34%	-	3.13%	=	33.21%
5	Feb	5.50%	7.43%	+	35.13%	=	42.56%	-	3.59%	=	38.97%
6	Mar	4.21%	5.36%	+	27.33%	=	32.69%	-	3.64%	=	29.05%
7	April	3.66%	4.47%	+	22.05%	=	26.52%	-	3.76%	=	22.76%
8	May	3.46%	4.14%	+	19.67%	=	23.81%	-	4.23%	=	19.58%
9	Jun	3.25%	3.87%	+	19.16%	=	23.03%	-	4.52%	=	18.51%
10	Jul	2.90%	3.37%	+	16.31%	=	19.68%	-	4.41%	=	15.27%
11	Aug	2.82%	3.22%	+	14.21%	=	17.43%	-	4.37%	=	13.06%
12	Sept	2.80%	3.20%	+	14.32%	=	17.52%	-	4.19%	=	13.33%
13	Oct	2.75%	3.15%	+	14.49%	=	17.64%	-	4.19%	=	13.45%
14	Nov	2.68%	3.05%	+	13.88%	=	16.93%	-	4.31%	=	12.62%
15	Dec 2009	2.56%	2.88%	+	12.58%	=	15.46%	-	4.35%	=	11.11%
16	Jan 2010	2.64%	3.00%	+	13.71%	=	16.71%	-	4.48%	=	12.23%
17	Feb	2.59%	2.97%	+	14.65%	=	17.62%	-	4.48%	=	13.14%
18	Mar	2.44%	2.75%	+	12.69%	=	15.44%	-	4.48%	=	10.96%
19	April	2.36%	2.63%	+	11.61%	=	14.24%	-	4.69%	=	9.55%
20											
21											
22	Recommended	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
23											
24	Short-term Trends										
25	Recent Twelve Months Avg	2.77%	3.19%	+	14.77%	=	17.96%	-	4.39%	=	13.57%
26	Recent Nine Months Avg	2.63%	2.98%	+	13.57%	=	16.56%	-	4.39%	=	12.16%
27	Recent Six Months Avg	2.55%	2.88%	+	13.19%	=	16.07%	-	4.47%	=	11.60%
28	Recent Three Months Avg	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
29											
30											

31 [1] Average Current Dividend Yield (D_0/P_0) of dividend paying stocks. Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

32 [2] Expected Dividend Yield (D_1/P_0) equals average current dividend yield (D0/P0) times one plus growth rate(g).

33 [3] Average 3-5 year price appreciation (annualized). Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

34 [4] Montly average 30 year U.S. Treasury. Federal Reserve.

35

Bella Vista Water Company (Consolidated)
Capital Asset Pricing Model (CAPM)

Exhibit
Rejoinder Schedule D-4.12

Line No.		Rf[1]	+	beta[3]	x	Rp		=	k
1									
2									
3	Historical Market Risk Premium CAPM	5.2%	+	0.78	x	6.7%	[4]	=	10.4%
4									
5	Current Market Risk Premium CAPM	5.2%	+	0.78	x	11.2%	[5]	=	13.9%
6									
7	Average								12.2%
8									
9									
10									
11									

12 [1] Forecasts of long-term treasury yields. See Rejoinder Schedule D-4.10.
13 [2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9.
14 [3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009
15 [4] Computed using DCF constant growth method to determine current market return onValue Line 1700 stocks
16 and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11.
17
18
19
20

Bella Vista Water Company (Consolidated)
Financial Risk Computation

Exhibit
Rejoinder Schedule D-4.13

Line No.											
1	**CAPM**										
2		**Rf**		+	**β**		x	**(Rp)**			**k**
3	Historical Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	6.7%	[3]	=	10.4%
4	Current Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	11.2%	[4]	=	13.9%
5											
6	Average										12.2%
7											
8											
9	**CAPM Relevered Beta**										
10		**Rf**		+	**β**		x	**(Rp)**			**k**
11	Historical Market Risk Premium	5.2%	[1]	+	0.71	[5]	x	6.7%	[3]	=	10.0%
12	Current Market Risk Premium	5.2%	[1]	+	0.71	[5]	x	11.2%	[4]	=	13.2%
13											
14	Average										11.6%
15											
16	Financial Risk Adjustment										**-0.6%**
17											
18											

19 [1] Forecast of long-term treasury yields. See Rejoinder Schedule D-4.10
20 [2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9
21 [3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009
22 [4] Computed using DCF constant growth method to determine current market return on Value Line 1700 stocks
23 and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11
24 [5] Relevered bata found on Rejoinder Schedule D-4.15
25

Bella Vista Water Company (Consolidated)
Financial Risk Computation
Unlevered Beta

Exhibit
Rejoinder Schedule D-4.14

Line No.		Company	VL Beta β_L [1]	Raw Beta Raw β_L [2]	Tax Rate t [3]	MV Debt D [4]	MV Equity E [4]	Unlevered Raw Beta β_U [5]
5	1.	American States	0.80	0.70	37.8%	31.7%	68.3%	0.54
6	2.	Aqua America	0.65	0.48	39.4%	35.7%	64.3%	0.36
7	3.	California Water	0.75	0.63	38.0%	31.7%	68.3%	0.49
8	4.	Connecticut Water	0.80	0.70	19.5%	35.5%	64.5%	0.49
9	5.	Middlesex	0.75	0.63	34.1%	34.0%	66.0%	0.47
10	6.	SJW Corp.	0.95	0.93	40.4%	33.2%	66.8%	0.72
13		Sample Water Utilities	0.78	0.68	34.8%	33.6%	66.4%	0.51

[1] Value Line Investment Analyzer data. See Rejoinder Scheule D-4.13
Value Line uses the historical data of the stock, but assumes that a security's beta moves toward the market average over time. The formula is as follows:
Adjusted beta = .33 + (.67) * Raw beta

[2] Raw Beta = (VL beta - .33)/(.67)

[3] Effective tax rates for year ended December 31, 2009.

[4] See Rejoinder Scehdule D-4.3

[5] Raw B_u = Raw B_L/ (1+ (1-t)*D/E)

Bella Vista Water Company (Consolidated)
Financial Risk Computation
Relevered Beta

Exhibit
Rejoinder Schedule D-4.15

Line No.		Unlevered Raw Beta β_U[1]	MV Book Debt BD[2]	MV Equity Capital EC[2]	Tax Rate t[3]	Relevered Raw Beta $\beta_{RL}=\beta_U (1+(1-t)BD/EC))$ β_{RL}	VL Adjusted Relevered Beta .33 + .67(Raw Beta) β_{RL}
1							
2							
3							
4							
5	Bella Vista Water Company (Cor	0.51	12.9%	87.1%	38.60%	0.56	0.71
6							
7							
8							
9							
10							
11							
12							

13 [1] Unlevered Beta from Table 18.

14 [2] Capital Structure of Company (Projected)

		BV (in Thousands)			MV (in Thousands)	%
15						
16						
17	Long-term Debt	$ 1,697.32	1.00		$ 1,697	12.90%
18	Preferred Stock	-	1.00		-	0.0%
19	Common Stock	5,812.21	1.97	(a)	11,428	87.1%
20	Total Capital	$ 7,509.53			$ 13,125	100.0%

21

22 (a) Current market-to-book ratio of sample water utilities. See work papers.

23

24 [3] Current Tax rate based on test year ending 3/31/2009. See Rejoinder Schedule D-1.

25

26

Bella Vista Water Company (Consolidated)
Size Premium[1]

Exhibit
Rejoinder Schedule D-4.16

Line No.		Beta(β)	Size Premium	Risk Premium for Small Water Utilities[7]
6	Mid-Cap Companies[2]	1.13	1.00%	
8	Low-Cap Companies[3]	1.26	1.64%	
10	Micro-Cap Companies[4]	1.51	3.00%	
12	Decile 10[5]	1.64	4.74%	2.46%

Line No.		Risk Premium for Small Water Utilities
20	Estimated Risk Premium for small water utilities[6]	0.99%

[1] Data from Table 7-11 of Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook.*
[2] Mid-Cap companies includes companies with market capitalization between $1,602 million and $5,936 million.
[3] Low-Cap companies includes companies with market capitalization between $432 million and $1,600 million.
[4] Micro-Cap companies includes companies with market capitalization less than $431 million.
[5] Decile 10 includes companies with market capitalization between $1.0 million and $214 million.
[6] From Table 2, Thomas M. Zepp, "Utility Stocks and the Size Effect Revisited," *The Quarterly Review of Economics and Finance*, 43 (2003), 578-582.
[7] Computed as the weighted differences between the Decile 10 risk premium and the inidicated risk premiums for the sample water utlities as shown below. Excludes risk due to differences in beta.

		Market Cap. (Millions)	Class	Size Premium	Difference to Decile 10	Weight	Weighted Size Premium
1.	American States	$ 659	Low-Cap	1.64%	3.10%	0.1666667	0.52%
2.	Aqua America	$ 2,501	Mid-Cap	1.00%	3.74%	0.1666667	0.62%
3.	California Water	$ 805	Low-Cap	1.64%	3.10%	0.1666667	0.52%
4.	Connecticut Water	$ 204	Decile 10	4.74%	0.00%	0.1666667	0.00%
5.	Middlesex	$ 243	Micro-Cap	3.00%	1.74%	0.1666667	0.29%
6.	SJW Corp.	$ 496	Low-Cap	1.64%	3.10%	0.1666667	0.52%
	Weighted Size Premium for Small Companies						2.46%

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Thomas J. Bourassa
Rejoinder Testimony
(Cost of Capital)
July 7, 2010

Bella Vista Water Company
Stand-Alone Schedules

Bella Vista Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Summary of Cost of Capital

Exhibit
Rejoinder Schedule D-1
Page 1
Witness: Bourassa

Line No.	Item of Capital	End of Test Year Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost	End of Projected Year Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost
1	Long-Term Debt	1,697,323	31.56%	6.28%	1.98%	$ 1,584,033	27.74%	6.27%	1.74%
2									
3	Stockholder's Equity[1]	3,681,371	68.44%	11.00%	7.53%	4,126,701	72.26%	11.00%	7.95%
4									
5	Totals	$ 5,378,694	100.00%		9.51%	$ 5,710,734	100.00%		9.69%
6									
7									
8	[1] Rebuttal adjustments to equity								
9	Acumm. depreciation adjustment		$ (176,221)						
10	CIAC adjustment		$ (421)						
11	Deferred Income Tax Adjustment		$ (558,105)						
12									
13									
14									
15									
16	SUPPORTING SCHEDULES:								
17	Rejoinder D-1								
18	Rejoinder D-2								
19	Rejoinder D-3								
20	Rejoinder D-4								
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									
33									

RECAP SCHEDULES:

Bella Vista Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Long Term Debt

Exhibit
Rejoinder Schedule D-2
Page 1
Witness: Bourassa

Line		End of Test Year				End of Projected Year			
No.	Description of Debt	Amount Outstanding[1]	Annual Interest	Interest Rate	Weighted Cost	Amount Outstanding	Annual Interest	Interest Rate	Weighted Cost
1	WIFA #1	108,754	6,634	6.10%	0.39%	99,968	6,098	6.10%	0.38%
2	WIFA #2	1,545,436	96,744	6.26%	5.70%	1,455,280	91,101	6.26%	5.75%
3	K-Mart	6,140	526	8.56%	0.03%	484	41	8.56%	0.00%
4	BVR/RC-3	13,849	1,011	7.30%	0.06%	9,854	719	7.30%	0.05%
5	BVR/RC-4	16,109	1,113	6.91%	0.07%	12,802	885	6.91%	0.06%
6	BVR-CCCII	7,035	504	7.16%	0.03%	5,645	404	7.16%	0.03%
7			-	0.00%	0.00%	-	-	0.00%	0.00%
8			-	0.00%	0.00%	-	-	0.00%	0.00%
9			-	0.00%	0.00%	-	-	0.00%	0.00%
10			-	0.00%	0.00%	-	-	0.00%	0.00%
11			-	0.00%	0.00%	-	-	0.00%	0.00%
12									
13	Totals	$ 1,697,323	$ 106,532		6.28%	$ 1,584,033	99,248		6.27%
14									
15	SUPPORTING SCHEDULES:					RECAP SCHEDULES:			
16						Rejoinder D-1			
17									
18									
19									
20									

Bella Vista Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Preferred Stock

Exhibit
Rejoinder Schedule D-3
Page 1
Witness: Bourassa

Line No.	Description of Issue	End of Test Year Shares Outstanding	Amount	Dividend Requirement	End of Projected Year Shares Outstanding	Amount	Dividend Requirement
1							
2							
3	NOT APPLICABLE, NO PREFERRED STOCK ISSUED OR OUTSTANDING						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17	SUPPORTING SCHEDULES:				RECAP SCHEDULES:		
18					Rejoinder D-1		
19							
20							

Bella Vista Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Common Equity

Exhibit
Rejoinder Schedule D-4
Page 1
Witness: Bourassa

Line No.		
1		
2	The Company is proposing a cost of common equity of	11.00% .
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	SUPPORTING SCHEDULES:	RECAP SCHEDULES:
18	Rejoinder D-4.1 to D-4.16	Rejoinder D-1
19		
20		

Bella Vista Water Company (Stand-Alone)
Summary of Results

Exhibit
Rejoinder Schedule D-4.1

Line No.	Method	Low	High	Midpoint
6	Range DCF Constant Growth Estimates[1]	9.1%	10.5%	9.8%
8	Range of CAPM Estimates[2]	10.4%	13.9%	12.2%
11	Average of DCF and CAPM midpoint estimates	9.8%	12.2%	11.0%
14	Financial Risk Adjustment[3]	-0.5%	-0.5%	-0.5%
16	Specific Company Risk Premium[4]	0.5%	0.5%	0.5%
18	Indicated Cost of Equity	9.8%	12.2%	11.0%
22	Recommended Cost of Equity			11.0%

[1] See Rejoinder Schedule D-4-8
[2] See Rejoinder Schedule D-4.12
[3] See Rejoinder Schedule D-4.16
[4] See testimony.

Bella Vista Water Company (Stand-Alone)
Selected Characteristics of Sample Group of Water Utilities

Exhibit
Rejoinder Schedule D-4.2

Line No.	Company[1]	% Water Revenues	Operating Revenues (millions)	Net Plant (millions)	S&P Bond Rating	Moody's Bond Rating
1	1. American States	76%	$ 361.0	$ 962.1	A	A2
2	2. Aqua America	90%	$ 670.5	$ 2,790.5	AA-	NR
3	3. California Water	99%	$ 449.4	$ 1,079.9	AA-	NR
4	4. Connecticut Water	90%	$ 67.5	$ 273.1	A	NR
5	5. Middlesex	89%	$ 91.2	$ 329.7	A	NR
6	6. SJW Corp.	96%	$ 216.1	$ 523.7	NR	NR
7						
8	Average	90%	$ 309.3	$ 993.2		
9						
10	Bella Vista Water Company (Stan (as of December 31, 2008)	100%	$ 3.5	$ 5.9	NR	NR

[1]AUS Utility Reports (May 2010).

Bella Vista Water Company (Stand-Alone)
Capital Structures

Exhibit
Rejoinder Schedule D-4.3

No.	Company	Book Value[1] Long-Term Debt	Book Value[1] Common Equity	Market Value[1] Long-Term Debt	Market Value[1] Common Equity
1	1. American States	47.7%	52.3%	31.7%	68.3%
2	2. Aqua America	55.7%	44.3%	35.7%	64.3%
3	3. California Water	47.2%	52.8%	31.7%	68.3%
4	4. Connecticut Water	51.0%	49.0%	35.5%	64.5%
5	5. Middlesex	47.4%	52.6%	34.0%	66.0%
6	6. SJW Corp.	49.8%	50.2%	33.2%	66.8%
7					
8	Average	49.8%	50.2%	33.6%	66.4%
9					
10	Bella Vista Water Company (Stand-Alone)[2]	31.6%	68.4%	N/A	N/A
11	(Adjusted as of December 31, 2008)				
12					
13	[1] Value Line Analyzer Data (April 23, 2010)				
14	[2] Adjusted Per Rejoinder Schedule D-1				
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					

Bella Vista Water Company (Stand-Alone)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.4

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Five-year historical average annual changes					Average of Future and Historical Growth
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1	American States	8.76%	4.98%	9.69%	2.88%	6.58%	5.38%	5.98%
2	Aqua America	NMF	6.20%	3.85%	8.81%	6.29%	9.02%	7.65%
3	California Water	4.93%	4.92%	6.62%	0.88%	4.34%	5.88%	5.11%
4	Connecticut Water	3.15%	2.88%	1.72%	1.39%	2.29%	7.25%	4.77%
5	Middlesex	2.61%	4.00%	0.41%	1.49%	2.13%	7.25%	4.69%
6	SJW Corp.	6.79%	5.68%	0.25%	5.53%	4.56%	7.25%	5.91%
	GROUP AVERAGE	5.25%	4.78%	3.76%	3.50%	4.36%	7.01%	5.68%
	GROUP MEDIAN	4.93%	4.95%	2.79%	2.18%	4.45%	7.25%	5.51%

[1] Average of changes in annual stock prices ending on April 23, 2010. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2005 to 2010.

[3] See Rejoinder Schedule D-4.6.

Bella Vista Water Company (Stand-Alone)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.5

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Ten-year historical average annual changes					Average of Future and Historical Growth
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1	1. American States	8.60%	4.80%	5.36%	1.79%	5.14%	5.38%	5.26%
2	2. Aqua America	7.94%	8.19%	6.34%	7.67%	7.53%	9.02%	8.28%
3	3. California Water	7.79%	3.91%	4.09%	0.80%	4.15%	5.88%	5.01%
4	4. Connecticut Water	4.73%	3.77%	2.08%	1.31%	2.97%	7.25%	5.11%
5	5. Middlesex	4.64%	3.81%	1.24%	1.71%	2.85%	7.25%	5.05%
6	6. SJW Corp.	3.01%	5.25%	1.44%	5.53%	3.81%	7.25%	5.53%
7								
8	GROUP AVERAGE	6.12%	4.96%	3.42%	3.13%	4.41%	7.01%	5.71%
9	GROUP MEDIAN	6.26%	4.36%	3.08%	1.75%	3.98%	7.25%	5.18%

[1] Average of changes in annual stock prices ending on April 23, 2009. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2000 to 2009.

[3] See Rejoinder Schedule D-4.6.

Bella Vista Water Company (Stand-Alone)
Analysts Forecasts of Earnings Per Share Growth

Exhibit
Rejoinder Schedule D-4.6

Line No.		[1]	[2]	[3]	[4]	[5]
		ESTIMATES OF EARNINGS GROWTH				Average Growth (G)
	Company	Zacks[1]	Reuters[1]	Yahoo[1]	Value Line[1]	(Cols 1-4)[2]
1	1. American States	4.00%	4.00%	7.00%	6.50%	5.38%
2	2. Aqua America	8.00%	8.25%	8.33%	11.50%	9.02%
3	3. California Water	7.00%	4.00%	6.00%	6.50%	5.88%
4	4. Connecticut Water			15.00%		7.25%
5	5. Middlesex			8.00%		7.25%
6	6. SJW Corp.			10.00%		7.25%
7						
8	GROUP AVERAGE	6.33%	5.42%	9.06%	8.17%	7.01%
9	GROUP MEDIAN					7.25%

[1] Data as of April 23, 2010

[2] Where no data available or single estimate, average of other utilities assumed to estimate for utility.

Bella Vista Water Company (Stand-Alone)
Current Dividend Yields for Water Utility Sample Group

Exhibit
Rejoinder Schedule D-4.7

Line No.	Company	Curent Stock Price (P_0)[1]	Current Dividend (D_0)[1]	Current Dividend Yield (D_0/P_0)[1]	Average Annual Dividend Yield (D_0/P_0)[1,2]
1	1. American States	$ 38.09	$ 1.04	2.73%	2.86%
2	2. Aqua America	$ 18.47	$ 0.60	3.25%	2.80%
3	3. California Water	$ 38.90	$ 1.19	3.06%	3.12%
4	4. Connecticut Water	$ 23.95	$ 0.91	3.81%	3.58%
5	5. Middlesex	$ 18.12	$ 0.72	3.98%	3.99%
6	6. SJW Corp.	$ 27.28	$ 0.70	2.55%	2.27%
7					
8	Average			3.23%	3.10%
9	Median			3.15%	2.99%

[1] Value Line Analyzer Data. Stock prices as of April 23, 2010.

[2] Average Annual Dividend is dividends declared per share for a year divided by the average annual price of the stock in the same year, expressed as a percentage. For comparison purposes only.

Bella Vista Water Company (Stand-Alone)
Discounted Cash Flow Analysis
DCF Constant Growth

Exhibit
Rejoinder Schedule D-4.8

Line No.		[1] Average Spot Dividend Yield (D_0/P_0)[1]	[2] Expected Dividend Yield (D_1/P_0)[2]	[3] Growth (g)		[4] Indicated Cost of Equity k=Div Yld + g (Cols 2+3)
8	DCF - Past and Future Growth	3.23%	3.41%	5.68%	[3]	9.1%
10	DCF - Future Growth	3.23%	3.46%	7.01%	[4]	10.5%
13		3.23%	3.43%	6.34%		9.8%

[1] Spot Dividend Yield = D_0/P_0. See Rejoinder Schedule D-4.7.

[2] Expected Dividend Yield = $D_1/P_0 = D_0/P_0 * (1+g)$.

[3] Growth rate (g). Average of Past and Future Growth. See Rejoinder Schedule D-4.4, column 7

4 Growth rate (g). Average of Analyst Estimates Future Growth. See Rejoinder Schedule D-4.6.

Bella Vista Water Company (Stand-Alone)
Market Betas

Exhibit
Rejoinder Schedule D-4.9

Line No.	Company	Beta (β)[1]
1.	American States	0.80
2.	Aqua America	0.65
3.	California Water	0.75
4.	Connecticut Water	0.80
5.	Middlesex	0.75
6.	SJW Corp.	0.95
7		
8	Average	**0.78**

[1] Value Line Investment Analyzer data (April 23, 2010)

Note: Beta is a relative measure of the historical sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percent-age changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00.

Bella Vista Water Company (Stand-Alone)
Forecasts of Long-Term Interest Rates
2011-2012

Exhibit
Rejoinder Schedule D-4.10

Line No.	Description	2011	2012	Average
1				
2				
3				
4				
5				
6	Blue Chip Consensus Forecasts[1]	5.1%	5.5%	5.3%
7				
8	Value Line[2]	4.9%	5.3%	5.1%
9				
10	Average			5.2%
11				
12				
13				
14				
15	[1] December 2009 Blue Chip Financial Forecasts consensus forecast of 30 Year U.S.Treasury			
16	[2] Value Line Quarterly forecast, dated February 26, 2010, Long-term Treasury			
17				
18				
19				
20				
21				
22				
23				
24				

Bella Vista Water Company (Stand-Alone)
Computation of Current Market Risk Premium

Exhibit
Rejoinder Schedule D-4.11

Line No.	Month	Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	+	Growth (g)[3]	=	Expected Market Return (k)	-	Monthly Average 30 Year Treasury Rate[4]	=	Market Risk Premium (MRP)
4	Jan 2009	4.86%	6.32%	+	30.02%	=	36.34%	-	3.13%	=	33.21%
5	Feb	5.50%	7.43%	+	35.13%	=	42.56%	-	3.59%	=	38.97%
6	Mar	4.21%	5.36%	+	27.33%	=	32.69%	-	3.64%	=	29.05%
7	April	3.66%	4.47%	+	22.05%	=	26.52%	-	3.76%	=	22.76%
8	May	3.46%	4.14%	+	19.67%	=	23.81%	-	4.23%	=	19.58%
9	Jun	3.25%	3.87%	+	19.16%	=	23.03%	-	4.52%	=	18.51%
10	Jul	2.90%	3.37%	+	16.31%	=	19.68%	-	4.41%	=	15.27%
11	Aug	2.82%	3.22%	+	14.21%	=	17.43%	-	4.37%	=	13.06%
12	Sept	2.80%	3.20%	+	14.32%	=	17.52%	-	4.19%	=	13.33%
13	Oct	2.75%	3.15%	+	14.49%	=	17.64%	-	4.19%	=	13.45%
14	Nov	2.68%	3.05%	+	13.88%	=	16.93%	-	4.31%	=	12.62%
15	Dec 2009	2.56%	2.88%	+	12.58%	=	15.46%	-	4.35%	=	11.11%
16	Jan 2010	2.64%	3.00%	+	13.71%	=	16.71%	-	4.48%	=	12.23%
17	Feb	2.59%	2.97%	+	14.65%	=	17.62%	-	4.48%	=	13.14%
18	Mar	2.44%	2.75%	+	12.69%	=	15.44%	-	4.48%	=	10.96%
19	April	2.36%	2.63%	+	11.61%	=	14.24%	-	4.69%	=	9.55%
20											
21											
22	Recommended	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
23											
24	Short-term Trends										
25	Recent Twelve Months Avg	2.77%	3.19%	+	14.77%	=	17.96%	-	4.39%	=	13.57%
26	Recent Nine Months Avg	2.63%	2.98%	+	13.57%	=	16.56%	-	4.39%	=	12.16%
27	Recent Six Months Avg	2.55%	2.88%	+	13.19%	=	16.07%	-	4.47%	=	11.60%
28	Recent Three Months Avg	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
29											
30											

31 [1] Average Current Dividend Yield (D_0/P_0) of dividend paying stocks. Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

32 [2] Expected Dividend Yield (D_1/P_0) equals average current dividend yield (D0/P0) times one plus growth rate(g).

33 [3] Average 3-5 year price appreciation (annualized). Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

34 [4] Montly average 30 year U.S. Treasury. Federal Reserve.

35

Bella Vista Water Company (Stand-Alone)
Capital Asset Pricing Model (CAPM)

Exhibit
Rejoinder Schedule D-4.12

Line No.		Rf[1]	+	beta[3]	x	Rp		=	k
1									
2									
3	Historical Market Risk Premium CAPM	5.2%	+	0.78	x	6.7%	[4]	=	10.4%
4									
5	Current Market Risk Premium CAPM	5.2%	+	0.78	x	11.2%	[5]	=	13.9%
6									
7	Average								12.2%

[1] Forecasts of long-term treasury yields. See Rejoinder Schedule D-4.10.
[2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9.
[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009
[4] Computed using DCF constant growth method to determine current market return onValue Line 1700 stocks
and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11.

Bella Vista Water Company (Stand-Alone)
Financial Risk Computation

Exhibit
Rejoinder Schedule D-4.13

Line No.											
1	**CAPM**										
2		**Rf**		+	**β**		x	**(Rp)**			**k**
3	Historical Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	6.7%	[3]	=	10.4%
4	Current Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	11.2%	[4]	=	13.9%
5											
6	Average										12.2%
7											
8											
9	**CAPM Relevered Beta**										
10		**Rf**		+	**β**		x	**(Rp)**			**k**
11	Historical Market Risk Premium	5.2%	[1]	+	0.72	[5]	x	6.7%	[3]	=	10.0%
12	Current Market Risk Premium	5.2%	[1]	+	0.72	[5]	x	11.2%	[4]	=	13.3%
13											
14	Average										11.7%
15											
16	Financial Risk Adjustment										**-0.5%**
17											
18											
19	[1] Forecast of long-term treasury yields. See Rejoinder Schedule D-4.10										
20	[2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9										
21	[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009										
22	[4] Computed using DCF constant growth method to determine current market return on Value Line 1700 stocks										
23	and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11										
24	[5] Relevered bata found on Rejoinder Schedule D-4.15										
25											

Bella Vista Water Company (Stand-Alone)
Financial Risk Computation
Unlevered Beta

Exhibit
Rejoinder Schedule D-4.14

Line No.		Company	VL Beta β_l [1]	Raw Beta Raw β_l [2]	Tax Rate t [3]	MV Debt D [4]	MV Equity E [4]	Unlevered Raw Beta β_u [5]
5	1.	American States	0.80	0.70	37.8%	31.7%	68.3%	0.54
6	2.	Aqua America	0.65	0.48	39.4%	35.7%	64.3%	0.36
7	3.	California Water	0.75	0.63	38.0%	31.7%	68.3%	0.49
8	4.	Connecticut Water	0.80	0.70	19.5%	35.5%	64.5%	0.49
9	5.	Middlesex	0.75	0.63	34.1%	34.0%	66.0%	0.47
10	6.	SJW Corp.	0.95	0.93	40.4%	33.2%	66.8%	0.72
13		Sample Water Utilities	0.78	0.68	34.8%	33.6%	66.4%	0.51

[1] Value Line Investment Analyzer data. See Rejoinder Scheule D-4.13
Value Line uses the historical data of the stock, but assumes that a security's beta moves toward the market average over time. The formula is as follows:
Adjusted beta = .33 + (.67) * Raw beta

[2] Raw Beta = (VL beta - .33)/(.67)

[3] Effective tax rates for year ended December 31, 2009.

[4] See Rejoinder Schedule D-4.3

[5] Raw B_u = Raw B_L / (1+ (1-t)*D/E)

Bella Vista Water Company (Stand-Alone)
Financial Risk Computation
Relevered Beta

Exhibit
Rejoinder Schedule D-4.15

Line No.		Unlevered Raw Beta β_U[1]	MV Book Debt BD[2]	MV Equity Capital EC[2]	Tax Rate t[3]	Relevered Raw Beta $\beta_{RL}=\beta_U (1+(1-t)BD/EC))$ β_{RL}	VL Adjusted Relevered Beta .33 + .67(Raw Beta) β_{RL}
1							
2							
3							
4							
5	Bella Vista Water Company (Star	0.51	19.0%	81.0%	38.60%	0.58	0.72
6							
7							
8							
9							
10							
11							
12							

13 [1] Unlevered Beta from Table 18.

14 [2] Capital Structure of Company (Projected)

		BV (in Thousands)			MV (in Thousands)	%
15						
16						
17	Long-term Debt	$ 1,697.32	1.00		$ 1,697	19.00%
18	Preferred Stock	-	1.00		-	0.0%
19	Common Stock	3,681.37	1.97	(a)	7,238	81.0%
20	Total Capital	$ 5,378.69			$ 8,935	100.0%

21

22 (a) Current market-to-book ratio of sample water utilities. See work papers.

23

24 [3] Current Tax rate based on test year ending 3/31/2009. See Rejoinder Schedule D-1.

25

26

Bella Vista Water Company (Stand-Alone)
Size Premium[1]

Exhibit
Rejoinder Schedule D-4.16

Line No.		Beta(β)	Size Premium	Risk Premium for Small Water Utilities[7]
6	Mid-Cap Companies[2]	1.13	1.00%	
8	Low-Cap Companies[3]	1.26	1.64%	
10	Micro-Cap Companies[4]	1.51	3.00%	
12	Decile 10[5]	1.64	4.74%	2.46%

		Risk Premium for Small Water Utilities
20	Estimated Risk Premium for small water utilities[6]	0.99%

[1] Data from Table 7-11 of Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook.*
[2] Mid-Cap companies includes companies with market capitalization between $1,602 million and $5,936 million.
[3] Low-Cap companies includes companies with market capitalization between $432 million and $1,600 million.
[4] Micro-Cap companies includes companies with market capitalization less than $431 million.
[5] Decile 10 includes companies with market capitalization between $1.0 million and $214 million.
[6] From Table 2, Thomas M. Zepp, "Utility Stocks and the Size Effect Revisited," *The Quarterly Review of Economics and Finance*, 43 (2003), 578-582.
[7] Computed as the weighted differences between the Decile 10 risk premium and the inidicated risk premiums for the sample water utlities as shown below. Excludes risk due to differences in beta.

		Market Cap. (Millions)	Class	Size Premium	Difference to Decile 10	Weight	Weighted Size Premium
1.	American States	$ 659	Low-Cap	1.64%	3.10%	0.1666667	0.52%
2.	Aqua America	$ 2,501	Mid-Cap	1.00%	3.74%	0.1666667	0.62%
3.	California Water	$ 805	Low-Cap	1.64%	3.10%	0.1666667	0.52%
4.	Connecticut Water	$ 204	Decile 10	4.74%	0.00%	0.1666667	0.00%
5.	Middlesex	$ 243	Micro-Cap	3.00%	1.74%	0.1666667	0.29%
6.	SJW Corp.	$ 496	Low-Cap	1.64%	3.10%	0.1666667	0.52%
	Weighted Size Premium for Small Companies						2.46%

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Thomas J. Bourassa
Rejoinder Testimony
(Cost of Capital)
July 7, 2010

Northern Sunrise Water Company
Stand-Alone Schedules

Northern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Summary of Cost of Capital

Exhibit
Rejoinder Schedule D-1
Page 1
Witness: Bourassa

Line No.	Item of Capital	End of Test Year Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost	End of Projected Year Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost
1	Long-Term Debt	-	0.00%	0.00%	0.00%	$ -	0.00%	0.00%	0.00%
2									
3	Stockholder's Equity[1]	466,936	100.00%	11.10%	11.10%	540,236	100.00%	11.10%	11.10%
4									
5	Totals	$ 466,936	100.00%		11.10%	$ 540,236	100.00%		11.10%
6									
7									
8	[1] Rebuttal Adjustments to equity								
9	Acumm. depreciation adjustment		$ (4,879)						
10	CIAC adjustment		$ 2						
11	Deferred Income Tax Adjustment		$ (57,847)						
12									
13									
14									
15									
16	SUPPORTING SCHEDULES:								
17	Rejoinder D-1								
18	Rejoinder D-2								
19	Rejoinder D-3								
20	Rejoinder D-4								
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									
33									

RECAP SCHEDULES:

Northern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Long Term Debt

Exhibit
Rejoinder Schedule D-2
Page 1
Witness: Bourassa

Line No.	Description of Debt	End of Test Year Amount Outstanding[1]	Annual Interest	Interest Rate	Weighted Cost	End of Projected Year Amount Outstanding	Annual Interest	Interest Rate	Weighted Cost
1			-	6.10%	0.00%	-	-	6.10%	0.00%
2			-	6.26%	0.00%	-	-	6.26%	0.00%
3			-	8.56%	0.00%	-	-	8.56%	0.00%
4			-	7.30%	0.00%	-	-	7.30%	0.00%
5			-	6.91%	0.00%	-	-	6.91%	0.00%
6			-	7.16%	0.00%	-	-	7.16%	0.00%
7			-	0.00%	0.00%	-	-	0.00%	0.00%
8			-	0.00%	0.00%	-	-	0.00%	0.00%
9			-	0.00%	0.00%	-	-	0.00%	0.00%
10			-	0.00%	0.00%	-	-	0.00%	0.00%
11			-	0.00%	0.00%	-	-	0.00%	0.00%
12									
13	Totals	$ -	$ -		0.00%	$ -	-		0.00%
14									
15	SUPPORTING SCHEDULES:					RECAP SCHEDULES:			
16	Rejoinder D-2					Rejoinder D-1			
17									
18									
19									
20									

Northern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Preferred Stock

Exhibit
Rejoinder Schedule D-3
Page 1
Witness: Bourassa

Line No.	Description of Issue	End of Test Year Shares Outstanding	Amount	Dividend Requirement	End of Projected Year Shares Outstanding	Amount	Dividend Requirement
1							
2							
3	NOT APPLICABLE, NO PREFERRED STOCK ISSUED OR OUTSTANDING						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17	SUPPORTING SCHEDULES:				RECAP SCHEDULES:		
18					Rejoinder D-1		
19							
20							

Northern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Common Equity

Exhibit
Rejoinder Schedule D-4
Page 1
Witness: Bourassa

Line No.		
1		
2	The Company is proposing a cost of common equity of	11.10% .
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	SUPPORTING SCHEDULES:	RECAP SCHEDULES:
18	Rejoinder D-4.1 to D-4.16	Rejoinder D-1
19		
20		

Northern Sunrise Water Company (Stand-Alone)
Summary of Results

Exhibit
Rejoinder Schedule D-4.1

Line No.	Method	Low	High	Midpoint
6	Range DCF Constant Growth Estimates[1]	9.1%	10.5%	9.8%
8	Range of CAPM Estimates[2]	10.4%	13.9%	12.2%
11	Average of DCF and CAPM midpoint estimates	9.8%	12.2%	11.0%
14	Financial Risk Adjustment[3]	-1.0%	-1.0%	-1.0%
16	Specific Company Risk Premium[4]	1.1%	1.1%	1.1%
18	Indicated Cost of Equity	9.9%	12.3%	11.1%
22	Recommended Cost of Equity			11.1%

[1] See Rejoinder Schedule D-4-8
[2] See Rejoinder Schedule D-4.12
[3] See Rejoinder Schedule D-4.16
[4] See testimony.

Northern Sunrise Water Company (Stand-Alone)
Selected Characteristics of Sample Group of Water Utilities

Exhibit
Rejoinder Schedule D-4.2

Line No.	Company[1]	% Water Revenues	Operating Revenues (millions)	Net Plant (millions)	S&P Bond Rating	Moody's Bond Rating
1	1. American States	76%	$ 361.0	$ 962.1	A	A2
2	2. Aqua America	90%	$ 670.5	$ 2,790.5	AA-	NR
3	3. California Water	99%	$ 449.4	$ 1,079.9	AA-	NR
4	4. Connecticut Water	90%	$ 67.5	$ 273.1	A	NR
5	5. Middlesex	89%	$ 91.2	$ 329.7	A	NR
6	6. SJW Corp.	96%	$ 216.1	$ 523.7	NR	NR
7						
8	Average	90%	$ 309.3	$ 993.2		
9						
10	Northern Sunrise Water Company (as of December 31, 2008)	100%	$ 0.2	$ 0.7	NR	NR

[1]AUS Utility Reports (May 2010).

Northern Sunrise Water Company (Stand-Alone)
Capital Structures

Exhibit
Rejoinder Schedule D-4.3

No.		Book Value[1]		Market Value[1]	
		Long-Term Debt	Common Equity	Long-Term Debt	Common Equity
	Company				
1.	American States	47.7%	52.3%	31.7%	68.3%
2.	Aqua America	55.7%	44.3%	35.7%	64.3%
3.	California Water	47.2%	52.8%	31.7%	68.3%
4.	Connecticut Water	51.0%	49.0%	35.5%	64.5%
5.	Middlesex	47.4%	52.6%	34.0%	66.0%
6.	SJW Corp.	49.8%	50.2%	33.2%	66.8%
	Average	49.8%	50.2%	33.6%	66.4%
	Northern Sunrise Water Company (Stanc[2] (Adjusted as of December 31, 2008)	0.0%	100.0%	N/A	N/A

[1] Value Line Analyzer Data (April 23, 2010)

[2] Adjusted Per Rejoinder Schedule D-1

Northern Sunrise Water Company (Stand-Alone)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.4

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Five-year historical average annual changes					Average of Future and Historical Growth
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1.	American States	8.76%	4.98%	9.69%	2.88%	6.58%	5.38%	5.98%
2.	Aqua America	NMF	6.20%	3.85%	8.81%	6.29%	9.02%	7.65%
3.	California Water	4.93%	4.92%	6.62%	0.88%	4.34%	5.88%	5.11%
4.	Connecticut Water	3.15%	2.88%	1.72%	1.39%	2.29%	7.25%	4.77%
5.	Middlesex	2.61%	4.00%	0.41%	1.49%	2.13%	7.25%	4.69%
6.	SJW Corp.	6.79%	5.68%	0.25%	5.53%	4.56%	7.25%	5.91%
	GROUP AVERAGE	5.25%	4.78%	3.76%	3.50%	4.36%	7.01%	5.68%
	GROUP MEDIAN	4.93%	4.95%	2.79%	2.18%	4.45%	7.25%	5.51%

[1] Average of changes in annual stock prices ending on April 23, 2010. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2005 to 2010.

[3] See Rejoinder Schedule D-4.6.

Northern Sunrise Water Company (Stand-Alone)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.5

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
			Ten-year historical average annual changes					Average of Future and Historical Growth
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1	1. American States	8.60%	4.80%	5.36%	1.79%	5.14%	5.38%	5.26%
2	2. Aqua America	7.94%	8.19%	6.34%	7.67%	7.53%	9.02%	8.28%
3	3. California Water	7.79%	3.91%	4.09%	0.80%	4.15%	5.88%	5.01%
4	4. Connecticut Water	4.73%	3.77%	2.08%	1.31%	2.97%	7.25%	5.11%
5	5. Middlesex	4.64%	3.81%	1.24%	1.71%	2.85%	7.25%	5.05%
6	6. SJW Corp.	3.01%	5.25%	1.44%	5.53%	3.81%	7.25%	5.53%
7								
8	GROUP AVERAGE	6.12%	4.96%	3.42%	3.13%	4.41%	7.01%	5.71%
9	GROUP MEDIAN	6.26%	4.36%	3.08%	1.75%	3.98%	7.25%	5.18%

[1] Average of changes in annual stock prices ending on April 23, 2010. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2000 to 2009.

[3] See Rejoinder Schedule D-4.6.

Northern Sunrise Water Company (Stand-Alone)
Analysts Forecasts of Earnings Per Share Growth

Exhibit
Rejoinder Schedule D-4.6

Line No.		[1]	[2]	[3]	[4]	[5]
		ESTIMATES OF EARNINGS GROWTH				Average Growth (G)
	Company	Zacks[1]	Reuters[1]	Yahoo[1]	Value Line[1]	(Cols 1-4)[2]
1	1. American States	4.00%	4.00%	7.00%	6.50%	5.38%
2	2. Aqua America	8.00%	8.25%	8.33%	11.50%	9.02%
3	3. California Water	7.00%	4.00%	6.00%	6.50%	5.88%
4	4. Connecticut Water			15.00%		7.25%
5	5. Middlesex			8.00%		7.25%
6	6. SJW Corp.			10.00%		7.25%
7						
8	GROUP AVERAGE	6.33%	5.42%	9.06%	8.17%	7.01%
9	GROUP MEDIAN					7.25%

[1] Data as of April 23, 2010

[2] Where no data available or single estimate, average of other utilities assumed to estimate for utility.

Northern Sunrise Water Company (Stand-Alone)
Current Dividend Yields for Water Utility Sample Group

Exhibit
Rejoinder Schedule D-4.7

Line No.	Company	Curent Stock Price (P_0)[1]	Current Dividend (D_0)[1]	Current Dividend Yield (D_0/P_0)[1]	Average Annual Dividend Yield (D_0/P_0)[1,2]
1	1. American States	$ 38.09	$ 1.04	2.73%	2.86%
2	2. Aqua America	$ 18.47	$ 0.60	3.25%	2.80%
3	3. California Water	$ 38.90	$ 1.19	3.06%	3.12%
4	4. Connecticut Water	$ 23.95	$ 0.91	3.81%	3.58%
5	5. Middlesex	$ 18.12	$ 0.72	3.98%	3.99%
6	6. SJW Corp.	$ 27.28	$ 0.70	2.55%	2.27%
7					
8	Average			3.23%	3.10%
9	Median			3.15%	2.99%

[1] Value Line Analyzer Data. Stock prices as of April 23, 2010.

[2] Average Annual Dividend is dividends declared per share for a year divided by the average annual price of the stock in the same year, expressed as a percentage. For comparison purposes only.

Northern Sunrise Water Company (Stand-Alone)
Discounted Cash Flow Analysis
DCF Constant Growth

Exhibit
Rejoinder Schedule D-4.8

Line No.		[1] Average Spot Dividend Yield (D_0/P_0)[1]	[2] Expected Dividend Yield (D_1/P_0)[2]	[3] Growth (g)	[4] Indicated Cost of Equity k=Div Yld + g (Cols 2+3)
1					
2					
3					
4					
5					
6					
7					
8	DCF - Past and Future Growth	3.23%	3.41%	5.68% [3]	9.1%
9					
10	DCF - Future Growth	3.23%	3.46%	7.01% [4]	10.5%
11					
12					
13		3.23%	3.43%	6.34%	9.8%
14					
15					
16					
17					
18					

19 [1] Spot Dividend Yield = D_0/P_0. See Rejoinder Schedule D-4.7.
20 [2] Expected Dividend Yield = $D_1/P_0 = D_0/P_0 * (1+g)$.
21 [3] Growth rate (g). Average of Past and Future Growth. See Rejoinder Schedule D-4.4, column 7
22 4 Growth rate (g). Average of Analyst Estimates Future Growth. See Rejoinder Schedule D-4.6.
23
24
25
26
27
28

Northern Sunrise Water Company (Stand-Alone)
Market Betas

Exhibit
Rejoinder Schedule D-4.9

Line No.	Company	Beta (β)[1]
1		
2	1. American States	0.80
3	2. Aqua America	0.65
4	3. California Water	0.75
5	4. Connecticut Water	0.80
6	5. Middlesex	0.75
7	6. SJW Corp.	0.95
8		
9	Average	**0.78**
10		
11		
12		
13	[1] Value Line Investment Analyzer data (April 23, 2010)	
14	Note: Beta is a relative measure of the historical sensitivity of a stock's price to overall fluctuations	
15	in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise	
16	(or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is	
17	derived from a regression analysis of the relationship between weekly percent-age changes in the	
18	price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In	
19	the case of shorter price histories, a smaller time period is used, but two years is the minimum.	
20	The Betas are adjusted for their long-term tendency to converge toward 1.00.	

Northern Sunrise Water Company (Stand-Alone)
Forecasts of Long-Term Interest Rates
2011-2012

Exhibit
Rejoinder Schedule D-4.10

Line No.	Description	2011	2012	Average
6	Blue Chip Consensus Forecasts[1]	5.1%	5.5%	5.3%
8	Value Line[2]	4.9%	5.3%	5.1%
10	Average			5.2%

[1] December 2009 Blue Chip Financial Forecasts consensus forecast of 30 Year U.S.Treasury
[2] Value Line Quarterly forecast, dated February 26, 2010, Long-term Treasury

Northern Sunrise Water Company (Stand-Alone)
Computation of Current Market Risk Premium

Exhibit
Rejoinder Schedule D-4.11

Line No.	Month	Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	+	Growth (g)[3]	=	Expected Market Return (k)	-	Monthly Average 30 Year Treasury Rate[4]	=	Market Risk Premium (MRP)
4	Jan 2009	4.86%	6.32%	+	30.02%	=	36.34%	-	3.13%	=	33.21%
5	Feb	5.50%	7.43%	+	35.13%	=	42.56%	-	3.59%	=	38.97%
6	Mar	4.21%	5.36%	+	27.33%	=	32.69%	-	3.64%	=	29.05%
7	April	3.66%	4.47%	+	22.05%	=	26.52%	-	3.76%	=	22.76%
8	May	3.46%	4.14%	+	19.67%	=	23.81%	-	4.23%	=	19.58%
9	Jun	3.25%	3.87%	+	19.16%	=	23.03%	-	4.52%	=	18.51%
10	Jul	2.90%	3.37%	+	16.31%	=	19.68%	-	4.41%	=	15.27%
11	Aug	2.82%	3.22%	+	14.21%	=	17.43%	-	4.37%	=	13.06%
12	Sept	2.80%	3.20%	+	14.32%	=	17.52%	-	4.19%	=	13.33%
13	Oct	2.75%	3.15%	+	14.49%	=	17.64%	-	4.19%	=	13.45%
14	Nov	2.68%	3.05%	+	13.88%	=	16.93%	-	4.31%	=	12.62%
15	Dec 2009	2.56%	2.88%	+	12.58%	=	15.46%	-	4.35%	=	11.11%
16	Jan 2010	2.64%	3.00%	+	13.71%	=	16.71%	-	4.48%	=	12.23%
17	Feb	2.59%	2.97%	+	14.65%	=	17.62%	-	4.48%	=	13.14%
18	Mar	2.44%	2.75%	+	12.69%	=	15.44%	-	4.48%	=	10.96%
19	April	2.36%	2.63%	+	11.61%	=	14.24%	-	4.69%	=	9.55%
20											
21											
22	Recommended	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
23											
24	Short-term Trends										
25	Recent Twelve Months Avg	2.77%	3.19%	+	14.77%	=	17.96%	-	4.39%	=	13.57%
26	Recent Nine Months Avg	2.63%	2.98%	+	13.57%	=	16.56%	-	4.39%	=	12.16%
27	Recent Six Months Avg	2.55%	2.88%	+	13.19%	=	16.07%	-	4.47%	=	11.60%
28	Recent Three Months Avg	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%

29
30
31 [1] Average Current Dividend Yield (D_0/P_0) of dividend paying stocks. Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks
32 [2] Expected Dividend Yield (D_1/P_0) equals average current dividend yield (D0/P0) times one plus growth rate(g).
33 [3] Average 3-5 year price appreciation (annualized). Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks
34 [4] Montly average 30 year U.S. Treasury. Federal Reserve.
35

Northern Sunrise Water Company (Stand-Alone)
Capital Asset Pricing Model (CAPM)

Exhibit
Rejoinder Schedule D-4.12

Line No.		Rf[1]	+	beta[3]	x	Rp		=	k
1									
2									
3	Historical Market Risk Premium CAPM	5.2%	+	0.78	x	6.7%	[4]	=	10.4%
4									
5	Current Market Risk Premium CAPM	5.2%	+	0.78	x	11.2%	[5]	=	13.9%
6									
7	Average								12.2%
8									
9									
10									
11									

[1] Forecasts of long-term treasury yields. See Rejoinder Schedule D-4.10.
[2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9.
[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009
[4] Computed using DCF constant growth method to determine current market return onValue Line 1700 stocks
and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11.

Northern Sunrise Water Company (Stand-Alone)
Financial Risk Computation

Exhibit
Rejoinder Schedule D-4.13

Line No.											
1	**CAPM**										
2		**Rf**		+	**β**		x	**(Rp)**			**k**
3	Historical Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	6.7%	[3]	=	10.4%
4	Current Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	11.2%	[4]	=	13.9%
5											
6	Average										12.2%
7											
8											
9	**CAPM Relevered Beta**										
10		**Rf**		+	**β**		x	**(Rp)**			**k**
11	Historical Market Risk Premium	5.2%	[1]	+	0.67	[5]	x	6.7%	[3]	=	9.7%
12	Current Market Risk Premium	5.2%	[1]	+	0.67	[5]	x	11.2%	[4]	=	12.7%
13											
14	Average										11.2%
15											
16	Financial Risk Adjustment										**-1.0%**
17											
18											
19	[1] Forecast of long-term treasury yields. See Rebuttal Schedule D-4.10										
20	[2] Value Line Investment Analyzer data. See Rebuttal Schedule D-4.9										
21	[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009										
22	[4] Computed using DCF constant growth method to determine current market return on Value Line 1700 stocks										
23	and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rebuttal Schedule D-4.11										
24	[5] Relevered bata found on Rebuttal Schedule D-4.15										
25											

Northern Sunrise Water Company (Stand-Alone)
Financial Risk Computation
Unlevered Beta

Exhibit
Rebuttal Schedule D-4.14

Line No.		Company	VL Beta β_l [1]	Raw Beta Raw β_l [2]	Tax Rate t [3]	MV Debt D [4]	MV Equity E [4]	Unlevered Raw Beta β_u [5]
1								
2								
3								
4								
5	1.	American States	0.80	0.70	37.8%	31.7%	68.3%	0.54
6	2.	Aqua America	0.65	0.48	39.4%	35.7%	64.3%	0.36
7	3.	California Water	0.75	0.63	38.0%	31.7%	68.3%	0.49
8	4.	Connecticut Water	0.80	0.70	19.5%	35.5%	64.5%	0.49
9	5.	Middlesex	0.75	0.63	34.1%	34.0%	66.0%	0.47
10	6.	SJW Corp.	0.95	0.93	40.4%	33.2%	66.8%	0.72
11								
12								
13		Sample Water Utilities	0.78	0.68	34.8%	33.6%	66.4%	0.51
14								
15								
16								
17								
18								
19								

20 [1] Value Line Investment Analyzer data.
21 Value Line uses the historical data of the stock, but assumes that a security's beta moves toward the market average over time. The formula is as follows:
22 Adjusted beta = .33 + (.67) * Raw beta
23 [2] Raw Beta = (VL beta - .33)/(.67)
24 [3] Effective tax rates for year ended December 31, 2009.
25 [4] See Rejoinder Scehdule D-4.3
26 [5] Raw B_u = Raw B_L / (1+ (1-t)*D/E)
27
28
29
30

Exhibit
Rejoinder Schedule D-4.15

Northern Sunrise Water Company (Stand-Alone)
Financial Risk Computation
Relevered Beta

Line No.		Unlevered Raw Beta β_U[1]	MV Book Debt BD[2]	MV Equity Capital EC[2]	Tax Rate t[3]	Relevered Raw Beta $\beta_{RL}=\beta_U (1+(1-t)BD/EC))$ β_{RL}	VL Adjusted Relevered Beta .33 + .67(Raw Beta) β_{RL}
1							
2							
3							
4							
5	Northern Sunrise Water Compan	0.51	0.0%	100.0%	26.80%	0.51	0.67
6							
7							
8							
9							
10							
11							
12							

13 [1] Unlevered Beta from Table 18.

14 [2] Capital Structure of Company (Projected)

	BV (in Thousands)			MV (in Thousands)	%
15					
16					
17	Long-term Debt	$ -	1.00	$ -	0.00%
18	Preferred Stock	$ -	1.00	-	0.0%
19	Common Stock	$ 477	1.97 (a)	938	100.0%
20	Total Capital	$ 477		$ 938	100.0%

21

22 (a) Current market-to-book ratio of sample water utilities. See work papers.

23

24 [3] Current Tax rate based on test year ending 2009. See Rejoinder Schedule D-1.

25

26

Northern Sunrise Water Company (Stand-Alone)
Size Premium[1]

Exhibit
Rejoinder Schedule D-4.16

Line No.		Beta(β)	Size Premium	Risk Premium for Small Water Utilities[7]
6	Mid-Cap Companies[2]	1.13	1.00%	
8	Low-Cap Companies[3]	1.26	1.64%	
10	Micro-Cap Companies[4]	1.51	3.00%	
12	Decile 10[5]	1.64	4.74%	2.46%

		Risk Premium for Small Water Utilities
20	Estimated Risk Premium for small water utilities[6]	0.99%

[1] Data from Table 7-11 of Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook.*
[2] Mid-Cap companies includes companies with market capitalization between $1,602 million and $5,936 million.
[3] Low-Cap companies includes companies with market capitalization between $432 million and $1,600 million.
[4] Micro-Cap companies includes companies with market capitalization less than $431 million.
[5] Decile 10 includes companies with market capitalization between $1.0 million and $214 million.
[6] From Table 2, Thomas M. Zepp, "Utility Stocks and the Size Effect Revisited," *The Quarterly Review of Economics and Finance*, 43 (2003), 578-582.
[7] Computed as the weighted differences between the Decile 10 risk premium and the inidicated risk premiums for the sample water utlities as shown below. Excludes risk due to differences in beta.

		Market Cap. (Millions)	Class	Size Premium	Difference to Decile 10	Weight	Weighted Size Premium
1.	American States	$ 659	Low-Cap	1.64%	3.10%	0.1666667	0.52%
2.	Aqua America	$ 2,501	Mid-Cap	1.00%	3.74%	0.1666667	0.62%
3.	California Water	$ 805	Low-Cap	1.64%	3.10%	0.1666667	0.52%
4.	Connecticut Water	$ 204	Decile 10	4.74%	0.00%	0.1666667	0.00%
5.	Middlesex	$ 243	Micro-Cap	3.00%	1.74%	0.1666667	0.29%
6.	SJW Corp.	$ 496	Low-Cap	1.64%	3.10%	0.1666667	0.52%
	Weighted Size Premium for Small Companies						2.46%

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Thomas J. Bourassa
Rejoinder Testimony
(Cost of Capital)
July 7, 2010

Southern Sunrise Water Company
Stand-Alone Schedules

Southern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Summary of Cost of Capital

Exhibit
Rejoinder Schedule D-1
Page 1
Witness: Bourassa

Line No.	Item of Capital	End of Test Year Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost	End of Projected Year Dollar Amount	Percent of Total	(e) Cost Rate	Weighted Cost
1	Long-Term Debt	-	0.00%	0.00%	0.00%	$ -	0.00%	0.00%	0.00%
2									
3	Stockholder's Equity[1]	1,339,497	100.00%	11.10%	11.10%	1,486,096	100.00%	11.10%	11.10%
4									
5	Totals	$ 1,339,497	100.00%		11.10%	$ 1,486,096	100.00%		11.10%
6									
7									
8	[1] Adjustments to equity								
9	Acumm. depreciation adjustment		$ 24,067						
10	CIAC adjustment		$ 1						
11	Deferred Income Tax Adjustment		$ (93,376)						
12									
13									
14									
15									
16	SUPPORTING SCHEDULES:								
17	Rejoinder D-1								
18	Rejoinder D-2								
19	Rejoinder D-3								
20	Rejoinder D-4								
21									
22									
23									
24									
25									
26									
27									
28									
29									
30									
31									
32									
33									

RECAP SCHEDULES:

Southern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Long Term Debt

Exhibit
Rejoinder Schedule D-2
Page 1
Witness: Bourassa

Line No.	Description of Debt	End of Test Year Amount Outstanding[1]	End of Test Year Annual Interest	End of Test Year Interest Rate	End of Test Year Weighted Cost	End of Projected Year Amount Outstanding	End of Projected Year Annual Interest	End of Projected Year Interest Rate	End of Projected Year Weighted Cost
1			-	6.10%	0.00%	-	-	6.10%	0.00%
2			-	6.26%	0.00%	-	-	6.26%	0.00%
3			-	8.56%	0.00%	-	-	8.56%	0.00%
4			-	7.30%	0.00%	-	-	7.30%	0.00%
5			-	6.91%	0.00%	-	-	6.91%	0.00%
6			-	7.16%	0.00%	-	-	7.16%	0.00%
7			-	0.00%	0.00%	-	-	0.00%	0.00%
8			-	0.00%	0.00%	-	-	0.00%	0.00%
9			-	0.00%	0.00%	-	-	0.00%	0.00%
10			-	0.00%	0.00%	-	-	0.00%	0.00%
11			-	0.00%	0.00%	-	-	0.00%	0.00%
12									
13	Totals	$ -	$ -		0.00%	$ -	-		0.00%
14									
15	SUPPORTING SCHEDULES:					RECAP SCHEDULES:			
16						Rejoinder D-1			
17									
18									
19									
20									

Southern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Preferred Stock

Exhibit
Rejoinder Schedule D-3
Page 1
Witness: Bourassa

Line No.	Description of Issue	End of Test Year Shares Outstanding	Amount	Dividend Requirement	End of Projected Year Shares Outstanding	Amount	Dividend Requirement
1							
2							
3	NOT APPLICABLE, NO PREFERRED STOCK ISSUED OR OUTSTANDING						
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17	SUPPORTING SCHEDULES:			RECAP SCHEDULES:			
18				Rejoinder D-1			
19							
20							

Southern Sunrise Water Company (Stand-Alone)
Test Year Ended March 31, 2009
Cost of Common Equity

Exhibit
Rejoinder Schedule D-4
Page 1
Witness: Bourassa

Line No.		
1		
2	The Company is proposing a cost of common equity of	11.10% .
3		
4		
5		
6		
7		
8		
9		
10		
11		
12		
13		
14		
15		
16		
17	SUPPORTING SCHEDULES:	RECAP SCHEDULES:
18	Rejoinder D-4.1 to D-4.16	Rejoinder D-1
19		
20		

Southern Sunrise Water Company (Stand-Alone)
Summary of Results

Exhibit
Rejoinder Schedule D-4.1

Line No.	Method	Low	High	Midpoint
1				
2				
3				
4	Method	Low	High	Midpoint
5				
6	Range DCF Constant Growth Estimates[1]	9.1%	10.5%	9.8%
7				
8	Range of CAPM Estimates[2]	10.4%	13.9%	12.2%
9				
10				
11	Average of DCF and CAPM midpoint estimates	9.8%	12.2%	11.0%
12				
13				
14	Financial Risk Adjustment[3]	-1.0%	-1.0%	-1.0%
15				
16	Specific Company Risk Premium[4]	1.1%	1.1%	1.1%
17				
18	Indicated Cost of Equity	9.9%	12.3%	11.1%
19				
20				
21				
22	Recommended Cost of Equity			11.1%
23				
24				
25				
26	1 See Rejoinder Schedule D-4-8			
27	2 See Rejoinder Schedule D-4.12			
28	3 See Rejoinder Schedule D-4.16			
29	[4] See testimony.			

Southern Sunrise Water Company (Stand-Alone)
Selected Characteristics of Sample Group of Water Utilities

Exhibit
Rejoinder Schedule D-4.2

Line No.	Company[1]	% Water Revenues	Operating Revenues (millions)	Net Plant (millions)	S&P Bond Rating	Moody's Bond Rating
1.	American States	76%	$ 361.0	$ 962.1	A	A2
2.	Aqua America	90%	$ 670.5	$ 2,790.5	AA-	NR
3.	California Water	99%	$ 449.4	$ 1,079.9	AA-	NR
4.	Connecticut Water	90%	$ 67.5	$ 273.1	A	NR
5.	Middlesex	89%	$ 91.2	$ 329.7	A	NR
6.	SJW Corp.	96%	$ 216.1	$ 523.7	NR	NR
	Average	90%	$ 309.3	$ 993.2		
	Southern Sunrise Water Company (as of December 31, 2008)	100%	$ 0.2	$ 0.7	NR	NR

[1]AUS Utility Reports (May 2010).

Southern Sunrise Water Company (Stand-Alone)
Capital Structures

Exhibit
Rejoinder Schedule D-4.3

No.		Book Value[1]		Market Value[1]	
		Long-Term Debt	Common Equity	Long-Term Debt	Common Equity
	Company				
1.	American States	47.7%	52.3%	31.7%	68.3%
2.	Aqua America	55.7%	44.3%	35.7%	64.3%
3.	California Water	47.2%	52.8%	31.7%	68.3%
4.	Connecticut Water	51.0%	49.0%	35.5%	64.5%
5.	Middlesex	47.4%	52.6%	34.0%	66.0%
6.	SJW Corp.	49.8%	50.2%	33.2%	66.8%
	Average	49.8%	50.2%	33.6%	66.4%
	Southern Sunrise Water Company (Stan[2] (Adjusted as of December 31, 2008)	0.0%	100.0%	N/A	N/A

[1] Value Line Analyzer Data (April 23, 2010)
[2] Adjusted Per Rejoinder Schedule D-1

Southern Sunrise Water Company (Stand-Alone)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.4

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
		Five-year historical average annual changes						Average of Future and Historical Growth
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
8	1. American States	8.76%	4.98%	9.69%	2.88%	6.58%	5.38%	5.98%
9	2. Aqua America	NMF	6.20%	3.85%	8.81%	6.29%	9.02%	7.65%
10	3. California Water	4.93%	4.92%	6.62%	0.88%	4.34%	5.88%	5.11%
11	4. Connecticut Water	3.15%	2.88%	1.72%	1.39%	2.29%	7.25%	4.77%
12	5. Middlesex	2.61%	4.00%	0.41%	1.49%	2.13%	7.25%	4.69%
13	6. SJW Corp.	6.79%	5.68%	0.25%	5.53%	4.56%	7.25%	5.91%
16	GROUP AVERAGE	5.25%	4.78%	3.76%	3.50%	4.36%	7.01%	5.68%
17	GROUP MEDIAN	4.93%	4.95%	2.79%	2.18%	4.45%	7.25%	5.51%

[1] Average of changes in annual stock prices ending on April 23, 2010. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2005 to 2010.

[3] See Rejoinder Schedule D-4.6.

Southern Sunrise Water Company (Stand-Alone)
Comparisons of Past and Future Estimates of Growth

Exhibit
Rejoinder Schedule D-4.5

Line No.		[1]	[2]	[3]	[4]	[5]	[6]	[7]
								Average of Future and Historical Growth
		Ten-year historical average annual changes						
	Company	Price[1]	Book Value[2]	EPS[2]	DPS[2]	Average Col 1-4	Average Future Growth[3]	Col 5-6
1	American States	8.60%	4.80%	5.36%	1.79%	5.14%	5.38%	5.26%
2	Aqua America	7.94%	8.19%	6.34%	7.67%	7.53%	9.02%	8.28%
3	California Water	7.79%	3.91%	4.09%	0.80%	4.15%	5.88%	5.01%
4	Connecticut Water	4.73%	3.77%	2.08%	1.31%	2.97%	7.25%	5.11%
5	Middlesex	4.64%	3.81%	1.24%	1.71%	2.85%	7.25%	5.05%
6	SJW Corp.	3.01%	5.25%	1.44%	5.53%	3.81%	7.25%	5.53%
7								
8	GROUP AVERAGE	6.12%	4.96%	3.42%	3.13%	4.41%	7.01%	5.71%
9	GROUP MEDIAN	6.26%	4.36%	3.08%	1.75%	3.98%	7.25%	5.18%

[1] Average of changes in annual stock prices ending on April 23, 2010. Data from Yahoo Finance website.

[2] Data derived from Value Line Investment Survey and/or 10K Reports for period 2000 to 2009.

[3] See Rejoinder Schedule D-4.6.

Southern Sunrise Water Company (Stand-Alone)
Analysts Forecasts of Earnings Per Share Growth

Exhibit
Rejoinder Schedule D-4.6

Line No.		[1]	[2]	[3]	[4]	[5]
		ESTIMATES OF EARNINGS GROWTH				Average
	Company	Zacks[1]	Reuters[1]	Yahoo[1]	Value Line[1]	Growth (G) (Cols 1-4)[2]
1	1. American States	4.00%	4.00%	7.00%	6.50%	5.38%
2	2. Aqua America	8.00%	8.25%	8.33%	11.50%	9.02%
3	3. California Water	7.00%	4.00%	6.00%	6.50%	5.88%
4	4. Connecticut Water			15.00%		7.25%
5	5. Middlesex			8.00%		7.25%
6	6. SJW Corp.			10.00%		7.25%
7						
8	GROUP AVERAGE	6.33%	5.42%	9.06%	8.17%	7.01%
9	GROUP MEDIAN					7.25%

[1] Data as of April 23, 2010

[2] Where no data available or single estimate, average of other utilities assumed to estimate for utility.

Southern Sunrise Water Company (Stand-Alone)
Current Dividend Yields for Water Utility Sample Group

Exhibit
Rejoinder Schedule D-4.7

Line No.	Company	Curent Stock Price (P_0)[1]	Current Dividend (D_0)[1]	Current Dividend Yield (D_0/P_0)[1]	Average Annual Dividend Yield (D_0/P_0)[1,2]
1	1. American States	$ 38.09	$ 1.04	2.73%	2.86%
2	2. Aqua America	$ 18.47	$ 0.60	3.25%	2.80%
3	3. California Water	$ 38.90	$ 1.19	3.06%	3.12%
4	4. Connecticut Water	$ 23.95	$ 0.91	3.81%	3.58%
5	5. Middlesex	$ 18.12	$ 0.72	3.98%	3.99%
6	6. SJW Corp.	$ 27.28	$ 0.70	2.55%	2.27%
7					
8	Average			3.23%	3.10%
9	Median			3.15%	2.99%

[1] Value Line Analyzer Data. Stock prices as of April 23, 2010.

[2] Average Annual Dividend is dividends declared per share for a year divided by the average annual price of the stock in the same year, expressed as a percentage. For comparison purposes only.

Southern Sunrise Water Company (Stand-Alone)
Discounted Cash Flow Analysis
DCF Constant Growth

Exhibit
Rejoinder Schedule D-4.8

Line No.		[1] Average Spot Dividend Yield (D_0/P_0)[1]	[2] Expected Dividend Yield (D_1/P_0)[2]	[3] Growth (g)		[4] Indicated Cost of Equity k=Div Yld + g (Cols 2+3)
1						
2						
3						
4						
5						
6						
7						
8	DCF - Past and Future Growth	3.23%	3.41%	5.68%	[3]	9.1%
9						
10	DCF - Future Growth	3.23%	3.46%	7.01%	[4]	10.5%
11						
12						
13		3.23%	3.43%	6.34%		9.8%
14						
15						
16						
17						
18						

19 [1] Spot Dividend Yield = D_0/P_0. See Rejoinder Schedule D-4.7.
20 [2] Expected Dividend Yield = $D_1/P_0 = D_0/P_0 * (1+g)$.
21 [3] Growth rate (g). Average of Past and Future Growth. See Rejoinder Schedule D-4.4, column 7
22 4 Growth rate (g). Average of Analyst Estimates Future Growth. See Rejoinder Schedule D-4.6.
23
24
25
26
27
28

Southern Sunrise Water Company (Stand-Alone)
Market Betas

Exhibit
Rejoinder Schedule D-4.9

Line No.		Company	Beta (β)[1]
1			
2	1.	American States	0.80
3	2.	Aqua America	0.65
4	3.	California Water	0.75
5	4.	Connecticut Water	0.80
6	5.	Middlesex	0.75
7	6.	SJW Corp.	0.95
8			
9		Average	**0.78**
10			
11			
12			

[1] Value Line Investment Analyzer data (April 23, 2010)

Note: Beta is a relative measure of the historical sensitivity of a stock's price to overall fluctuations in the New York Stock Exchange Composite Index. A Beta of 1.50 indicates a stock tends to rise (or fall) 50% more than the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percent-age changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. In the case of shorter price histories, a smaller time period is used, but two years is the minimum. The Betas are adjusted for their long-term tendency to converge toward 1.00.

Southern Sunrise Water Company (Stand-Alone)
Forecasts of Long-Term Interest Rates
2011-2012

Exhibit
Rejoinder Schedule D-4.10

Line No.	Description	2011	2012	Average
6	Blue Chip Consensus Forecasts[1]	5.1%	5.5%	5.3%
8	Value Line[2]	4.9%	5.3%	5.1%
10	Average			5.2%

[1] December 2009 Blue Chip Financial Forecasts consensus forecast of 30 Year U.S.Treasury

[2] Value Line Quarterly forecast, dated February 26, 2010, Long-term Treasury

Southern Sunrise Water Company (Stand-Alone)
Computation of Current Market Risk Premium

Exhibit
Rejoinder Schedule D-4.11

Line No.	Month	Dividend Yield (D_0/P_0)[1]	Expected Dividend Yield (D_1/P_0)[2]	+	Growth (g)[3]	=	Expected Market Return (k)	-	Monthly Average 30 Year Treasury Rate[4]	=	Market Risk Premium (MRP)
1	Jan 2009	4.86%	6.32%	+	30.02%	=	36.34%	-	3.13%	=	33.21%
2	Feb	5.50%	7.43%	+	35.13%	=	42.56%	-	3.59%	=	38.97%
3	Mar	4.21%	5.36%	+	27.33%	=	32.69%	-	3.64%	=	29.05%
4	April	3.66%	4.47%	+	22.05%	=	26.52%	-	3.76%	=	22.76%
5	May	3.46%	4.14%	+	19.67%	=	23.81%	-	4.23%	=	19.58%
6	Jun	3.25%	3.87%	+	19.16%	=	23.03%	-	4.52%	=	18.51%
7	Jul	2.90%	3.37%	+	16.31%	=	19.68%	-	4.41%	=	15.27%
8	Aug	2.82%	3.22%	+	14.21%	=	17.43%	-	4.37%	=	13.06%
9	Sept	2.80%	3.20%	+	14.32%	=	17.52%	-	4.19%	=	13.33%
10	Oct	2.75%	3.15%	+	14.49%	=	17.64%	-	4.19%	=	13.45%
11	Nov	2.68%	3.05%	+	13.88%	=	16.93%	-	4.31%	=	12.62%
12	Dec 2009	2.56%	2.88%	+	12.58%	=	15.46%	-	4.35%	=	11.11%
13	Jan 2010	2.64%	3.00%	+	13.71%	=	16.71%	-	4.48%	=	12.23%
14	Feb	2.59%	2.97%	+	14.65%	=	17.62%	-	4.48%	=	13.14%
15	Mar	2.44%	2.75%	+	12.69%	=	15.44%	-	4.48%	=	10.96%
16	April	2.36%	2.63%	+	11.61%	=	14.24%	-	4.69%	=	9.55%
17											
18											
19	Recommended	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
20											
21	Short-term Trends										
22	Recent Twelve Months Avg	2.77%	3.19%	+	14.77%	=	17.96%	-	4.39%	=	13.57%
23	Recent Nine Months Avg	2.63%	2.98%	+	13.57%	=	16.56%	-	4.39%	=	12.16%
24	Recent Six Months Avg	2.55%	2.88%	+	13.19%	=	16.07%	-	4.47%	=	11.60%
25	Recent Three Months Avg	2.46%	2.78%	+	12.98%	=	15.77%	-	4.55%	=	11.22%
26											
27											

[1] Average Current Dividend Yield (D_0/P_0) of dividend paying stocks. Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

[2] Expected Dividend Yield (D_1/P_0) equals average current dividend yield (D0/P0) times one plus growth rate(g).

[3] Average 3-5 year price appreciation (annualized). Data from Value Line Investment Analyzer Software Data - Value Line 1700 Stocks

[4] Montly average 30 year U.S. Treasury. Federal Reserve.

Southern Sunrise Water Company (Stand-Alone)
Capital Asset Pricing Model (CAPM)

Exhibit
Rejoinder Schedule D-4.12

Line No.		Rf[1]	+	beta[3]	x	Rp		=	k
1									
2									
3	Historical Market Risk Premium CAPM	5.2%	+	0.78	x	6.7%	[4]	=	10.4%
4									
5	Current Market Risk Premium CAPM	5.2%	+	0.78	x	11.2%	[5]	=	13.9%
6									
7	Average								12.2%
8									
9									
10									
11									

12 [1] Forecasts of long-term treasury yields. See Rejoinder Schedule D-4.10.
13 [2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9.
14 [3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009
15 [4] Computed using DCF constant growth method to determine current market return onValue Line 1700 stocks
16 and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11.
17
18
19
20

Southern Sunrise Water Company (Stand-Alone)
Financial Risk Computation

Exhibit
Rejoinder Schedule D-4.13

Line No.											
1	**CAPM**										
2		**Rf**		+	**β**		x	**(Rp)**			**k**
3	Historical Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	6.7%	[3]	=	10.4%
4	Current Market Risk Premium	5.2%	[1]	+	0.78	[2]	x	11.2%	[4]	=	13.9%
5											
6	Average										12.2%
7											
8											
9	**CAPM Relevered Beta**										
10		**Rf**		+	**β**		x	**(Rp)**			**k**
11	Historical Market Risk Premium	5.2%	[1]	+	0.67	[5]	x	6.7%	[3]	=	9.7%
12	Current Market Risk Premium	5.2%	[1]	+	0.67	[5]	x	11.2%	[4]	=	12.7%
13											
14	Average										11.2%
15											
16	Financial Risk Adjustment										**-1.0%**
17											
18											
19	[1] Forecast of long-term treasury yields. See Rejoinder Schedule D-4.10										
20	[2] Value Line Investment Analyzer data. See Rejoinder Schedule D-4.9										
21	[3] Historical Market Risk Premium from (Rp) MorningStar SBBI 2010 Valuation Yearbook Table A-1 Long-Horizon ERP 1926-2009										
22	[4] Computed using DCF constant growth method to determine current market return on Value Line 1700 stocks										
23	and CAPM with beta of 1.0 to compute Current Market Risk Premium (Rp). See Rejoinder Schedule D-4.11										
24	[5] Relevered bata found on Rejoinder Schedule D-4.15										
25											

Southern Sunrise Water Company (Stand-Alone)
Financial Risk Computation
Unlevered Beta

Exhibit
Rejoinder Schedule D-4.14

Line No.		Company	VL Beta β_L [1]	Raw Beta Raw β_L [2]	Tax Rate t [3]	MV Debt D [4]	MV Equity E [4]	Unlevered Raw Beta β_u [5]
1								
2								
3								
4								
5	1.	American States	0.80	0.70	37.8%	31.7%	68.3%	0.54
6	2.	Aqua America	0.65	0.48	39.4%	35.7%	64.3%	0.36
7	3.	California Water	0.75	0.63	38.0%	31.7%	68.3%	0.49
8	4.	Connecticut Water	0.80	0.70	19.5%	35.5%	64.5%	0.49
9	5.	Middlesex	0.75	0.63	34.1%	34.0%	66.0%	0.47
10	6.	SJW Corp.	0.95	0.93	40.4%	33.2%	66.8%	0.72
11								
12								
13		Sample Water Utilities	0.78	0.68	34.8%	33.6%	66.4%	0.51
14								
15								
16								
17								
18								
19								

20 [1] Value Line Investment Analyzer data. See Table 13.
21 Value Line uses the historical data of the stock, but assumes that a security's beta moves toward the market average over time. The formula is as follows:
22 Adjusted beta = .33 + (.67) * Raw beta
23 [2] Raw Beta = (VL beta - .33)/(.67)
24 [3] Effective tax rates for year ended December 31, 2009.
25 [4] See Rejoinder Scehdule D-4.3
26 [5] Raw B_u = Raw B_L/ (1+ (1-t)*D/E)
27
28
29
30

Exhibit
Rejoinder Schedule D-4.15

Southern Sunrise Water Company (Stand-Alone)
Financial Risk Computation
Relevered Beta

Line No.		Unlevered Raw Beta β_U[1]	MV Book Debt BD[2]	MV Equity Capital EC[2]	Tax Rate t[3]	Relevered Raw Beta $\beta_{RL}=\beta_U (1+(1-t)BD/EC))$ β_{RL}	VL Adjusted Relevered Beta .33 + .67(Raw Beta) β_{RL}
1							
2							
3							
4							
5	Southern Sunrise Water Compar	0.51	0.0%	100.0%	35.93%	0.51	0.67
6							
7							
8							
9							
10							
11							
12							

13 [1] Unlevered Beta from Table 18.

14 [2] Capital Structure of Company (Projected)

		BV (in Thousands)			MV (in Thousands)	%
15						
16						
17	Long-term Debt	$ -	1.00		$ -	0.00%
18	Preferred Stock	-	1.00		-	0.0%
19	Common Stock	1,339.50	1.97	(a)	2,634	100.0%
20	Total Capital	$ 1,339			$ 2,634	100.0%

21

22 (a) Current market-to-book ratio of sample water utilities. See work papers.

23

24 3 Current Tax rate based on test year ending 2009. See Rejoinder Schedule D-1.

25

26

Southern Sunrise Water Company (Stand-Alone)
Size Premium[1]

Exhibit
Rejoinder Schedule D-4.16

Line No.		Beta(β)	Size Premium	Risk Premium for Small Water Utilities[7]
6	Mid-Cap Companies[2]	1.13	1.00%	
8	Low-Cap Companies[3]	1.26	1.64%	
10	Micro-Cap Companies[4]	1.51	3.00%	
12	Decile 10[5]	1.64	4.74%	2.46%

		Risk Premium for Small Water Utilities
20	Estimated Risk Premium for small water utilities[6]	0.99%

[1] Data from Table 7-11 of Morningstar, *Ibbotson SBBI 2010 Valuation Yearbook.*
[2] Mid-Cap companies includes companies with market capitalization between $1,602 million and $5,936 million.
[3] Low-Cap companies includes companies with market capitalization between $432 million and $1,600 million.
[4] Micro-Cap companies includes companies with market capitalization less than $431 million.
[5] Decile 10 includes companies with market capitalization between $1.0 million and $214 million.
[6] From Table 2, Thomas M. Zepp, "Utility Stocks and the Size Effect Revisited," *The Quarterly Review of Economics and Finance*, 43 (2003), 578-582.
[7] Computed as the weighted differences between the Decile 10 risk premium and the inidicated risk premiums for the sample water utlities as shown below. Excludes risk due to differences in beta.

		Market Cap. (Millions)	Class	Size Premium	Difference to Decile 10	Weight	Weighted Size Premium
1.	American States	$ 659	Low-Cap	1.64%	3.10%	0.1666667	0.52%
2.	Aqua America	$ 2,501	Mid-Cap	1.00%	3.74%	0.1666667	0.62%
3.	California Water	$ 805	Low-Cap	1.64%	3.10%	0.1666667	0.52%
4.	Connecticut Water	$ 204	Decile 10	4.74%	0.00%	0.1666667	0.00%
5.	Middlesex	$ 243	Micro-Cap	3.00%	1.74%	0.1666667	0.29%
6.	SJW Corp.	$ 496	Low-Cap	1.64%	3.10%	0.1666667	0.52%
	Weighted Size Premium for Small Companies						2.46%

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BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC. AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02465A-09-0411
IN THE MATTER OF THE APPLICATION OF NORTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-20453A-09-0412
IN THE MATTER OF THE APPLICATION OF SOUTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-20454A-09-0413

IN THE MATTER OF THE JOINT APPLICATION OF BELLA VISTA WATER CO., INC., NORTHERN SUNRISE WATER COMPANY, INC., AND SOUTHERN SUNRISE WATER COMPANY, INC. FOR APPROVAL OF AUTHORITY TO CONSOLIDATE OPERATIONS, AND FOR THE TRANSFER OF UTILITY ASSETS TO BELLA VISTA WATER CO., INC. PURSUANT TO ARIZONA REVISED STATUTES 40-285.	DOCKET NO. W-02465A-09-0414 DOCKET NO. W-20453A-09-0414 DOCKET NO. W-20454A-09-0414

REBUTTAL TESTIMONY OF

PETER EICHLER

May 25, 2010

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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 2845 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 Bella Vista Water Company, Northern Sunrise Water Company, and Southern Sunrise Water Company. Since this is a consolidated docket, I will refer to the companies as the Bella Vista Companies, or specifically to each Company where appropriate.

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 rate case 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 9 months. Prior to my employment at Liberty Water, I spent four 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. In addition, I have completed a

Masters of Business Administration degree from the University of 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 also completed NARUC's Utility School in November 2009.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE ARIZONA CORPORATION COMMISSION?

A. Yes, I testified on behalf of Rio Rico Utilities, Inc. in its recent evidentiary hearing on RRUI's pending rate case. That was the first time that I testified before a regulatory commission. This case is my second.

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 method in response to the direct testimonies of Ms. Crystal S. Brown on behalf of Commission Staff and Mr. Timothy J. Coley on behalf of RUCO relating to Liberty Water's affiliate cost allocations to the Bella Vista Companies.

Based on my review of Staff's and RUCO's testimony, it appears that further explanation is necessary relating to our affiliate cost methodology and the benefits provided to Bella Vista and Liberty Water's other regulated utilities in Arizona through services provided by Algonquin Power Trust ("APT") and Algonquin Water Services d/b/a Liberty Water ("Liberty Water"). 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 Bella Vista Water Company, Northern Sunrise Water Company, Southern Sunrise Water Company, Litchfield Park Service Company, Black Mountain Sewer Company, Gold Canyon Sewer Company, and Rio Rico Utilities Inc. (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 defines what portions of the affiliate costs are direct costs and what portion are indirect costs. This document was previously disclosed in this case in response to data requests.

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

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

A. Initially, I will note that Algonquin Power Income Fund converted to a common share ownership structure traded on the Toronto Stock Exchange ("TSX") in late 2009. As a result, APIF is now known as Algonquin Power & Utilities Corp ("APUC"). During the test year, the ultimate parent company was known as Algonquin Power Income Fund. In my testimony, I refer to APIF and APUC synonymously.

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 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. Those seven facilities are known as the Trafalgar facilities.

Q. PLEASE SUMMARIZE THE SHARED SERVICES MODEL AND THE RELATIONSHIP BETWEEN BELLA VISTA, LIBERTY WATER, AND ALGONQUIN POWER TRUST

A. There are two main components to this shared services model. First, Liberty Water provides the day to day operating costs associated with the operations of all its utilities including our Bella Vista facilities. You could call these direct costs, as noted in the cost allocation paper attached as **Exhibit PE-RB1**. These costs include operations labor costs allocated 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. Staff and RUCO do not dispute the allocations to Bella Vista from Liberty Water. Second, APT provides the corporate administration costs associated with the running of a publicly traded company to support all of its power generation and infrastructure facilities (including the 17 regulated utilities). These are all indirect costs, again as noted in the cost allocation paper attached as **Exhibit PE-RB1**. These costs are for services received by the utilities such as strategic planning costs, access to capital, audit, tax services, unit holder communication, trustee fees, and other costs. These costs are allocated to Liberty Water's 17 regulated utilities based on the number of utilities to total facilities (17/63) and then further allocated to each regulated utility based on customer count.

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

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. The APT costs are all indirect costs, whereas Liberty Water (AWS) costs are mostly direct costs. Therefore, where appropriate, costs have been directly charged. RUCO also criticizes the cost allocation model by claiming that the APT costs have not been reported separately as either an indirect cost or a direct cost. On this point, RUCO's analysis is flawed because Bella Vista has reported all of the APT costs as indirect costs, which necessitates that the APT costs be allocated to the regulated utilities, including Bella Vista, pursuant to an allocation methodology. Liberty Water's allocation of the APT costs follows the NARUC Guidelines on those issues, which expressly recognizes allocation of indirect costs. The NARUC Guidelines also recognize the allocation of common costs, which are corporate costs that benefit both regulated and unregulated affiliates.

Q. THE MAIN FOCUS OF STAFF'S AND RUCO'S OPPOSITION TO THE APT COSTS SEEMS TO BE WHETHER THE APT COSTS BENEFIT BELLA VISTA'S RATEPAYERS. DOES APIF'S BUSINESS MODEL PROVIDE BENEFITS TO REGULATED UTILITIES SUCH AS BELLA VISTA?

A. Yes. The benefits are even more pronounced when compared to the truly minimal costs per customer for the APT services. 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. 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 and in turn, APIF's unit holders earn returns on their invested capital.

Q. WHO ARE APIF'S UNIT HOLDERS?

A. APUC's shareholders are both institutional and retail investors. Approximately 20% of APUC'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 APUC's shares are held directly by retail investors (individuals) who look for a stable, sustainable level of income in the form of dividend payments. Approximately 30% of APUC'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. Bella Vista and the other Regulated Utilities in Arizona do not operate as stand-alone utilities. Instead, the Arizona utilities owned by Liberty Water operate under a shared services model, which is designed to pool and share expenses to minimize costs. As I testified above, Bella Vista is operated by Algonquin Water Services, which operates under the name Liberty Water, along with the 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 BELLA VISTA?

A. All operations and engineering labor is directly charged by Liberty Water to Bella Vista 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, 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 corporate 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 Bella Vista 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 Bella Vista, Black Mountain and Rio Rico 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 Bella Vista, 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 Bella Vista 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 Bella Vista are based on actual costs, either directly charged or through the allocations described above.

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 costs are mainly indirect costs incurred by APT as necessary to run a company that is traded on a stock exchange. 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. This fact is important because it shows that APIF and its investors do not generate additional revenue or dividends from the APT costs. Staff and RUCO seem to suggest that the APT costs provide a hidden source of income for APIF or its investors. But that simply isn't true. The APT costs are simply necessary costs of doing business as a publicly traded company. Also, it bears emphasis that the APT costs already have been incurred, and allocation of those costs to the Regulated Utilities and unregulated facilities simply allows recovery of those costs.

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

A. First, the services provided by APT are necessary to allow Bella Vista 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 Bella Vista under the APIF corporate model. Far West Sewer & Water Company is a perfect example.[1] Absent consistent access to capital, Bella Vista would not be able to provide a high level of service.

The overriding focus of Liberty's shared services model is that such model will provide a broader range of services for a cheaper price than operating as a stand-alone utility. Our shared services model also avoids the types of problems

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

various stand-alone utilities have suffered from lack of financing, lack of oversight and poor management, including Far West and the McLain utilities.[2] In addition, Bella Vista receives benefits by having strategic direction, corporate governance, financial controls, and an audit done at the Income Fund level. This model benefits Bella Vista's long term health and allows the company to provide high quality utility service for a fraction of the price.

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

A. For the reason I just mentioned. Bella Vista is a strong utility because it is part of the Algonquin/Liberty Water shared services model. The same is now true of Black Mountain and Gold Canyon. 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 a high level of service at reduced operating expenses.

I really can't stress enough how much we believe the Regulated Utilities benefit from strategic direction on long term capital and operational needs and requirements. Many of the substantial problems and failures experienced by stand-alone Arizona utilities resulted from lack of proper management. This type of strategic planning allows Bella Vista 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 Bella Vista and its ratepayers. 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. Smaller utilities that are not part of a larger corporation usually

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

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.

Q. THANK YOU, MR. EICHLER. CAN YOU DIG A LAYER DEEPER AND EXPLAIN THE MAJOR CATEGORIES WITHIN THE APT COST POOL?

A. Yes. The APT costs are a pool of costs incurred for the provision of certain services that ratepayers receive. In general, these costs can be broken down in to four categories:

1) Strategic Management - 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.

2) Access to Capital - 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.

3) Financial Controls and Corporate Governance - 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.

4) Administrative - 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.

The APT costs and their benefits to ratepayers are explained in further detail in the cost allocation paper attached as **Exhibit PE-RB1.**

Q. CAN YOU GIVE US A SPECIFIC EXAMPLE OF HOW THESE COSTS BENEFIT RATEPAYERS?

A. Yes. A look at the former McLain Systems, now known as Northern Sunrise and Southern Sunrise, provides a perfect case study to demonstrate the benefits of these costs and Liberty Water's business model. Liberty Water acquired these systems in 2007 in a state of disarray to the point where some customers were not receiving water to their homes. The system was a virtual disaster. Local businesses would not even give Liberty Water trade credit due to the poor business decisions and actions of the previous owner. The system also needed significant capital improvements.

The services available to Liberty Water under its shared services model and the ongoing access to capital through the services provided by APT allowed Liberty Water to step in and acquire the McLain systems and resolve the service

and facility problems. Liberty Water was the only entity that stepped up to address the McLain systems, which is testament to the benefits of the APIF business model. The ability of Liberty Water to provide services benefited the customers in the following ways:

Strategic Management – Skilled managers were able to acquire the systems and restore drinking water with lightning speed. Until water service was restored, temporary water supplies were brought in to ensure that drinking water was available immediately. Leveraging existing expertise, capital planning processes began immediately to ensure the long term supply and quality of water issues were fixed immediately.

Access to Capital – Liberty Water has invested over $800,000 in the McLain systems to ensure that there is a long term sustainable water solution available to the area. These funds were readily available to be invested due to the continued access to capital Liberty Water receives through APIF, which is contingent on the services procured by APT. This access to capital also ensures that ongoing needs are continually met both from a capital and operating expenditure perspective.

Financial Controls and Corporate Governance– The financial controls provided by APT such as audits, governance, and other such controls, have ensured that the McLain systems are not subject to poor financial decisions and that all such decision are subject to proper oversight. Those controls were lacking prior to Liberty's ownership. On an ongoing basis, these services ensure the continued financial health, strong governance, and also contribute to ensuring access to capital is available, as many of these financial controls are required for continued access to the TSX.

Put frankly, Liberty Water was able to acquire the McLain systems, act quickly to restore service and provide long-term solutions only because of the APIF business model and the services provided by APT.

Q. HAS THE APIF BUSINESS MODEL ALLOWED LIBERTY WATER TO PROVIDE SIMILAR BENEFITS TO ITS OTHER ARIZONA UTILITIES?

A. Yes, the McLain system is just one of many examples where Liberty Water has taken over troubled systems, implemented necessary system upgrades and restored high quality service to customers. Liberty Water has been able to do those things as a direct result of its shared services model and access to capital resulting from the APT services. For example, as recently noted during the evidentiary hearing in the Rio Rico Utilities rate case, public comments by County Supervisor John Maynard attested to the fact that water service has dramatically improved since Liberty Water had acquired RRUI. Likewise, Black Mountain Sewer Company had experienced odor problems in its system and Liberty Water fixed those problems by investing capital and resources to remove a bad lift station and upgrade the collection system to resolve the odor problems. Further, at Gold Canyon Sewer Company, Liberty Water took over a developer built and operated sewer system with major odor and discharge problems. Again, Liberty Water invested capital and engineering to resolve those problems and render high quality service to customers. These circumstances demonstrate the substantial benefits and advantages available to customers under the Liberty Water business model. Put simply, Liberty Water is an entity that gets things done, and provides high quality utility service with low operating expenses.

Q. THANK YOU. WHAT ABOUT SYSTEMS THAT ARE NOT IN A STATE OF DISARRAY? DO THE APT COSTS PROVIDE BENEFITS TO CUSTOMERS OF THOSE SYSTEMS?

A. Absolutely. In this case, Bella Vista Water Company itself was not in a state of disarray when Liberty Water acquired it in 2002. Even so, the addition of strategic management, access to capital, and financial controls have allowed the service levels to increase while costs have outperformed the level they would be at on a standalone basis. The services received have given the utility structure, long term planning processes, and have allowed the operations to gain efficiencies by utilizing the shared services model. That's not to mention that a company operating under the Liberty Water umbrella does not face the same type of management and operational risks that it would as a stand alone utility.

Q. ARE THERE ANY OTHER BENEFITS YOU WOULD LIKE TO POINT TO?

A. Yes. In general, Liberty Water is a company that acquires systems, commits to them, and ensures that any issues that arise or exist are resolved expeditiously. Simply put, without the services received from APT, Liberty Water would not be able to operate the systems and fix these issues. As I've noted above, there are several other examples outside of the McLain systems, including odor issues at Black Mountain and Gold Canyon, the spill at Cassilas Bonitas, the tremendous increase in service that was pointed to by County Supervisor Maynard in the recent Rio Rico Utilities rate case, and many other examples,

Q. HAVE YOU PREPARED ANY SCHEDULES DEMONSTRATING THE BENEFITS TO RRUI'S RATEPAYERS OF THE LIBERTY WATER BUSINESS MODEL?

A. Yes. In the "Comparison of Operating Expenses Under Liberty Water v. Bella Vista as Stand-Alone" (attached as **Exhibit RB-PE2),** I compared the stand-alone operating costs of Bella Vista Water Company at the time Liberty Water acquired it in 2002-2003 to the end of 2008. The operating expenses in 2002-2003 reflect

Bella Vista's operations as a stand-alone and the operating expenses in 2003-2008 reflect Bella Vista's operating expenses under Liberty Water. On average, Bella Vista's costs were 10% lower under the Liberty Water structure than on a standalone basis. That type of savings would not be possible without strong strategic management, efficient deployment of capital, and the benefits of the shared services model.

Q. HAVE YOU MADE ANY COMPARISON OF THE BENEFITS PROVIDED FROM THE APT SERVICES TO THE COSTS INCURRED BY CUSTOMERS ON A MONTHLY OR YEARLY BASIS?

A. Yes, the chart entitled "Yearly and Monthly Costs Per Customer for the APT Central Office Costs" (attached as **Exhibit PE-RB3)** is an analysis of the monthly and yearly costs that would be incurred by each customer for the APT cost pool. This breakdown demonstrates that the costs incurred by customers for the APT services are minimal when compared to the substantial benefits provided by the Liberty Water shared services model.

A simple cost-benefit analysis demonstrates the substantial benefits of the APT cost allocations. The average customer cost per month for the APT Central Office Costs is $1.09 per month for Bella Vista's customers. For $1.09 per month, Bella Vista's customers get ongoing access to financial capital from the Toronto Stock Exchange, they get financial oversight of utility operations, they get strategic planning, they get auditing services and they get tax filings for the regulated utilities. A charge of $1.09 per month for access to capital, sound fiscal management and increased service is not excessive or unfair to Bella Vista's ratepayers.

Q. HOW DO THE COSTS COMPARE TO THE BENEFITS PROVIDED?

A. The benefits provided by the Liberty Water business model substantially outweigh the minimal costs to Bella Vista's customers. The charted attached as **Exhibit PE-RB3** illustrates that fact. As noted, that chart breaks down the yearly and monthly cost per customer for each cost category contained in the APT cost pool. The analysis is amazing. On a combined basis, the monthly costs per customer is $1.09, and range from $0.21/month for audit services to less than one cent per month for licenses/fees to participate in the TSX. Rent for the corporate office in Canada costs $0.08/month and strategic management services provided by APT costs each customer seventeen cents $0.17 per month. The escrow fees required to pay public investor dividends equal three cents $0.03 per month and the costs for legally required communications with APIF's investors is $0.04 per month. The benefits of the APT cost allocations far outweigh the actual costs to customers.

Q. MR. EICHLER, HAS ANY OTHER LIBERTY WATER COMPANY APPLIED TO HAVE SIMILAR COSTS INCLUDED IN THEIR COST OF SERVICE IN ARIZONA?

A. Yes. At present, Liberty Water has pending applications in three other dockets in Arizona (LPSCO, RRUI and Black Mountain). Liberty Water is seeking recovery of the APT costs in all of these dockets.

Q. HAS THE POOL REMAINED CONSISTENT DURING THESE APPLICATIONS?

A. The pool has remained consistent in the methodology employed and the types of costs incurred. At the same time, there have been some changes from case to case as the methodology is fine tuned and we continue to respond to Staff's and RUCO's concerns.

Q. HOW HAS THE APT COST POOL CHANGED?

A. As each rate case is heard, and differing positions are taken by Staff and RUCO, the Company evaluates each position and changes as necessary. For example, in the Rio Rico rate case, Staff correctly pointed out that the true-up calculation of the pool was not converted to US dollars. The Company has now adopted that change in its methodology. Further, a greater amount of rigor is applied to the costs in the pool to minimize the risk of costs that can be directly charged to other operations being allocated to utilities.

Q. CAN YOU EXPLAIN HOW LIBERTY WATER'S COST ALLOCATION MODEL HAS EVOLVED OVER THE COURSE OF THESE RATE CASES?

A. Yes, I think it's important to point out how the cost allocation model has evolved over time in relation to concerns raised by Staff and RUCO. Liberty Water first sought rate treatment for Central Office Costs in the Black Mountain rate case, including affiliate profit. In turn, Staff, RUCO and the Commission voiced their objections to including affiliate profit in the allocations. In response, Liberty Water revised its cost allocation methodology to exclude affiliate profit and to allocate only the actual costs incurred at the APT level. Liberty Water then presented its revised methodology in the Black Mountain, LPSCO and RRUI rate cases.

One of the problems in presenting a cost allocation methodology is that the Commission has not adopted any cost allocation standards, rules or regulations. As such, review and determination of cost allocations is an organic process that evolves through litigation of rate cases. In each rate case for the Liberty Water utilities, Staff and RUCO have voiced their concerns and comments on the cost allocations. Staff and RUCO have applied differing and changing views of the costs allocations in those cases. The primary focus of Staff's and RUCO's

comments has been removal of costs from the APT pool, which Staff and RUCO believe are improper and should be directly charged to APIF or other unregulated facilities. In each case, Liberty Water responded by removing those costs that Staff and/or RUCO felt were objectionable or by explaining the inclusion of those costs. Liberty Water has been receptive to Staff's and RUCO's concerns relating to the cost allocations. For example, Staff and RUCO have identified a number of costs included in the APT cost pool that should be directly allocated to unregulated affiliates or to APIF itself. In those instances, Liberty Water has addressed those concerns by removing those costs from the pool.

Q. HAS THE DIALOGUE BETWEEN LIBERTY WATER AND STAFF IMPROVED RELATING TO COST ALLOCATIONS?

A. Yes and I believe Staff has a much better understanding of Liberty Water's cost allocation model. In its closing brief in the recent RRUI case, "Staff has acknowledged that it is not opposed to the concept of a shared services model, [but] Staff still has some concerns given some of the inappropriate costs it found during its audit of the cost pool. While not entirely opposed to the shared service model, Staff would urge the Company to review its cost pool and only include those expenses that are necessary to provide services to the ratepayer."[3] We received that message from Staff and attempted to follow Staff' suggestion. To its credit, Staff acknowledged the benefits of the Liberty Water shared services model and now seeks verification that the final pool doesn't include any improper invoices. In light of Staff's concerns, we removed all of the invoices questioned by Staff and RUCO, and removed additional invoices that might be questionable from the cost pool.

[3] Staff Closing Br. at 9, Docket No. WS-02676A-09-0257.

Q. WHAT ARE SOME OF THE CRITICISMS THAT HAVE BEEN ADDRESSED IN THE COST ALLOCATION POOL?

A. The major criticism of the cost pool is that Staff and RUCO believe that the bulk of the APT services do not benefit ratepayers. This has been addressed in previous testimony, and I provide a further detailed explanation of how these services benefit utilities above. Even on that issue, however, the benefits of the APT costs greatly outweigh the truly minimal costs to customers for the APT allocations.

Further, both Staff and RUCO have claimed that inappropriate costs were allocated to the pool that ought to have been directly charged to a different operation. While sometimes the Company and interveners have differing opinions on the ability to directly charge costs, where the issue was contentious, the costs were removed.

Q. WHY WERE CONTENTIOUS COSTS REMOVED?

A. The costs were removed for varying reasons. Most importantly, the Company firmly believes in the need to increase stakeholder trust. For this reason, the Company has been as transparent as possible in the recovery of these costs, and decided to remove contentious costs in order to reduce disputes with the parties. Further, the contentious costs often create significant disputes during trials and increase rate case expenses. It is not productive to continually debate these costs when the real debate is over the merit of the services provided by APT.

Q. HOW DO ERRORS OR INAPPROPRIATE COSTS MAKE THEIR WAY IN TO THE CENTRAL OFFICE COSTS POOL?

A. Initially, the central office costs are charged to each utility based on a budget amount. They are trued up for rate making purposes using the actual costs incurred. At this stage, the true-up process is a manual process. While care and attention is given to ensure that inappropriate costs are identified and removed, as

is often the case with manual processes, some errors occur. They also are a function of the fact that the Commission does not have any rules or regulations govern cost allocations, which makes the APT cost pool subject to change. We acknowledge that certain of the costs including in the original pool should be allocated to other facilities and we have removed those costs from the pool.

Q. BACK TO THE REMOVAL OF CONTENTIOUS COSTS, YOU MENTION A NEED TO INCREASE STAKEHOLDER TRUST AND COMMUNICATIONS. CAN YOU ELABORATE ON THAT?

A. Yes. Open communication with all of our stakeholders, including regulators and interveners is a critical part of Liberty Water's operations. It is the Company's intent to continue to work towards increasing the communications and clarity of Liberty Water's cost allocation methodology in order to continue to increase trust. The Company recognizes the consistent effort necessary to earn the trust of stakeholders as a reliable and transparent partner, and to that end, the revisions of positions taken by the Company has occurred. While Liberty Water recognizes that agreement with stakeholders on every issue is unrealistic, it is nevertheless committed to ensuring that disagreements are based on differences of opinion, not distrust; and we are working towards a level of cooperation that fosters opportunities for constructive, collaborative resolution of major issues rather than litigation.

Q. TO THAT END, WHAT TRUST BUILDING ASSURANCES CAN YOU PROVIDE THAT NO FURTHER ISSUES ARE PRESENT?

A. As suggested in our closing briefs in the Rio Rico Utilities Inc. case, the Company would be willing to subject the APT cost pool to an independent attestation by a third party CPA to prove that the costs in the pool are materially indirect costs. This independent attestation also is consistent with the NARUC Guidelines on cost

allocations. To the extent Staff or RUCO still question the contents of the final cost pool, Bella Vista proposes to alleviate such concerns by providing an independent "attestation" of the final APT cost pool. Specifically, the NARUC Guidelines state: "Any jurisdictional regulatory authority may request an independent attestation engagement of the [Cost Allocation Manual]."[4] An attestation by an independent CPA would resolve Staff's and RUCO's concerns about whether the final APT cost pool includes charges relating to unregulated business operations or reflect services that can't be verified from invoices. Rather than deny 98% of the APT costs, we would urge the Commission to approve the APT costs allocations subject to Bella Vista providing an "Attestation Engagement" to verify the contents of the cost pool. The Company would not seek reimbursement for costs related to the independent attestation.

Q. HOW DO YOU ENVISION THE INDEPENDENT ATTESTATION ENGAGEMENT?

A. The NARUC Guidelines define "Attestation Engagement" as "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."[5] In essence, the Commission would approve the APT cost allocations subject to Bella Vista providing a letter from an independent CPA attesting to the contents of the APT cost pool and verifying that the cost pool does not include any costs that should or could be directly charged to any specific utilities or facilities. The Company would be happy to work together with Staff, RUCO and the Commission to design the

[4] NARUC Guidelines For Cost Allocations and Affiliate Transactions at 4, ¶ E (3).

[5] *Id.* at 2, ¶ (A) (2).

parameters of the audit. Staff, RUCO, and the Commission also would be free to select the auditor.

IV. REBUTTAL TO STAFF.

Q. CAN YOU PLEASE SUMMARIZE STAFF'S POSITION ON THE CENTRAL OFFICE COSTS?

A. Staff is seeking to disallow 90% of the central costs, and then allocate the remaining 10% among 70 facilities. This means that the Bella Vista Companies would receive a $1/70^{th}$ share of the remaining 10%, or an effective disallowance of over 99% of the allocation pool.

Q. IS STAFF'S PROPOSAL REASONABLE?

A. No. Staff is suggesting that the Strategic Management, Financial Controls, Access to Capital and Administration services provided by APT should be provided for a cost of $3,132 per year. To suggest that all the services mentioned could be attained for that cost is unreasonable.

Q. WHAT IS THE NATURE OF YOUR DISAGREEMENT?

A. Staff's claim is that 90% of the costs are clearly attributable to APUC. I strongly disagree. APT would not exist if APUC did not own the facilities it owns and would not procure those services. In some cases, the argument would be circular. For example, to suggest that access to capital benefits shareholders is counterintuitive. Staff's suggestion would have the shareholders paying for costs related to accessing capital that they themselves are providing. Similar arguments can be made for Strategic Management and Financial controls. These services would not be required if APUC did not own any facilities, and as demonstrated above, the benefit definitely inures to Bella Vista and its ratepayers.

Q. ARE THERE ANY OTHER SOURCES OF DISAGREEMENT?

A. Yes. Staff claims that APUC owns 70 facilities. The Company has stated in previous cases and in this case that the seven "Trafalgar" facilities are not owned and do not receive the benefits of the APT costs. That fact is absolutely undisputable. While the Company disagrees that 70 facilities are owned by APUC, it is nevertheless willing to accept the number of facilities as 70 in order to minimize disputes and to add a trust building measure. This creates an initial allocation factor of 24.29% instead of the original 26.98%.

Q. OK, AND WHAT ABOUT THE "UNALLOWABLE EXPENSES" CLAIMED BY STAFF?

A. Staff claims there are $123,829 of unallowable expenses in the office expense category. Staff's claim is that these amounts should be capitalized versus expensed. While the Company's view is that capitalizing versus expensing items is somewhat subjective, it is nevertheless willing to accept Staff's recommendation and remove these costs.

Q. STAFF ALSO SUGGESTS THAT THE CENTRAL OFFICE COSTS SHOULD BE TAKEN IN THE CONTEXT OF A COMPARISON WITH A STAND-ALONE COMPANY. HOW DO YOU RESPOND TO THAT?

A. I have two primary concerns with this position. First, I don't believe this is a realistic standard. Even among stand-alone companies, there will be many variations in the types of costs incurred. For example, companies may choose to outsource certain activities while others may choose to perform them in house. In this situation, two stand-alone companies may themselves have very different cost comparisons.

Secondly, although I'm not aware of a stand-alone utility that is publicly traded in Arizona, any stand-alone utility that would be publicly traded would incur

all of these costs and likely in a much more impactful way than the costs incurred by Bella Vista. I also should note that Staff's stand-alone standard assumes that stand-alone companies provide the same level of service and financial security as companies under a shared service model, which simply isn't true, as shown by the laundry list of failed stand-alone utilities in Arizona.

For these reasons, I firmly believe the best and only way to compare utilities is on a total operating cost basis; however, I'd also like to reiterate the findings of my analysis shown in my Rebuttal schedule **PE-RB2**, which I discuss in detail below. This analysis shows that Bella Vista's costs have come down under the shared services model versus a standalone basis.

Q. HAVE YOU UNDERTAKEN AN ANALYSIS OF TOTAL OPERATING COSTS?

A. Yes. My rebuttal Schedule attached as **Exhibit PE-RB4** is a comparison of 23 utilities from Arizona on a total cost per customer basis. The chart demonstrates that the Bella Vista Companies rank eighth out of 23 in lowest cost (i.e. the eighth lowest total cost per customer).

Q. DO YOU THINK THE CHARTS ACCURATELY REPRESENT BELLA VISTA'S PERFORMANCE?

A. Yes, I do. However, I believe its relative performance will get even better in years to come.

Q. ON WHAT BASIS DO YOU MAKE THAT STATEMENT, MR. EICHLER?

A. I am relying on Liberty Water's continued focus on efficiency. As demonstrated in my Rebuttal Schedule attached as **Exhibit PE-RB2**, Bella Vista's costs have come down versus a stand-alone model over time. Those charts show that Bella Vista has operated more cost effectively under Liberty Water than it did as a stand-alone utility prior to acquisition by Liberty Water. The minimal cost per customer for the

the APT allocations is more than offset by the reduced operating expenses under Liberty Water. Since the Northern and Sunrise systems were only acquired in late 2007 in such a state of disarray, I believe that over time those two companies will become more efficient, and the overall costs per customer will reduce further.

V. REBUTTAL TO RUCO

Q. CAN YOU CHARACTERIZE RUCO'S TESTIMONY?

A. RUCO's testimony on central office costs seeks to disallow the majority of the central office costs because they are not directly attributable to water service. RUCO also takes exception to some of the items contained in the pool, such as "hockey tickets, superbowl tickets, basketball tickets, gold watches, etc." Finally, RUCO takes exception to the allocation methodology.

Q. LET'S TAKE THOSE ONE AT A TIME. HOW DO YOU RESPOND TO THE ARGUMENT THAT THE CENTRAL OFFICE COSTS ARE NOT DIRECTLY ATTRIBUTABLE TO WATER SERVICE?

A. I strongly disagree with RUCO. To start, the APT costs are indirect administrative costs, which necessarily means they can't be directly charged to one facility. RUCO's testimony is circular on this point. Further, as I stated above, I believe that in a capital intensive industry such as the water utility industry, access to capital is a company's lifeline. In Arizona, we've seen several companies fail such as the McLain systems, or be in severe financial distress, such as the Far West systems. RUCO's suggestion that services such as access to capital, financial controls, and strategic management do not relate to providing water service is misguided. I would challenge Mr. Coley and RUCO to determine how the McLain systems would have been fixed without strategic management and access to capital, and further challenge Mr. Coley to consider whether financial controls and governance could have helped avoid the disastrous situation in the first place.

Q. WHAT ABOUT RUCO'S ASSERTION THAT SOME OF THE COSTS ARE INAPPROPRIATE?

A. RUCO states that the pool includes tickets for the Super Bowl, hockey, basketball, and a gold watch, among other things. This is not true. There are **no** super bowl, hockey, or basketball tickets in the cost pool. I did manage to locate a Fossil watch which was given to an employee in recognition of service and while that expenditure is prudent in my view, it has been removed from the cost pool so as to reduce the amount in dispute. I also removed two invoices which were inadvertently included for membership to a Canadian Wind Association.

Q. DO YOU HAVE CONCERNS REGARDING RUCO'S CHARACTERIZATION OF THESE ERRORS?

A. Yes. I believe RUCO's characterization is akin to "throwing the baby out with the bath water." The impact of those mistakes was approximately $200 of a $144,000 original request. RUCO's attempt to use those minimal errors to reject virtually the entire cost pool simply is not fair or reasonable. Rather, the proper solution is removal of those errors from the pool, which is exactly what we have done.

Q. RUCO AND STAFF WILL UNDOUBTEDLY ARGUE THAT A SINGLE ERROR IS ONE ERROR TOO MANY IN THE CENTRAL OFFICE COST POOL. HOW DO YOU RESPOND TO THAT?

A. As an accountant, I can understand that statement; however, as described above, manual processes sometimes open themselves up to errors. Liberty Water has not claimed its process is perfect, but, like Staff and RUCO, when errors are made, efforts are made to continually improve processes and make corrections.

To that end, as I discussed above, the Company would be willing to have an independent attestation by a CPA of Staff, RUCO and the Commission's choosing

to verify the cost pool. Such independent attestation would remedy RUCO's concerns about errors in the cost pool.

Q. HAS THE COMPANY PREPARED THE CENTRAL OFFICE COST POOL IN GOOD FAITH?

A. Yes. Absolutely. And as demonstrated in the Rio Rico case and this case, when errors are made, the Company is quick to respond by acknowledging fault where appropriate and making necessary corrections.

Q. WHAT ABOUT RUCO'S POSITION ON USING THE MOST RECENT AND CURRENT EXCHANGE RATE?

A. RUCO's adjustment was made using a current exchange rate. The average exchange rate used to calculate the pool of expenses was $0.89; however, at the time of writing this testimony (May 20, 2010), the exchange rate according to the Bank of Canada converts Canadian dollars at $0.94. The Canadian dollar has appreciated against the US dollar and is likely to remain appreciated for some time. As a result, Mr. Coley's suggestion would increase the cost allocation pool. In fact, at the time of Mr. Coley's submission (around April 12, 2010), the two currencies were at parity, meaning Mr. Coley ought to have adjusted the allocated costs up if he were following his own testimony. The Company is not advocating this position, but would not oppose it if desired by the Commission.

VI. SUMMARY

Q. IN SUMMARY, WHAT IS THE TOTAL AMOUNT FOR THE CENTRAL OFFICE COST POOL FROM YOUR REBUTTAL TESTIMONY?

A. In total, the amount sought for recovery is now $125,830 instead of $144,906. This adjustment will be reflected in Thomas Bourassa's Rebuttal Schedule C-2, page 7.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rebuttal Testimony
May 25, 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 have any staff and the costs incurred by it are non-labor based. 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)

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 UTILITIES	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.

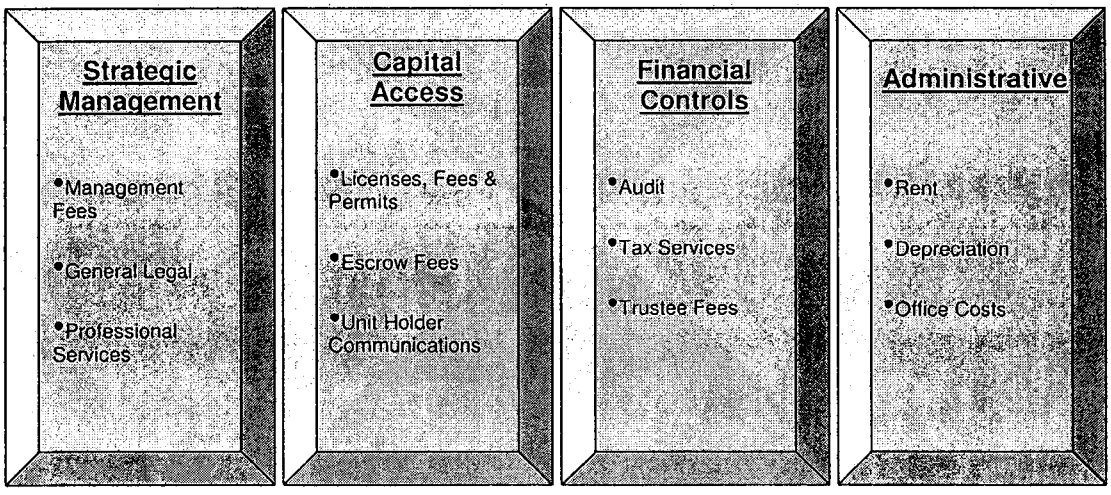
Attached as Appendix 3 is an overview of the services and allocations for APT. As noted above, APT is a wholly-owned subsidiary of APIF. APT is integral to APIF's business structure as a publicly traded income fund on the Toronto Stock Exchange. APIF sells units to public investors in order to generate 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

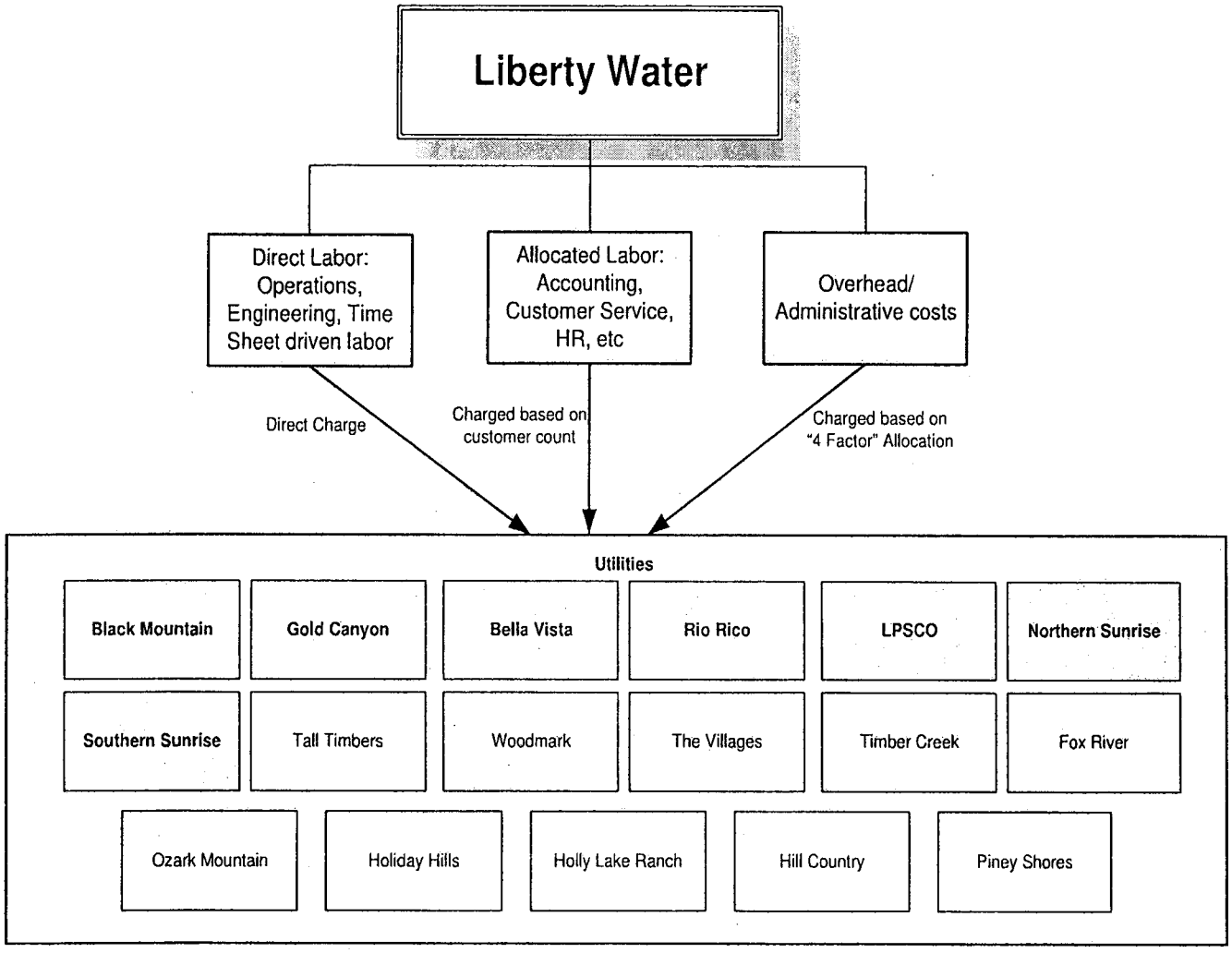
Description	Trustee Fees are paid to the Board of Trustees, which meets on a quarterly basis.
Ratepayer Benefits	Trustees act in the same manner as Boards of Directors. They have a duty to shareholders to ensure that they will act in their best interests. This means that they must act in a way that optimizes 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

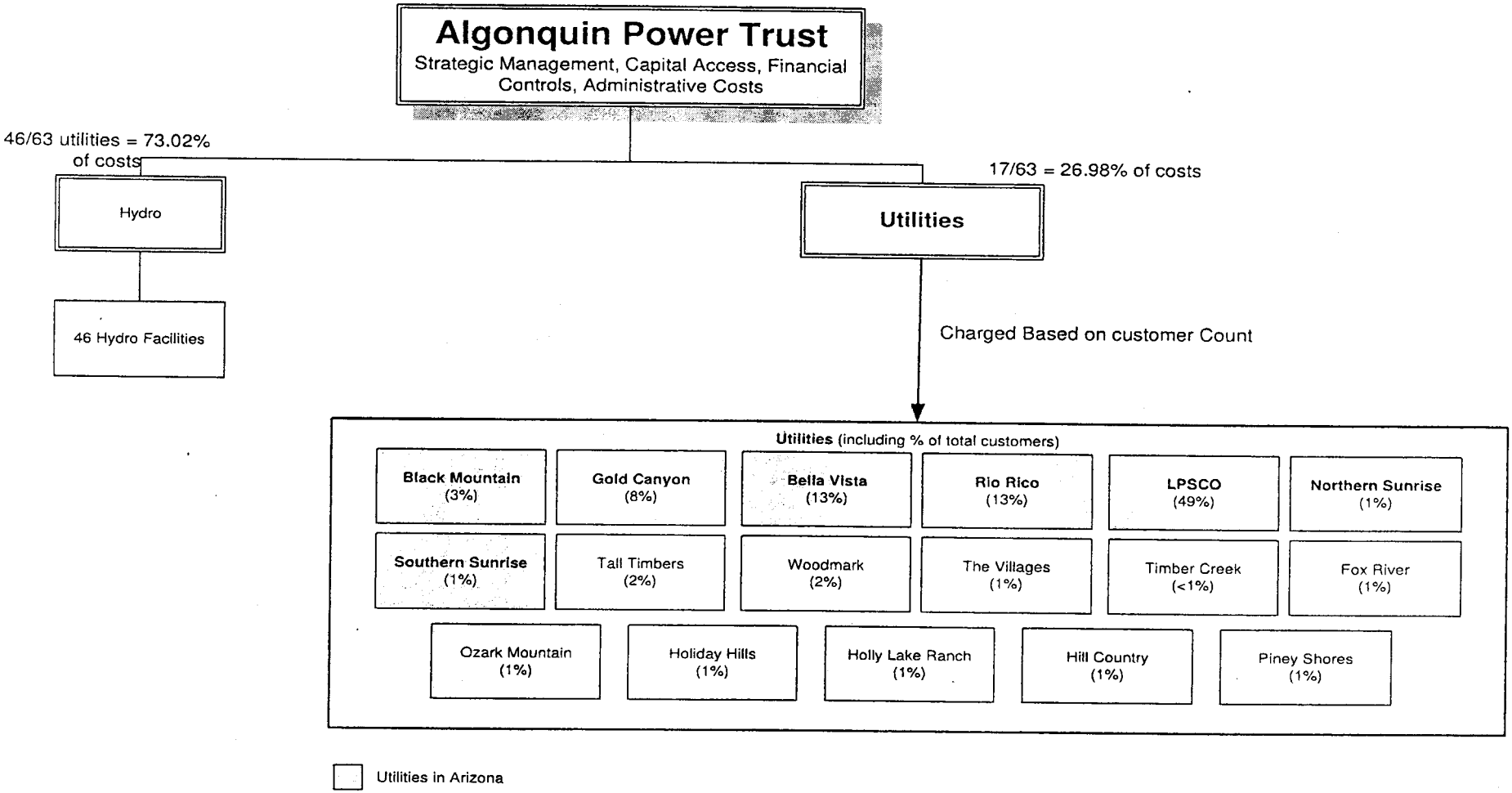
EMPLOYEE NAME: Martin Gariant | EMPLOYEE No: 1092 | Week Ending : November 7, 2009

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:	45.00	0.00	0.00	0.00	0.00	45.00	0.00	0.00

SIGNATURE _____ SUPERVISOR _____

Appendix 3: Overview of APT Cost Allocations:



2267183

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rebuttal Testimony
May 25, 2010

Exhibit
PE-RB2

BELLA VISTA WATER COMPANY
COMPARISON OF OPERATING EXPENSES UNDER LIBERTY WATER V. BELLA VISTA AS STAND-ALONE
(Based On Utility Annual Reports 2002-2008)

YEAR	2002 <1>	2003	2004	2005	2006	2007	2008
Total Operating Expenese	$2,427,523	$2,615,670	$2,407,438	$2,669,527	$2,728,476	$2,926,400	$3,188,842
# of Customers	6,971	7,162	7,416	7,788	8,009	8,501	8,541
Bella Vista Total Operating Expenses Per Customer	$348.23	$365.22	$324.63	$342.77	$340.68	$344.24	$373.36
Consumer Price Index Inflation % <2>	n/a	0.019	0.033	0.034	0.025	0.041	0.001
Bella Vista Operating Expense Per Customer as Stand-Alone Utility (Inlation Adjusted) <3>	$348.23	$354.85	$366.56	$379.02	$388.50	$404.42	$404.83
Bella Vista Operating Expense Per Customer Under Liberty Water		$365.22	$324.63	$342.77	$340.68	$344.24	$373.36
% Savings Under Liberty Water Model Compared to Stand-Alone Model <4>		-2.84%	12.92%	10.57%	14.04%	17.48%	8.43%

NOTES:

<1> Liberty Water acquired Bella Vista Water Company in 2002-2003. The 2002 Annual Report reflects operating expenses for Bella Vista Water Company as a stand-alone utility. The operating expenses for 2003-2008 reflect Liberty Water's shared services model.

<2> The Consumer Price Index inflation percentage is based on U.S. Department of Labor Bureau of Labor Statistics annual index for the Consumer Price Index from 1913-2010.

<3> The inflation adjusted yearly operating expense per customer for Bella Vista as a stand-alone utility is calculated based on the 2002 operating expenses/customer for Bella Vista and multiplying that figure by the CPI percentage for the following year. For example, in 2002, the operating expense/customer was $348.23, which is mutiplied by the CPI index for 2003 (1.9%), which yields an inflation adjusted number of $354.84. That calculation is made for 2003-2008 to reflect Bella Vista's inflation adjusted operating expenses per customer as a stand-alone utility.

<4> This chart illustrates that Liberty Water's shared services model has been an average of 11.2% cheaper in terms of total operating expenses per customer from 2004-2008 when comparing Bella Vista's total operating expenses per customer to the inflation adjusted operating expenses for Bella Vista as a stand-alone utility.

COMPARISON OF AVERAGE OPERATING COSTS PER CUSTOMER UNDER LIBERTY WATER V. STAND-ALONE BASIS

	Operating Cost Per Customer Under Liberty Water (2003-2008)	Actual Operating Cost Per Customer As Stand-Alone (2002)	Inflation Adjusted Operating Cost Per Customer As Stand-Alone (2003-2008)	CPI Inflation Index Adjustment (2003-2008)
2002	n/a	$348.23	$348.23	
2003	$365.22	n/a	$354.85	1.90%
2004	$324.63	n/a	$366.56	3.30%
2005	$342.77	n/a	$379.02	3.40%
2006	$340.68	n/a	$388.50	2.50%
2007	$344.24	n/a	$404.42	4.10%
2008	$373.36	n/a	$404.83	0.01%
Average	$348.48	$348.23	$378.06	2.54%

NOTE: This chart illustrates that the average operating costs per customers for the six years that Bella Vista has been owned and operated by Liberty Water ($348.48) is equal to the operating costs per customer for Bella Vista as a stand-alone utility in 2002--without adjusting for inflation or increases in the Consumer Price Index. When compared to the inflation adjusted operating cost per customer for Bella Vista as a stand-alone utility (using the Department of Labor Consumer Price Index), Bella Vista's operating costs per customer are $30.00 less per customer, which translates to nearly an 8% savings for customers.

BELLA VISTA WATER COMPANY
TOTAL OPERATING COSTS PER CUSTOMER 2002-2008
(Based On Utility Annual Reports 2002-2008)

YEAR	2002 <1>	2003	2004	2005	2006	2007	2008
Total Operating Expenese	$2,427,523	$2,615,670	$2,407,438	$2,669,527	$2,728,476	$2,926,400	$3,188,842
# of Customers	6,971	7,162	7,416	7,788	8,009	8,501	8,541
Yearly Operating Expense Per Customer	$348.23	$365.22	$324.63	$342.77	$340.68	$344.24	$373.36
Monthly Operating Expense Per Customer	$29.02	$30.43	$27.05	$28.56	$28.39	$28.69	$31.11
Consumer Price Index Inflation % <2>	n/a	0.019	0.033	0.034	0.025	0.041	0.001
Inflation Adjusted Yearly Operating Expense Per Customer as Stand-Alone <3>	n/a	$354.85	$366.56	$379.02	$388.50	$404.42	$404.83
Bella Vista Yearly Operating Expense Per Customer Under Libery Water	n/a	$365.22	$324.63	$342.77	$340.68	$344.24	$373.36
Amount Below Inflation Adjusted Yearly Operating Expenses	n/a	($10.37)	$41.93	$36.25	$47.82	$60.18	$31.47

NOTES:

<1> Liberty Water acquired Bella Vista Water Company in 2002-2003. The 2002 Annual Report reflects operating expenses for Bella Vista Water Company as a stand-alone utility. The operating expenses for 2003-2008 reflect Liberty Water's shared services model.

<2> The Consumer Price Index inflation percentage is based on U.S. Department of Labor Bureau of Labor Statistics annual index for the Consumer Price Index from 1913-2010.

<3> The inflation adjusted yearly operating expense per customer for Bella Vista is calculated based on the 2002 operating expenses/customer for Bella Vista and multiplying that figure by the CPI percentage for the following year. For example, in 2002, the operating expense/customer was $348.23, which is mutiplied by the CPI index for 2003 (1.9%), which yields an inflation adjusted number of $354.84. The actual operating expense per customer for Bella Vista under Liberty Water's ownership then is compared to the inflation adjusted number Bella Vista Water Company would have incurred as a stand-alone utility.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rebuttal Testimony
May 25, 2010

Exhibit
PE-RB3

YEARLY AND MONTHLY COSTS PER CUSTOMER FOR THE APT CENTRAL OFFICE COSTS

APT COST	BUDGET	ACTUAL TOTAL <1>	ALLOCATION % <2>	ALLOCATED AMOUNT	BV/NS/SS %	BV/NS/SS AMOUNT	# OF BV/NS/SS CUSTOMERS <3>	YEARLY COST PER CUSTOMER	MONTHLY COST PER CUSTOMER
Audit	$507,000	$680,812	24.29%	$165,369.14	14.52%	$24,011.60	9,610	$2.50	$0.21
Tax Services	$265,000	$469,804	24.29%	$114,115.40	14.52%	$16,569.56	9,610	$1.72	$0.14
Legal Services	$300,000	$138,531	24.29%	$33,649.29	14.52%	$4,885.88	9,610	$0.51	$0.04
Other Prof. Services	$455,000	$452,202	24.29%	$109,839.98	14.52%	$15,948.77	9,610	$1.66	$0.14
Management Fees	$636,619	$563,803	24.29%	$136,947.75	14.52%	$19,884.81	9,610	$2.07	$0.17
Unit Holder Commun.	$314,100	$145,658	24.29%	$35,380.39	14.52%	$5,137.23	9,610	$0.53	$0.04
Trustee Fees	$204,000	$127,116	24.29%	$30,876.44	14.52%	$4,483.26	9,610	$0.47	$0.04
Escrow Fees	$75,000	$85,354	24.29%	$20,732.47	14.52%	$3,010.36	9,610	$0.31	$0.03
Rent	$430,739	$273,965	24.29%	$66,546.05	14.52%	$9,662.49	9,610	$1.01	$0.08
License/Fees	$305,000	$14,565	24.29%	$3,537.96	14.52%	$513.71	9,610	$0.05	$0.00
Office Expenses	$254,000	$425,755	24.29%	$103,415.89	14.52%	$15,015.99	9,610	$1.56	$0.13
Depreciation	$204,242	$189,797	24.29%	$46,101.75	14.52%	$6,869.16	9,610	$0.71	$0.06
							TOTAL	$13.11	$1.09

NOTES:

<1> The actual amounts are stated in United States dollars as converted from Canadian dollars using the prevailing monthly exchange rate published by the Bank of Canada.

<2> The allocation percentage reflects that 24.29% of the total costs are allocated to the 17 regulated utilities owned by APIF, with the remaining 73.02% allocated to the remaining 46 unregulated facilities owned by APIF.

<3> The total number of customers for all 63 facilities and utilities owned by APIF is 64,094. Bella Vista Water Company has 8,472 customers, Northern Sunrise has 349 customers and Southern Sunrise has 789. The total number of customers for Bella Vista, Northen Sunrise and Southern Sunrise equals 9,610 customers.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rebuttal Testimony
May 25, 2010

Exhibit
PE-RB4

COMPARISION OF BELLA VISTS'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)	Az-Am Water Co. (Sun City)	Willow Valley Water	Bella Vista Water Company - Consolidated	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)
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
Customers[2]	6,346	16,635	7,672	4,124	15,465	23,140	1,554	9,730	4,656	4,953	2,565	22,455	15,371	34,402	6,419
Total Revenue	$1,905,111	$5,113,631	$3,103,252	$1,686,342	$5,701,431	$9,283,101	$482,166	$4,123,206	$2,214,952	$2,588,943	$1,026,587	$10,934,895	$9,453,438	$18,818,613	$3,521,124
Total Expenses	$1,666,701	$5,076,491	$2,410,387	$1,316,453	$5,114,006	$8,422,016	$586,481	$3,860,581	$1,938,319	$2,071,226	$1,158,005	$10,277,900	$7,196,180	$16,217,325	$3,096,417
Salary/Wages	$186,584	$899,973	$752,628		$703,217	$1,225,670	$248,567				$204,471		$857,540	$1,440,677	
Pension/Benefits							$55,580						$205,327		
Purchased Water		$44,384		$58	($2,690)			691		$1,233		$374,207		$901,467	
Purchased Power	$376,962	$501,877	$359,090	$71,171	$830,074	$1,722,582	$33,979	$582,046	$192,581	$181,940	$111,139	$1,387,878	$588,793	$1,954,815	$518,834
Chemicals	$12,570	$7,846	$61,759	$14,733	$227,889	$37,037		$5,584	$33,911	$28,463	$88,249	$531,617	$3,505	$1,121,555	$319,722
Materials/Supp.		$103,944	$56,770		$57,226	$78,546	$18,274				$13,616		$41,783	$161,107	
Testing Serv.	$34,435		706				$5,401	$66,247					$36,113		
Cust. Accounting		$132,002			$133,476	$235,348			$267,290	$275,893	$22,062	$909,384		$370,806	$323,108
Admin/General							$12,770		$378,361	$506,659		$1,761,682			$641,077
Contr. Serv. Other	$56,007		$57,743					$1,632,457					$67,741		
Management Fees		$940,899		$486,871	$999,903	$1,509,322					$166,461			$2,775,604	
Rent		$15,559	$8,229		$14,331	$60,016	$9,185	$66,597			$5,059		$94,639	$63,217	
Transportation			$58,567				$12,699	$132,231					$43,326		
Insurance-GL	$18,339	$209,312	$69,678		$191,120	$354,396	$5,119	$63,045			$63,729		$53,083	$396,645	
Insurance Other		$51,991			$58,622	$93,255	$1,058				$8,974			$158,153	
Misc.	$74,039	$354,017	($79,668)		$232,408	$300,084	$9,936	$150,232			$42,644		$34,089	$591,329	
Depreciation	$605,880	$883,235	$666,306	$214,780	$1,323,541	$1,565,706	$126,911	$657,557	$426,056	$416,943	$291,351	$2,329,760	$3,431,687.00	$4,397,190	$731,033
Income Taxes	$109,419	($196,927)	$185,211	$154,685	($324,059)	$9,746	($41,507)	$265,464	$73,220	$158,301	($159,839)	($549,326)	$924,207	($138,756)	($153,125)
Property Taxes	$107,326	$221,795	$48,114	$65,159	$179,896	$156,074		$221,805	$151,656	$116,684	$44,112	$806,467	$423,523	$803,071	$125,837
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
Cost/Customer[3]	$262.64	$305.17	$314.18	$319.22	$330.68	$363.96	$377.40	$396.77	$416.31	$418.18	$451.46	$457.71	$468.17	$471.41	$482.38
Rank out of 23	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15

[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 Chemicals divided by the total number of customers.

	Chaparral City Water Co.	Arizona Water Co. (Winkleman)	Arizona Water Co. (San Manuel)	Arizona Water Co. (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	12/31/2007	12/31/2007	12/31/2008	12/31/2008	12/31/2007	12/31/2007
Customers[2]	13,423	171	1,573	1,524	6,300	1,688	8,764	4,884
Total Revenue	$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	$6,856,065	$88,524	$859,882	$931,996	$4,263,281.58	$1,176,153	$7,215,051	$6,296,235
Salary/Wages	$982,169				$1,146,370.93	$145,812	$801,914	$715,859
Pension/Benefits								
Purchased Water	$802,368		$241,318		$138,403.02	$68,561	$444,337	
Purchased Power	$609,412	$7,310	$38,358	$149,736	$354,337.27	$217,417	$965,412	$693,068
Chemicals	$116,571	$1,372	$40,816	$15,542	$5,633.36	$11,430	$90,637	$236,982
Materials/Supp.	$21,358					$11,129	$64,824	$87,860
Testing Serv.	$47,072				$20,926.77	$11,443		
Cust. Accounting		$11,332	$104,428	$100,428.00				
Admin/General		$16,116	$151,590	$151,590.00				
Contr. Serv. Other	$268,977				$455,818.27	$93,990	$14,739	$21,467
Management Fees							$1,132,699	$923,778
Rent					$350,895.47			
Transportation	$74,600				$185,890.68	$13,868.00		
Insurance-GL	$29,241				$39,453.09	$9,475	$240,221	$184,827
Insurance Other	$102,877				$78,822.54	$17,952	$45,435	$45,435
Misc.	$850,715				$156,563.92	$21,875.00	$351,828	$351,828
Depreciation	$2,051,748	$19,928	$106,134	$181,393	$958,802.67	$177,320	$1,979,583	$1,615,824
Income Taxes	$111,401	($1,170)	($77,597)	$65,869		$88,268	$228,400	$228,400
Property Taxes	$187,217	$10,675	$68,170	$53,921	$158,746.98	26059	$268,996	$268,996
Other Taxes	$48,353	$1,235	$9,102.00	$12,458	$91,543.43	$19,206	$67,972	$67,972
Cost/Customer[3]	$510.77	$517.68	$546.65	$611.55	$676.71	$696.77	$823.26	$1,289.16
Rank out of 23	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**

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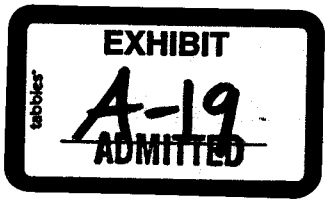
BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC. AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02465A-09-0411
IN THE MATTER OF THE APPLICATION OF NORTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-20453A-09-0412
IN THE MATTER OF THE APPLICATION OF SOUTHERN SUNRISE WATER COMPANY, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-20454A-09-0413



IN THE MATTER OF THE JOINT APPLICATION OF BELLA VISTA WATER CO., INC., NORTHERN SUNRISE WATER COMPANY, INC., AND SOUTHERN SUNRISE WATER COMPANY, INC. FOR APPROVAL OF AUTHORITY TO CONSOLIDATE OPERATIONS, AND FOR THE TRANSFER OF UTILITY ASSETS TO BELLA VISTA WATER CO., INC. PURSUANT TO ARIZONA REVISED STATUTES 40-285.	DOCKET NO. W-02465A-09-0414 DOCKET NO. W-20453A-09-0414 DOCKET NO. W-20454A-09-0414

REJOINDER TESTIMONY OF

PETER EICHLER

July 7, 2010

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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 2845 Bristol Circle, Oakville, Ontario L6A 7H7.

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY IN THIS CASE?

A. Yes, my rebuttal testimony was submitted in support of the rebuttal filing in this docket by Bella Vista Water Company, Northern Sunrise Water Company, and Southern Sunrise Water Company (the "Bella Vista Companies").

Q. WHAT IS THE PURPOSE OF YOUR REJOINDER TESTIMONY?

A. The purpose of my rejoinder testimony is to further support the Bella Vista Companies' application for rate relief by providing a detailed explanation of Liberty Water's affiliate cost allocation method in response to the surrebuttal testimonies of Staff and RUCO. Specifically, I respond to the surrebuttal testimonies of Crystal Brown on behalf of Staff and Tim Coley on behalf of RUCO.

II. REJOINDER TO STAFF.

Q. HOW WOULD YOU CHARACTERIZE STAFF'S SURREBUTTAL TESTIMONY ON THE ISSUE OF CENTRAL OFFICE COSTS?

A. I would characterize the testimony as attempting to further Staff's position on Central Office Costs, while remaining silent on the points and proposals I made in my rebuttal testimony. Interestingly, Mr. Brown did not dispute Staff's position taken in the recent Rio Rico rate case that Staff "is not opposed to the concept of a shared services model," as I stated in my rebuttal testimony (page 19). In her surrebuttal testimony, Ms. Brown makes a few generic criticisms of the APT cost allocations, but those criticisms can be readily answered and addressed.

Q. WHAT IS STAFF'S POSITION ON THE CENTRAL OFFICE COSTS?

A. In Ms. Brown's surrebuttal testimony, Staff takes the position that although the APT Central Office Costs benefit Northern Sunrise, Southern Sunrise, and Bella Vista, those costs should be disallowed because the parent company would have incurred the same level of costs whether it owned the Bella Vista Utilities or not. Based on that assumption, Ms. Brown then concludes that the APT costs primarily benefit the Income Fund and are driven by the Fund's desire for business growth.

Q. WHAT DO YOU THINK OF THAT POSITION?

A. I can agree with Staff that the Central Office Costs provide significant benefits to Northern Sunrise, Southern Sunrise, and Bella Vista, but I disagree with Staff on the remainder of these issues. For starters, the presumption that the APT costs would have been incurred irrespective of whether Liberty Water owned the Bella Vista facilities is not correct. Further, Staff's conclusion that the APT costs are driven by business growth for other unregulated affiliates simply is not true.

Q. PLEASE EXPLAIN.

A. The Central Office Costs are incurred by APT strictly and solely to benefit the facilities and utilities owned by the parent company. Put simply, if the parent did not own any facilities, the Central Office Costs would not be incurred. Likewise, if the parent owned half as many facilities as it owns today, it would incur a much lower amount of costs, because access to capital requirements would be lower, audit requirements would be less, tax services would be required in much lower proportions, depreciation would be lower because less staff would be required which in turn would mean less office furniture, computers, servers, etc. In short, Staff's contention simply is not true. Also, the notion that the APT costs drive or facilitate growth of the Income Fund's business activities isn't correct. The APT costs are incurred solely to serve the facilities currently owned by the parent.

Incurring audit costs for the facilities owned by the parent does not result in business growth. Rather, it is a cost of doing business. APIF and its investors do not generate additional profits from the APT costs, nor do those costs allow the parent's business to grow. The APT costs are simply necessary costs of doing business as a publicly traded company. In her testimony, Ms. Brown does not explain how audit costs, tax costs, legal costs or other similar cost incurred by APT generate revenue or growth for the parent company. Nor can she provide such explanation because the APT costs do not generate revenue or business for the parent company.

Q. ARE THERE ANY APT COSTS THAT REMAIN THE SAME EVEN IF THE NUMBER OF FACILITIES INCREASES?

A. Yes, there are likely some small costs that don't increase, such as the fees for listing on the Toronto Stock Exchange. Those listing fees do not change with the number of facilities. There are fewer examples of these types of costs than ones that increase incrementally with the number of facilities.

Q. CAN YOU EXPLAIN WHY THOSE TYPES OF COSTS SHOULD BE INCLUDED IN THE APT COST POOL AND ALLOCATED TO THE BELLA VISTA COMPANIES?

A. Definitely. Let me explain by providing an analogy. Let's assume a company owns two regulated businesses and buys a scalable software package that benefits both companies. Subsequently, the parent company purchases a third unregulated business. There is no need to upgrade the software package, so the company does not incur any additional costs. Following Staff's logic, the third business should not be allocated any of the software costs because those software costs would have been incurred whether or not the parent company owned the third unregulated business, which obviously would be unfair to ratepayers of the first two companies.

The inverse is also true. Under either scenario, the software costs are used by and benefit all of the companies and should be allocated to them accordingly.

Q. DOES THE FACT THAT THE PARENT COMPANY OWNS MANY FACILITIES AND UTILITIES BENEFIT THE REGULATED UTILITIES?

A. Absolutely. The economies of scale increase with added utilities and facilities. To illustrate, let's consider audit costs as an example. If the parent currently owns 50 facilities and expands to say 75 facilities, I would expect the audit costs to increase by an amount less than 50% (25 additional facilities is equal to a 50% increase in the total number of facilities). This means that as the parent company grows, the utilities continue to receive the benefits of these services at lower costs. That result is the purpose and primary benefit of a shared service model like the one used by Liberty Water, including the APT Central Office Costs, and companies like Global Water Resources, Arizona Water Company and Arizona-American. The success of that concept for Liberty Water's shared services model is demonstrated by my comparison of Bella Vista's total operating expenses per customer contained in my rebuttal testimony, which Staff has not disputed or contested.

Q. HAVE THE APT CENTRAL OFFICE COSTS PROVIDED ANY OTHER BENEFITS TO THE ARIZONA UTILITIES?

A. Yes, our acquisition and salvation of the McLain system is a prime example. We have taken over troubled systems, implemented necessary system upgrades and restored high quality service to customers. Liberty Water is able to do those things in large part because of its shared services model and access to capital resulting from the APT services. Over and over again, Liberty Water has invested capital and engineering to resolve utility problems and render high quality service to customers. Our numerous success stories demonstrate the substantial benefits and advantages available to customers under the Liberty Water business model. Put

simply, Liberty Water is an entity that gets things done, and provides high quality utility service with reasonable and transparent operating expenses. To illustrate this fact yet again, I've attached as **Exhibit PE-RJ1** a copy of a June 27, 2010 article from the Sierra Vista Herald, which includes comments from customers about Liberty Water's efforts to resolve the prior problems with the McLain systems. One customer even stated that he "was constantly calling the ACC (Arizona Corporation Commission) and talking to [Commissioner] Mayes about all the problems we were having. But there have been no problems with Liberty Water." Other comments included those from real estate agents in the area who said they couldn't sell homes until we acquired the McLain systems, took over operations and fixed the utility. Liberty Water was able to resolve the McLain crisis because the organization has experienced, professional employees that worked on the McLain crisis – Liberty did not have to hire those employees and add those costs to the McLain system.

Q. WHAT OTHER CRITICISMS OF THE CENTRAL OFFICE COST ALLOCATIONS DOES STAFF HAVE?

A. Staff asserts that Bella Vista failed to show that the APT cost allocations comply with the NARUC Guidelines. Ms. Brown criticizes Bella Vista for not providing time or cost studies to demonstrate compliance with the NARUC Guidelines.

Q. HOW DO YOU RESPOND TO THAT?

A. Mr. Brown's testimony on this issue may be the result of sincere concerns about the cost allocations, but her testimony mischaracterizes the NARUC guidelines and Liberty's compliance with those guidelines. The focal issue raised by Staff under the NARUC Guidelines is whether Bella Vista and the parent companies have direct charged any and all direct charges under the Guidelines first, before placing those costs into an allocation pool, which is allowed under the Guidelines. A time

or cost study will not answer that question because such study does not determine whether, for cost allocation purposes, a charge is a direct charge or not. To the extent Ms. Brown is critical of the invoices provided by Bella Vista relating to the APT Costs, the Company has provided many (emphasis added) invoices to substantiate these costs. We have provided all invoices over $5,000 and have made informal offers to Staff to provide any other specific invoice requested by Staff. We have more than met our burden of providing supporting invoices for the APT costs.

Q. WHAT ABOUT A TIME STUDY?

A. Ms. Brown doesn't explain what she means by a time or cost study, but such a study typically involves an analysis of a specific job by a qualified worker in an effort to find the most efficient or appropriate method in terms of time and effort. Here, a time study would not determine whether or not an invoice is a direct or indirect charge under the NARUC Guidelines.

Q. COULD YOU PERFORM A TIME STUDY ON THE APT COST POOL?

A. A fundamental premise of a time study is that it is a study of labor. As outlined in my previous testimony and attachments, the APT cost pool does not include any direct labor charges.

Q. SO COULD YOU DO A TIME STUDY RELATING TO THE APT COSTS?

A. No.

Q. SO ARE YOU SAYING THE COST POOL CONFORMS TO THE NARUC GUIDELINES?

A. Yes. The cost pool is compliant with the guidelines and so are our allocations of the APT costs to the Bella Vista Utilities. Mr. Brown's criticism seems focused on whether the costs are excessive, not whether we have complied with the NARUC Guidelines. Without question, the Commission should be concerned with whether

costs are excessive – but that is the function of audits and reviews, and that is why Liberty has been so forthcoming with invoices. The NARUC Guidelines are not intended to avoid passing through costs; rather, the Guidelines ensure that costs are properly allocated and that affiliate transactions do not create unjust returns. The NARUC Guidelines state only that costs that can be directly charged should be directly charged. Our methodology does exactly that. The APT costs are all indirect costs, whereas Liberty Water (AWS) costs are direct utility costs, with the majority being direct labor costs. Therefore, where possible, costs have been directly charged. We have reported all of the APT costs as indirect costs, which necessitates that the APT costs be allocated to the unregulated facilities and regulated utilities, including Bella Vista, pursuant to an allocation methodology. Liberty Water's allocation of the APT costs follows the NARUC Guidelines on those issues, which expressly recognize allocation of indirect costs.

Q. DOES STAFF HAVE ANY OTHER CONCERNS WITH THE CENTRAL OFFICE COSTS?

A. Yes. Staff claims that the Central Office Costs are incurred to create a profit for the parent company and, therefore, Staff claims that the costs benefit the parent company and its shareholders. Further, Staff claims that the parent company's business plans to grow its business are the primary driver for incurrence of the APT costs.

Q. HOW DO YOU RESPOND TO THOSE ISSUES?

A. I have several concerns with Staff's position. First, the fact that the parent company is a "for profit" and "growth oriented" company does not bear on the usefulness of these services to the Companies in this proceeding. The Bella Vista Companies themselves are "for profit" companies. Whether a company is "for profit" or not-for-profit does not have any bearing on the relevance or justness of

these costs or whether those costs are used by the utilities in providing service. Taken to the extreme, I do not believe the cost pool would be significantly different if the parent company were not-for-profit. The costs have little or nothing to do with the profit orientation of the parent. Second, as noted above, the APT costs do not generate profit for investors and the APT costs do not result in business growth.

Q. WHAT ABOUT THE PARENT COMPANY'S GROWTH HISTORY?

A. While the parent has demonstrated a strong history of growth, that has nothing to do with the APT cost pool. Audits of current facilities, tax planning and compliance for current facilities, legal services, rent, depreciation, HR and IT systems, escrow services, etc. all are relevant to the facilities and utilities currently owned, not to future facilities or utilities that may be acquired. Further, as I discussed above, the parent's growth allows the Companies to take advantage of the parent's economies of scale and also allows additional benefits such as strengthened access to capital.

Q. WHAT ABOUT STAFF'S DISALLOWANCE OF THE FEES RELATED TO MANAGEMENT SERVICES?

A. Staff suggests that the Management Fees relate to management of the fund, not the utilities. Essentially, Ms. Brown claims that the management fees in the APT Cost Pool relate to management of the income fund and would be duplicative of the Liberty Water costs for management of the Bella Vista Utilities.

Q. WHAT IS "MANAGEMENT OF THE FUND"?

A. Management of the fund and management of the facilities and utilities owned by the fund are not duplicative. "Management of the Fund" includes activities such as coordinating access to capital, corporate oversight and governance of the utilities, coordinating legal services, audit services, etc. As mentioned above, Staff admits that there are benefits of these services to the Companies. It also should be noted

that Ms. Brown does not identify what management services provided by APT are duplicative with management services provided by Liberty Water. The reality is that the management services provided by Liberty Water relate to day to day operations of the utilities; and the management services provided by APT relate to capital financing, strategic decisions, taxes, audits and other similar issues.

Q. SO WHAT IS YOUR RECOMMENDATION?

A. My recommendation continues to be for allowance of the APT costs. They are prudently incurred, provide benefits to the utilities and are necessary in the provision of service.

Q. NOW THAT YOU HAVE BEEN THROUGH THE RATE CASE PROCESS BEFORE THE COMMISSION, WHY DO YOU BELIEVE STAFF IS SO CONCERNED ABOUT THE APT COST ALLOCATIONS?

A. I believe Staff's added scrutiny results from the last Black Mountain Sewer Corporation rate case filed in 2005, Docket No. SW-02361A-05-0657, which involved charging and allocation of affiliate profit. We appreciate and understand Staff's scrutiny given those prior circumstances.

Q. IS THERE ANY AFFILIATE PROFIT IN THE APT COSTS HERE?

A. No. We took the message delivered by the Commission in that case and excluded any and all affiliate profit from the APT Cost Pool.

Q. NOW, IN THE LPSCO AND RIO RICO RATE CASES, STAFF EXPRESSED CONCERNS ABOUT IMPROPER CHARGES INCLUDED IN THE COST POOL. ARE THERE ANY INAPPROPRIATE CHARGES IN THE APT COST POOL IN THIS CASE?

A. No. As stated in by rebuttal testimony, we removed any and all questionable charges from the pool in response to Staff's and RUCO's concerns.

Q. WERE YOU THE WITNESS FOR LIBERTY WATER AT THE RIO RICO HEARING?

A. Yes.

Q. DO YOU RECALL A LINE OF QUESTIONING BY STAFF ATTORNEY MITCHELL REGARDING WHAT ASSURANCES YOU CAN GIVE STAFF THAT NO INAPPROPRIATE COSTS ARE INCLUDED IN THE POOL?

A. Yes.

Q. WHAT WAS YOUR ANSWER IN THAT CASE?

A. In response to that question, I consulted the NARUC Guidelines on Cost Allocations, and I noticed a section that describes an "Independent Attestation" that can be requested by a regulatory commission. Subsequently, Liberty Water offered to have an independent attestation by a third party CPA as picked by Staff and/or RUCO at the company's expense.

Q. DID YOU PROPOSE THE SAME INDEPENDENT ATTESTATION IN THIS CASE?

A. Yes. As stated in my rebuttal testimony, we proposed to subject the APT cost pool to an independent attestation by a third party CPA to prove that the costs in the pool are materially indirect costs. This proposal would alleviate Staff's concerns about improper charges by providing an independent "attestation" of the final APT cost pool. An attestation by an independent CPA would resolve Staff's and RUCO's concerns about whether the final APT cost pool includes charges relating to unregulated business operations or reflect services that can't be verified from invoices.

Q. WHAT WAS STAFF'S RESPONSE TO THE INDEPENDENT ATTESTATION PROPOSAL IN THIS CASE?

A. Staff did not address the independent attestation in its surrebuttal testimony. As a result, while I remain hopeful that the solution is agreeable to Staff, I cannot speculate as to Staff's position.

III. REJOINDER TO RUCO.

Q. HAS RUCO TAKEN A POSITION DIFFERENT FROM ITS DIRECT FILING ON THE CENTRAL OFFICE COSTS?

A. No. RUCO continues to propose disallowance of the APT costs. RUCO's primary objection is that the APT costs are excessive and unnecessary.

Q. ON WHAT BASIS DOES RUCO SUGGEST IN SURREBUTTAL THAT THE APT COSTS ARE EXCESSIVE?

A. In its surrebuttal testimony, RUCO has attempted to show that Bella Vista (Consolidated)'s labor costs are high on a per customer basis as compared to other selected water companies in Arizona.

Q. DO YOU AGREE WITH THE ANALYSIS?

A. Absolutely not. Mr. Coley has presented the same labor comparison that he presented in the Rio Rico rate case. At hearing in that case, however, Mr. Coley expressly acknowledged the shortcomings of his comparative analysis.[1] Among other things, Mr. Coley acknowledged that the APT costs are not labor costs; he conceded that the other water companies in his analysis itemize and account for labor costs in different ways; and he admitted that those other comparable

[1] Transcript of March 12, 2010 hearing, Rio Rico Utilities, Inc., Docket No. WS-02676A-09-0257 ("RRUI Tr.") at 402 – 403, 409 – 416, 418 – 419, 432 – 434, 437 – 439.

companies provide differing levels of utility service to customers.[2] Mr. Coley has presented the same flawed analysis relating to Bella Vista.

Q. PLEASE EXPLAIN.

A. There are several significant flaws with Mr. Coley's analysis. The following is a short list:

1) Mr. Coley's analysis overstates Bella Vista Water Company's labor expenses, and understates other companies' labor expenses to make his point. As provided to RUCO, and attached to my rejoinder testimony as **Exhibit PE-RJ2**, the total labor costs per customer for Bella Vista, as filed on a consolidated basis are $7.40. Including the APT costs, the total monthly cost per customer is $8.65 ($7.40 + $144,906/12 months/9610 customers). This is lower than every comparable company used by Mr. Coley except Lago Del Oro. Mr. Coley produced a similar analysis in the Rio Rico rate case, but he acknowledged that the Outside Services account encompasses far more than labor costs.[3] In this case, it seems as if he is going against his previous acknowledgement.

2) Mr. Coley's analysis does not compare costs from the same year. Most of the comparisons from Mr. Coley's analysis are either from a 2007 or even a 2006 test year in the case of Chaparral City. That's over a two year difference from the March 31, 2009 test year for the Bella Vista Companies.

3) Mr. Coley also does not take in to account the different operating methods of different utilities. Some utilities choose to outsource certain functions while others may perform them in-house. This makes comparability of labor costs near impossible. Mr. Coley failed to make that adjustment even though he acknowledged at the Rio Rico hearing that the various utilities report costs

[2] *Id.*

[3] RRUI Tr. at 402 – 409.

differently using different business models and different accounting methods.[4] Also, other utilities may have varying levels of automation in their utilities, and with more automation (SCADA, AMR/AMI Meters, etc.), there is less need for labor costs.

4) Perhaps the fatal flaw of Mr. Coley's testimony is that he is using labor statistics to disallow a cost pool that has nothing to do with labor. As stated many times, the APT costs are non-labor, indirect costs. In short, Mr. Coley is comparing apples to oranges.

5) As noted above, yet another flaw in Mr. Coley's analysis is that companies may choose to report the same costs in different line items. For example, some may report salaries under the Salaries and Wages account, while others that operate shared services models or use third party operating companies may record them in "Outside Services" and companies that do a little of each may record expenses in both.

6) It is my understanding that Mr. Coley has understated costs for other companies such as Arizona Water Company. For example, Arizona Water Company allocates some $2.0M in salaries from its Phoenix office and meter shop to its utilities. These costs were not included in Mr. Coley's analysis.

7) Mr. Coley also has left out payroll taxes for some companies and included it for others. For example, the three "standalone" companies used by Mr. Coley (Rio Verde, Bermuda Water Company and Lago Del Oro) did not have any amounts for payroll taxes included.

[4] *Id.* at 412 – 414.

Q. SO IS THERE A BETTER ANALYSIS THAT SHOWS HOW EFFICIENT BELLA VISTA IS IN RELATION TO A PEER GROUP?

A. Yes. For all the reasons I mentioned above, a line by line comparison of efficiency is near impossible. A better way would be to evaluate companies on a total operating cost per customer basis (controllable costs) as I provided in my rebuttal exhibits PE-RB3 and PE-RB4.

Q. REMIND US, MR. EICHLER, WHAT WERE THE RESULTS OF THOSE STUDIES?

A. The results were that Bella Vista, on a consolidated basis, ranked 8th out of the 23 water companies evaluated. I also demonstrated that Bella Vista's operating costs have decreased on a per customer basis under Liberty Water as compared to its prior operations as a stand-alone utility. I also prepared the chart attached to this rejoinder testimony as **Exhibit PE-RJ3**, which is a comparison of Bella Vista's controllable costs per customer versus 22 other water utilities. As shown on that chart, Bella Vista ranks eighth (8th) out of 23 for total costs.

Q. DID RUCO COMMENT ON THAT STUDY OR EVALUATE ITS RESULTS?

A. No. Mr. Coley did not address or respond to my comparisons and rebuttal exhibits.

Q. DO YOU HAVE ANY OTHER CONCERNS WITH RUCO'S ANALYSIS?

A. Yes. As I stated in my testimony in Rio Rico, Mr. Coley is trying to compare labor costs to disallow a set of costs that are not labor related. The APT costs are indirect costs related to strategic management, access to capital, corporate governance and administration. I am unsure why Mr. Coley continues to try and use labor as the driver for his analysis.

Q. RUCO ALSO OPPOSES YOUR SUGGESTION FOR AN INDEPENDENT ATTESTATION OF THE CENTRAL OFFICE COSTS ON THE GROUNDS

THAT OTHER STAFF AND RUCO WITNESSES ALREADY HAVE LOOKED AT THE POOL. HOW DO YOU RESPOND TO THAT TESTIMONY?

A. RUCO's proposed denial of an independent audit is puzzling on several fronts. Mr. Coley opposes the independent attestation for two reasons. First, he claims that the independent attestation will not address the inadequacy of the invoices as determined by Staff and RUCO. Second, Mr. Coley claims that an independent CPA isn't qualified to determine whether the APT costs are attributable to a utility. These arguments are red herrings and should be disregarded for several reasons. To start, the independent attestation is expressly authorized by the NARUC Guidelines. RUCO can't pick and choose what portions of the NARUC Guidelines it likes and dislikes in this case. Further, Mr. Coley misunderstands what an independent auditor would do. To the extent an invoice does not explain the charge incurred to Staff's or RUCO's satisfaction, the auditor then would contact the company involved or potentially the vendor and determine exactly what services were provided. Whether or not the invoice is adequate on its face does not change the nature and benefits of the actual services provided. Further, the CPAs or analysts referenced by Mr. Coley that have audited the cost pool thus far have not been independent. They have either been employed by the Arizona Corporation Commission or RUCO, or under contract to one of these parties. That is not an independent third-party attestation as envisioned by the NARUC Guidelines. Again, the independent attestation concept originates from the NARUC Guidelines for Cost Allocations, which Mr. Coley and RUCO purport to be the guiding principles of cost allocations.

Q. WHAT DO THE NARUC GUIDELINES SAY ON INDEPENDENT ATTESTATIONS?

A. The NARUC Guidelines state (page 4):

"3. Any jurisdictional regulatory authority may request an independent attestation engagement of the [Cost Allocation Manual]. 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."

Q. IS YOUR RECOMMENDATION CONSISTENT WITH THIS SECTION OF THE NARUC GUIDELINES?

A. Yes. In fact, my recommendation takes it a step further by proposing that the attestation be conducted by an auditor selected by RUCO and Staff (at Bella Vista's cost) and by offering to allow RUCO and Staff to choose the scope and purpose of the audit.

Q. DO YOU BELIEVE AN AUDIT HAS TO BE DONE?

A. No. As I mentioned earlier in my rejoinder, we have provided any and all invoices necessary to verify the APT costs. I have suggested the attestation engagement only as a measure to provide additional assurances to Staff and RUCO regarding the contents of the APT Cost Pool given their limited resources and in hopes of eliminating an issue in dispute between the Company and Staff/RUCO.

IV. <u>OTHER ANALYSIS.</u>

Q. MR. EICHLER, ARE YOU AWARE OF ANY OTHER UTILITIES WHO RUN BUSINESS MODELS SIMILAR TO LIBERTY WATER'S BUSINESS MODEL IN ARIZONA?

A. Yes. There are several companies that operate similar models.

Q. DO THOSE COMPANIES INCLUDE SIMILAR COST ALLOCATIONS IN THEIR RATE APPLICATIONS?

A. In our pending rate case for Black Mountain Sewer Corporation, Ms. Brown was Staff's witness on cost allocations and she testified that she was comfortable with and made no disallowances for shared costs in the recent Global Water rate cases.[5] As a result, I have undertaken a comparative analysis of the costs included by Global Water to the proposed Central Office Costs in Liberty Water's application. In the recent Rio Rico hearing, Mr. Coley acknowledged that the Commission has approved cost allocations for Chaparral City Water Company, Arizona Water Company and Arizona-American Water Company.[6] Perhaps the best comparison is Global Water, which uses a corporate cost allocation model very similar to Liberty Water. In Global's pending rate cases for its various utilities, Global included corporate costs allocations virtually identical to our cost allocations here and yet neither Staff nor RUCO opposed Global Water's cost allocations. It seems unfair for the Commission to approve costs allocations for Global but deny 99% of our cost allocations without any explanation.

Q. WHAT WAS THE OUTCOME OF YOUR ANALYSIS RELATING TO GLOBAL?

A. I have prepared **Exhibit PE-RJ4,** which shows a comparison of the types of costs included in the APT cost allocations versus the types of costs included by Global Water. My analysis shows that most of the costs allocated by APT also are allocated by Global. I hypothesize that other costs such as Escrow & Transfer Agent costs are not incurred because Global is not a publicly traded entity.

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[5] Transcript of November 25, 2009 hearing, *Black Mountain Sewer Corporation*, Docket No. SW-02361A-08-0609 at 781-782.

[6] RRUI Tr. at 432 – 435.

Q. ARE THERE ANY SIGNIFICANT DIFFERENCES IN YOUR ALLOCATIONS THAT YOU CAN POINT TO?

A. No. While the allocation factors may vary, the overall concepts are the same. Arizona utilities incur these costs prudently to operate shared services models and should be allowed uniformly in all cases.

Q. DOES THIS CONCLUDE YOUR REJOINDER TESTIMONY?

A. Yes.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rejoinder Testimony
July 7, 2010

Exhibit
PE-RJ1

SIERRA VISTA THE HERALD
Published on *The Sierra Vista Herald* (http://www.svherald.com)

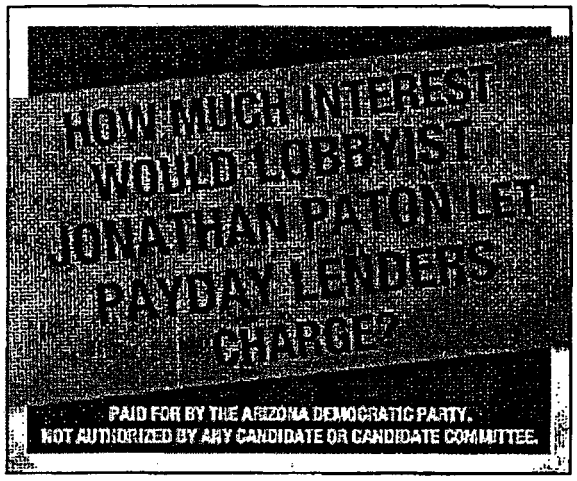
Customer praise flows for water service

From left, Michael Bullington and Kadin Hidecker play "Fix the Leak," a leaky house game, at Liberty Water Co.'s open house on Saturday. Liberty Water President David Pasieka of Canada is supervising the youngsters. (Dana Cole • Herald/Review)

By Dana Cole
Herald/Review

SIERRA VISTA — During an open house on Saturday at the Liberty Water Co. office, 4055 Campus Drive, customers praised the company for the improvements and upgrades Liberty has made since acquiring their water systems.

Liberty Water — formerly Algonquin Water Services — owns Bella Vista, Northern Sunrise and Southern Sunrise water companies. The systems, located in the Hereford/Palominas and Whetstone areas, were in dire condition before Liberty assumed ownership. Customers endured frequent water outages during summer that, at times, lasted days.



"Thankfully, those days are over," said Tim Bullington, a Re-Max agent who recalls the concerns people had about purchasing homes in the affected areas. "We had to go through a disclosure process where customers signed waivers stating they were informed of the frequent, long-term outages," Bullington said. "I was constantly calling the ACC (Arizona Corporation Commission) and talking to Kris Mayes about all the problems we were having. But there have been no problems with Liberty Water."

Hereford resident Tanny Schmidt remembers those outages. "It was so inconvenient for us. When we had an outage, sometimes the water company would drop off a couple of cases of bottled water, but when you need to do laundry, flush toilets and take showers, it just wasn't adequate."

Liberty Water President David Pasieka made the trip from the company's corporate office in Canada to attend the open house and talk to customers. "These comments are good news," he said. "It's really what we're trying to do here. We're trying to build a sustainable water utility in our service areas."

With 19 water and sewer facilities in four states, Liberty Water is a growth company looking to expand its services, Pasieka said.

The open house featured games for youngsters, refreshments and raffle prizes.

If you find a correction for this story, please contact our editorial department [1]

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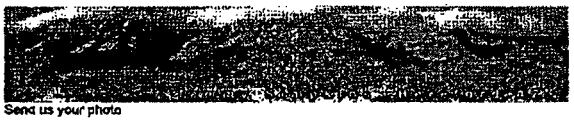
SIERRA VISTA THE HERALD



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Customer praise flows for water service

Sun, 06/27/2010 - 00:01

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From left, Michael Bullington and Kadin Hilscher play "Fix the Leak," a leaky home game, at Liberty Water Co.'s open house on Saturday. Liberty Water President David Pasieka of Canada is supervising the youngsters. (Dana Cole - Herald/Review)

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BY DANA COLE
Herald/Review

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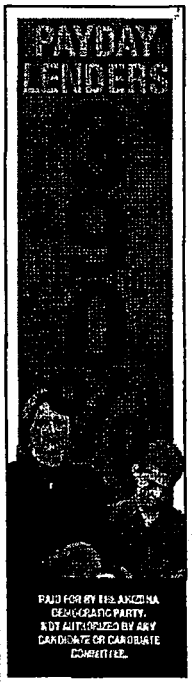

Poll

What do you think of the firing of Gen. Stanley McChrystal?

Right	50%
Wrong	44%
Undecided	6%

Total votes: 64
Older polls

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- HELP OTHERS SUCCEED! Foster Care Licensing Specialist needed. Must be
- ATTN: RNS Would you like to create your own work

Most popular stories in the last week

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- Robbery with AK-47 reported near Mall at Sierra Vista (3,018 reads)
- Police seek 3 suspects after heist in mall lot (2,474 reads)
- Woman gets 10-year sentence in plea deal (1,609 reads)
- Traffic stop results in pursuit of vehicle suspected of smuggling illegal immigrants (1,115 reads)
- Giffords slams boycotts over immigration law (1,008 reads)
- Chase through Sierra Vista ends with arrest (998 reads)
- Driver wanted on felony warrant flees after traffic stop (782 reads)
- Promoted Sierra Vista police officers look forward to new responsibilities (778 reads)
- National Guard to send 524 to Arizona border (604 reads)
- Hiring freeze creates more work for many (578 reads)

Latest Comments

Huachuca Henry
Succeed? LOL. You need your temperature taken pal. AZ is one of the taker states as far fed...view

CCWHM
Giffords did come out with a press release, that was as much, if not more, about the...view

MyBella
So was he captured.. or did he flee? I am guessing that he was arrested since it says he wa...view

MyBella
....I completely agree with you, this deal helps Carondolet and only hurts SVRHC and ou...view

Mr. Polyhistor
What you suggest requires both parents to, themselves, have a solid understanding of the co...view

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W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rejoinder Testimony
July 7, 2010

Exhibit
PE-RJ2

EXHIBIT PE-RJ2

BELLA VISTA CONSOLIDATED WATER COMPANY CONTRACTUAL SERVICES BREAKDOWN

Contractual Services ($1,599,375)		TOTAL	LABOR COSTS
1.	Operations Labor (Liberty Water):	$482,661[1]	$482,661
2.	Administrative Labor (Liberty Water):	$270,164[2]	$270,164
3.	Administrative Allocation (Liberty Water):	$256,445[3]	$68,551
4.	Central Office Costs (APT):	$144,906[4]	$0.00
5.	Technical Services Labor:	$31,654	$31,654
6.	Contract Services Miscellaneous:	$114,984[5]	$0.00
7.	Labor Burdens:	$298,847[6]	

TOTAL COSTS FOR CONTRACTUAL SERVICES:	**$1,599,375**
TOTAL LABOR COSTS FOR CONTRACTUAL SERVICES:	**$853,030**
TOTAL LABOR BURDENS FOR CONTRACTUAL SERVICES:	**$298,847**
TOTAL NON-LABOR COSTS FOR CONTRACT SERVICES:	**$447,785**

BELLA VISTA 2008 CUSTOMER COUNT FOR WATER SERVICE:	**9,610**
BELLA VISTA ANNUAL LABOR/WAGE COST PER CUSTOMER:	**$88.76**
BELLA VISTA MONTHLY LABOR/WAGE COST PER CUSTOMER:	**$7.40**

2329626

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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, excluding 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees. This exhibit is based on company's "as filed" numbers.

[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, excluding 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~~ BVWC 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. The 33% labor is excluding 35% for burdens such as payroll taxes, health benefits, retirement plans, and other insurance provided to employees.

[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~~. BVWC

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

[6] Labor burdens include costs for payroll taxes (which are a legal requirement), health benefits, retirement plans, and insurance provided to employees.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rejoinder Testimony
July 7, 2010

Exhibit
PE-RJ3

COMPARISON OF BELLA VISTA (CONSOLIDATED)'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.	Az-Am Water Co.	Willow Valley Water	Bella Vista Water	Arizona Water Co. (Coolidge)	Arizona Water Co. (Lakeside)	Az-Am Water Co.	Arizona Water Co. (Casa	Global Water Co. (Santa	Az-Am Water Co.	Arizona Water Co. (Sedona)	Chaparral City Water Co.	Arizona Water Co.	Arizona Water Co. (San Manuel)	Arizona Water Co. (Oracle)	H20, Inc.	Rio Verde Utilities, Inc.	Az-Am Water Co.	Az-Am Water Co.
Test Year	12/31/2008	12/31/2007	12/31/2008	12/31/2007	12/31/2007	12/31/2008	12/31/2008	3/31/2009	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	23,140	1,554	9,610	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	$9,283,101	$482,166	$4,162,136	$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	$8,422,016	$586,481	$3,932,129	$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)			$708		$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	$1,722,582	$33,979	$609,459	$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	$37,037		$5,715	$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	$78,546	$18,274	$49,998			$13,616		$41,783	$161,107		$21,358					$11,129	$64,824	$87,860
Testing Serv.	$34,435		706				$5,401	$51,155					$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					$1,626,931					$67,741			$268,977				$455,818.27	$93,990	$14,739	$21,4
Management Fees		$940,899		$486,871	$999,903	$1,509,322					$166,461			$2,775,604								$1,132,699	$92.
Rent		$15,559	$8,229		$14,331	$60,016	$9,185	$60,740			$5,059		$94,639	$63,217						$350,895.47			
Transportation			$58,567				$12,699	$116,419					$43,326			$74,600				$185,890.68	$13,868.00		
Insurance-GL	$18,339	$209,312	$69,678		$191,120	$354,396	$5,119	$59,410			$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	$7,290			$8,974			$158,153		$102,877				$78,822.54	$17,952	$45,435	$45,435
Misc.	$74,039	$354,017	($79,668)		$232,408	$300,084	$9,936	$92,502			$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	$1,565,706	$126,911	$1,048,142	$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)	$9,746	($41,507)	($19,780)	$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	$156,074		$201,215	$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	$363.96	$377.40	$409.17	$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

[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 Chemicals divided by the total number of customers.

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Peter Eichler
Rejoinder Testimony
July 7, 2010

Exhibit
PE-RJ4

Rejoinder Schedule Exhibit PE-RJ4
Peter Eichler
Comparison of Liberty Water Central Office Costs to Global Water

Type of Cost - APT	APT Cost Pool	Global Water	Description
Management Fees	Allocates 24.28% to Liberty Utilities	Includes 16% of Exec Management C	Pg 3 of Testimony of Gregory A. Barber, SVP & CFO cites that 84% of these costs are allocated to Global Shareholders
Legal Fees	Allocates 24.28% to Liberty Utilities	Includes 52% allocated to utilities	GWM Parent Company Allocation Appendix 1
Rent	Allocates 24.28% to Liberty Utilities	Includes 52% allocated to utilities	GWM Parent Company Allocation Appendix 1
Depreciation	Allocates 24.28% to Liberty Utilities	Includes 52% allocated to utilities	GWM Parent Company Allocation Appendix 1 - Rent Equipment. Since Equipment is rented, there is likely no depreciation
Computer Repair & Mtce	Allocates 24.28% to Liberty Utilities	Includes 62% allocated to utilities	GWM Parent Company Allocation Appendix 1
Other Professional Services	Allocates 24.28% to Liberty Utilities	Includes 62% allocated to utilities	Likely included in "Dues & Subscriptions"

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02465A-09-0411
AND ALL RELATED MATTERS.	W-20453A-09-0412 W-20454A-09-0413 W-02465A-09-0414 W-20453A-09-0414 W-20454A-09-0414

At: Tucson, Arizona

Date: July 21, 2010

Filed:

REPORTER'S TRANSCRIPT OF PROCEEDINGS

VOLUME I
(Pages 1 through 211)

ARIZONA REPORTING SERVICE, INC.
Court Reporting
Suite 502
2200 North Central Avenue
Phoenix, Arizona 85004-1481

By: COLETTE E. ROSS
Certified Reporter
Certificate No. 50658

Prepared for:

you. Take it up with Mr. Coley. Thank you.

ALJ RODDA: Thank you.

This is a different attorney? Switching up on me?

MS. MITCHELL: Yes, we are switching because I have the cost allocation issues, and I just wanted to touch on a follow-up on the question that you had posed to Mr. Sorensen if I could just.

ALJ RODDA: You can do that, yes.

MS. MITCHELL: Thank you.

RECROSS-EXAMINATION

BY MS. MITCHELL:

Q. I have lost my page.

In your rejoinder testimony on page 6 you talk about -- and it comes over from page 5 -- you talk about that there is some similarities in the Liberty model with the Global Water model, is that correct?

A. Yes.

Q. Are you familiar with the model used by Arizona-American?

A. Not as much so, no.

Q. Are you aware that they, too, have a service company that allocates cost across their regulated entities?

A. It wouldn't surprise me.

Q. Have you ever had any discussions with anyone at Arizona-American on how they manage their service, their shared services model?

A. No, I have not had direct discussion with Arizona-American, but sounds like something I might want to do.

Q. It sounds like something you want to do. And they may be open to having a discussion with you about that.

The only reason I brought that up is it never seems to be a problem with Arizona-American rate cases on cost allocation, but it appears to be a problem with the Liberty Water companies. And it is just a suggestion. I'm through testifying on that point.

ALJ RODDA: Just a further suggestion?

MR. SHAPIRO: Can she just be sworn in?

THE WITNESS: But they can make the suggestion.

BY MS. MITCHELL:

Q. Until now we have never had that issue with Arizona-American.

And I just want to ask one follow-up question on between your questions with Mr. Shapiro on the hookup fee and the CIAC. When you get the hookup fee, what account does it go in? And maybe this may be a Mr. Bourassa

Shared Service Model Comparison - Arizona American vs Liberty Water

	Service Category	Arizona American*	Liberty Water Allocator	Liberty Water Service Provider	Description
1	Accounting	customer count	customer count	Liberty Water	Accounting is done by LW Staff in Avondale
2	Audit Services	customer count	customer count	Algonquin Power Trust	Audit work performed primarily by KPMG
3	Corporate Planning	customer count	4 factor	Liberty Water	Utility Planning services provided by Liberty Water
4	Customer Service	customer count	customer count	Liberty Water	Customer Service provided by LW Staff in Avondale
5	Engineering	customer count	4 factor	Liberty Water	Engineering Services provided by LW Staff in Avondale
6	Executive	customer count	customer count	Algonquin Power Trust	Management Services provided by APT
7	External Affairs	customer count	customer count	Algonquin Power Trust	Unitholder Communications provided by APT
8	Finance	customer count	customer count	Liberty Water	Finance functions performed by Staff in Avondale/Oakville
9	Human Resources	customer count	4 factor	Liberty Water	HR Services performed by Staff in Avondale
10	Information Technology	customer count	4 factor	Liberty Water	IT services provided by Staff in Avondale
11	Investor Relations	customer count	customer count	Algonquin Power Trust	Unitholder Communications provided by APT
12	Legal	customer count	customer count	Algonquin Power Trust	General Legal provided by APT
13	Operations	customer count	Direct charge	Liberty Water	Operations labor is directly charged
14	Regulatory Services	customer count	4 factor	Liberty Water	Regulatory Services provided by Liberty Water Staff
15	Risk Management	customer count	customer count	Algonquin Power Trust	Part of Audit services provided by APT
16	Shared Services	customer count	N/A	N/A	
17	Supply Chain	customer count	N/A	N/A	
18	Treasury	customer count	N/A	N/A	

Notes:

a Both companies directly charge costs to the extent possible. The chart above reflects only costs that are allocated

b Services by APT are initially allocated to Liberty Water based on number of facilities. The costs are then allocated within Liberty Water based on customer count

*Service Company Services provided from American Water Service Company to Arizona American. Information derviced from Kentucky American Water Company Case No. 2008-00427 filed before the Public Service Commission of Kentucky. Testimony of Patrick L. Baryenbruch dated October 31, 2008. Services received by Arizona American are identical to those received by Kentucky American as confirmed in telephone discussions with the Director of Rates from Arizona American. Services are also described in C-1 statements in Arizona American filings in pending rate case SW-01303A-09 and W-01303A-09

APT SERVICES PROVIDED vs AMERICAN WATER SERVICE COMPANY

	APT Services	American Water Service Company
1	Audit	Internal Audit provided by Corporate Office.
2	Tax Services	Primarily Shared Service with support from Regional Office
3	General Legal	Primarily Regional Office with support from Corporate Office
4	Professional Services	HR and IT management services scatterred at Corporate Office, Regional Office, Local
5	Management Services	Executive Management provided by American Water
6	Unitholder Communications	External Affairs provided by American Water
7	Escrow Fees	N/A
8	Office Expenses	Billed as part of "Administration"
9	Rent	Billed as part of "Administration"
10	Depreciation	Regional Offices administer PC acquisition functions

BELLA VISTA WATER COMPANY (CONSOLIDATED)
DOCKET NO. W-02453A-09-0414
RUCO'S FOURTH SET OF INFORMAL DATA REQUESTS

The Company provides the following responses to RUCO's third set of informal data requests without waiving any legal or other objections and the Company reserves the right to assert any and all legal or other objections to these informal data requests as necessary at hearing.

7.01 **Algonquin Power Trust ("APT") Office Building** – Please provide any and all documents supporting your assertion that the lease to APT is at market rate.

Response: As stated on page 36 of APUC's 2009 Annual Financial Results: "APUC 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 2009 were $331 (2008 - $296). APUC believes the lease is on terms equivalent to fair market value for prime office space of similar size and quality at the time the lease was executed." Further, Algonquin Power Corporation hired LNR Corporation to conduct a market analysis and survey of available office buildings in August/September 1999 and October 1999. Copies of those rental market analyses are attached to this response. The October 1999 market survey revealed only three viable building options with total occupancy market prices comparable to the Lease between Algonquin Property Limited Partnership and APT. The June 1, 2010 memorandum attached to this data response summarizes the background information and market analysis relating to the corporate office building.

Company Contact: Peter Eichler, Manager, Financial Planning & Analysis

7.02 **Algonquin Power Trust ("APT") Office Building** – Please identify the total square footage of the building and the specific square footage of the space leased to APT.

Response: The square footage of the lease is identified in the Lease provided as a response to RUCO informal DR 6.02.

Company Contact: Peter Eichler, Manager, Financial Planning & Analysis

7.03 **Algonquin Power Trust ("APT") Office Building** – Please provide the cost or purchase price of the APT office building and supporting documentation listing cost and/or purchase price.

Response: This information is not available to employees of Liberty Water. This data request also seeks information which goes beyond

reasonable discovery for an expense of $0.08 customer per month, or $805.21 total per month. The total costs incurred by customers of the consolidated Bella Vista Companies for lease of the corporate office is $0.08 per month, or $0.96 per year. Further, leases are based on market rates and not purchase prices. As set forth above, the monthly price under the Lease between APLP and APT was and is within the comparable market range. Further, RUCO's attempt to compare the lease amount incurred by APT with the original construction price for the building is not appropriate and fails to address other variables to such as the ability to access capital, the cost of such capital, etc.

During the test year, Liberty Water staff located at 2845 Bristol Circle drew rent charges of approximately $5,545.50 per month. Of this amount, the consolidated companies in this case are allocated $805.21 per month, which again translates to $0.08/month per customer.

Company Contact: Peter Eichler, Manager, Financial Planning & Analysis

7.04 **Algonquin Power Trust ("APT") Office Building** - Admit that the leassors of the APT lease are shareholders in the parent. If denied, please explain.

Response: Deny. Alqonquin Property Limited Partnership ("APLP") is the lessor or landlord of the APT office building under the Lease with APT as the lessee or tenant. APLP is not a shareholder in the parent company..

Company Contact: Peter Eichler, Manager, Financial Planning & Analysis

Attachment 1

~~Aug 99~~

Aug 15/99

Corporate Real Estate Advisors

advisors

Prepared for

Algonquin Power Corporation Inc.

Mississauga

LNR CORPORATION, BROKER

Client Needs Analysis Questionnaire

LNR

Prepared for
Algonquin Power Corporation Inc.
Mississauga

Prepared by
LNR Corporation, BROKER
Gary Hewitt
CORPORATE REAL ESTATE ADVISOR
09 • 15 • 99

client needs analysis questionnaire
Algonquin Power Corporation Inc.

LNR

1. Questionnaire completed by: MARK UNSWORTH

2. Address of current premises under evaluation:

2085 Hurontario Street
Suite 210
Mississauga, Ontario

client needs analysis questionnaire
Algonquin Power Corporation Inc.

LNR

Section 1: Current Situation

3. Number of employees at this address: 32

4a. In an effort to identify features which could be improved, please rate your satisfaction with your current premises in terms of the following:

	Very Satisfied (1)	Satisfied (2)	Fairly Satisfied (3)	Fairly Dissatisfied (4)	Very Dissatisfied (5)	Comments
Elevator Service	✓					
Air Conditioning			✓			
Heating			✓			
Cleaning			✓			COULD IMPROVE
Electrical Outlets			✓			PLAN FOR FEWER EXT. CORDS.
Lighting / Brightness			✓			BUT NEED TO USE DESK LAMPS.
Windows	✓					
Views	✓					
Washrooms		✓				CLEANLINESS A PROBLEM SOMETIMES.
Wheelchair Access		✓				
Building Finishes		✓				
Shipping/Receiving		✓				
Parking – Availability	✓					
Parking – Price	✓					NONE
Access by Car	✓					
Access by Public Transit	✓					
Local Amenities			✓			
Current Size of Premises					✓	- EXPANSION REQUIRED
Current Layout					✓	- PRESENTLY USE ± 9,000 Ft² RENTABLE SPACE.

LNR

4b. Please give a brief explanation of the reasons for any areas of dissatisfaction or list other areas which require improvement.

-REQUIRE TO HAVE ALL PERSONNEL LOCATED ON ONE FLOOR FOR BETTER COMMUNICATION WITHIN COMPANY.

LNR

Section 2: Future Requirements

5. If you were to relocate, what would be the preferred geographic boundaries for your new location?

	NORTH	SOUTH	EAST	WEST
EXAMPLE	*Bloor St.*	*Front St.*	*Church St.*	*Bathurst St.*
1st Choice	ALONG QEW;	WEST	OF HWY. 10	TO
2nd Choice	TRAFALGAR RD.	/	KERR ST.	ARE

6. Would you consider renewing/renegotiating your existing lease and remaining in your current premises, or relocating within the building?

YES; ONLY IF ABLE TO LOCATE ONTO ONE FLOOR

7. At which date is a move possible for your operations?

Earliest: IMMEDIATELY.

Latest: DEC. 1'99

8. What are your budget guidelines for annual gross rent?

$230,000

LNR

9. What length of lease term will you require?

Minimum: 5 years Maximum: 10 years

10. What is the number of employees anticipated for this location?

Initially: 32 employees

2 Years Hence: 40 employees

5 Years Hence: 60 employees

11. Have you estimated the total square footage required during your next lease term? If yes, please specify.

Initially: ≈ 10,000 SF

12. How many parking spaces will be required?

Staff: 32 spaces

Visitors: 2 ? spaces

13. Do you require wheelchair access or further special needs for your premises?

No.

14. What type of shipping/receiving facilities are required?

Basic

LNR

15. Please list any specific technological issues.

N/A

16. If you relocate, what kind of image would you wish your new building to portray?

MODERN, CONSERVATIVE, BASIC

17. Please specify any buildings that are of interest to you with respect to this requirement.

N/A

18. Please list any other requirements that need to be addressed?

N/A

client needs analysis questionnaire
Algonquin Power Corporation Inc.

LNR

Section 3: Space Layout Requirements

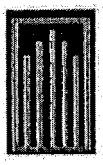
	CURRENT SITUATION			FUTURE REQUIREMENTS		
	# OF PEOPLE	# OF OFFICES	APPROX. AREA IN SF (E.G. 10X10)	# OF PEOPLE	# OF OFFICES	APPROX. AREA IN SF (E.G. 10X10)
PARTNERS — Senior Offices (with window)	4	4	15 X 15	4	4	≈ 15 X 15
MANAGERS — Private Offices (with window)	4	4	10 X 12	5	5	10 X 12
Private Offices (interior)						
Open Work Area(s)				23		10 X 10
Conference Room #1 (APC)				12	≈	20 X 12
Conference Room #2 (APS)				6	≈	17 X 15
Reception Area c/w COAT Room.					≈	20 X 15
Filing Area(s)				2	{	20 X 10 20 X 18
Storage Area(s) — presently off site				1		30 X 15
Kitchen/Lunchroom						15 X 10
Computer/Telecom Room						10 X 15
Other (please specify) — CENTRAL FAX/COPIER RM./OFFICE SUPPLIES						10 X 15
LIBRARY ROOM - APC						20 X 20
GENERAL AREAS FOR:						
- AREA PRINTERS.						

- AREA FAX, COPIERS

* — POSSIBLY EMPTY OFFICES (OPEN CONCEPT) WITH SMALL CONFERENCE ROUND TABLE FOR 2-3 PEOPLE.

Attachment 2

Survey of Available Space



LNR

Prepared for

Algonquin Power Systems Inc.

Mississauga

Prepared by

LNR Corporation, BROKER

Gary Hewitt

CORPORATE REAL ESTATE ADVISOR

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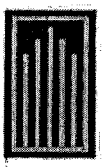

LNR

Section 1	Introduction
Section 2	Survey Objectives
Section 3	Stacking Plan
Section 4	Survey Summary
Section 5	Financial Comparisons
Section 6	Location Map

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introduction

LNR

The information contained in this Survey of Available Space was compiled by various sources of listing, marketing and landlord information deemed to be accurate and reliable, however all financial information is estimated only and is subject to change at any time.

The reader should note that all estimated net rental rates are exclusive of any cost of renovation or construction of leasehold improvements unless otherwise noted (herein referred to as net effective rates ("NER"). In most instances, landlords will provide a leasehold improvement allowance for the tenant's use. The amount of this allowance is amortized over the term of the lease at an appropriate discount rate and added to the net rental rate. As an example, if the net effective rental rate on an "As Is" basis is $15.00 PSF per annum and the tenant requires a $35.00 PSF improvement allowance, the net rental rate would be increased by $5.20 on a ten year basis. Specifically, the net rental rate payable by the tenant would be $20.20 PSF per annum.

This survey contains detailed information regarding specific buildings which currently have office space for lease that meet the selection criteria of Algonquin Power Systems Inc.

objectives

LNR

Optimal Space Required:	Approx. 9,500 - 10,500 rentable SF
Geographic Area:	Highway 427 to Dorval Drive Burnhamthorpe Road to QEW
Lease Term:	Five to ten years
Rental Rate:	Market rent
Occupancy Date:	December 1, 1999 - September 2000
Parking Requirements:	Minimum of 3 spaces per 1,000 SF of rentable area
Image:	• Algonquin Power Systems Inc. is looking for a building of similar quality to it's existing head office at 2085 Hurontario Street.
Other Criteria:	• Flexibility to expand if desired • Good access to major surface routes • Amenities within area of proposed alternative

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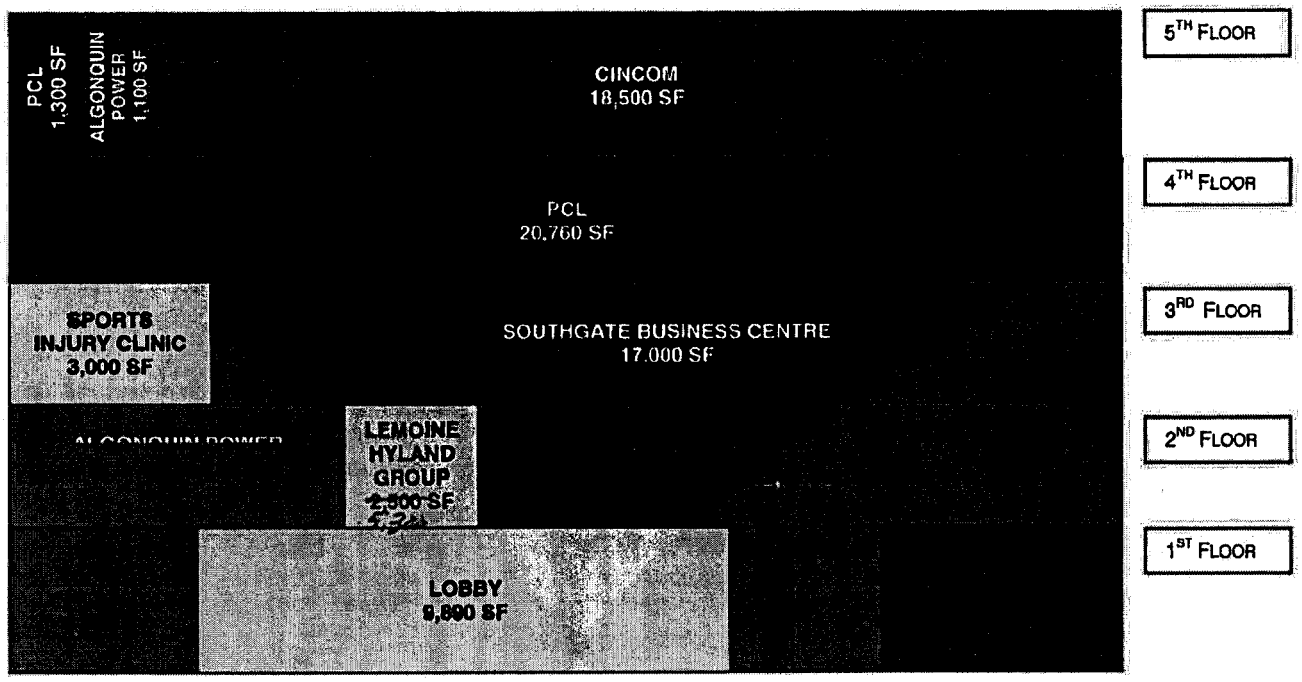
2085 Hurontario Street
Southgate Executive Centre

Stacking Plan



Floor #	Tenant	SF (Approximate)	Expiry
5	Cincom Systems of Canada Ltd.	18,500	2001
	PCL Constructors Canada	1,300	2001
	Algonquin Power Systems	1,100	2001
4	PCL Constructors Canada	20,760	2006
3	Southgate Business Centre	17,000	2002
	Sports Injury Clinic	3,000	N/A
2	Winfair Group of Companies	12,000	2002
	Algonquin Power Systems	6,600	2001
	Lemoine Hyland Group	~~6,500~~ 5,300	2005
1	Vacant (Temporarily Occupied by PCL)	4,500	Month to Month
	Alberta Distillers	3,500	2001
	Algonquin Power Systems	1,670	2001
	Doctor's Offices	1,200	N/A

survey summary

LNR

Address	Area (SF)	Floor #	Approx. Net Rental Rate	Est. Taxes & Op. Cost (1999)	Total Occupancy Costs
151 City Centre Drive	9,500	8	$12.00"as is"	$ 7.83	$ 19.83
304 The East Mall	9,500	5	$ 9.00"as is"	$ 13.50	$ 22.50
1235 North Service Rd. W.	9,500	4	$14.50	$ 8.07	$ 22.57
√ 2020 Winston Park Drive	9,500	3	$15.50	$ 8.50	$ 24.00
151 City Centre Drive	9,500	7	$17.00	$ 7.83	$ 24.83
21 Four Seasons Place	9,500	2	$12.00	$13.35	$ 25.35
√ 201 City Centre Drive	9,500	2	$17.00	$ 11.87	$ 28.87

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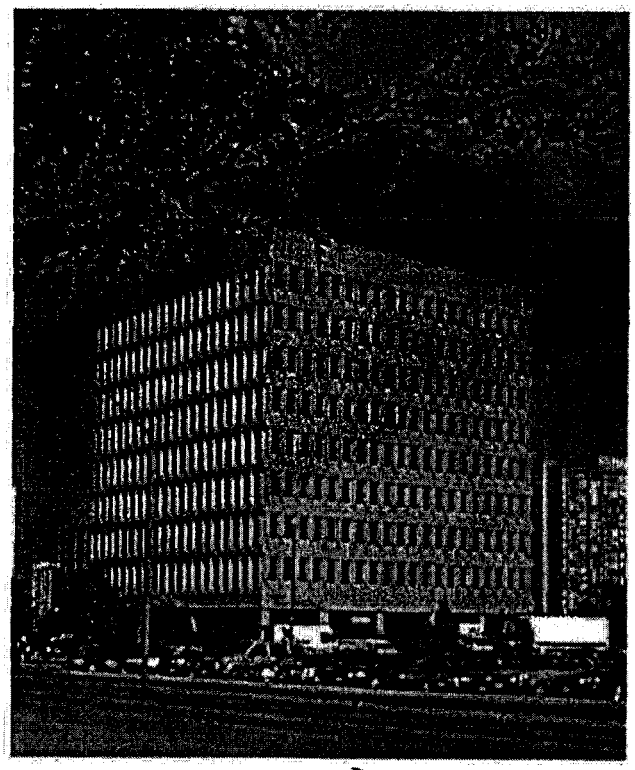
option

151 City Centre Drive
UCO Building
Mississauga, Ontario

LNR



Building Size	**79,259 SF**
Building Quality	**B**
Completed	**1983**
Number of Floors	**9**
Floor Plate Size	**9,500 SF**

Details on Available Space

Space Available	**9,500 SF**
Floor Number	**8**
Offer Type	**Sublet**
Term of Lease	**To March 30, 2005**
Date Available	**Immediate**
Estimated Net Rent	**$12.00 "as is"**

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$7.83**

Total Occupancy Costs
(estimated 1999)

$19.83

Location

- Across from Square One

Comments

- Space has existing improvements in place
- Surface parking is available free of charge at a ratio of 3 spaces per 1,000 SF leased

Owner

- Edgefund Realty

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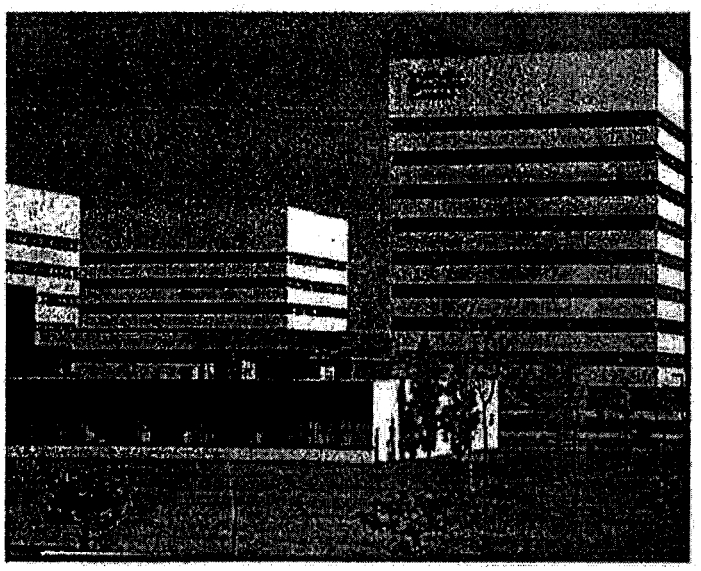
option 2

304 The East Mall
Valhalla Executive Centre
Etobicoke, Ontario

LNR



Building Size	**320,000 SF**
Building Quality	**B+**
Completed	**1977**
Number of Floors	**00**
Floor Plate Size	**14,659 SF**

Details on Available Space

Space Available	**14,659 SF (Divisible to 9,500)**
Floor Number	**5**
Offer Type	**Direct**
Term of Lease	**5 years**
Date Available	**December 1, 1999**
Estimated Net Rent	**$9.00 "as is"**

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$13.50**

Total Occupancy Costs
(estimated 1999)

$22.50

Location

- The East Mall between Burnhamthorpe Road and Bloor Street

Comments

- Nortel Network's former space
- Leasehold improvements in good condition
- Part of 3 building complex
- On TTC route
- Complex has been extensively renovated
- Parking is available at a ratio of 3 spaces per 1,000 SF leased

Owner

- Transglobe Properties

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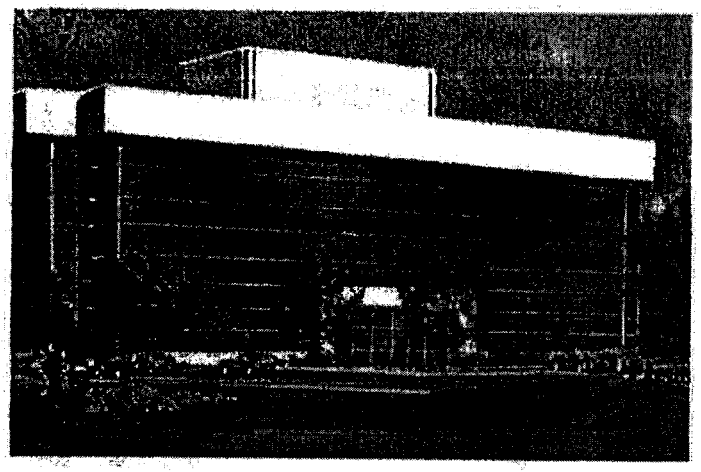
option 3

LNR

1235 North Service Rd. W.
Ennisclare Corporate Centre
Phase II
Oakville, Ontario



Building Size	**80,000 SF**
Building Quality	**A**
Completed	**Fall of 1999**
Number of Floors	**5**
Floor Plate Size	**16,400 SF**

Details on Available Space

Space Available	**16,400 SF (Divisible to 9,500)**
Floor Number	**4**
Offer Type	**Direct**
Term of Lease	**10 years**
Date Available	**December 1, 1999**
Estimated Net Rent	**$14.50 years 1 to 5 ***
	$16.50 years 5 to 10

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$8.07**

Total Occupancy Costs
(estimated 1999)

$22.57

Location

- West of Dorval Road and the QEW

Comments

- * $25.00 PSF improvement allowance included in net rental rate
- Building completed September of 1999
- Surface parking is available free of charge at a ratio of 4 spaces per 1,000 SF leased

Owner

- Beutel Goodman Real Estate

Manager

- Beutel Goodman Real Estate

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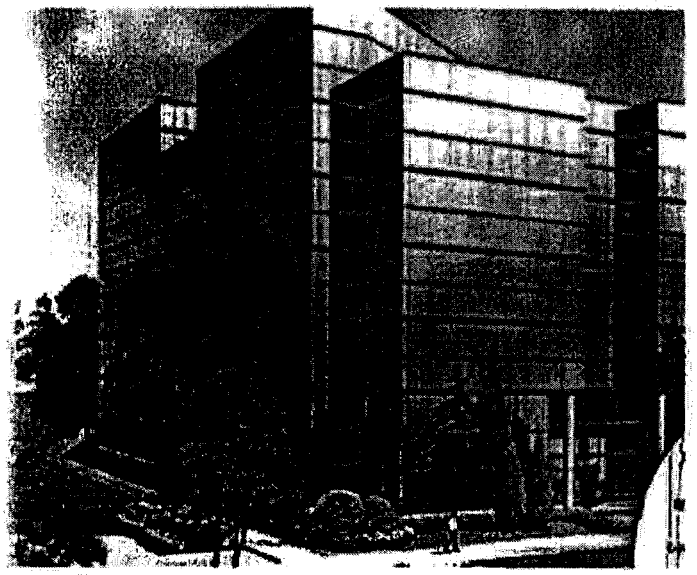
option

2020 Winston Park Dr.
Oakville, Ontario

LNR



Building Size	**130,000 SF**
Building Quality	**A**
Completed	**Summer of 2000**
Number of Floors	**7**
Floor Plate Size	**19,000 SF**

Details on Available Space

Space Available	**19,100 SF (Divisible to 9,500)**
Floor Number	**3**
Offer Type	**Direct**
Term of Lease	**10 years**
Date Available	**September 1, 2000**
Estimated Net Rent	**$15.50 years 1 to 5 ***
	$17.00 years 6 to 10

Additional Costs
(estimated 2000)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$8.50**

Total Occupancy Costs
(estimated 2000)

$24.00

Location

- Winston Churchill Boulevard and the QEW

Comments

- * $20.00 PSF improvement allowance included in net rental rate
- All amenities within 1 block; i.e. fitness club, theatre, restaurants
- Surface parking is available free of charge at a ratio of 4 spaces per 1,000 SF leased

Owner

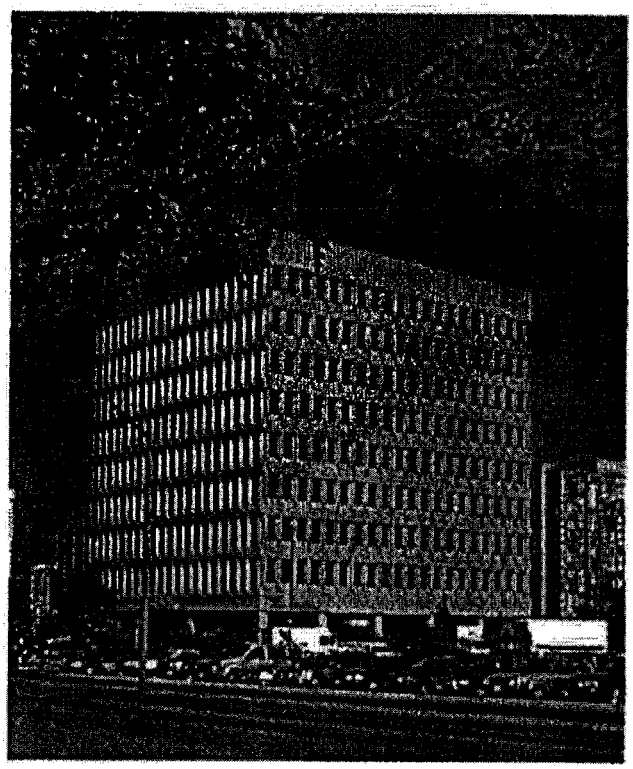
- Westbury Management

Manager

option

151 City Centre Drive
UCO Building
Mississauga, Ontario

LNR



Building Size	**79,259 SF**
Building Quality	**B**
Completed	**1983**
Number of Floors	**9**
Floor Plate Size	**9,500 SF**

Details on Available Space

Space Available	**9,500 SF**
Floor Number	**7**
Offer Type	**Direct**
Term of Lease	**5 to 10 years**
Date Available	**Immediate**
Estimated Net Rent	**$17.00 ***

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$7.83**

Total Occupancy Costs
(estimated 1999)

$24.83

Location

- Across from Square One

Comments

- * $25.00 PSF improvement allowance included in net rental rate
- Space has existing improvements in place
- Former insurance offices
- Surface parking is available free of charge at a ratio of 3 spaces per 1,000 SF leased

Owner

- Edgefund Realty

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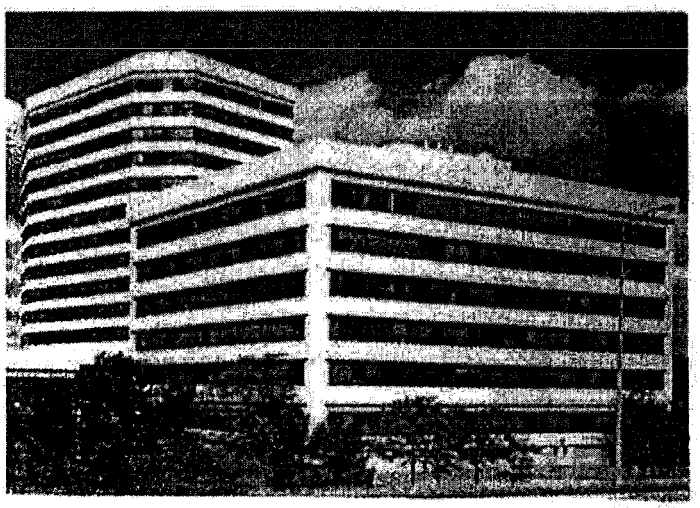
option 6

21 Four Seasons Place
Etobicoke, Ontario



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Building Size	**159,600 SF**
Building Quality	**B+**
Completed	**1985**
Number of Floors	**6**
Floor Plate Size	**14,602 SF**

Details on Available Space

Space Available	**14,602 SF (Divisible to 9,500)**
Floor Number	**2**
Offer Type	**Direct**
Term of Lease	**5 years**
Date Available	**Immediate**
Estimated Net Rent	**$12.00***

Additional Costs
(estimated 1999)

Total Extra Costs **$13.35**

Total Occupancy Costs
(estimated 1999)

$25.35

Location

- Burnhamthorpe Road (Hwy 427) and The East Mall

Comments

- * $25.00 PSF improvement allowance included in net rental rate
- Underground parking is available at $40.00 per month per space at a ratio of 3 spaces per 1,000 SF leased

Owner

- Dundee Realty Management Corp.

Manager

- Dundee Realty Management Corp.

option

201 City Centre Drive
Mississauga, Ontario

LNR

Building Size	**204,870 SF**
Building Quality	**A**
Completed	**1980**
Number of Floors	**11**
Floor Plate Size	**20,367 SF**

Details on Available Space

Space Available	**12,036 SF (Divisible to 9,500)**
Floor Number	**2**
Offer Type	**Direct**
Term of Lease	**5 years**
Date Available	**Immediate**
Estimated Net Rent	**$17.00 ***

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$11.87**

Total Occupancy Costs
(estimated 1999)

$28.87

Location

- Highway 10 and Burnhamthorpe Road

Comments

- * $25.00 PSF improvement allowance included in net rental rate
- Surface parking is available free of charge at a ratio of 3 spaces per 1,000 SF leased

Owner

- CIBC Development Corporation

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29-Sep-99

Algonquin Power Systems Inc.
Financial Comparison of Options
Prepared By: LNR Corporation

	Alternative 1	Alternative 2	Alternative 3	Alternative 4
	Sublet commencing December 1, 1999 available on 8th floor until March 30, 2005. Assume extension for 1 year 4 months at same net rent.	Direct lease with landlord on 5th floor commencing December 1, 1999.	10 year lease alternative commencing December 1, 1999.	10 year lease alternative commencing December 1, 1999.
BUILDING	151 City Centre Drive	304 The East Mall	Ennisclare Corporate Centre - II	2020 Winston Park Drive
TERM (Yrs)	6.67	6.67	10.00	10.00
TOTAL Rentable Square Footage	9,500	9,500	9,500	9,500
Net Rental Rate (PSF)				
Years 1-5	$12.00	$9.00	$14.50	$15.50
Years 6 - Expiry	$12.00	$9.00	$16.50	$17.00
Including Tenant Improvements (PSF)	-	-	$25.00	$20.00
Additional Rent (PSF)	$7.83	$13.50	$8.07	$8.50
Avg Annual Gross Rent (PSF) Over 6 Yr 8 Mth Term	$20.45	$23.58	$23.58	$24.95
Net Effective Rent (PSF) Over 6 Yr 8 Mth Term	$12.00	$9.00	$11.57	$13.12
6 YEAR 8 MONTH CASH FLOW				
Year 1	$188,385	$213,750	$214,415	$228,000
Year 2	$190,570	$217,645	$216,695	$230,470
Year 3	$192,850	$221,635	$219,070	$232,940
Year 4	$195,225	$225,720	$221,540	$235,505
Year 5	$197,695	$229,900	$224,010	$238,165
Year 6	$200,165	$234,270	$245,575	$255,170
Year 7 (8 Months)	$135,153	$159,157	$163,717	$172,013
TOTAL GROSS RENT OVER 6 YR 8 MTH TERM	$1,300,043	$1,502,077	$1,506,795	$1,592,263
NPV OF GROSS RENT OVER 6 YR 8 MTH TERM	$988,657	$1,140,082	$1,140,084	$1,206,272

	Alternative 5	Alternative 6	Existing Location	Alternative 7
	Direct lease with landlord on 7th floor commencing December 1, 1999.	Direct lease with landlord on 2nd floor commencing December 1, 1999.	Existing landlord proposal commencing December 1, 1999.	Direct lease with landlord on 2nd floor commencing December 1, 1999.
BUILDING	151 City Centre Drive	21 Four Seasons Place	2085 Hurontario Street	201 City Centre Drive
TERM (Yrs)	6.67	6.67	6.67	6.67
TOTAL Rentable Square Footage	9,500	9,500	10,642	9,500
Net Rental Rate (PSF)				
Years 1-5	$17.00	$12.00	$ 15.00 *	$17.00
Years 6 - Expiry	$17.00	$12.00	$15.00	$17.00
Including Tenant Improvements (PSF)	$25.00	$25.00	$ 9.00 *	$25.00
Additional Rent (PSF)	$7.83	$13.35	$8.99	$11.87
Avg Annual Gross Rent (PSF) Over 6 Yr 8 Mth Term	$25.45	$26.41	$23.91	$29.82
Net Effective Rent (PSF) Over 6 Yr 8 Mth Term	$12.09	$7.09	$13.44	$12.09
6 YEAR 8 MONTH CASH FLOW				
Year 1	$235,885	$240,825	$227,499	$274,265
Year 2	$238,070	$244,625	$239,640	$277,685
Year 3	$240,350	$248,520	$261,155	$281,200
Year 4	$242,725	$252,510	$264,241	$284,810
Year 5	$245,195	$256,690	$267,327	$288,515
Year 6	$247,665	$260,965	$270,520	$292,315
Year 7 (8 Months)	$166,820	$176,890	$182,546	$197,473
TOTAL GROSS RENT OVER 6 YR 8 MTH TERM	$1,616,710	$1,681,025	$1,712,927	$1,896,263
NPV OF GROSS RENT OVER 6 YR 8 MTH TERM	$1,230,404	$1,276,813	$1,295,044	$1,441,806

* REFER TO EXISTING LOCATION SPREADSHEET IN FINANCIAL COMPARISONS.
* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 2001 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
* PRESENT VALUE CALCULATIONS ARE BASED ON THE ASSUMPTION OF EQUAL MONTHLY RENTAL PAYMENTS WITHIN EACH YEAR (PERIOD).
* ALL ESTIMATES OF GROSS RENT CONTAINED HEREIN REFLECT THE IMPACT OF BILLS 106 AND 149, THE FAIR MUNICIPAL FINANCE ACT 1997 (INCL. BUS. TAXES).
– THE FINANCIAL ANALYSIS CONTAINED WITHIN THIS DOCUMENT IS BASED UPON INFORMATION AND FINANCIAL PARAMETERS FROM SOURCES DEEMED RELIABLE, BUT NO WARRANTY OR REPRESENTATION IS MADE AS TO THE ACCURACY RELATED THERETO.
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ALTERNATIVE 1

Client: ***Algonquin Power Systems Inc.***

Address: ***151 City Centre Drive***

LEASE DESCRIPTION

Sublet commencing December 1, 1999 available on 8th floor until March 30, 2005. Assume extension for 1 year 4 months at same net rent.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	80	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$0.00
YEARS:	6.67	MONTHLY	0.72%			TOTAL	$0

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	8	0	0	0
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	0	0	0
Base Rent (Yr)	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Rent (Yr)	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$0.00	$0.00	$0.00
Tax & Op. (Yr)	$7.83	$8.06	$8.30	$8.55	$8.81	$9.07	$9.34	$0.00	$0.00	$0.00
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$114,000	$114,000	$114,000	$114,000	$114,000	$114,000	$76,000	$0	$0	$0
Tenant Imp.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$114,000	$114,000	$114,000	$114,000	$114,000	$114,000	$76,000	$0	$0	$0
Additional Rent	$74,385	$76,570	$78,850	$81,225	$83,695	$86,165	$59,153	$0	$0	$0
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$74,385	$76,570	$78,850	$81,225	$83,695	$86,165	$59,153	$0	$0	$0
Total Rent	$188,385	$190,570	$192,850	$195,225	$197,695	$200,165	$135,153	$0	$0	$0
PV of Total Rent	$181,145	$168,115	$156,080	$144,956	$134,670	$125,094	$78,598	$0	$0	$0
Monthly Cost	$15,699	$15,881	$16,071	$16,269	$16,475	$16,680	$16,894	$0	$0	$0
Cost/SF	$19.83	$20.06	$20.30	$20.55	$20.81	$21.07	$14.23	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$1,300,043	$988,657
AVERAGE ANNUAL RENT	$195,007	NER
AVERAGE MONTHLY RENT	$16,251	$12.00
	÷ 95%	AVG GROSS RENT
		$20.45

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR. ESCALATING AT 3% PER ANNUM.
* PRESENT VALUE CALCULATIONS ARE BASED ON THE ASSUMPTION OF EQUAL MONTHLY RENTAL PAYMENTS WITHIN EACH YEAR (PERIOD).
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G:\Finance\Excel Categories Various\FINANCE\Algonquin Power Systems\[Alternative Analysis.xls]Residual Obligation

ALTERNATIVE 2

Client: ***Algonquin Power Systems Inc.***

Address: ***304 The East Mall***

LEASE DESCRIPTION

Direct lease with landlord on 5th floor commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	80	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$0.00
YEARS:	6.67	MONTHLY	0.72%			TOTAL	$0

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	8	0	0	0
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	0	0	0
Base Rent (Yr)	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Rent (Yr)	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$9.00	$0.00	$0.00	$0.00
Tax & Op. (Yr)	$13.50	$13.91	$14.33	$14.76	$15.20	$15.66	$16.13	$0.00	$0.00	$0.00
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$85,500	$85,500	$85,500	$85,500	$85,500	$85,500	$57,000	$0	$0	$0
Tenant Imp.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$85,500	$85,500	$85,500	$85,500	$85,500	$85,500	$57,000	$0	$0	$0
Additional Rent	$128,250	$132,145	$136,135	$140,220	$144,400	$148,770	$102,157	$0	$0	$0
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$128,250	$132,145	$136,135	$140,220	$144,400	$148,770	$102,157	$0	$0	$0
Total Rent	$213,750	$217,645	$221,635	$225,720	$229,900	$234,270	$159,157	$0	$0	$0
PV of Total Rent	$205,535	$192,000	$179,376	$167,599	$156,608	$146,408	$92,557	$0	$0	$0
Monthly Cost	$17,813	$18,137	$18,470	$18,810	$19,158	$19,523	$19,895	$0	$0	$0
Cost/SF	$22.50	$22.91	$23.33	$23.76	$24.20	$24.66	$16.75	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$1,502,077	$1,140,082
AVERAGE ANNUAL RENT	$225,312	NER $9.00
AVERAGE MONTHLY RENT	$18,776	AVG GROSS RENT $23.58

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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ALTERNATIVE 3

Client: ***Algonquin Power Systems Inc.***

Address: ***Enniscliare Corporate Centre - II***

LEASE DESCRIPTION

10 year lease alternative commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$237,500

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500
Base Rent (Yr)	$10.78	$10.78	$10.78	$10.78	$10.78	$12.78	$12.78	$12.78	$12.78	$12.78
Tenant Imp. (Yr)	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72
Net Rent (Yr)	$14.50	$14.50	$14.50	$14.50	$14.50	$16.50	$16.50	$16.50	$16.50	$16.50
Tax & Op. (Yr)	$8.07	$8.31	$8.56	$8.82	$9.08	$9.35	$9.63	$9.92	$10.22	$10.53
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$102,410	$102,410	$102,410	$102,410	$102,410	$121,410	$121,410	$121,410	$121,410	$121,410
Tenant Imp.	$35,340	$35,340	$35,340	$35,340	$35,340	$35,340	$35,340	$35,340	$35,340	$35,340
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$137,750	$137,750	$137,750	$137,750	$137,750	$156,750	$156,750	$156,750	$156,750	$156,750
Additional Rent	$76,665	$78,945	$81,320	$83,790	$86,260	$88,825	$91,485	$94,240	$97,090	$100,035
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$76,665	$78,945	$81,320	$83,790	$86,260	$88,825	$91,485	$94,240	$97,090	$100,035
Total Rent	$214,415	$216,695	$219,070	$221,540	$224,010	$245,575	$248,235	$250,990	$253,840	$256,785
PV of Total Rent	$206,174	$191,162	$177,300	$164,495	$152,595	$153,473	$142,326	$132,023	$122,498	$113,687
Monthly Cost	$17,868	$18,058	$18,256	$18,462	$18,668	$20,465	$20,686	$20,916	$21,153	$21,399
Cost/SF	$22.57	$22.81	$23.06	$23.32	$23.58	$25.85	$26.13	$26.42	$26.72	$27.03

	GROSS	NPV	
TOTAL RENT	$2,351,155	$1,555,734	
TOTAL RENT (6 YRS 8 MTHS)	$1,506,795	$1,140,084	
AVERAGE ANNUAL RENT	$235,116	NER	
		$11.57	
AVERAGE MONTHLY RENT	$19,593		
		AVG GROSS RENT	
		$24.35	
		$23.58	(6 YRS 8 MTHS)

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ALTERNATIVE 4

Client: ***Algonquin Power Systems Inc.***

Address: ***2020 Winston Park Drive***

LEASE DESCRIPTION

10 year lease alternative commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$20.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$190,000

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500	9,500
Base Rent (Yr)	$12.53	$12.53	$12.53	$12.53	$12.53	$14.03	$14.03	$14.03	$14.03	$14.03
Tenant Imp. (Yr)	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97
Net Rent (Yr)	$15.50	$15.50	$15.50	$15.50	$15.50	$17.00	$17.00	$17.00	$17.00	$17.00
Tax & Op. (Yr)	$8.50	$8.76	$9.02	$9.29	$9.57	$9.86	$10.16	$10.46	$10.77	$11.09
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR.7	YR. 8	YR. 9	YR. 10
Base Rent	$119,035	$119,035	$119,035	$119,035	$119,035	$133,285	$133,285	$133,285	$133,285	$133,285
Tenant Imp.	$28,215	$28,215	$28,215	$28,215	$28,215	$28,215	$28,215	$28,215	$28,215	$28,215
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$147,250	$147,250	$147,250	$147,250	$147,250	$161,500	$161,500	$161,500	$161,500	$161,500
Additional Rent	$80,750	$83,220	$85,690	$88,255	$90,915	$93,670	$96,520	$99,370	$102,315	$105,355
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$80,750	$83,220	$85,690	$88,255	$90,915	$93,670	$96,520	$99,370	$102,315	$105,355
Total Rent	$228,000	$230,470	$232,940	$235,505	$238,165	$255,170	$258,020	$260,870	$263,815	$266,855
PV of Total Rent	$219,237	$203,314	$188,526	$174,864	$162,238	$159,469	$147,936	$137,220	$127,311	$118,145
Monthly Cost	$19,000	$19,206	$19,412	$19,625	$19,847	$21,264	$21,502	$21,739	$21,985	$22,238
Cost/SF	$24.00	$24.26	$24.52	$24.79	$26.07	$26.86	$27.16	$27.46	$27.77	$28.09

	GROSS	NPV	
TOTAL RENT	$2,469,810	$1,638,261	
TOTAL RENT (6 YRS 8 MTHS)	$1,592,263	$1,206,272	
AVERAGE ANNUAL RENT	$246,981	NER	
		$13.12	
AVERAGE MONTHLY RENT	$20,582		
		AVG GROSS RENT	
		$25.64	
		$24.95	(6 YRS 8 MTHS)

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ALTERNATIVE 5

Client: ***Algonquin Power Systems Inc.***

Address: ***151 City Centre Drive***

LEASE DESCRIPTION

Direct lease with landlord on 7th floor commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	80	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	6.67	MONTHLY	0.72%			TOTAL	$237,500

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	8	0	0	0
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	0	0	0
Base Rent (Yr)	$12.09	$12.09	$12.09	$12.09	$12.09	$12.09	$12.09	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$4.91	$4.91	$4.91	$4.91	$4.91	$4.91	$4.91	$0.00	$0.00	$0.00
Net Rent (Yr)	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00
Tax & Op. (Yr)	$7.83	$8.06	$8.30	$8.55	$8.81	$9.07	$9.34	$0.00	$0.00	$0.00
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$114,855	$114,855	$114,855	$114,855	$114,855	$114,855	$76,570	$0	$0	$0
Tenant Imp.	$46,645	$46,645	$46,645	$46,645	$46,645	$46,645	$31,097	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$161,500	$161,500	$161,500	$161,500	$161,500	$161,500	$107,667	$0	$0	$0
Additional Rent	$74,385	$76,570	$78,850	$81,225	$83,695	$86,165	$59,153	$0	$0	$0
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$74,385	$76,570	$78,850	$81,225	$83,695	$86,165	$59,153	$0	$0	$0
Total Rent	$235,885	$238,070	$240,350	$242,725	$245,195	$247,665	$166,820	$0	$0	$0
PV of Total Rent	$226,819	$210,019	$194,523	$180,225	$167,026	$154,779	$97,013	$0	$0	$0
Monthly Cost	$19,657	$19,839	$20,029	$20,227	$20,433	$20,639	$20,853	$0	$0	$0
Cost/SF	$24.83	$25.06	$25.30	$25.55	$25.81	$26.07	$17.56	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$1,616,710	$1,230,404
AVERAGE ANNUAL RENT	$242,507	NER $12.09
AVERAGE MONTHLY RENT	$20,209	AVG GROSS RENT $25.45

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ALTERNATIVE 6

Client: ***Algonquin Power Systems Inc.***

Address: ***21 Four Seasons Place***

LEASE DESCRIPTION

Direct lease with landlord on 2nd floor commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	80	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	6.67	MONTHLY	0.72%			TOTAL	$237,500

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	8	0	0	0
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	0	0	0
Base Rent (Yr)	$7.09	$7.09	$7.09	$7.09	$7.09	$7.09	$7.09	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$4.91	$4.91	$4.91	$4.91	$4.91	$4.91	$4.91	$0.00	$0.00	$0.00
Net Rent (Yr)	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$12.00	$0.00	$0.00	$0.00
Tax & Op. (Yr)	$13.35	$13.75	$14.16	$14.58	$15.02	$15.47	$15.93	$0.00	$0.00	$0.00
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$67,355	$67,355	$67,355	$67,355	$67,355	$67,355	$44,903	$0	$0	$0
Tenant Imp.	$46,645	$46,645	$46,645	$46,645	$46,645	$46,645	$31,097	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$114,000	$114,000	$114,000	$114,000	$114,000	$114,000	$76,000	$0	$0	$0
Additional Rent	$126,825	$130,625	$134,520	$138,510	$142,690	$146,965	$100,890	$0	$0	$0
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$126,825	$130,625	$134,520	$138,510	$142,690	$146,965	$100,890	$0	$0	$0
Total Rent	$240,825	$244,625	$248,520	$252,510	$256,690	$260,965	$176,890	$0	$0	$0
PV of Total Rent	$231,569	$215,801	$201,135	$187,490	$174,857	$163,091	$102,870	$0	$0	$0
Monthly Cost	$20,069	$20,385	$20,710	$21,043	$21,391	$21,747	$22,111	$0	$0	$0
Cost/SF	$25.35	$25.75	$26.16	$26.58	$27.02	$27.47	$18.62	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$1,681,025	$1,276,813
AVERAGE ANNUAL RENT	$252,154	NER $7.09
AVERAGE MONTHLY RENT	$21,013	AVG GROSS RENT $26.41

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EXISTING LOCATION

Client: ***Algonquin Power Systems Inc.***

Address: ***2085 Hurontario Street***

LEASE DESCRIPTION

Existing landlord proposal commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS		
# OF MONTHS:	80	ANNUAL	9.00%	ANNUAL	3.00%		Area 1	Area 2
YEARS:	6.67	MONTHLY	0.72%			PER SQ. FT	$0.00	$9.00
						TOTAL	$0	$41,382

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	8	0	0	0
Area 1	6,044	6,044	6,044	6,044	6,044	6,044	6,044	0	0	0
Area 2	4,598	4,598	4,598	4,598	4,598	4,598	4,598	0	0	0
Area 1			Blended Base Rent							
Base Rent (Yr)	$10.40	$11.93	$15.00	$15.00	$15.00	$15.00	$15.00	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Rent (Yr)	$10.40	$11.93	$15.00	$15.00	$15.00	$15.00	$15.00	$0.00	$0.00	$0.00
Area 2										
Base Rent (Yr)	$13.23	$13.23	$13.23	$13.23	$13.23	$13.23	$13.23	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$1.77	$1.77	$1.77	$1.77	$1.77	$1.77	$1.77	$0.00	$0.00	$0.00
Net Rent (Yr)	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$15.00	$0.00	$0.00	$0.00
Tax & Op. (Yr)	$8.99	$9.26	$9.54	$9.83	$10.12	$10.42	$10.73	$0.00	$0.00	$0.00
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Area 1										
Base Rent	$62,858	$72,125	$90,660	$90,660	$90,660	$90,660	$60,440	$0	$0	$0
Tenant Imp.	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$62,858	$72,125	$90,660	$90,660	$90,660	$90,660	$60,440	$0	$0	$0
Area 2										
Base Rent	$60,832	$60,832	$60,832	$60,832	$60,832	$60,832	$40,554	$0	$0	$0
Tenant Imp.	$8,138	$8,138	$8,138	$8,138	$8,138	$8,138	$5,426	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$68,970	$68,970	$68,970	$68,970	$68,970	$68,970	$45,980	$0	$0	$0
Combined Net Rent	$131,828	$141,095	$159,630	$159,630	$159,630	$159,630	$106,420	$0	$0	$0
Additional Rent	$95,672	$98,545	$101,525	$104,611	$107,697	$110,890	$76,126	$0	$0	$0
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$95,672	$98,545	$101,525	$104,611	$107,697	$110,890	$76,126	$0	$0	$0
Total Rent	$227,499	$239,640	$261,155	$264,241	$267,327	$270,520	$182,546	$0	$0	$0
PV of Total Rent	$218,756	$211,404	$211,361	$196,201	$182,103	$169,062	$106,159	$0	$0	$0
Monthly Cost	$18,958	$19,970	$21,763	$22,020	$22,277	$22,543	$22,818	$0	$0	$0
Cost/SF	$21.38	$22.52	$24.54	$24.83	$25.12	$25.42	$17.15	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$1,712,927	$1,295,044
AVERAGE ANNUAL RENT	$256,939	NER *
AVERAGE MONTHLY RENT	$21,412	$13.44
		AVG GROSS RENT
		$23.91

* Net Effective Rent of Area 1 is $15.00 PSF for the extended term and $13.23 PSF for Area 2

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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* ALL ESTIMATES OF GROSS RENT CONTAINED HEREIN REFLECT THE IMPACT OF BILLS 106 AND 149, THE FAIR MUNICIPAL FINANCE ACT 1997 (INCL. BUS. TAXES).
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G:\Finance\Excel Categories Various\FINANCE\Algonquin Power Systems\[Alternative Analysis.xls]Residual Obligation

ALTERNATIVE 7

Client: ***Algonquin Power Systems Inc.***

Address: ***201 City Centre Drive***

LEASE DESCRIPTION

Direct lease with landlord on 2nd floor commencing December 1, 1999.

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	80	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	6.67	MONTHLY	0.72%			TOTAL	$237,500

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	8	0	0	0
Area	9,500	9,500	9,500	9,500	9,500	9,500	9,500	0	0	0
Base Rent (Yr)	$12.09	$12.09	$12.09	$12.09	$12.09	$12.09	$12.09	$0.00	$0.00	$0.00
Tenant Imp. (Yr)	$4.91	$4.91	$4.91	$4.91	$4.91	$4.91	$4.91	$0.00	$0.00	$0.00
Net Rent (Yr)	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$17.00	$0.00	$0.00	$0.00
Tax & Op. (Yr)	$11.87	$12.23	$12.60	$12.98	$13.37	$13.77	$14.18	$0.00	$0.00	$0.00
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$114,855	$114,855	$114,855	$114,855	$114,855	$114,855	$76,570	$0	$0	$0
Tenant Imp.	$46,645	$46,645	$46,645	$46,645	$46,645	$46,645	$31,097	$0	$0	$0
Free Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$161,500	$161,500	$161,500	$161,500	$161,500	$161,500	$107,667	$0	$0	$0
Additional Rent	$112,765	$116,185	$119,700	$123,310	$127,015	$130,815	$89,807	$0	$0	$0
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$112,765	$116,185	$119,700	$123,310	$127,015	$130,815	$89,807	$0	$0	$0
Total Rent	$274,265	$277,685	$281,200	$284,810	$288,515	$292,315	$197,473	$0	$0	$0
PV of Total Rent	$263,724	$244,966	$227,584	$211,473	$196,536	$182,683	$114,840	$0	$0	$0
Monthly Cost	$22,855	$23,140	$23,433	$23,734	$24,043	$24,360	$24,684	$0	$0	$0
Cost/SF	$28.87	$29.23	$29.60	$29.98	$30.37	$30.77	$20.79	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$1,896,263	$1,441,806
AVERAGE ANNUAL RENT	$284,440	NER $12.09
AVERAGE MONTHLY RENT	$23,703	AVG GROSS RENT $29.82

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G:\Finance\Excel Categories Various\FINANCE\Algonquin Power Systems\[Alternative Analysis.xls]Residual Obligation

RESIDUAL LEASE OBLIGATION

Client: ***Algonquin Power Systems Inc.***

Address: ***2085 Hurontario Street***

LEASE DESCRIPTION

Residual lease obligation from December 1, 1999 to July 31, 2001

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	20	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$0.00
YEARS:	1.67	MONTHLY	0.72%			TOTAL	$0

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	8	0	0	0	0	0	0	0	0
Area 1	6,044	6,044	0	0	0	0	0	0	0	0
Area 2	2,770	2,770	0	0	0	0	0	0	0	0
Net Rent - A1 (Yr)	$10.40	$10.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Rent - A2 (Yr)	$13.11	$13.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Additional Rent (Yr)	$8.99	$9.26	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Net Rent - A1	$62,858	$41,905	$0	$0	$0	$0	$0	$0	$0	$0
Net Rent - A2	$36,315	$24,210	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$99,172	$66,115	$0	$0	$0	$0	$0	$0	$0	$0
Additional Rent	$79,238	$54,412	$0	$0	$0	$0	$0	$0	$0	$0
Total Rent	$178,410	$120,527	$0	$0	$0	$0	$0	$0	$0	$0
PV of Total Rent	$171,553	$107,845	$0	$0	$0	$0	$0	$0	$0	$0
Monthly Cost	$14,868	$15,066	$0	$0	$0	$0	$0	$0	$0	$0
Cost/SF	$20.24	$13.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$298,937	$279,398
AVERAGE ANNUAL RENT	$179,362	AVG GROSS RENT $20.35
AVERAGE MONTHLY RENT	$14,947	

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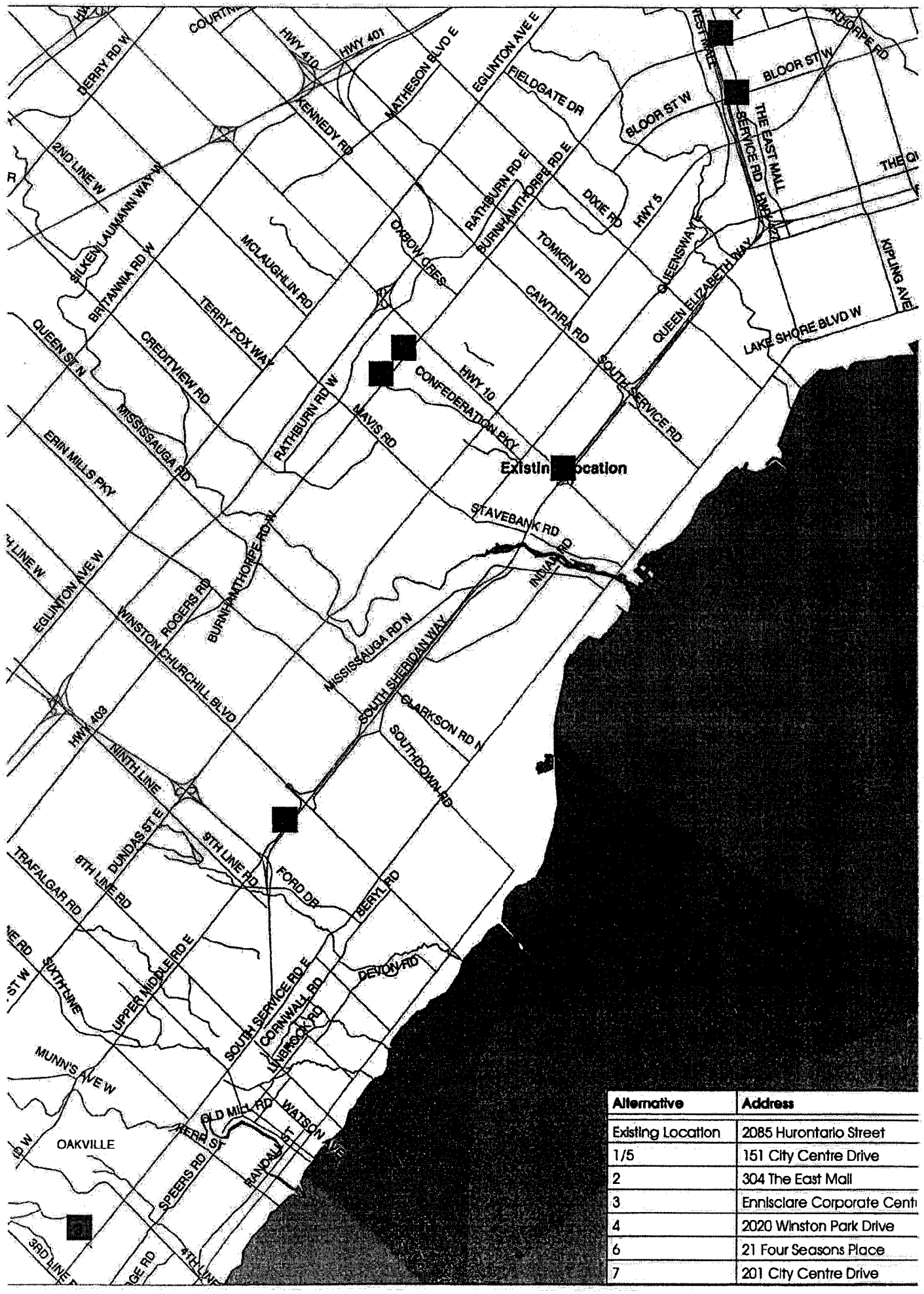
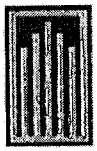
G:\Finance\Excel Categories Various\FINANCE\Algonquin Power Systems\[Alternative Analysis.xls]Residual Obligation



Alternative	Address
Existing Location	2085 Hurontario Street
1/5	151 City Centre Drive
2	304 The East Mall
3	Enniscare Corporate Centi
4	2020 Winston Park Drive
6	21 Four Seasons Place
7	201 City Centre Drive

Attachment 3

Survey of Available Space



LNR

Prepared for

Algonquin Power Systems Inc.

Mississauga

Prepared by

LNR Corporation, BROKER

Gary Hewitt

CORPORATE REAL ESTATE ADVISOR

10 • 19 • 99

objectives

LNR

Optimal Space Required:	Approx. 10,000 rentable SF
Geographic Area:	Close proximity to the QEW west of Hurontario Street
Lease Term:	Five to ten years
Rental Rate:	Market rent
Occupancy Date:	December 1, 1999 - September 2000
Parking Requirements:	Minimum of 3 spaces per 1,000 SF of rentable area
Image:	• Algonquin Power Systems Inc. is looking for a building of similar quality to its existing head office at 2085 Hurontario Street.
Other Criteria:	• Flexibility to expand if desired • Good access to major surface routes • Amenities within area of proposed alternative

survey summary

LNR

Address	Option	Area (SF)	Floor #	Approx Net Rental Rate Years 1-5	Est. Taxes & Op. Cost (1999)	Total Occupancy Costs
Existing Location						
2085 Hurontario Street		10,000	5	$17.22	$ 8.99	$26.21
Relocation Options						
2695 North Sheridan Way	1	10,000	1	$14.73	$11.95	$26.68
1235 North Service Road. West	2	10,000	4	$14.50	$ 8.07	$22.57
4145 North Service Road	3	10,000	3	$15.72	$ 7.95	$23.67
3027 Harvester Road	4	10,000	4	$10.47	$10.33	$20.80

10 yr. deal

10•19•99

option

LNR

2695 North Sheridan Way Mississauga, Ontario

Building Size	**55,000 SF**
Building Quality	**B+**
Completed	**1988**
Number of Floors	**3**
Floor Plate Size	**20,600 SF**

Details on Available Space

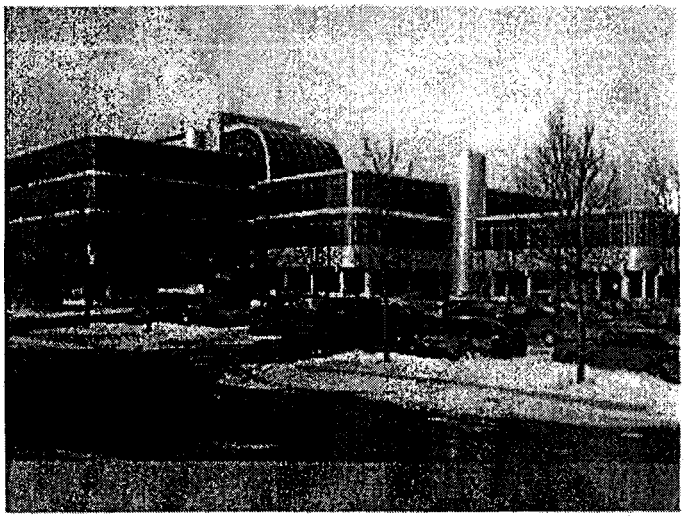
Space Available	**10,000 SF**
Floor Number	**1**
Offer Type	**Direct**
Term of Lease	**10 years**
Date Available	**Immediate**
Estimated Net Rent	**$14.73 years 1 to 5***
	$16.73 years 6 to 10*

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$11.95**

Total Occupancy Costs
(estimated)

$26.68



Location

- East of Winston Churchill Boulevard and the QEW

Comments

- *$15.00 PSF improvement allowance included in net rental rate
- Free surface parking available at 3 spaces per 1,000 SF leased
- Underground parking available at $40 per space per month

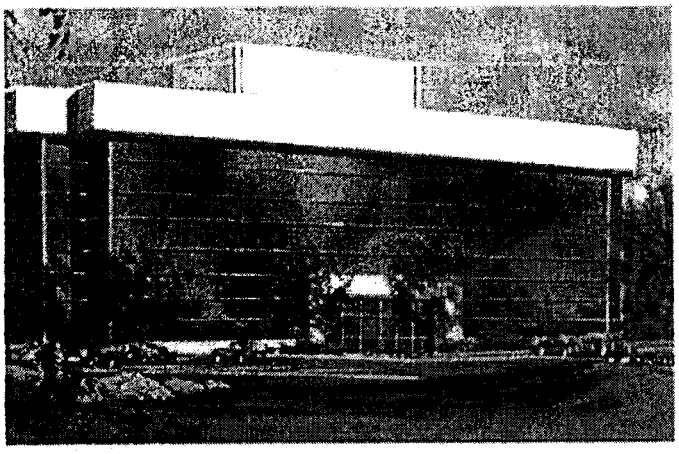
Further Details

- Low rise campus style building
- Park like setting
- Unit has seperate ground level entrance
- Good quality improvements in place
- Opportunity for corporate signage

option

LNR

1235 North Service Rd. W.
Ennisclare Corporate Centre
Phase II
Oakville, Ontario



Building Size	**80,000 SF**
Building Quality	**A**
Completed	**1999**
Number of Floors	**5**
Floor Plate Size	**16,400 SF**

Details on Available Space

Space Available	**10,000 SF**
Floor Number	**4**
Offer Type	**Direct**
Term of Lease	**10 years**
Date Available	**December 1, 1999**
Estimated Net Rent	**$14.50 years 1 to 5 ***
	$16.50 years 6 to 10*

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$8.07**

Total Occupancy Costs
(estimated 1999)

$22.57

Location

- West of Dorval Road and the QEW

Comments

- * $25.00 PSF improvement allowance included in net rental rate
- Building completed September of 1999
- Surface parking is available free of charge at a ratio of 4 spaces per 1,000 SF leased

Further Details

- On site building management
- Brand new building and systems
- First Class suburban office building
- Free rent period possible to offset existing lease obligation

(possibly 6 months)

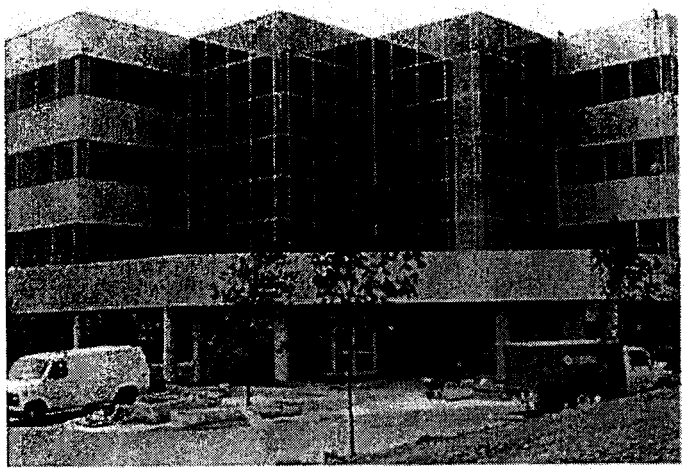
Owner

- Beutel Goodman Real Estate

option

LNR

4145 North Service Rd.
Burlington, Ontario



Building Size	**62,385 SF**
Building Quality	**B+**
Completed	**1991**
Number of Floors	**4**
Floor Plate Size	**15,952 SF**

Details on Available Space

Space Available	**10,000 SF (Approx.)**
Floor Number	**3**
Offer Type	**Sublet and Direct**
Term of Lease	**5 to 10 years**
Date Available	**Immediate**
Estimated Net Rent	**$15.72 years 1 to 5 ***
	$16.72 years 6 to 10*

Additional Costs
(estimated 1999)

Total Extra Costs	**$7.95**

Total Occupancy Costs
(estimated 1999)

$23.67

Location

- North Service Road east of Walkers Line

Comments

- * $25.00 PSF improvement allowance included in net rental rate
- Space has elevator exposure
- Numerous private offices
- Ample free surface parking

Further Details

- On site building management
- May be able to utilize some of the existing improvements in place
- Good access to QEW off Appleby or Walkers Line
- Free rent period possible to offset exising lease obligation

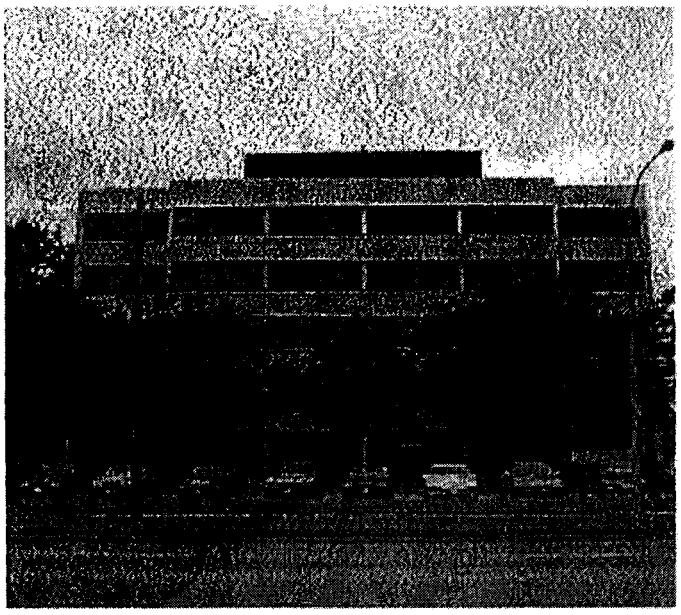
Owner

- O&Y Enterprises

option

LNR

3027 Harvester Rd.
Burlington, Ontario



Building Size	**60,000 SF**
Building Quality	**B-**
Completed	**1975**
Number of Floors	**5**
Floor Plate Size	**12,000 SF**

Details on Available Space

Space Available	**10,000 SF**
Floor Number	**4**
Contiguous SF	**2,000**
Offer Type	**Direct**
Term of Lease	**10 years**
Date Available	**Immediate**
Estimated Net Rent	**$10.47 years 1 to 5 ***
	$12.47 years 6 to 10*

Additional Costs
(estimated 1999)

Operating Costs	**Incl.**
Taxes	**Incl.**
Hydro	**Incl.**
Total Extra Costs	**$10.33**

Total Occupancy Costs
(estimated 1999)

$20.80

Location

- Harvester Road, south of the QEW near Guelph Line

Comments

- *$20.00 PSF improvement allowance included in net rental rate
- Free surface parking is available at a ratio of 5 spaces per 1,000 SF leased

Further Details

- Holiday Inn adjacent to subject property
- Numerous restaurants within walking distance
- Smaller floor plates offer full floor identity
- Quick access to QEW
- Free rent period possible to offset existing lease obligation

Owner

- Sun Life Assurance Company

19-Oct-99

Algonquin Power Systems Inc.
Financial Comparison of Options
Prepared By: LNR Corporation

	Existing Location	Option 1	Option 2
	New 10 year lease in existing building, assuming landlord can assemble 10,000 SF on 5th Floor commencing December 1, 1999	New 10 year lease on 1st Floor commencing December 1, 1999	New 10 year lease on 5th Floor commencing December 1, 1999
BUILDING	2085 Hurontario Street, 5th Floor	2695 North Sheridan Way, Suite 105	1235 North Service Road, Ennisclare II
TERM (Yrs)	10	10	10
TOTAL Rentable Square Footage	10,000	10,000	10,000
Net Rental Rates (PSF)			
Years 1-5	$17.22	$14.73	$14.50
Years 6-10	$19.22	$16.73	$16.50
Including Tenant Improvements (PSF	$25.00	$15.00	$25.00
Additional Rent (PSF)	$8.99	$11.95	$8.07
Net Effective Rent (PSF)	$14.20	$13.29	$11.57
Average Annual Gross Rent (PSF)	$28.10	$28.94	$25.01
CASH FLOW			
Year 1	$262,100	$266,800	$225,700
Year 2	$264,800	$270,400	$235,000
Year 3	$267,600	$274,100	$237,700
Year 4	$270,500	$277,900	$240,500
Year 5	$273,400	$281,800	$243,400
Year 6	$296,400	$305,800	$266,400
Year 7	$299,500	$310,000	$269,400
Year 8	$302,700	$314,300	$272,500
Year 9	$306,000	$318,700	$275,700
Year 10	$309,400	$323,200	$279,000
TOTAL GROSS RENT	$2,852,400	$2,943,000	$2,545,300
NPV OF GROSS RENT	$1,890,119	$1,946,291	$1,681,946

	Option 3	Option 4	
	New 10 year lease on 3rd Floor commencing December 1, 1999	New 10 year lease on 4th Floor commencing December 1, 1999	
BUILDING	4145 North Service Road	3027 Harvester Road, Hartford Life	
TERM (Yrs)	10	10	
TOTAL Rentable Square Footage	10,000	10,000	
Net Rental Rates (PSF)			
Years 1-5	$15.72	$10.47	
Years 6-10	$16.72	$12.47	
Including Tenant Improvements (PSF	$25.00	$20.00	
Additional Rent (PSF)	$7.95	$10.33	
Net Effective Rent (PSF)	$12.40	$8.28	
Average Annual Gross Rent (PSF)	$25.04	$22.86	
CASH FLOW			
Year 1	$236,700	$208,000	
Year 2	$239,100	$211,100	
Year 3	$241,600	$214,300	
Year 4	$244,100	$217,600	
Year 5	$246,700	$221,000	
Year 6	$259,400	$244,500	
Year 7	$262,200	$248,100	
Year 8	$265,100	$251,800	
Year 9	$268,000	$255,600	
Year 10	$271,000	$259,500	
TOTAL GROSS RENT	$2,533,900	$2,331,500	
NPV OF GROSS RENT	$1,684,564	$1,537,521	

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G:\Finance\Excel Categories Various\FINANCE\A99 Financial Services\[Conceptual Alternative Analysis.xls]Option 4(b)

Reduce rent - greatest cost on rent

EXISTING LOCATION

Client: ***Algonquin Power Systems Inc.***

Address: *2085 Hurontario Street, 5th Floor*

LEASE DESCRIPTION

New 10 year lease in existing building, assuming landlord can assemble 10,000 SF on 5th Floor commencing December 1, 1999

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$250,000

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Base Rent (Yr)	$13.50	$13.50	$13.50	$13.50	$13.50	$15.50	$15.50	$15.50	$15.50	$15.50
Tenant Imp. (Yr)	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72
Net Rent (Yr)	$17.22	$17.22	$17.22	$17.22	$17.22	$19.22	$19.22	$19.22	$19.22	$19.22
Tax & Op. (Yr)	$8.99	$9.26	$9.54	$9.83	$10.12	$10.42	$10.73	$11.05	$11.38	$11.72
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR.7	YR. 8	YR. 9	YR. 10
Base Rent	$135,000	$135,000	$135,000	$135,000	$135,000	$155,000	$155,000	$155,000	$155,000	$155,000
Tenant Imp.	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200
Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
...al Net Rent	$172,200	$172,200	$172,200	$172,200	$172,200	$192,200	$192,200	$192,200	$192,200	$192,200
Additional Rent	$89,900	$92,600	$95,400	$98,300	$101,200	$104,200	$107,300	$110,500	$113,800	$117,200
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$89,900	$92,600	$95,400	$98,300	$101,200	$104,200	$107,300	$110,500	$113,800	$117,200
Total Rent	$262,100	$264,800	$267,600	$270,500	$273,400	$296,400	$299,500	$302,700	$306,000	$309,400
PV of Total Rent	$252,027	$233,599	$216,577	$200,848	$186,240	$185,236	$171,719	$159,223	$147,669	$136,981
Monthly Cost	$21,842	$22,067	$22,300	$22,542	$22,783	$24,700	$24,958	$25,225	$25,500	$25,783
Cost/SF	$26.21	$26.48	$26.76	$27.05	$27.34	$29.64	$29.95	$30.27	$30.60	$30.94

	GROSS	NPV
TOTAL RENT	$2,852,400	$1,890,119
AVERAGE ANNUAL RENT	$285,240	
AVERAGE MONTHLY RENT	$23,770	
NET EFFECTIVE RENT (PSF)	$14.29	
AVERAGE GROSS RENT (PSF)	$28.10	

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
* PRESENT VALUE CALCULATIONS ARE BASED ON THE ASSUMPTION OF EQUAL MONTHLY RENTAL PAYMENTS WITHIN EACH YEAR (PERIOD).
* ALL ESTIMATES OF GROSS RENT CONTAINED HEREIN REFLECT THE IMPACT OF BILLS 106 AND 149, THE FAIR MUNICIPAL FINANCE ACT 1997 (INCL. BUS. TAXES).

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OPTION 1

Client: ***Algonquin Power Systems Inc.***

Address: *2695 North Sheridan Way, Suite 105*

LEASE DESCRIPTION

New 10 year lease on 1st Floor commencing December 1, 1999

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$15.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$150,000

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Base Rent (Yr)	$12.50	$12.50	$12.50	$12.50	$12.50	$14.50	$14.50	$14.50	$14.50	$14.50
Tenant Imp. (Yr)	$2.23	$2.23	$2.23	$2.23	$2.23	$2.23	$2.23	$2.23	$2.23	$2.23
Net Rent (Yr)	$14.73	$14.73	$14.73	$14.73	$14.73	$16.73	$16.73	$16.73	$16.73	$16.73
Tax & Op. (Yr)	$11.95	$12.31	$12.68	$13.06	$13.45	$13.85	$14.27	$14.70	$15.14	$15.59
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$125,000	$125,000	$125,000	$125,000	$125,000	$145,000	$145,000	$145,000	$145,000	$145,000
Tenant Imp.	$22,300	$22,300	$22,300	$22,300	$22,300	$22,300	$22,300	$22,300	$22,300	$22,300
Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$147,300	$147,300	$147,300	$147,300	$147,300	$167,300	$167,300	$167,300	$167,300	$167,300
Additional Rent	$119,500	$123,100	$126,800	$130,600	$134,500	$138,500	$142,700	$147,000	$151,400	$155,900
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$119,500	$123,100	$126,800	$130,600	$134,500	$138,500	$142,700	$147,000	$151,400	$155,900
Total Rent	$266,800	$270,400	$274,100	$277,900	$281,800	$305,800	$310,000	$314,300	$318,700	$323,200
PV of Total Rent	$256,546	$238,539	$221,838	$206,343	$191,962	$191,111	$177,739	$165,325	$153,798	$143,091
Monthly Cost	$22,233	$22,533	$22,842	$23,158	$23,483	$25,483	$25,833	$26,192	$26,558	$26,933
Cost/SF	$26.68	$27.04	$27.41	$27.79	$28.18	$30.58	$31.00	$31.43	$31.87	$32.32

	GROSS	NPV
TOTAL RENT	$2,943,000	$1,948,291
AVERAGE ANNUAL RENT	$294,300	
AVERAGE MONTHLY RENT	$24,525	
NET EFFECTIVE RENT (PSF)	$13.29	
AVERAGE GROSS RENT (PSF)	$28.94	

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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OPTION 2

Client: ***Algonquin Power Systems Inc.***

Address: ***1235 North Service Road, Ennisclare II***

LEASE DESCRIPTION

New 10 year lease on 5th Floor commencing December 1, 1999

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$250,000

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Base Rent (Yr)	$10.78	$10.78	$10.78	$10.78	$10.78	$12.78	$12.78	$12.78	$12.78	$12.78
Tenant Imp. (Yr)	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72
Net Rent (Yr)	$14.50	$14.50	$14.50	$14.50	$14.50	$16.50	$16.50	$16.50	$16.50	$16.50
Tax & Op. (Yr)	$8.07	$9.00	$9.27	$9.55	$9.84	$10.14	$10.44	$10.75	$11.07	$11.40
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR.7	YR. 8	YR. 9	YR. 10
Base Rent	$107,800	$107,800	$107,800	$107,800	$107,800	$127,800	$127,800	$127,800	$127,800	$127,800
Tenant Imp.	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200
[illegible]let Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
[illegible] Net Rent	$145,000	$145,000	$145,000	$145,000	$145,000	$165,000	$165,000	$165,000	$165,000	$165,000
Additional Rent	$80,700	$90,000	$92,700	$95,500	$98,400	$101,400	$104,400	$107,500	$110,700	$114,000
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$80,700	$90,000	$92,700	$95,500	$98,400	$101,400	$104,400	$107,500	$110,700	$114,000
Total Rent	$225,700	$235,000	$237,700	$240,500	$243,400	$266,400	$269,400	$272,500	$275,700	$279,000
PV of Total Rent	$217,026	$207,310	$192,378	$178,573	$165,804	$166,487	$154,461	$143,338	$133,047	$123,522
Monthly Cost	$18,808	$19,583	$19,808	$20,042	$20,283	$22,200	$22,450	$22,708	$22,975	$23,250
Cost/SF	$22.57	$23.50	$23.77	$24.05	$24.34	$26.64	$26.94	$27.25	$27.57	$27.90

	GROSS	NPV
TOTAL RENT	$2,545,300	$1,681,946
AVERAGE ANNUAL RENT	$254,530	
AVERAGE MONTHLY RENT	$21,211	
NET EFFECTIVE RENT (PSF)	$11.57	
AVERAGE GROSS RENT (PSF)	$25.01	

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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OPTION 3

Client: ***Algonquin Power Systems Inc.***

Address: ***4145 North Service Road***

LEASE DESCRIPTION

New 10 year lease on 3rd Floor commencing December 1, 1999

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$25.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$250,000

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Base Rent (Yr)	$12.00	$12.00	$12.00	$12.00	$12.00	$13.00	$13.00	$13.00	$13.00	$13.00
Tenant Imp. (Yr)	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72	$3.72
Net Rent (Yr)	$15.72	$15.72	$15.72	$15.72	$15.72	$16.72	$16.72	$16.72	$16.72	$16.72
Tax & Op. (Yr)	$7.95	$8.19	$8.44	$8.69	$8.95	$9.22	$9.50	$9.79	$10.08	$10.38
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$120,000	$120,000	$120,000	$120,000	$120,000	$130,000	$130,000	$130,000	$130,000	$130,000
Tenant Imp.	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200	$37,200
Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$157,200	$157,200	$157,200	$157,200	$157,200	$167,200	$167,200	$167,200	$167,200	$167,200
Additional Rent	$79,500	$81,900	$84,400	$86,900	$89,500	$92,200	$95,000	$97,900	$100,800	$103,800
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$79,500	$81,900	$84,400	$86,900	$89,500	$92,200	$95,000	$97,900	$100,800	$103,800
Total Rent	$236,700	$239,100	$241,600	$244,100	$246,700	$259,400	$262,200	$265,100	$268,000	$271,000
PV of Total Rent	$227,603	$210,927	$195,535	$181,246	$168,052	$162,113	$150,333	$139,445	$129,331	$119,980
Monthly Cost	$19,725	$19,925	$20,133	$20,342	$20,558	$21,617	$21,850	$22,092	$22,333	$22,583
Cost/SF	$23.67	$23.91	$24.16	$24.41	$24.67	$25.94	$26.22	$26.51	$26.80	$27.10

	GROSS	NPV
TOTAL RENT	$2,533,900	$1,684,564
AVERAGE ANNUAL RENT	$253,390	
AVERAGE MONTHLY RENT	$21,116	
NET EFFECTIVE RENT (PSF)	$12.40	
AVERAGE GROSS RENT (PSF)	$25.04	

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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OPTION 4

Client: ***Algonquin Power Systems Inc.***

Address: ***3027 Harvester Road, Hartford Life***

LEASE DESCRIPTION

New 10 year lease on 4th Floor commencing December 1, 1999

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	120	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$20.00
YEARS:	10.00	MONTHLY	0.72%			TOTAL	$200,000

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	12	12	12	12	12	12	12	12	12
Area	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000	10,000
Base Rent (Yr)	$7.50	$7.50	$7.50	$7.50	$7.50	$9.50	$9.50	$9.50	$9.50	$9.50
Tenant Imp. (Yr)	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97	$2.97
Net Rent (Yr)	$10.47	$10.47	$10.47	$10.47	$10.47	$12.47	$12.47	$12.47	$12.47	$12.47
Tax & Op. (Yr)	$10.33	$10.64	$10.96	$11.29	$11.63	$11.98	$12.34	$12.71	$13.09	$13.48
Free Net Rent (Mths)	0	0	0	0	0	0	0	0	0	0
Free Add. Rent (Mths)	0	0	0	0	0	0	0	0	0	0

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR. 7	YR. 8	YR. 9	YR. 10
Base Rent	$75,000	$75,000	$75,000	$75,000	$75,000	$95,000	$95,000	$95,000	$95,000	$95,000
Tenant Imp.	$29,700	$29,700	$29,700	$29,700	$29,700	$29,700	$29,700	$29,700	$29,700	$29,700
Net Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$104,700	$104,700	$104,700	$104,700	$104,700	$124,700	$124,700	$124,700	$124,700	$124,700
Additional Rent	$103,300	$106,400	$109,600	$112,900	$116,300	$119,800	$123,400	$127,100	$130,900	$134,800
Free Add. Rent	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Add. Rent	$103,300	$106,400	$109,600	$112,900	$116,300	$119,800	$123,400	$127,100	$130,900	$134,800
Total Rent	$208,000	$211,100	$214,300	$217,600	$221,000	$244,500	$248,100	$251,800	$255,600	$259,500
PV of Total Rent	$200,006	$186,226	$173,440	$161,569	$150,545	$152,801	$142,248	$132,449	$123,347	$114,889
Monthly Cost	$17,333	$17,592	$17,858	$18,133	$18,417	$20,375	$20,675	$20,983	$21,300	$21,625
Cost/SF	$20.80	$21.11	$21.43	$21.76	$22.10	$24.45	$24.81	$25.18	$25.56	$25.95

	GROSS	NPV
TOTAL RENT	$2,331,500	$1,537,521
AVERAGE ANNUAL RENT	$233,150	
AVERAGE MONTHLY RENT	$19,429	
NET EFFECTIVE RENT (PSF)	$8.28	
AVERAGE GROSS RENT (PSF)	$22.86	

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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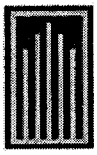
residual lease obligation



LNR

Effective December 1, 1999 Algonquin Power Systems Inc.'s remaining lease obligation would be $298,937 (as per accompanying spreadsheet).

The two most viable alternatives to minimize the impact of this obligation on a relocation are as follows:

1 Sublet existing premises and negotiate a free rent period with a future landlord to offset the portion of rent not recovered from the sublet;

2 Negotiate a lease buyout with the current landlord and obtain the equivalent value in free rent from a future landlord.

10•19•99

RESIDUAL LEASE OBLIGATION

Client: ***Algonquin Power Systems Inc.***

Address: ***2085 Hurontario Street***

LEASE DESCRIPTION

Residual lease obligation from December 1, 1999 to July 31, 2001

ASSUMPTIONS TABLE

TERM		DISCOUNT RATE		T&O ESC %		TENANT IMPROVEMENTS	
# OF MONTHS:	20	ANNUAL	9.00%	ANNUAL	3.00%	PER SQ. FT	$0.00
YEARS:	1.67	MONTHLY	0.72%			TOTAL	$0

	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 8	Year 9	Year 10
# OF MONTHS:	12	8	0	0	0	0	0	0	0	0
Area 1	6,044	6,044	0	0	0	0	0	0	0	0
Area 2	2,770	2,770	0	0	0	0	0	0	0	0
Net Rent - A1 (Yr)	$10.40	$10.40	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Net Rent - A2 (Yr)	$13.11	$13.11	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Additional Rent (Yr)	$8.99	$9.26	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

CASHFLOW ANALYSIS

	YR. 1	YR. 2	YR. 3	YR. 4	YR. 5	YR. 6	YR.7	YR. 8	YR. 9	YR. 10
Net Rent - A1	$62,858	$41,905	$0	$0	$0	$0	$0	$0	$0	$0
Net Rent - A2	$36,315	$24,210	$0	$0	$0	$0	$0	$0	$0	$0
Total Net Rent	$99,172	$66,115	$0	$0	$0	$0	$0	$0	$0	$0
Additional Rent	$79,238	$54,412	$0	$0	$0	$0	$0	$0	$0	$0
Total Rent	$178,410	$120,527	$0	$0	$0	$0	$0	$0	$0	$0
PV of Total Rent	$171,553	$107,845	$0	$0	$0	$0	$0	$0	$0	$0
Monthly Cost	$14,868	$15,066	$0	$0	$0	$0	$0	$0	$0	$0
Cost/SF	$20.24	$13.67	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00

	GROSS	NPV
TOTAL RENT	$298,937	$279,398
AVERAGE ANNUAL RENT	$179,362	
AVERAGE MONTHLY RENT	$14,947	
AVERAGE GROSS RENT (PSF)	$20.35	

* REALTY TAXES & OPERATING COSTS ARE BASED ON ESTIMATED 1999 RATES PSF PER YR, ESCALATING AT 3% PER ANNUM.
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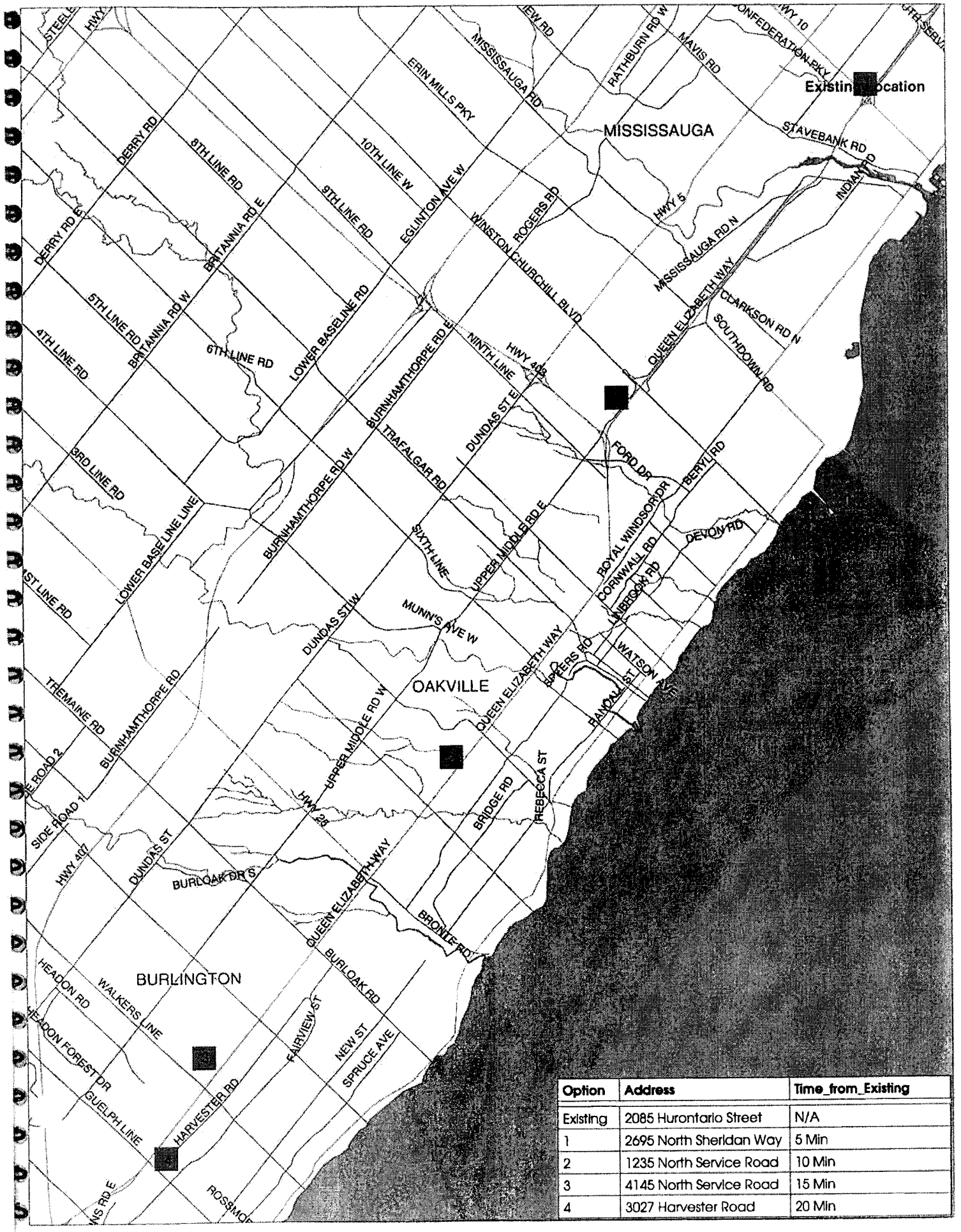
At least $130,000 return

Option to sell lease back i.e. 5 months



Option	Address	Time_from_Existing
Existing	2085 Hurontario Street	N/A
1	2695 North Sheridan Way	5 Min
2	1235 North Service Road	10 Min
3	4145 North Service Road	15 Min
4	3027 Harvester Road	20 Min

ALGONQUIN POWER
Management Inc.

MEMORANDUM

TO: File
Algonquin Power Income Fund

FROM: Chris Jarratt
Direct Line: 905-465-4513 Facsimile: 905-465-4540
Email: Chris. Jarratt@AlgonquinPower.com

DATE: 2 June, 2010

RE: Lease of 2845 Bristol Circle Street

SENT BY:

The purpose of this memorandum is to summarize the background information relating to the above noted lease arrangement.

Between the summer of 1990 and December 1, 2001, the Algonquin group of companies leased space at 2085 Hurontario Street (Mississauga). Originally, Algonquin leased approximately 2500 ft2 of space on the second floor. Due to growth of the company, this original space requirement was increased incrementally to 9370 ft2, located in 3 separate offices on 3 separate floors at the 2085 Hurontario Street premises.

As the Algonquin group of companies grew, the primary occupant of the leased space became Algonquin Power Systems Inc. ("APS") as most of the employees of the Algonquin group were employees of this subsidiary company. In the summer of 1999, the President of APS (Bob Dodds) commenced a search for new leased space. The primary objective of the initiative was to obtain non fragmented office space as it was becoming increasingly difficult to function from 3 separate offices located on 3 separate floors of the building. Secondary objectives of the initiative were to secure a long term lease, find space which provided expansion potential, and to find a better maintained building (building maintenance at 2085 Hurontario Street had significantly deteriorated by the late 90's). The realty company of LNR were retained to assist Algonquin in this initiative.

On August 15, 1999, APS completed a questionnaire for LNR which described the existing and future of the company. The questionnaire was completed by Mark Unsworth of APS, and is attached in Attachment 1. The existing and expected future needs of the company were summarized as follows:

- Current number of employees 32, growing to 60 in 5 years
- Requirement to have all personnel on one floor or contiguous space
- Location of along QEW between Hwy 10 and Trafalgar Road
- Budget of $230,000 per year
- Lease term of between 5 and 10 years
- Approximately 10,000 ft2
- Possibility of expansion
- Modern, basic premises

On September 28, 1999, LNR prepared a preliminary package which presented 7 options of available space which more or less fit their understanding of Algonquin's requirements (see Attachment 2). Of the 7 options presented, only 1 option was considered to be acceptable; 2020 Winston Park Drive. Due to the fact that the majority of Algonquin employees resided west of the then present location (Burlington/Oakville/Hamilton), the remaining options were discarded on the basis of unsatisfactory location. In general, the initial LNR effort was not well received by Algonquin, and LNR were tasked with finding more appropriate options.

On October 19, 1999, LNR presented the results of another package which presented 5 new options, including new space at the then present 2085 Hurontario premises (see Attachment 3). Notwithstanding the building maintenance deterioration concern which we had with 2085 Hurontario premises, the reduced disruption factor of staying in the same building warranted consideration of staying at the then current location. Of the 4 other options presented by LNR, only 1 (2695 North Sheridan Way) was considered to meet Algonquin's requirements. In addition, another property was brought to our attention by JJ Barnicke that met our needs. Accordingly, only 3 options were considered at the time to meet the needs

The following table summarizes the expected costs of the three feasible alternatives:

Location	Area (ft^2)	Net Rental Rate (years 1-5)	Estimated TIM (taxes, insurance & maintenance)	Additional Tennant Improvement	Total Occupancy Costs (years 1-5)
2085 Hurontario St	10,000	$17.22	$8.99		$26.21
2695 North Sheridan Way	10,000	$14.73	$11.95	$3.72 (note 1)	$28.17
90 Burnamthorpe Rd West	14,513	$16.50	$11.25	$2.33 (note 2)	$28.58 (note 3)
Average					$27.65

Note 1 – original quote only included $15 per sqft for tenant improvements. Increased to $25 per sqft to be consistant with requirements and other comparables)
Note 2 – Space was partially finished. Includes $15 per sqft for additional tenant improvements
Note 3 – Assumed that negotiated price would be 95% of "asking" price.

Based on the above market information, Algonquin Power Corporation elected to construct a building for its own purposes. The project was undertaken by Algonquin Property Limited Partnership and rent for the tenant (Algonquin Power Trust) was set at $19.75 per sqft for a 5 year term, plus Additional Rent (taxes, insurance and maintenance) estimated to be $9.00 per sqft. The total Occupancy Cost of $28.75 was approximately equal to the alternatives which were available at that time. In addition, the initiative to construct a custom building offered the following advantages:

1. "Custom" building which ideally suited the needs of the company
2. Excellent highway exposure to Highway 403
3. Expandable to 15,000 sq ft (initially, only 12,000 sqft were leased)
4. Optimum central location
5. Longer term lease (10 years) available

BELLA VISTA WATER COMPANY,
NORTHERN SUNRISE WATER COMPANY, INC.
&
SOUTHERN SUNRISE WATER COMPANY, INC.
WATER HOOK-UP FEE TARIFF

IV. Terms and Conditions

(B) Use of Off-Site Hook-up Fee: Off-site hook-up fees may only 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. Off-site hook-up fees shall not be used to cover repairs, maintenance, or operational costs. The Company shall not record amounts collected under this tariff as CIAC until such amounts have been expended for plant.

****

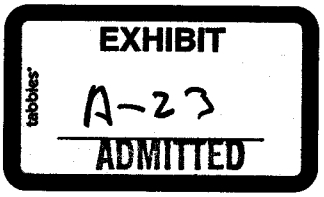
Uniform System of Accounts for Class A Water Utilities

Contributions in Aid of Construction

271. Contributions in Aid of Construction

A. This account shall include:

1. Any amount 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 or construction costs of the utility's property, facilities, or equipment used to provide utility services to the public.



BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF BELLA VISTA WATER CO., INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	DOCKET NO. W-02465A-09-0411
AND ALL RELATED MATTERS.	W-20453A-09-0412 W-20454A-09-0413 W-02465A-09-0414 W-20453A-09-0414 W-20454A-09-0414

At: Tucson, Arizona

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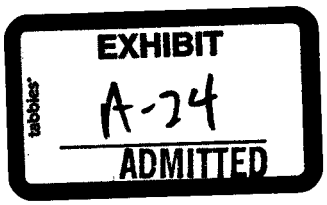

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By: COLETTE E. ROSS
Certified Reporter
Certificate No. 50658

Prepared for:

Q. You would agree that access to capital is a benefit to ratepayers?

A. Yes.

Q. And can you provide a citation to any finance authority, not the Commission's prior decisions, but any authority in the finance area that supports the use of book values in the Hamada equation?

A. I haven't seen any analysis on the Hamada methodology used in the regulatory setting.

MR. SHAPIRO: Thank you again.

And thank you.

THE WITNESS: Thank you.

ALJ RODDA: Okay, Ms. Ruht.

MS. RUHT: Okay.

REDIRECT EXAMINATION

BY MS. RUHT:

Q. Good afternoon again. My first question, to your knowledge have there been any significant changes on how the Arizona Commission regulates water utilities since the McLain and Bella Vista companies were purchased?

A. Not to my knowledge. Well, hold on just one second. I am uncertain to say when they were purchased exactly.

Q. 2002 for Bella Vista, 2006 for Northern and

Southern.

MR. SHAPIRO: I think '07 was the order in the McLain situation. I am not -- February 2007 was the purchase of the McLain assets.

BY MS. RUHT:

Q. Okay. Then since 2007.

A. No, no meaningful changes.

Q. And I know we just talked about this with Mr. Shapiro, but are there benefits to the utility having access to a capital market?

A. Yes.

Q. Okay. And Staff does expect the company with assets to the capital market to use those benefits, correct?

A. Definitely. And that's why we do a financial risk adjustment.

Q. And on the subject of financial risk adjustments, is the company's income tax rate a factor in determining the financial risk adjustment?

A. Yes, that is correct.

Q. So that the company, the company with, two companies with the same capital structure but with different tax rates might have different financial risk adjustments?

A. Correct. And, again, that's another moving

piece of what I was talking about. There is, you know, differences in beta, differences in the timing of the updated analysis. And tax rate is one of those moving pieces as well.

MS. RUHT: Okay. I have no further questions.

ALJ RODDA: Okay. Does anyone else have any questions while this witness is here?

MR. SHAPIRO: Yes.

ALJ RODDA: Ms. Wood, do you?

MS. WOOD: Yes, I do, actually, just one question.

ALJ RODDA: Okay. Why don't you go first.

RECROSS-EXAMINATION

BY MS. WOOD:

Q. I know there has been considerable discussion about the book value for your Hamada adjustment, correct?

A. Yes.

Q. Isn't it true that Mr. Bourassa used book value and market value in his financial risk assessment? He did the same thing, didn't he?

MR. SHAPIRO: I am sorry. Could I have that question read back, please.

(The record was read by the reporter as requested.)

BY MS. WOOD:

Q. And I actually -- yes, I can just turn you to his direct testimony, page 35, on cost of capital.

A. What exhibit is that? I am sorry.

MS. WOOD: I will need help there.

ALJ RODDA: Did you say direct?

MS. WOOD: Direct, I believe.

THE WITNESS: A-8, please.

MS. WOOD: 35. And the actual exhibit number?

MS. MITCHELL: 8.

ALJ RODDA: A-8.

MS. MITCHELL: That's for Bella Vista cost of capital, if that's the one you want.

MS. WOOD: Thank you.

MS. MITCHELL: Was there a separate one for Northern? A-8, page --

MS. WOOD: 35.

THE WITNESS: I am there.

BY MS. WOOD:

Q. On line 15 does he not say for the purposes of my analysis, I assume market value of debt is book value, correct?

A. Well, he is referring to the market value of debt. He uses the same book value of debt. He uses the book value of debt as his market value of debt, but he

uses the market value -- well, for as far as the equity is concerned, if my understanding is correct, he multiplies by the market to book ratio in the equity. So that's how.

But he uses, he uses the debt number for -- the book value for debt as his market value, and for equity he uses the book value multiplied by the market to book ratio, if I recall that well.

MS. WOOD: Okay. Thank you for that clarification.

ALJ RODDA: All right. Mr. Shapiro.

RECROSS-EXAMINATION

BY MR. SHAPIRO:

Q. So Mr. Bourassa, correct me if I am wrong, Mr. Bourassa didn't use book values in his Hamada, he used market values?

A. Well, but for the debt. That's, that's what I am -- for the debt portion all that -- well, I mean --

Q. Well, let me ask it this way. He is not criticizing you for using book values in Hamada when he did the exact same thing that he is criticizing you for?

A. Right.

Q. You do a different approach?

A. Right.

Q. Okay. And if Staff wants the company to use its access to the capital markets --

Which is what you said, correct?

A. Yes.

Q. -- then shouldn't the company be allowed to recover the costs of accessing the capital markets?

A. What precisely are you asking me?

Q. I am asking you: If the company has something that is a benefit to the ratepayers and it costs the company to provide that benefit, then the company should recover that cost, shouldn't it?

ALJ RODDA: Is this part of his testimony or is this to the cost allocation?

MR. SHAPIRO: He was just asked by Staff counsel if Staff wants the company to use access to capital markets.

ALJ RODDA: No, I understand that. I am just -- he just seemed like he was puzzled.

MR. SHAPIRO: I guess I am just asking his opinion to follow up that question.

ALJ RODDA: That's all I was asking.

MR. SHAPIRO: Thank you.

BY MR. SHAPIRO:

Q. If the company is spending money to provide something of benefit to its ratepayers, in your opinion

should the company be recovering the cost of providing that benefit?

A. I would have to -- well, I really don't know the particulars. I mean, what I can tell you is that -- were you going to say something?

Q. Well, I guess the particulars were the question you asked. You see it as a benefit that Algonquin, as the parent of these utilities, has access to the capital market, correct?

A. Correct.

Q. Okay. And Staff expects a company that has access to the capital markets to use that access to the benefit of its ratepayers?

A. Correct.

Q. If there is a cost to having that access, shouldn't that cost be part of the cost of service if it is a benefit to the ratepayers?

A. Well, you can see a company benefiting through a lesser financial risk adjustment if they -- if they benefit ratepayers by accessing the capital markets and getting access to debt, you would see a smaller financial risk adjustment.

Q. Right. But if it costs money for the utility to be able to obtain that access, if they have to pay money in order to be able to get to that capital, then that

should be part of the cost of service, no?

MS. RUHT: I'm going to object to that, because I think Mr. Shapiro is attempting to elicit an answer beyond the cost of capital. He is on the cost allocation issue, which Mr. Chaves is not a witness for.

MR. SHAPIRO: I guess my response would be then maybe the question that Ms. Ruht asked should be stricken as well, if I am not allowed to follow up on the very same question.

But if you can't answer it, that's fine.

ALJ RODDA: I am going to allow you to answer it to the extent you can. I don't recall your answer really.

THE WITNESS: Well, but my answer was that the company sees a benefit in a lesser financial risk adjustment. If they were to access the capital markets, you would see a higher cost of equity.

ALJ RODDA: So you are saying that they do get a benefit --

THE WITNESS: Right.

ALJ RODDA: -- by the adjustment you are making.

BY MR. SHAPIRO:

Q. The capital markets don't just provide debt financing; that's where you get equity financing, too, correct?

A. Yes, the capital markets is where you get equity and debt.

Q. And both of them are of benefit?

A. Yes.

MR. SHAPIRO: Thank you, Mr. Chaves.

Thank you, Judge Rodda.

ALJ RODDA: Okay. Did you have anything final, Ms. Ruht?

MS. RUHT: I have one last question, I hope.

FURTHER REDIRECT EXAMINATION

BY MS. RUHT:

Q. Do you see there being any concern with Mr. Bourassa's assumption of the market value of debt in calculating a market value Hamada adjustment?

A. Can you repeat the question?

Q. Yes.

A. Slowly, slower.

Q. I guess previously there was still a discussion between you and Ms. Wood, and this kind of stems from that. So is there a concern with Mr. Bourassa's assumption of the market value of debt in calculating a market value Hamada adjustment?

A. Well, it is very tough to be able to calculate the market value cost of debt, what --

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Prepared for:

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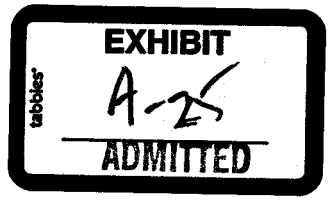

financing in order to achieve the needed infrastructure improvements.

Q. Okay. So rather than focusing on the infrastructure improvements, you think that they should have taken the time to look at the sample companies and their capital structures and figured out a way to make sure that Northern and Southern Sunrise had a compatible capital structure; that was a priority for you?

A. Well, I think that any company should look at that. I mean that's just good management. That's just good financial management.

Q. So what you are essentially doing is punishing the party that remedied the McLain mess by saying, well, thank you very much, but you should have put in debt, so now we are going to lower your ROE. Isn't that essentially what you are doing? That's the reward you are giving Liberty Water for fixing the McLain mess, right?

A. No, I am not. I meant, you know --

Q. There would be --

A. -- I will be the first to agree, I suppose, no good deed goes unpunished.

Q. Thank you.

A. But the fact of the matter is this is not punishing them. This is simply ensuring that the ratepayers get a fair and reasonable shake on this --

Q. You don't think the ratepayer -- I am sorry, go ahead.

A. -- yeah, that this company should have considered financing some of these improvements with lower cost debt --

Q. And you know that that --

A. -- which would be reflected in rates.

Q. How do you know that debt was even available to make these improvements, Mr. Rigsby?

A. Well, all I can say, Mr. Shapiro, is that Arizona-American is one of the larger water companies here in the state. Their parent actually has a lending subsidiary that issues --

Q. Excuse me, but this isn't Arizona-American, is it? This is Algonquin.

A. No, this is not Arizona-American. But this is, again, same thing, that we have a publicly -- a large publicly traded corporation who is the parent company that has access to the capital markets. They have access to the equity markets, they have access to debt markets. And even over the span of time they have acquired utility assets, and in financing those utility -- in acquiring those subsidiaries, they have used combinations of both debt and equity.

Q. But again, couldn't it be, couldn't a reasonable

and prudent plan be to get the improvements made and then go deal with how they are financed so there is no delays waiting for debt to be obtained and approved by the Commission? Because it does have to be approved, right; that takes time?

A. I am sure that -- well, given the fact that the Commission wanted to see these systems improved, I don't think there is much doubt in my mind that, had the company gone ahead and filed a financing agreement to have debt approved to finance improvements, I would think that the Commission would have gone ahead and expedited.

Q. Oh, Mr. Rigsby, you don't know that would have occurred; you are speculating, aren't you?

A. Perhaps I am speculating. But again, as you said, it was the --

Q. You were the witness --

A. -- Commission's desire.

ALJ RODDA: Sorry, you have to let him finish.

BY MR. SHAPIRO:

Q. You were the witness in the Arizona Water Company case, right?

MS. WOOD: Has he been allowed to answer?

MR. SHAPIRO: He pulled back so I thought he was done.

ALJ RODDA: I think we are just getting a little breather.

Mr. Rigsby, did you finish your last response?

THE WITNESS: Yeah. All I was trying to say was that I think, and again this is speculation on my part, I will concede it is speculation, but it was my understanding that getting these systems up and going and working the way they should was a high priority by the Commission, and it just seemed to me that, had the company come in, approached the Commission and said well, look, we would like to go ahead and get these infrastructure improvements in place and we would also like to finance some of it with debt, and so we are submitting a financing agreement and we would appreciate it if you would expedite the approval of it, so, again, just speculation on my part --

BY MR. SHAPIRO:

Q. Well, if you were the lender, would you loan Northern Sunrise money at the debt rate you are offering?

A. I may not -- okay. I may -- let me step up a second here.

If I were a lender, okay, I would not ignore the fact that this is a company that is a subsidiary of a very large corporate entity that has access to the capital markets. And again, as I say, I see no reason

why this large corporate entity couldn't have obtained debt at reasonable rates through the debt markets in order to provide financing for some of these improvements.

You know, we have got a company here in Arizona, Arizona Water, it is the second, I want to say it is the second largest water provider in the state. They routinely place debt issuance.

ALJ RODDA: Mr. Rigsby, just so I understand what you are saying --

THE WITNESS: Sure.

ALJ RODDA: -- you are saying is it the parent that's going to be borrowing the money under your scenario, or is it the subsidiary that the parent has to guarantee, or who?

THE WITNESS: What I am saying is that the corporate -- there is no reason, in my opinion, why the corporate entity can't obtain debt financing through, say, a bond issuance, perhaps.

ALJ RODDA: When you say the corporate entity, you mean Algonquin?

THE WITNESS: Algonquin, excuse me. I am sorry. Yeah, I am referring to the parent. It would be a situation like you have right now with Arizona-American. Their parent company is American Water Works. American

Water Works has their own lending subsidiary. What they do is they place debt issuance, they issue debt for their subsidiaries like Arizona-American and Pennsylvania-American and New Jersey-American and so forth.

ALJ RODDA: So the parent or a subsidiary of the parent is lending money to the affiliates?

THE WITNESS: The parent company, okay, would be obtaining debt through the capital markets, okay, to be used by the operating subsidiary.

ALJ RODDA: And then -- but that's not debt of the operating subsidiaries, is it, or is it somehow?

THE WITNESS: They would issue debt. Let's say they issue -- let's say if they want to issue debt for all of their Liberty Water subsidiaries, they could do that. And they could finance capital improvements from the proceeds that they obtained through the debt issuance. And so there could be, there would be an allocation of that among the various systems.

ALJ RODDA: So an allocation of the debt depending on the investment?

THE WITNESS: Yes. In other words, it would -- let's say, make it simple, let's say you have got five systems, and you need a million dollars in financing for each. Okay? So you are going to, say, issue debt

for -- let's say you issue a bond for $5 million, I am trying to keep this simple, $5 million. And so what -- let's say $5 million at 6 percent interest or whatever. And so the capital structure would reflect that, that, you know, a million dollars of plant was financed by debt at a cost of 6 percent.

ALJ RODDA: So I am just trying to relate, you know, what you are saying here to the situation with the improvement of the McLain systems.

THE WITNESS: It wouldn't necessarily have just been for the McLain systems. I mean the company, they have a number of operating subsidiaries here in the state, as Mr. Shapiro has noted. We are looking at Gold Canyon Sewer.

ALJ RODDA: We are talking now about this case.

THE WITNESS: Sure.

ALJ RODDA: And I just --

THE WITNESS: Sure.

ALJ RODDA: But does Algonquin, the parent, or whether some level of the structure has debt, they have --

THE WITNESS: They have issued debt.

ALJ RODDA: -- bonds?

THE WITNESS: They have financed certain acquisitions with debt, combination of debt and equity.

ALJ RODDA: But they just haven't allocated it down. I mean they could have financed some of these improvements from, you know, the parent could have issued debt and then put equity into these subsidiaries. You don't really know, or do you know where the equity --

THE WITNESS: All we know is the company, other than those operating subsidiaries that already had debt on their books when they acquired, when Algonquin acquired them, are the only ones, capital structure, with debt in it, in them. Okay? A number of others, Gold Canyon in particular, the Northern and Southern Sunrise systems, and I believe also Rio Rico, they are seeking 100 percent equity capital structure.

ALJ RODDA: Okay.

I am sorry, Mr. Shapiro.

MR. SHAPIRO: That's okay.

ALJ RODDA: I was just trying to understand.

BY MR. SHAPIRO:

Q. Well, let me follow up on that. You said that the parent company could guarantee debt. What do they get for putting their name on some subsidiary's debt and making them the guarantor? What is the advantage?

A. What do they get? Well, they get a lower cost method of financing capital improvements, and they get a

balanced capital structure out of that.

Q. And if the utility defaults, then they are responsible, right?

A. Are you talking -- you are talking about the operating, the Liberty Water operating subsidiaries?

Q. Yes.

A. Why -- there is always some risk of default, but it is typically, when you are looking at regulated utilities, there is not as much risk. I mean they have the ability to come in for rate relief when they need it. For the most, I mean their rates are regulated by the commissions, so for the most part they have relatively stable revenues as a result of that.

Q. So are you saying that it is the shareholder's obligation to guarantee debt, or that they should guarantee debt?

A. I am saying that the corporate parent should employ lower cost debt in order to finance capital improvements in order to achieve a balanced capital structure.

Q. But you are not saying if the subsidiary can't qualify for debt it is the obligation of the parent to either guarantee it or to be a lender, are you?

A. There is nothing different between that and the situation that you have with American Water with their

lending subsidiary.

Q. That's not the question, Mr. Rigsby. I am not talking Arizona-American, I am talking about this company. And I am asking whether it is your view that if the subsidiary cannot obtain debt on its own that the shareholder, I am asking you is the shareholder obligated, or are you simply testifying they should make sure that that subsidiary can get debt?

A. Okay. I don't think that an operating subsidiary that is owned by, again, a large publicly traded corporation that has access to the capital markets would have to obtain debt on its own. Its corporate parent could obtain debt for them.

Q. You are just speculating that's the case, though, right? You haven't determined whether Bella Vista, Northern Sunrise, Southern Sunrise could get debt on their own in this market?

A. I didn't mean to interrupt you, but Bella Vista has obtained debt on its own.

Q. When was that?

A. Bella Vista obtained debt under its previous ownership.

Q. That was some time ago, under different economic circumstances, right?

A. It may well have been, but there is always going

to be a need for debt financing.

Q. But again, there is no guarantee that the -- the person borrowing or the entity borrowing is the utility, not the parent, right?

A. Under the scenario that I have given you today, okay, again, I see no reason why a large publicly traded corporate entity that has access to the debt and equity markets cannot obtain debt financing for its operating subsidiaries. I can't make it any clearer than that.

Q. And how did you use -- well, how did you consider the risk of obtaining debt for your subsidiaries in your cost of capital analysis, or did you not?

A. The cost of debt that I recommended in this was derived from the costs of debt of other publicly traded water companies here in the U.S. that are followed by Value Line.

Q. That wasn't my question. My question was: The impact on the investor of facilitating debt, guaranteeing debt, making loans to its subsidiaries, that has an impact on its overall investment and its overall risk profile, doesn't it?

A. It does to a degree.

Q. And how --

A. But then it is no different from any other corporate entity out there that employs debt financing.

It has to go into the capital markets and obtain debt.

Q. Access to capital markets is a benefit that Algonquin brings to the table, correct?

A. Well, you folks have made that argument when it comes to equity capital, but it seems like we can't get over this hurdle on debt financing.

Q. But I am just talking generally. It is viewed, and you heard Staff say, that Algonquin has access to the capital markets, that's a benefit. Do you agree that access to capital markets for equity or debt financing is beneficial?

A. I would agree with that.

Q. And you would agree there is a cost to maintain that access to capital markets, correct?

A. I would agree with that.

Q. And that's the cost that largely is being disallowed by RUCO in this case and the other Liberty Water cases, correct?

A. I would not want to comment on that, because I was not specifically involved in those cost allocation issues.

Q. So you are the chief analyst at RUCO?

A. I am a public utilities analyst at RUCO.

Q. You are not the senior analyst?

A. I am acting as the chief of accounting, rates,

solutions

2009 ANNUAL REPORT

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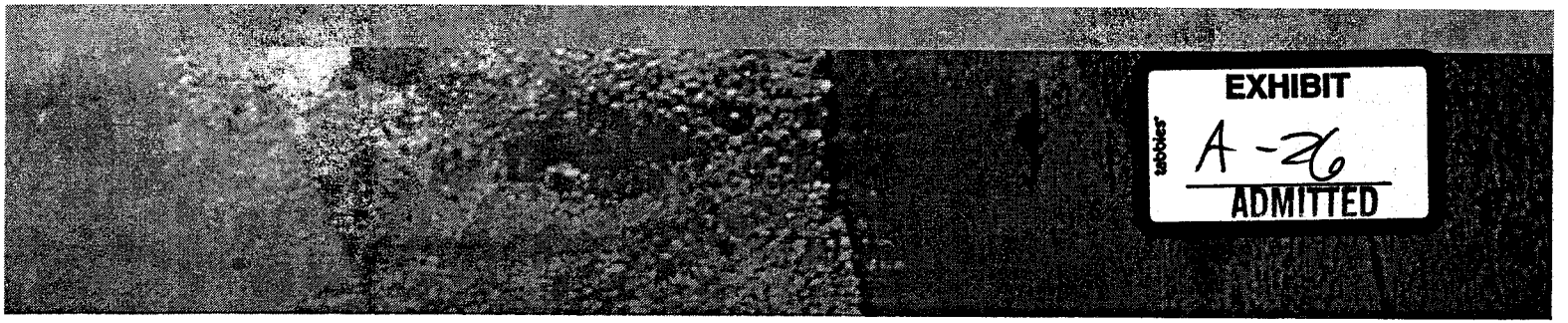


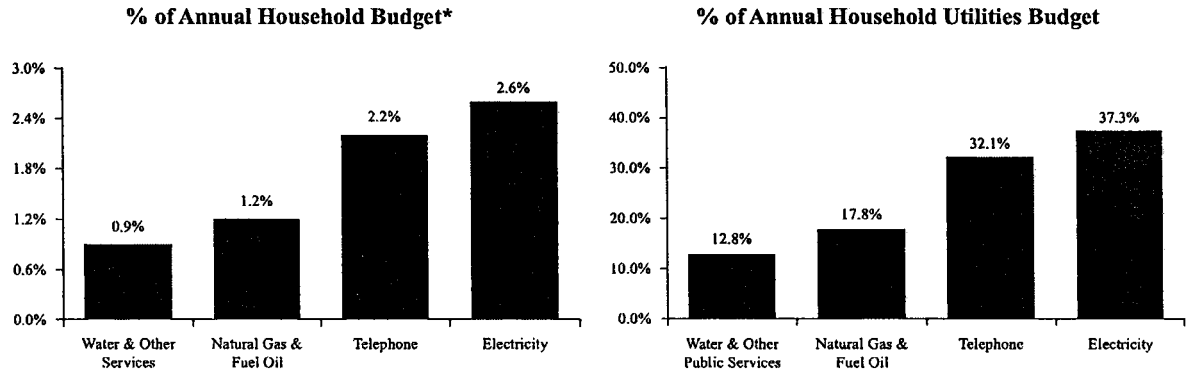
This large number of relatively small water and wastewater utilities results in inefficiencies in the marketplace, since smaller utilities may not have the operating expertise, financial and technological capability or economies of scale to provide services or raise capital as efficiently as larger utilities. These inefficiencies may lead to industry consolidation in the future, as the larger investor-owned utilities acquire smaller, local water and wastewater systems. Larger utilities that have greater access to capital are generally more capable of making mandated and other necessary infrastructure upgrades to both water and wastewater systems. In addition, water and wastewater utilities with large customer bases, spread across broad geographic regions, may more easily absorb the impact of adverse weather, such as droughts, excessive rain and cool temperatures in specific areas. Larger utilities generally are able to spread overhead expenses over a larger customer base, thereby reducing the costs to serve each customer. Since many administrative and support activities can be efficiently centralized to gain economies of scale and sharing of best practices, companies that participate in industry consolidation have the potential to improve operating efficiencies, lower unit costs and improve service at the same time.

Water and Wastewater Rates

Investor-owned water and wastewater utilities generate operating revenue from customers based on rates that are established by state PUCs through a rate-setting process that may include public hearings, evidentiary hearings and the submission by the utility of evidence and testimony in support of the requested level of rates. In evaluating a rate case, state PUCs typically focus on five areas: (i) the amount and prudence of investment in facilities considered "used and useful" in providing public service; (ii) the operating and maintenance costs and taxes associated with providing the service (typically by making reference to a representative 12-month period of time, known as a test year); (iii) the appropriate rate of return; (iv) the tariff or rate design that allocates operating revenue requirements equitably across the customer base; and (v) the quality of service the utility provides, including issues raised by customers.

For most consumers, water and wastewater bills make up a relatively small percentage of household expenditures compared to other utility services.

The following chart sets forth the relative cost of water in the United States as a percentage of total household utility expenditures:



* Source: Bureau of Labor Statistics-Consumer Expenditures Survey, 2007-2008 (assumes four person household).

Our Regulated Businesses

Our core Regulated Businesses, which consist of locally managed utility subsidiaries that generally are economically regulated by the states in which they operate, accounted for approximately 90.4% of our consolidated operating revenue in 2009. Our Regulated Businesses provide a high degree of financial stability because: (i) high barriers to entry provide limited protection from competitive pressures; (ii) economic regulation

Regulation

Economic Regulation

Our subsidiaries in the states in which we operate our Regulated Businesses are generally subject to extensive economic regulation by their respective state PUCs. The term "economic regulation" is intended to indicate that these state PUCs regulate the economic aspects of service to the public from systems that fall within their jurisdiction, but do not generally establish water quality standards, that are set by the EPA and/or state environmental authorities and enforced through state environmental or health agencies. State PUCs have broad authority (derived from state laws and state constitutions under which they operate) to regulate many of the economic aspects of the utilities that fall within their jurisdiction. For example, state PUCs issue certificates of public convenience and necessity (or similar authorizations) that may be required for a company to provide public utility services in specific areas of the state. They also must approve the rates and conditions under which service is provided to customers and have extensive authority to establish rules and regulations under which the utilities operate. Although specific authority might differ from state to state, in most states, these state PUCs must approve rates, accounting treatments, long-term financing programs, significant capital expenditures and plant additions, transactions between the regulated subsidiary and affiliated entities, reorganizations and mergers and acquisitions, in many instances prior to their completion. The jurisdiction exercised by each state PUC is prescribed by state laws and regulations and therefore varies from state to state. Regulatory policies not only vary from state to state, they may change over time. These policies will affect the timing as well as the extent of recovery of expenses and the realized return on invested capital.

Economic regulation of utilities deals with many competing, and occasionally conflicting, public interests and policy goals. The primary responsibility of state PUCs is to achieve the overall public interest by balancing the interests of customers and the utility and its stockholders. Although the specific approach to economic regulation does vary, certain general principles are consistent across the states in which our regulated subsidiaries operate. Based on the United States Constitution and state constitutions that prohibit confiscation of property without due process of law and just compensation, as well as state statutory provisions and court precedent, utilities are entitled to recover, through rates charged to customers, prudent and reasonable operating costs as well as an opportunity to earn an appropriate return on and recovery of our prudent, used and useful capital investment necessary to provide service to customers. The state PUCs will also generally accord a utility the right to serve specific areas and will also provide investor-owned utilities with limited protection from competition because the requirement of an investor-owned utility to operate pursuant to a certificate of public convenience and necessity (or similar authorizations) typically prevents other investor-owned utilities from competing with it in the authorized area. In return, the utility undertakes to provide reliable service on a nondiscriminatory basis to all customers within the authorized area.

Our operating revenue is typically determined by reference to a volumetric charge based on consumption and a base fee component set by a tariff approved by the relevant state PUC. Certain states have utilized a full or partial single rate policy, under which all customers in a state or certain regions within a state are charged utilizing a single rate structure, regardless of which of our individual systems serves them. The single tariff structure is based on costs that are determined on a state-wide or intra-state regional basis, thereby moderating the impact of periodic fluctuations in local costs while lowering administrative costs for us and our customers.

The process to obtain approval for a change in rates involves filing a petition or rate case with the state PUC on a periodic basis as determined by our capital expenditures needs and our operating costs. Rate cases are normally initiated by the regulated utility whenever the utility determines it needs to recover increased operating expenses or a return on new capital investment, or otherwise determines that its current authorized return is not sufficient, given current market conditions, to provide a reasonable return on investment. Typically a rate case will not be filed, however, unless the current or expected future return is below the allowed rate of return currently authorized by the regulator. A state PUC may also initiate a rate proceeding or investigation if it believes a utility may be earning in excess of its authorized rate of return. Rate cases often involve a lengthy and

costly administrative process. The utility, the state PUC staff, consumer advocates, and any other interveners who may participate in the process, prepare and file evidence, consisting of supporting testimony and documentation. This is presented in public hearings in connection with the rate case. These hearings, which are economic and service quality fact-finding in nature, are typically conducted in a trial-like setting before the state PUC or an administrative law judge. During the process, the utility is required to provide staff and interveners with all relevant information they may request concerning the utility's operations, expenses and investments. The sworn evidentiary record then forms the basis for a state PUC decision.

Some state PUCs are more restrictive than others with regard to the types of expenses and investments that may be recovered in rates as well as with regard to the transparency of their rate-making processes and how they reach their final rate determinations. However, in evaluating a rate case, state PUCs typically focus on five areas:

- the amount and prudence of investment in facilities considered "used and useful" in providing public service;
- the operating and maintenance costs and taxes associated with providing the service (typically by making reference to a representative 12-month period of time, known as a test year);
- the appropriate rate of return;
- the tariff or rate design that allocates revenue requirements equitably among the customer classes; and
- the quality of service the utility provides, including issues raised by customers.

The decisions of state PUCs and the timing of those decisions can have a significant impact on the operations and earnings of our Regulated Businesses. Rate cases and other rate-related proceedings can take several months to over a year to complete. Therefore, there is frequently a delay, or regulatory lag, between the time one of our regulated subsidiaries makes a capital investment or incurs an operating expense increase and when those costs are reflected in rates. For instance, an unexpected increase in chemical costs or new capital investment that is not appropriately reflected in the most recently completed rate case will generally not be recovered by the regulated subsidiary until the next rate case is filed and approved by the state PUC. Our rate case management program is guided by the goals of obtaining efficient recovery of costs of capital and utility operating and maintenance costs, including costs incurred for compliance with environmental regulations. The management team at each of our regulated subsidiaries anticipates the time required for the regulatory process and files a rate case with the goal of obtaining rates that reflect as closely as possible the cost of providing service at the time the rates become effective. Even if rates are sufficient, we face the risk that we will not achieve the rates of return on our invested capital and a return of our invested capital that are permitted by the state PUC.

Our regulated subsidiaries also pursue methods to minimize the adverse impact of regulatory lag and have worked with state PUCs and legislatures to implement a number of approaches to achieve this result. A number of states in which our Regulated Businesses operate have adopted efficient rate policies, including some form of single tariff pricing, forward-looking test years, pass-through provisions or infrastructure surcharges. States that have adopted a full or partially single tariff pricing policy include: Pennsylvania, New Jersey, West Virginia, Kentucky, Ohio, Indiana, Illinois and Iowa.

Forward-looking test years and infrastructure surcharges reduce the regulatory lag associated with the traditional method of recovering rates from state PUCs. Forward-looking test year mechanisms allow us to earn, on a more timely basis, a return of our current or projected costs and a rate of return on our current or projected invested capital and other "known and measurable changes" in our business. Some states have permitted use of a fully forecasted test year instead of historical data to set rates. Examples of these states include: Illinois, Kentucky, New York, Tennessee and California. In all states in which we operate on a regulated basis, PUCs have allowed utilities to update historical data for some changes that occur for some limited period of time

subsequent to the historical test year. This allows utilities to take account of some more current costs or capital investments in the rate-setting process. The extent to which historical data can be updated will generally vary from state to state and whether the changes are known and measurable.

Also, an increasing number of states are permitting rates to be adjusted outside of a general rate case for certain costs, such as a return on capital investments to replace aging infrastructure or increases in expenses beyond the utility's control, such as purchased water costs. This infrastructure surcharge mechanism allows our rates to be adjusted and charged to customers outside the context of a general rate proceeding for pre-specified portions of our capital expenditures to replace aging infrastructure closer to the time these capital projects are placed in service. For example, Pennsylvania, Illinois, Missouri, Indiana, New York, California and Ohio are examples of states that have in the past allowed tariffs that permit the imposition of surcharges on customers' bills for infrastructure replacement. New Jersey, California, Virginia and Illinois have allowed surcharges for purchased water costs. California has allowed surcharges for power and conservation, and New York has allowed surcharges for certain costs such as power and chemicals. These constructive regulatory mechanisms encourage us to maintain a steady capital expenditure program to repair and improve water and wastewater systems as needed by reducing the regulatory lag on the recovery of prudent expenditures.

Also, some of the states in which we operate permit pass-through provisions that allow for an increase in certain operating costs, such as purchased power and property taxes to be passed on to and recovered from customers outside of a general rate case proceeding.

Another regulatory mechanism to address issues of regulatory lag includes the potential ability, in certain circumstances, to recover in rates a return on utility plant before it is in service, instead of capitalizing an allowance for funds used during construction. Examples of states that have allowed such recovery include: Texas, Pennsylvania, Ohio, Kentucky, Virginia, Illinois and California.

In addition, some states have permitted us to seek pre-approval of certain capital projects and associated costs. In this pre-approval process, the PUCs assess the prudency of such projects.

Recently, the state of California has decoupled revenues from water sold. This progressive regulation enables utilities to focus on conservation as revenues are not tied to sales. Also, as a result of this regulation, utilities would be less susceptible to consumption changes as a result of weather conditions.

The ability of the Company to seek regulatory treatment as described above does not guarantee that the state PUCs will accept the Company's proposal in the context of a particular rate case. However, the Company strives to use these and other regulatory policies to address issues of regulatory lag wherever appropriate and to expand their use in areas where they may not currently apply.

Environmental, Health and Safety and Water Quality Regulation

Our water and wastewater operations are subject to extensive United States federal, state and local, and in the case of our Canadian operations, Canadian laws and regulations governing the protection of the environment, health and safety, the quality of the water we deliver to our customers, water allocation rights and the manner in which we collect, treat, discharge and dispose of wastewater. We are also subject to certain regulations regarding fire protection services in the areas we serve. These regulations include the Safe Drinking Water Act, the Clean Water Act and other federal, state, local and Canadian laws and regulations governing the provision of water and wastewater services, particularly with respect to the quality of water we distribute. We also are subject to various federal, state, local and Canadian laws and regulations governing the storage of hazardous materials, the management and disposal of hazardous and solid wastes, discharges to air and water, the cleanup of contaminated sites, dam safety and other matters relating to the protection of the environment and health and safety. State PUCs also set conditions and standards for the water and wastewater services we deliver.

While our business mix will continue to focus predominantly on regulated activities, we are pursuing opportunities in Non-Regulated Businesses that are complementary to our Regulated Businesses and our capabilities. Our Non-Regulated focus centers around public/private partnerships, including municipalities and divisions of the United States Department of Defense as well as industrial customers. We will continue to capitalize on our O&M expertise and our existing municipal and federal government relationships while building on our newly acquired subsidiary's (EMC) customer base in the industrial sector in identifying and bidding for new ventures that have attractive risk and return characteristics. We will also expand our Non-Regulated Homeowner Services business, which provides services to domestic homeowners to protect against the cost of repairing broken or leaking pipes inside and outside their homes, in areas within and beyond our existing regulated footprint and to small commercial establishments.

Research and Development

We established a formal research and development program in 1981 with the goal of improving water quality and operational effectiveness in all areas of our businesses. Our research and development personnel are located at two of our facilities: the regional center in Voorhees, New Jersey and our research laboratory in Delran, New Jersey. In addition, our quality control and testing laboratory in Belleville, Illinois supports research through sophisticated testing and analysis. Since its inception, our research and development program has evolved to become a leading water-related research program, achieving advancements in the science of drinking water, including sophisticated water testing procedures and desalination technologies.

Since the formation of the EPA in 1970, we have collaborated with the agency to achieve effective environmental, health and safety and water quality regulation. This relationship has developed to include sharing of our research and national water quality monitoring data in addition to our treatment and distribution system optimization research. Our engagement with the EPA has helped us to achieve a leadership position for our company within the water and wastewater industry and has provided us with early insight into emerging regulatory issues and initiatives; thereby allowing us to anticipate and to accommodate our future compliance requirements.

In 2009, we spent $2.75 million on research and development, which represents an increase of 10% over the $2.5 million spent in 2008. Approximately one-third of our research budget is comprised of competitively awarded outside research grants. Such grants reduce the cost of research and allow collaboration with leading national and international researchers.

We believe that continued research and development activities are critical to providing quality and reliable service at reasonable rates, maintaining our leadership position in the industry and will provide us with a competitive advantage as we seek additional business with new and existing customers.

Support Services

Our American Water Works Service Company subsidiary provides centrally administered professional services to our Regulated Businesses under the terms of contracts with these companies that have been approved by state PUCs, where necessary. These services, which are provided at cost, may include accounting, administration, business development, communications, corporate secretarial, engineering, financial, health and safety, human resources, information systems, legal, operations, procurement, rates, security, risk management, water quality and research and development. Similar services may be provided to our Non-Regulated Businesses. These arrangements afford our affiliated companies professional and technical talent on an economical and timely basis.

We operate two national customer service centers, with personnel located in Alton, Illinois and Pensacola, Florida. These centers employ approximately 700 people in total.

Production costs increased by $14.7 million, or 5.1%, for 2009 compared to 2008. Production costs by major expense type were as follows:

	For the Years Ended December 31,			
	2009	2008	Increase (Decrease)	Percentage
	(in thousands)			
Fuel and power	$108,578	$110,641	$ (2,063)	(1.9)%
Purchased water	97,966	95,253	2,713	2.8%
Chemicals	63,289	50,823	12,466	24.5%
Waste disposal	33,465	31,854	1,611	5.1%
Total	$303,298	$288,571	$14,727	5.1%

The decrease in fuel and power costs was primarily due to lower fuel prices in addition to the decreased water sales volumes partially offset by increased electric rates. Purchased water increased due to rate increases by our suppliers. The increase in chemical costs is due to rising prices for those commodities compared to the same period in the prior year.

Employee-related costs including wage and salary, group insurance, and pension expense increased $34.7 million, or 6.9%, for 2009 compared to 2008. These employee-related costs represented 40.8% and 38.8% of operation and maintenance expenses for 2009 and 2008, respectively.

	For the Years Ended December 31,			
	2009	2008	Increase (Decrease)	Percentage
	(in thousands)			
Salaries and wages	$391,074	$379,509	$11,565	3.0%
Pensions	50,392	39,315	11,077	28.2%
Group insurance	77,102	67,330	9,772	14.5%
Other benefits	21,657	19,396	2,261	11.7%
Total	$540,225	$505,550	$34,675	6.9%

Salaries and wages increased $5.8 million and $3.8 million in our Regulated and Non-Regulated Businesses, respectively. These increases primarily resulted from increased employee headcount as a result of enhancing customer service and merit wage rate increases partially offset by $4.3 million of wages related to job reclassification of certain hourly employees for services performed which was recorded in 2008 in addition to less expense for overtime worked in 2009. The increase in pension expense was primarily due to an increase in our Regulated Businesses' pension expense of $11.7 million, or 25.8%, for 2009 over 2008. This increase is mainly attributable to an increase in the amortization of actuarial losses attributable to lower than expected returns on plan assets in 2008 as a result of the decline in the economic environment. These market conditions are also the primary reason for the increase in costs for the other post employment benefits which are included in the group insurance amounts above. Medical benefit expenses, which are included in group insurance, for employees increased due to an increase in the number of employees and the rising cost of health care. Other benefits increased primarily as a result of increased salaries and wages which in turn resulted in increased Company contribution to the 401(k) and defined contribution plans. Also other benefit expenses increased due to the benefit expense related to the new employee stock purchase plan.

Operating supplies and services include the day-to-day expenses of office operation, legal and other professional services, as well as information systems and other office equipment rental charges. For 2009 these costs decreased by $34.7 million, or 12.3%, compared to 2008.

	For the Years Ended December 31,			
	2009	2008	Increase (Decrease)	Percentage
		(in thousands)		
Contracted services	$ 83,399	$111,847	$(28,448)	(25.4)%
Office supplies and services	63,134	63,422	(288)	(0.5)%
Transportation	32,240	36,337	(4,097)	(11.3)%
Rents	22,481	22,543	(62)	(0.3)%
Other	47,267	49,081	(1,814)	(3.7)%
Total	$248,521	$283,230	$(34,709)	(12.3)%

Contracted services decreased in 2009 compared to the same period in 2008. This decrease was primarily attributable to a decrease in contracted services in our Non-Regulated Businesses of $19.1 million in 2009 as compared to 2008, primarily as a result of a decreased level of activity for our design, build and operate project in Fillmore, California. Additionally, consulting fees associated with our remediation efforts to comply with the Sarbanes-Oxley Act of 2002 decreased $9.4 million. The decrease in transportation costs is due to lower gasoline prices, on average, in 2009 as compared to 2008. Other operating supplies and services decreased due to lower divestiture and initial public offering ("IPO") related costs. These costs totaled $1.9 million in 2009 compared to $12.4 million in 2008. Offsetting these decreases were 2009 condemnation costs of $2.4 million, the establishment of reserves for assets not recoverable at this time associated with the California rate case of $1.0 million, an increase in business development costs of $1.0 million and $1.5 million of profits included in our Non-Regulated Businesses' expenses in 2008 as a result of the finalization and acceptance by the third party related to construction projects. Also included is an adjustment of $3.4 million attributable to previously capitalized costs.

Maintenance materials and services, which include emergency repairs as well as costs for preventive maintenance, decreased $4.5 million, or by 3.3%, for 2009 compared to 2008.

	For the Years Ended December 31,			
	2009	2008	Increase (Decrease)	Percentage
		(in thousands)		
Maintenance services and supplies	$ 90,843	$ 94,790	$(3,947)	(4.2)%
Removal costs, net	40,938	41,515	(577)	(1.4)%
Total	$131,781	$136,305	$(4,524)	(3.3)%

Our Regulated Businesses' maintenance materials and service costs decreased by $1.2 million in 2009. In addition to the lower removal costs, the 2008 costs included $2.6 million associated with a program in Illinois to maintain valves and fire hydrants. Offsetting these decreases were additional costs incurred by our Arizona subsidiary attributable to a backbilling by the City of Glendale, Arizona for our pro rata share of sewer line maintenance amounting to $1.0 million as well as increased tank painting costs of $0.7 million in one of our operating subsidiaries. The Non-Regulated Businesses' maintenance and services expenses decreased by $3.3 million, mainly due to decreased Homeowner Services maintenance services and supplies due to favorable claims experience.

Customer billing and accounting expenses increased by $3.8 million, or 8.5%, for 2009 compared to 2008.

	For the Years Ended December 31,			
	2009	2008	Increase (Decrease)	Percentage
	(in thousands)			
Uncollectible accounts expense	$21,423	$20,298	$1,125	5.5%
Postage	12,600	11,829	771	6.5%
Other	13,745	11,885	1,860	15.6%
Total	$47,768	$44,012	$3,756	8.5%

The increase was primarily the result of higher uncollectible accounts expense in our Regulated Businesses of $2.7 million due to an unusually low balance in 2008 as the result of a collection effort in the first quarter of 2008 to collect previously written off accounts. Our overall 2009 write-off percentages and specific provisions for certain receivables, including a number of commercial and industrial customers that have filed for bankruptcy, increased in 2009 due the uncertainty of collectability, which we believe is attributable to the current economic environment. Our Non-Regulated Businesses' uncollectible expense decreased by $1.6 million primarily as a result of the collection of accounts previously written-off. The increase in the other category is mainly due to an increase in collection fees in our Regulated Businesses.

Other operation and maintenance expenses include casualty and liability insurance premiums and regulatory costs. These costs increased by $6.6 million, or 14.4%, for 2009 compared to 2008.

	For the Years Ended December 31,			
	2009	2008	Increase (Decrease)	Percentage
	(in thousands)			
Insurance	$37,410	$33,173	$4,237	12.8%
Regulatory expenses	15,352	12,957	2,395	18.5%
Total	$52,762	$46,130	$6,632	14.4%

Insurance expense increased due to less favorable claims experience in 2009 compared to 2008 in addition to higher general liability and property insurance premiums. Regulatory expenses increased in 2009 primarily as a result of a $3.5 million write-off of rate case expenses as well as $1.3 million of on-going rate case expenses associated with our California subsidiary; costs incurred in connection with the rate case appeal in our Tennessee subsidiary as well as increased amortization of costs related to final rate orders received in several states. Partially offsetting these increases were decreases associated with the write-off of deferred rate case expenses in Tennessee, Illinois, and Ohio in 2008 amounting to $3.2 million.

Depreciation and amortization. Depreciation and amortization expense increased by $23.0 million, or 8.5%, for 2009 compared to 2008. This increase was primarily due to additional assets placed in service, mainly in our Regulated Businesses, over the last year and a $2.4 million write-off of certain software costs.

General taxes. General taxes expense, which includes taxes for property, payroll, gross receipts, and other miscellaneous items, remained relatively unchanged, increasing by only $0.1 million or 0.1% in 2009 compared to 2008.

Gain on sale of assets. The gain on sale of assets was $0.8 million for 2009 compared to a gain of $0.4 million for 2008. The gains in 2009 and 2008 are primarily attributable to non-recurring sales of assets no longer used in our operations.

Impairment charge. The impairment charge was $450.0 million for 2009 compared to $750.0 million for 2008. The 2009 amount recorded included an impairment charge to goodwill of our Regulated Businesses in the amount of $448.2 million and our Non-Regulated Businesses of $1.8 million. The 2009 impairment charge, which was recorded in the first quarter of 2009, was primarily related to the high degree of stock market volatility experienced and as of March 31, 2009, the sustained period for which the Company's market price was below its carrying value. The 2008 impairment charge was primarily due to the market price of the Company's common stock (both the initial public offering price and the price during subsequent trading) being less than what was anticipated during our 2007 annual test. Also contributing to the impairment was a decline in the fair value of the Company's debt (due to increased interest rates). See "Factors Affecting Our Results of Operations—Goodwill Impairment."

Other income (deductions). Interest expense, net of interest income, the primary component of our other income (deductions), increased by $11.4 million, or 4.0%, for 2009 compared to 2008. The increase is primarily due to increased borrowings associated with capital expenditures. In addition, AFUDC decreased by $4.0 million in 2009 as compared to the same period in the prior year as a result of certain key projects being placed in-service. Other items contributing to the change include lower miscellaneous income for 2009 compared to 2008 primarily as a result of the change in market value of investments held for certain employees' elected deferred compensation.

Provision for income taxes. Our consolidated provision for income taxes increased $9.6 million, or 8.6%, to $121.4 million for 2009 from $111.8 million for 2008. The effective tax rates of (108.7%) and (24.8%) for 2009 and 2008, respectively, reflect the tax effects of the goodwill impairment charges as discrete items, as the Company considers these charges as infrequently occurring or unusual. In addition to the tax benefits associated with the goodwill impairment charges 2009 included tax benefits attributable to the impact of tax law changes as well as other discrete items. The Company's annual effective tax rate was 39.3 % and 39.8 % for 2009 and 2008, respectively, excluding the impact of the goodwill impairment charges and the various other discrete items.

Net loss. The net loss for 2009 was $233.1 million compared to a net loss of $562.4 million for 2008. The variation between the periods is the result of the aforementioned changes.

Comparison of Results of Operations for the Years Ended December 31, 2008 and 2007

Operating revenues. Our operating revenues increased by $122.7 million, or 5.5%, to $2,336.9 million for 2008 from $2,214.2 million for 2007. Regulated Businesses' revenues increased by $95.2 million, or 4.8%, for 2008 compared to 2007. The Non-Regulated Businesses' revenues for 2008 increased by $29.5 million, or 12.2%, from 2007.

The increase in the Regulated Businesses' revenues was primarily due to rate increases obtained through general rate cases totaling approximately $132.8 million as well as higher revenues resulting from surcharges of $4.5 million and from customer growth and acquisitions of approximately $3.3 million. This increase was offset by a $52.3 million decrease in revenues related to lower customer consumption, mainly in our states in the Midwestern region of the United States primarily due to the extremely wet weather conditions in those areas during 2008, as well as decreased usage in 2008 compared to 2007 in New Jersey and Pennsylvania mainly due to drier weather conditions in 2007.

Our Non-Regulated Businesses' operating revenues increased by $29.5 million, or 12.2%, to $272.2 million in 2008 from $242.7 for 2007. The net increase was primarily attributable to higher revenues in our Contract Operations Group and our Homeowner Services Group, partially offset by decreased revenues in our Applied Water Management Group and Canadian Fixed Residuals. The increase in Contract Operations Group revenues was primarily attributable to incremental revenues associated with design and build contracts, as well as increased military construction and O&M project revenues. The increase from our Homeowner Service Group

represented increased product penetration within its existing customer base. Applied Water Management Group revenues were lower than the prior year as a result of the decline in design and build activity resulting from the downturn in new home construction.

The following table sets forth the amounts and percentages of Regulated Businesses' revenues and water sales volume by customer class:

	For the Years Ended December 31,							
	2008		2007		2008		2007	
	Operating Revenues (dollars in thousands)				Water Sales Volume (gallons in millions)			
Customer Class								
Water service:								
Residential	$1,197,723	57.5%	$1,146,133	57.7%	214,045	52.9%	223,386	52.8%
Commercial	403,596	19.4%	385,272	19.4%	89,920	22.2%	93,010	22.0%
Industrial	101,769	4.9%	94,734	4.8%	42,032	10.4%	44,609	10.5%
Public and other	255,637	12.3%	247,578	12.4%	58,838	14.5%	62,299	14.7%
Other water revenues	44,157	2.1%	38,277	1.9%	—	—	—	—
Total water revenues	2,002,882	96.2%	1,911,994	96.2%	404,835	100.0%	423,304	100.0%
Wastewater service	79,858	3.8%	75,571	3.8%				
	$2,082,740	100.0%	$1,987,565	100.0%				

Water services—Water service operating revenues from residential customers for 2008 increased $51.6 million, or 4.5%, from 2007, primarily due to rate increases offset by a decrease in sales volume. The volume of water sold to residential customers decreased by 9.3 billion gallons, or 4.2%, from 2007, largely as a result of wetter weather conditions in California and the Midwestern region of the United States in 2008 and drier weather conditions in New Jersey and Pennsylvania in 2007.

Water service operating revenues from commercial water customers for 2008 increased by $18.3 million, or 4.8%, mainly due to rate increases offset by decreases in sales volume compared to 2007. The volume of water sold to commercial customers decreased by 3.1 billion gallons, or 3.3%, from 2007.

Water service operating revenues from industrial customers for 2008 increased $7.0 million, or 7.4%, from 2007 mainly due to rate increases, offset by decreased sales volume that we believe were caused by the downturn in the economy. The volume of water sold to industrial customers decreased 2.6 billion gallons, or 5.8%, from 2007.

Water service operating revenues from public and other customers increased $8.1 million, or 3.3%, from 2007 mainly due to rate increases. Revenues from municipal governments for fire protection services and customers requiring special private fire service facilities totaled $104.3 million for 2008, an increase of $5.0 million from 2007. Revenues generated by sales to governmental entities and resale customers for 2008 totaled $151.3 million, an increase of $3.1 million from 2007.

Wastewater services—Our subsidiaries provide wastewater services in 12 states. Revenues from these services for 2008 increased by $4.3 million, or 5.7%, from 2007. The increase was attributable to increases in rates charged to customers principally in Arizona, New Jersey and Pennsylvania.

Operation and maintenance. Operation and maintenance expense increased $57.3 million, or 4.6%, for 2008 compared to 2007.

over 2007. Pension expense in excess of the amount contributed to the pension plans is deferred by certain of our regulated subsidiaries pending future recovery in rates as contributions are made to the plans. Although our pension expense calculated in accordance with authoritative guidance remained relatively unchanged, pension expense increased for 2008 due to increased contributions by certain of our regulated operating companies whose costs are recovered based on the Company's funding policy, which is to fund at least the minimum amount required by the Employee Retirement Income Security Act of 1974 which we refer to as ERISA, rather than the calculated expense under the guidance. The increase in the contributions is attributable to a change in the discount rate and lower than expected returns on plan assets. Medical benefit expenses for employees increased due to an increase in the number of employees and the rising cost of health care. Other benefits increased primarily as a result of increased salaries and wages which in turn resulted in increased Company contribution to the 401(k) and defined contribution plans. Also other benefit expenses increased due to the benefit expense related to the new employee stock purchase plan.

Operating supplies and services include the day-to-day expenses of office operation, legal and other professional services, as well as information systems and other office equipment rental charges. For 2008, these costs decreased by $10.2 million, or 3.5%, compared to 2007.

	For the Years Ended December 31,			
	2008	2007	Increase (Decrease)	Percentage
	(in thousands)			
Contracted services	$111,847	$110,083	$ 1,764	1.6%
Office supplies and services	63,422	62,464	958	1.5%
Transportation	36,337	35,051	1,286	3.7%
Rents	22,543	21,985	558	2.5%
Other	49,081	63,892	(14,811)	(23.2)%
Total	$283,230	$293,475	($ 10,245)	(3.5)%

Contracted services increased in 2008 compared to the same period in 2007. This increase was primarily due to higher contracted services in our Contract Operations group in 2008 as compared to 2007, associated with several operating contracts (including a DBO project in Fillmore, California). Offsetting this increase were lower consulting fees associated with our remediation efforts to comply with Sarbanes-Oxley Act of 2002. These costs decreased by $22.6 million to $9.4 million in 2008 from $32.0 million in 2007. The increase in transportation costs is primarily the result of higher diesel and gasoline prices in 2008. Other operating supplies and services were lower in 2008 as 2007 costs were higher due to a write-off of certain deferred costs totaling $1.1 million by our New Jersey subsidiary as they were no longer deemed recoverable. Additionally, our Non-Regulated Businesses recorded loss contingencies of $3.6 million in 2007. Other decreases are associated with the cost of materials primarily related to our Contract Operations Group, due to changes in project work performed.

Maintenance materials and services, which include emergency repairs as well as costs for preventive maintenance, increased $8.3 million, or by 6.5%, for 2008 compared to 2007.

	For the Years Ended December 31,			
	2008	2007	Increase (Decrease)	Percentage
	(in thousands)			
Maintenance services and supplies	$ 94,790	$ 92,041	$2,749	3.0%
Removal costs, net	41,515	35,975	5,540	15.4%
Total	$136,305	$128,016	$8,289	6.5%

Our Regulated Businesses' maintenance materials and service costs increased by $6.8 million in 2008 mainly due to increased costs of $1.7 million associated with a program in Illinois to maintain valves and fire

hydrants, and higher cost of removal expenses of $5.5 million in certain of our operating companies, partially offset by lower paving costs of $1.4 million in our New Jersey and Missouri operating companies. The Non-Regulated Businesses' maintenance and services expenses increased by $1.7 million as a result of higher frequency of claims, primarily resulting from the increase in the number of customer contracts, with the service line protection program in our Homeowner Services Group, as well as from increased costs associated with the Contract Operations Group mainly due to costs associated with new military operations and maintenance projects.

Customer billing and accounting expenses increased by $5.8 million, or 15.0%, for 2008 compared to 2007.

	For the Years Ended December 31,			
	2008	2007	Increase (Decrease)	Percentage
	(in thousands)			
Uncollectible accounts expense	$20,298	$16,445	$3,853	23.4%
Postage	11,829	10,932	897	8.2%
Other	11,885	10,879	1,006	9.2%
Total	$44,012	$38,256	$5,756	15.0%

The increase was primarily the result of higher uncollectible accounts expense in our Regulated Businesses of $0.6 million and in our Non-Regulated Businesses of $3.7 million primarily due to increased uncollectible expense in the Applied Water Management Group of $1.8 million primarily due to the collection of $1.2 million in 2007 for an amount that was previously written-off as well as higher uncollectible expense in our Contract Operation Group. In addition, postage expense increased in our Regulated subsidiaries $0.9 million compared to 2007.

Other operation and maintenance expenses include casualty and liability insurance premiums and regulatory costs. These costs increased by $0.8 million, or 1.8%, for 2008 compared to 2007.

	For the Years Ended December 31,			
	2008	2007	Increase (Decrease)	Percentage
	(in thousands)			
Insurance	$33,173	$37,276	($4,103)	(11.0)%
Regulatory expenses	12,957	8,029	4,928	61.4%
Total	$46,130	$45,305	$ 825	1.8%

Insurance expense decreased due to more favorable claims experience in 2008 compared to 2007. Regulatory expenses increased primarily due to write-offs of deferred rate case expenses, primarily in Tennessee, Illinois, California, and Ohio as well as increased rate case amortization costs associated with rate cases settled in 2007.

Depreciation and amortization. Depreciation and amortization expense increased by $3.9 million, or 1.5%, for 2008 compared to 2007. This increase was primarily due to additional assets placed in service, mainly in our Regulated Businesses, over the last year.

General taxes. General taxes expense, which includes taxes for property, payroll, gross receipts, and other miscellaneous items, increased by $15.9 million, or 8.7%, in 2008 compared to 2007. This increase is primarily due to increased gross receipts taxes of $7.9 million primarily in New Jersey and Missouri and higher property tax expense of $4.2 million primarily in Ohio and Missouri. Additionally, payroll taxes increased by $2.7 million, due to increased salaries and wages and higher payroll tax limits.

Gain on sale of assets. The gain on sale of assets was $0.4 million for 2008 compared to a gain of $7.3 million for 2007. The gains in 2008 and 2007 are primarily attributable to non-recurring sales of assets no longer used in our operations.

TWILUX, an affiliate and wholly owned subsidiary of RWE, was the holder of $1,750,000 of the Company's preferred stock. Preferred dividends included in interest expense amounted to $0 in 2009 and 2008, and $74,569, in 2007, respectively. The preferred stock was redeemed in 2007 utilizing the proceeds from $1,750,000 in variable rate borrowings from RWE. The variable rate borrowings from RWE were subsequently redeemed with proceeds from the senior notes issuance. (See Note 11)

One of the Company's Directors is employed by an electrical utility that supplies electricity and electrical services to the Company's subsidiaries in Ohio, Pennsylvania, and New Jersey. The Company purchased, from various subsidiaries of this electrical utility, approximately $8,558 and $7,183 of such services in 2009 and 2008, respectively. This Director has announced his intended retirement from that electrical utility effective March 31, 2010.

Note 21: Discontinued Operations

In 2007, the Company completed the sale of its Residuals business for $9,660. There was no gain or loss recorded on the sale. Summarized results during 2007 of this business included operating revenues of $7,128, pre-tax loss of $636, and a tax benefit of $85, resulting in a loss from discontinued operations of $551. There were no assets or liabilities classified as discontinued operations in the accompanying Consolidated Balance Sheets at December 31, 2009 and 2008, respectively.

Note 22: Segment Information

The Company has two operating segments referred to as the Regulated Businesses and Non-Regulated Businesses segments. The Company's chief operating decision maker regularly reviews the operating results of the Regulated and Non-Regulated Businesses segments to assess segment performance and allocate resources. The evaluation of segment performance and the allocation of resources are based on several measures. The measure that is most consistent with that used by management is adjusted earnings before interest and income taxes from continuing operations ("Adjusted EBIT").

The Regulated Businesses segment includes the Company's 23 utility subsidiaries that provide water and wastewater services to customers in 20 U.S. states. With the exception of one company, each of these public utility subsidiaries is subject to regulation by public utility commissions and local governments. In addition to providing similar products and services and being subject to the public utility regulatory environment, each of the regulated subsidiaries has similar economic characteristics, production processes, types and classes of customers and water distribution or wastewater collection processes. Each of these companies is also subject to both federal and state regulation regarding the quality of water distributed and the discharge of wastewater residuals.

The Non-Regulated Businesses segment is comprised of non-regulated businesses that provide a broad range of non-regulated water and wastewater services and products including homeowner water and sewer line maintenance services, water and wastewater facility operations and maintenance services, granular carbon technologies and products for cleansing water and wastewater, wastewater residuals management services and water and wastewater facility engineering services.

The accounting policies of the segments are the same as those described in the summary of significant accounting policies (see Note 2). The Regulated and Non-Regulated Businesses segment information includes intercompany costs that are allocated by American Water Works Service Company, Inc. and intercompany interest that is charged by AWCC, which are eliminated to reconcile to the consolidated results of operations. Inter-segment revenues, which are primarily recorded at cost plus mark-up that approximates current market prices, include carbon regeneration services and leased office space, furniture and equipment provided by the Company's non-regulated subsidiaries to its regulated subsidiaries. Other includes corporate costs that are not allocated to the Company's subsidiaries, eliminations of inter-segment transactions, fair value adjustments and

associated income and deductions related to the Acquisitions that have not been allocated to the segments for evaluation of segment performance and allocation of resource purposes. The adjustments related to the Acquisitions are reported in Other, as they are excluded from segment performance measures evaluated by management. The following table includes the Company's summarized segment information:

	As of or for the Year Ended December 31, 2009			
	Regulated	Non-Regulated	Other	Consolidated
Net operating revenues	$ 2,207,290	$257,710	$ (24,297)	$ 2,440,703
Depreciation and amortization	272,462	5,871	15,907	294,240
Impairment charge	—	—	450,000	450,000
Total operating expenses, net	1,617,815	238,072	411,207	2,267,094
Adjusted EBIT(1)	591,606	21,264		
Total assets	11,659,525	247,594	1,545,532	13,452,651
Capital expenditures	779,428	5,837	—	785,265

	As of or for the Year Ended December 31, 2008			
	Regulated	Non-Regulated	Other	Consolidated
Net operating revenues	$ 2,082,740	$272,186	$ (17,998)	$ 2,336,928
Depreciation and amortization	254,803	5,858	10,600	271,261
Impairment charge	—	—	750,000	750,000
Total operating expenses, net	1,554,731	248,425	720,668	2,523,824
Adjusted EBIT(1)	531,774	26,307		
Total assets	10,941,133	244,891	2,045,794	13,231,818
Capital expenditures	1,005,360	3,446	—	1,008,806

	As of or for the Year Ended December 31, 2007			
	Regulated	Non-Regulated	Other	Consolidated
Net operating revenues	$ 1,987,565	$242,678	$ (16,028)	$ 2,214,215
Depreciation and amortization	254,998	10,295	2,042	267,335
Impairment charge	—	—	509,345	509,345
Total operating expenses, net	1,490,794	225,600	482,692	2,199,086
Adjusted EBIT(1)	500,088	23,579		
Total assets	10,180,482	280,692	2,490,153	12,951,327
Capital expenditures	738,824	11,986	—	750,810

(1) Management evaluates the performance of its segments and allocates resources based on several factors, of which the primary measure is Adjusted EBIT. Adjusted EBIT does not represent cash flow for periods presented and should not be considered as an alternative to net income as an indicator of the Company's operating performance or as an alternative to cash flows as a source of liquidity. Adjusted EBIT as defined by the Company may not be comparable with Adjusted EBIT as defined by other companies.

Arizona American Water Company - Agua Fria Water
Test Year Ended December 31, 2007
Adjusted Test Year Income Statement

Exhibit
Schedule C-1
Page 1
Witness: Hubbard

Line No.		[A] Test Year Book Results	[B] Total Pro Forma Adjustments	[C] Test Year Adjusted Results	[D] Proposed Rate Increase	[E] Adjusted with Rate Increase
1	Revenues					
2	Water Revenues	$ 16,648,743	$ 1,264,754	$ 17,913,497	$ 9,102,203	$ 27,105,699
3	Other Revenues	2,611,835	(1,605,718)	906,117		906,117
4						
5		$ 19,260,578	$ (241,065)	$ 18,819,613	$ 9,102,203	$ 28,010,816
6	Operating Expenses					
7	Labor	$ 1,342,803	$ 98,069	$ 1,440,877		$ 1,440,877
8	Purchased Water	899,344	2,123	901,467		901,467
9	Fuel & Power	1,790,845	163,667	1,954,515		1,954,515
10	Chemicals	191,424	930,131	1,121,555		1,121,555
11	Waste Disposal	(870)	-	(870)		(870)
12	Management Fees	2,768,348	9,256	2,775,604		2,775,604
13	Group Insurance	379,489	17,152	396,641		396,641
14	Pensions	191,116	49,297	240,413		240,413
15	Regulatory Expense	27,029	36,985	64,012		64,012
16	Insurance Other Than Group	158,153	-	158,153		158,153
17	Customer Accounting	364,298	6,510	370,808		370,808
18	Rents	63,217	-	63,217		63,217
19	General Office Expense	161,107	-	161,107		161,107
20	Miscellaneous	797,248	(8,281)	787,967	22,024	809,990
21	Maintenance Expense	183,519	437,819	891,338		891,338
22	Depreciation & Amortization	4,117,536	279,554	4,397,190		4,397,190
23	Taxes Other Than Income-Property Taxes	668,456	243,615	909,071	125,965	929,036
24	Taxes Other Than Income-Other	118,719	13,213	128,923		128,923
25	Income Taxes	(648,244)	509,488	(138,756)	3,490,954	3,352,198
26						
27	Total Operating Expenses	$ 13,426,416	$ 2,787,809	$ 16,217,326	$ 3,638,972	$ 19,856,296
28	Utility Operating Income	$ 5,831,162	$ (3,028,874)	$ 2,601,288	$ 5,463,230	$ 8,154,518
29	Other Income & Deductions					
30	Other Income & Deductions	743,094	(743,094)	-		-
31	Interest Expense	2,509,493	312,520	2,822,013		2,822,013
32	Other Expense	(1,034)	-	(1,034)		(1,034)
33	Gain/Loss Sale of Fixed Assets	251,993	-	251,993		251,993
34	Total Other Income & Deductions	$ (1,513,372)	$ (1,055,614)	$ (2,568,986)	$ -	$ (2,568,986)
35	Net Profit (Loss)	$ 4,117,790	$ (4,085,488)	$ 32,302	$ 5,463,230	$ 5,585,532
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UNIFORM SYSTEM OF ACCOUNTS FOR CLASS A WATER UTILITIES

1996

NATIONAL ASSOCIATION OF
REGULATORY UTILITY COMMISSIONERS
1201 Constitution Avenue, N.W., Suite 1102
Post Office Box 684
Washington, DC 20044-0684
Telephone No. (202) 898-2200
Facsimile No. (202) 898-2213

Price: $25.00

EXHIBIT
tabbies
A-28
ADMITTED

670. Bad Debt Expense

This account shall be charged with amounts sufficient to provide for losses from uncollectible utility revenues. Concurrent credits shall be made to account 143.

675. Miscellaneous Expenses

This account shall include all expenses not includible in other operating expenses accounts.

Items

1. Industry association dues for company memberships.
2. Contributions for conventions and meetings of the industry.
3. Communication service not chargeable to other accounts.
4. Trustee, registrar, and transfer agent fees and expenses.
5. Stockholders meeting expenses.
6. Dividend and other financial notices.
7. Printing and mailing dividend checks.
8. Director's fees and expenses.
9. Publishing and distributing annual reports to stockholders.
10. Public notices of financial, operating and other data required by regulatory statutes, not including, however, notices required in connection with security issues or acquisition of property.
11. Write off of expenditures for preliminary surveys, plans, investigations, etc., included in account 183 - Preliminary Survey and Investigation Charges, relative to projects which have been abandoned.

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As filed with the Securities and Exchange Commission on May 13, 2008
Registration No. 333-

UNITED STATES SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM S-1

REGISTRATION STATEMENT
UNDER
THE SECURITIES ACT OF 1933

GLOBAL WATER RESOURCES, INC.*

(Exact name of registrant as specified in its charter)

Delaware	4941	20-2545412
(State or other jurisdiction of Incorporation of organization)	(Primary Standard Industrial Classification Code Number)	(I.R.S. Employer Identification Number)

21410 N. 19th Avenue
Suite 201
Phoenix, AZ 85027
(623) 580-9600
(Address, including zip code, and telephone number, including area code, of registrant's principal executive offices)

Trevor T. Hill
Global Water Resources, Inc.
21410 N. 19th Avenue
Suite 201
Phoenix, AZ 85027
(623) 580-9600
(Name, address, including zip code, and telephone number, including area code, of agent for service)

Copies to:

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Squire, Sanders & Dempsey LLP
4900 Key Tower
127 Public Square
Cleveland, OH 44114
(216) 479-8500

Approximate date of commencement of proposed sale to the public: As soon as practicable after the effective date of this Registration Statement.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box. ☐

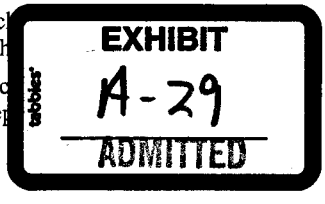
If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ☐

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, chec
and list the Securities Act registration statement number of the earlier effective registration statement for th

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-acc
smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller re
Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer ☐ Accelerated filer ☐



Non-accelerated filer ☐ Smaller reporting company ☐
(Do not check if a smaller reporting company)

CALCULATION OF REGISTRATION FEE

Title of Each Class of Securities to be Registered	Amount to be Registered	Proposed Maximum Offering Price Per Share(1)	Proposed Maximum Aggregate Offering Price(2)	Amount of Registration Fee
Common Stock, $0.01 par value			$ 50,000,000	$ 1,965

(1) Estimated solely for the purpose of computing the amount of the registration fee, in accordance with Rule 457(o) under the Securities Act of 1933.

(2) Includes offering price of shares that the underwriter has the option to purchase to cover over-allotments, if any.

THE REGISTRANT HEREBY AMENDS THIS REGISTRATION STATEMENT ON SUCH DATE OR DATES AS MAY BE NECESSARY TO DELAY ITS EFFECTIVE DATE UNTIL THE REGISTRANT SHALL FILE A FURTHER AMENDMENT WHICH SPECIFICALLY STATES THAT THIS REGISTRATION STATEMENT SHALL THEREAFTER BECOME EFFECTIVE IN ACCORDANCE WITH SECTION 8(a) OF THE SECURITIES ACT, OR UNTIL THE REGISTRATION STATEMENT SHALL BECOME EFFECTIVE ON SUCH DATE AS THE SECURITIES AND EXCHANGE COMMISSION, ACTING PURSUANT TO SAID SECTION 8(a), MAY DETERMINE.

* The Registrant was incorporated on May 2, 2008 and will consummate a reorganization immediately prior to the effectiveness of this Registration Statement. Accordingly, the Registrant has no historical operations, assets or financial results on an independent basis. The information reported in the enclosed Prospectus assumes the completion of the Reorganization unless otherwise noted therein. See "The Reorganization."

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The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

SUBJECT TO COMPLETION, DATED , 2008

PRELIMINARY PROSPECTUS

Shares

Common Stock

We are offering shares of common stock with this prospectus.

This is our initial public offering, and no public market currently exists for our shares. We anticipate that the initial public offering price will be between $ and $ per share.

We have applied to list our common stock on the Nasdaq Global Select Market under the symbol "GWRI".

We have granted the underwriters an option, exercisable within 30 days after the date of this prospectus, to purchase up to additional shares of common stock upon the same terms and conditions as the shares offered by this prospectus to cover over-allotments, if any.

Investing in our shares of common stock involves risks. See "Risk Factors" beginning on page 7 of this prospectus.

	Per Share	Total
Public offering price	$	$
Underwriting discounts and commissions	$	$
Proceeds to Global Water Resources, Inc.	$	$

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

Janney Montgomery Scott LLC, on behalf of the underwriters, expects to deliver the shares on or about , 2008.

JANNEY MONTGOMERY SCOTT LLC

The date of this prospectus is , 2008.

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Through and including , 2008 (the 25th day after the date of this prospectus), all dealers that effect transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealers' obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

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PROSPECTUS SUMMARY

This summary highlights key aspects of our business and our offering of common stock that are described more fully elsewhere in this prospectus. This summary does not contain all of the information that you should consider before making an investment decision. You should read the entire prospectus carefully, including the Risk Factors beginning on page 7 and our financial statements and related notes beginning on page F-3, before making an investment decision.

Unless the context otherwise requires, the information set forth in this Prospectus gives effect to the proposed transactions (the "Reorganization") described herein under "The Reorganization," and the terms "Company," "we" and "our" refers to Global Water Resources, Inc. and to Global Water Resources, LLC and its subsidiaries after giving effect to the Reorganization. Unless otherwise indicated, the information set forth in this Prospectus does not give effect to the exercise of the Underwriters' over-allotment option.

Our Company

We are a water resource management company that provides water, wastewater and recycled water utility services. Recycled water is highly treated and purified wastewater that is distributed throughout the communities we serve for a variety of non-potable uses through a separate distribution system of purple pipes. We call our integrated approach "Total Water Management," or "TWM," a term which we use to mean managing the entire water cycle, both to conserve water and to maximize its total economic value. Our application of TWM has proven to be effective as a means of water scarcity management that promotes sustainable communities in areas where management expects growth to outpace existing potable water supply.

We currently own and operate 16 water and wastewater utilities in strategically targeted communities in metropolitan Phoenix, Arizona. We have grown significantly since our formation in 2003, with total revenues increasing from $4.9 million to $25.8 million from 2004 to 2007, and service connections increasing from 8,145 to 38,682 from December 31, 2004 to December 31, 2007, with the potential capacity in our planning areas to serve approximately two million service connections in the future.

Our TWM model focuses on the broad issues of water supply and scarcity and applies principles of water conservation through water reclamation and reuse. Its basic premise is that our water supply is limited but renewable, and should be managed to ensure that development is sustainable in the face of water scarcity. Key elements of TWM include:

- planning regional integrated water and wastewater facilities;
- stretching a limited resource by deploying the appropriate water for the appropriate use;
- integrating water, wastewater and recycled water treatment and delivery of recycled water through a separate distribution system of purple pipes;
- gaining market and regulatory acceptance of broader utilization of recycled water; and
- combining proven technologies with a water scarcity management platform that provides a socially responsible approach to sustainable community growth.

In addition to providing regulated water, wastewater and recycled water services, we engage in activities that generate additional revenue, including financing agreements with developers and builders, the creation and resale of stored water credits and provision of back-office billing and laboratory services to third parties. In the future, we may also provide water transmission pipeline services to communities that are importing water to fulfill their water supply needs.

Our Growth Strategy

Our objective is to become the largest investor-owned operator of integrated water utilities in areas of the arid western U.S. where water scarcity management is necessary for long-term economic sustainability and growth.

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Our growth strategy involves the following elements:

- acquiring or forming utilities in the path of prospective population growth;
- expanding our service areas geographically and organically growing our customer base;
- deploying our TWM approach into these utilities and service areas;
- structuring and operating related unregulated businesses; and
- replicating our business model in areas of water scarcity.

We believe this plan can be executed in our current service areas as well as in other geographic areas where water scarcity management is necessary to support long-term growth and in which regulatory authorities recognize the need for water conservation through water recycling.

Our Strengths

Well Positioned for Long-Term Growth. We have acquired or formed 16 regulated water and wastewater utilities and increased our total service area from 18 square miles at December 31, 2004 to more than 375 square miles at December 31, 2007. These service areas include large, undeveloped service territories that provide for predictable and significant organic growth for the foreseeable future. Additionally, our planning areas have the potential capacity to serve approximately two million service connections in the future.

Demonstrated Ability to Align Green and Socially Responsible Practices into our Profitable Growth Company. We have developed a profitable model that allows us to employ resource conservation. We have integrated smart technologies into a water scarcity management platform that provides a socially responsible approach to sustainable community growth. Our model improves operating efficiencies while also leveraging the increased value of recycled water as an emerging renewable resource.

Replicable Total Water Management Business Model. Our business model is highly replicable and we have demonstrated this successfully in Arizona. Specifically, our West Valley operations are modeled after and built on the successes we achieved in our Maricopa-Casa Grande planning area. Our model is effective in any high growth region of current or future water scarcity. We are currently in the process of expanding into Idaho and Nevada, demonstrating that there is demand for our TWM-based platform beyond Arizona.

Entrepreneurial, Innovative Management Approach. In contrast to the traditional water utility model built exclusively on rate base and volume accretion, our management team has an entrepreneurial focus emphasizing growth and efficiency. Underpinning this entrepreneurial approach, we have significant regulatory and permitting experience in our industry and in the regions that we serve. Our management team also has a record of success in acquiring accretive utilities, integrating these companies and managing infrastructure deployment in periods of high growth.

Company Information

We were organized as a Delaware limited liability company on September 24, 2003. Immediately prior to the consummation of this offering, we will be reorganized as a Delaware corporation, as described under "The Reorganization." Our principal executive offices are located at 21410 N. 19th Avenue, Suite 201, Phoenix, Arizona 85027, and our telephone number is (623) 580-9600. Our website address is www.gwresources.com. The information on our website is not part of this prospectus.

You should carefully consider the information contained in the "Risk Factors" section of this prospectus beginning on page 7 before you decide to purchase our common stock.

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RISK FACTORS

An investment in our common stock involves risk. Before you decide to purchase our common stock, you should carefully consider these risk factors together with all of the other information included in this prospectus, including the information contained in the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations" and our combined consolidated financial statements included elsewhere in this prospectus and the notes thereto. If any of the following risks actually occurs, our profitability, results of operations, liquidity and cash flows could be adversely affected, which in turn could adversely affect the value of our common stock.

Risks Related to Our Business

Our growth depends significantly on increased residential and commercial development in our service areas.

Our revenue growth depends on population growth and successful residential and commercial development within our service areas. Real estate development is a cyclical industry and the growth rate of development, especially residential development, during 2006 and 2007, both nationally and in Arizona, has been significantly below the rates for recent prior years. According to Arizona State University Realty Studies, residential building permits in Arizona's Maricopa and Pinal Counties decreased by 17% and 28%, respectively, from 2006 to 2007.

Sales of single family residences are affected by national and regional economic factors, including:

- interest rates and general levels of economic output;
- levels of activity in the local real estate market;
- the state of domestic credit markets, mortgage standards and availability of credit;
- competition from other builders and other projects in the area and other states;
- costs and availability of labor and materials;
- government regulations affecting land development, homebuilding and mortgage financing;
- increased commute times and fuel costs that may affect the desirability of outlying suburbs; and
- environmental issues.

A deepened or prolonged slowdown of the development process and growth rate within the various developments in our service areas could materially and adversely affect the growth of our customer base and revenues.

Development in our service areas is also contingent upon construction or acquisition of major public improvements such as arterial streets, drainage facilities, telephone and electrical facilities, recreational facilities, street lighting and local in-tract improvements such as site grading. Many of these improvements are built by municipalities with public financing, and municipal resources and access to capital may not be sufficient to support development in areas of rapid population growth. If municipalities, developers, builders or homeowners are unable, financially or otherwise, to make the improvements necessary to complete new residential or commercial developments, our potential revenue growth from new water and wastewater connections within such developments would be reduced.

We may have difficulty accomplishing our growth strategy within and outside of our current service areas.

Our ability to expand our business, both within our current service areas and into new areas, involves significant risks, including, but not limited to:

- not receiving or maintaining necessary regulatory permits, licenses and approvals;

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- downturns in economic or population growth and development in our service areas;
- risks related to planning and commencing new operations, including inaccurate assessment of the demand for water, engineering and construction difficulties and inability to begin operations as scheduled;
- droughts or water shortages that could increase water conservation efforts to a point that materially reduces our consumption-based revenue;
- regulatory restrictions or other factors that could adversely affect our access to sources of water supply;
- our potential inability to identify suitable acquisition opportunities or to form the relationships with developers and municipalities necessary to form strategic partnerships; and
- barriers to entry presented by existing water utilities in prospective service areas.

If we are unable to execute our growth strategy effectively, we will need to rely more heavily on regulatory rate increases to increase our revenue.

Any pending or future acquisitions we decide to undertake involve risks.

An important element of our growth strategy is the acquisition or development of other water and wastewater utilities. The negotiation of potential acquisitions and development of new projects could require us to incur significant costs and expose us to significant risks, including:

- risks relating to the condition of assets acquired;
- operating risks, including equipment, technology and supply problems, regulatory requirements and approvals necessary for acquisitions;
- risks that potential acquisitions may require the disproportionate attention of our senior management, which could distract them from the management of our existing business; and
- risks related to our ability to retain experienced personnel of the acquired company.

These issues could have a material adverse effect on our business and our ability to finance our operations. The businesses and other assets we acquire in the future may not achieve sufficient revenue or profitability to justify our investment, and any difficulties we encounter in the integration process could interfere with our operations and reduce operating margins. Acquisitions could also result in dilutive issuance of our equity securities, incurrence of debt and contingent liabilities, fluctuations in quarterly results and acquisition-related expenses.

If we do not manage our anticipated growth effectively, we may not be able to develop or implement the infrastructure necessary to support our operations and could suffer a loss of profitability.

We have a limited operating history. Since our formation in 2003, we have grown rapidly, with our total revenues increasing from $4.9 million in 2004 to $25.8 million in 2007, and service connections increasing from 8,145 as of December 31, 2004 to 38,682 as of December 31, 2007. We have also expanded geographically, from 18 square miles of planning areas at December 31, 2004 to more than 375 square miles at December 31, 2007. Our growth has been driven principally by acquisitions and by organic growth resulting from increased development and service connections within our existing service areas.

Although we may not be able to achieve similar growth or grow at all, in future periods, we expect to continue to expand significantly our facilities, infrastructure, research and development, marketing, testing, management and administrative operations as well as our financial and accounting controls. This expansion has placed, and will continue to place, strain on our management and administrative, operational, technical and financial infrastructure. If our management is unable to manage growth effectively, the quality of our

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result in decreased customer billing and lower revenues that we would not be able to recoup without prior regulatory approval for a rate increase. These conditions could also lead to decreases in revenue from our stored water credit business or increases in capital expenditures needed to build infrastructure to secure alternative water sources. Furthermore, customers may use less water even after a drought has ended because of conservation patterns developed during the drought. Population growth could also decline under drought conditions as individuals and businesses move out of the area or elect not to relocate there. Lower water use for any reason could lead to lower revenue.

Also, demand for water is seasonal. Demand for water varies with temperature and rainfall levels. In the event that temperatures during the typically warmer months are cooler than normal, or if there is more rainfall than normal, the demand for our water may decrease, which would adversely affect our profitability, results of operations, liquidity and cash flows.

We depend substantially on our Chief Executive Officer, who would be difficult to replace. If we lose his services, our business would be adversely affected.

Our continued growth and success depend in large part on the management and technical skills of the members of our senior management, particularly Trevor T. Hill, our Chief Executive Officer. Although Mr. Hill is subject to an employment agreement, he could terminate his employment with us at any time. Loss of his services would negatively affect our business by harming our ability to pursue our growth strategy and to continue to manage and oversee the improvement of our operations. See "Management."

We rely on our information technology, or IT, systems to assist with the management of our business and customer relationships, and a disruption of these systems could adversely affect our business.

Our IT systems are an integral part of our business, and a serious disruption of our IT systems could significantly limit our ability to manage and operate our business efficiently, which in turn could cause our business to suffer and cause our results of operations to be reduced. We depend on our IT systems to bill customers, provide customer service, manage construction projects, manage our financial records, track assets, remotely control and monitor certain of our plants and facilities and manage human resources and accounts receivable collections. Our IT systems also allow us to bill customers on a timely basis, maintain cost-effective operations and provide service to our customers. Our IT systems are vulnerable to damage or interruption from:

- power loss, computer systems failures and internet, telecommunications or data network failures;
- operator negligence or improper operation by, or supervision of, employees;
- physical and electronic loss of customer data or security breaches, misappropriation and similar events;
- computer viruses;
- intentional acts of vandalism and similar events; and
- fires, floods, earthquakes and other natural disasters.

Such damages or interruptions may result in physical and electronic loss of customer or financial data, security breaches, misappropriation and similar events. In addition, the lack of redundancy for certain of our IT systems, including billing systems, could exacerbate the impact on our company of any of the foregoing events. In addition, we may not be successful in developing or acquiring technology that is competitive and responsive to the needs of our business and we might lack sufficient resources to make the necessary investments in technology to allow us to continue to operate at our current level of efficiency.

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We may not be able to continue to obtain appropriate liability or workers' compensation insurance at a reasonable cost.

Our systems are subject to the normal risks of operation as well as the additional risks of receiving, processing, treating and disposing of waste materials. In recent years, societal factors have resulted in increased litigation and escalating monetary claims against industries and employers. As a safeguard, we maintain general liability and workers' compensation insurance coverages. There is no guarantee that insurance will continue to be available at affordable premiums or that we will continue to be able to obtain coverage against catastrophic claims and losses. While we may self-insure for some risks in the future, should an uninsured or underinsured loss occur, we may be unable to meet our obligations as they become due.

Inflation could adversely affect our profitability.

Our profitability depends in part on the prices we must pay for the electricity, materials and services we need in order to conduct our business. If inflation increases these prices in our service areas, we will experience an increase in our operating costs that may not be immediately and fully recoverable in our rates.

Risks Related to our Finances and Capital Requirements

We will need additional capital to grow our business, and additional financing may not be available to us on favorable terms when required, or at all.

We expect that our current sources of liquidity, together with the anticipated net proceeds of this offering, will be sufficient to fund our anticipated future growth and operations for approximately 12 months following the completion of this offering. We anticipate that we will need additional capital to finance our growth after such 12-month period or to accelerate our expected growth during such 12-month period. We have based this estimate of our liquidity needs on assumptions that may prove to be incorrect, and we may spend our available financial resources more rapidly than we currently anticipate.

Adequate funds to support our growth may not be available when needed or on terms acceptable to us. We also may need to raise additional funds to support more rapid expansion, improve our facilities and infrastructure, develop new and enhanced technologies or respond to evolving regulatory standards. If we raise funds by issuing additional common stock, other equity securities or indebtedness, the percentage ownership of our then-current stockholders may be diluted substantially and the equity or debt securities issued to new investors may have rights, preferences or privileges senior to those of the holders of our then-existing capital stock. We may also experience difficulty in raising the necessary capital in view of the recent volatility in the capital markets and increases in the cost of infrastructure finance, and increasingly stringent rating standards could make it more difficult for us to finance our growth by issuing tax-exempt bonds as we have in the past. If adequate funds are not available or are not available on acceptable terms, we may not be able to take advantage of expansion opportunities, make the capital expenditures necessary to support our growth or otherwise execute our strategic plan.

Increased operating expenses associated with the expansion of our business may negatively impact our operating income.

Increased operating expenses associated with any expansion of our business may negatively impact our income as we, among other things:

- seek to acquire new service areas;
- expand geographically in and outside of Arizona;
- make significant capital expenditures to support our ability to provide services in our existing service areas;
- fund development costs for our system and technology; and

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You will experience immediate and substantial dilution as result of this offering and may experience additional dilution in the future, and the initial public offering price may not reflect such dilution.

The initial public offering price of our common stock in this offering is substantially higher than the net tangible book value per share of the outstanding common stock. As a result, investors purchasing shares of common stock in this offering will pay a price that substantially exceeds the value of our assets after subtracting our liabilities. As a result, investors will:

- incur immediate dilution of $ per share, based on the initial public offering price of $ per share; and
- contribute % of the total amount invested to date to fund our company based on the assumed initial offering price to the public of $ per share, but will own only % of the shares of common stock outstanding upon completion of this offering.

You will experience additional dilution upon the issuance of equity securities under our current or future equity incentive plans or if we otherwise issue additional shares of our common stock or securities convertible into common stock. See "Dilution."

We intend to pay only nominal cash dividends on our common stock.

We intend to pay only nominal cash dividends on our common stock in the foreseeable future. As a result, prospective purchasers seeking significant dividend income should not invest in the common stock offered under this prospectus. Even if we pay nominal cash dividends, we may not maintain sufficient earnings in the future to continue to do so. All decisions regarding the payment and declaration of dividends lie within the sole discretion of our board of directors. As a result, capital appreciation, if any, of our common stock will be your primary source of gain for the foreseeable future. See "Dividend Policy."

Our executive officers and directors and their affiliates will exercise control over stockholder voting matters in a manner that may not be in the best interests of all of our stockholders. This ownership concentration may adversely affect the market price of our shares.

Upon completion of this offering, our current executive officers and directors and their affiliates will together control approximately % of our outstanding common stock. As a result, these stockholders will collectively be able to control all matters requiring approval of our stockholders, including the election of directors and approval of significant corporate transactions, and will have significant control over our management and policies. The interests of this group of stockholders may not always coincide with the interests of other stockholders. The concentration of ownership also may delay, prevent or deter a change in control of our company even when the change could deprive our stockholders of an opportunity to receive a premium for their common stock as part of a sale of our company or our assets and might affect the prevailing market price of our common stock.

We will incur increased costs as a result of being a public company, and these additional expenses and other burdens associated with being a public company could have a material adverse effect on our operating results and financial condition.

As a public company, we will incur significant legal, accounting, and other expenses that we did not incur as a private company that may adversely affect our profitability. In addition, the Sarbanes-Oxley Act of 2002, as well as the related rules and regulations enacted by the SEC and Nasdaq require specific corporate governance practices for public companies. We expect these rules and regulations to increase our legal and financial compliance costs. In addition, we will incur additional costs associated with our public company reporting requirements. For example, we will be required to devote significant resources to complete the assessment and documentation of our internal control system and financial processes under Section 404 of the Sarbanes-Oxley Act of 2002 and may incur significant costs to remediate any material weaknesses we identify through these efforts. We also expect these rules and regulations to make it more difficult and more expensive

for us to obtain director and officer liability insurance, and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified persons to serve on our board of directors or as executive officers. We cannot predict or estimate the amount of additional costs we may incur or the timing of such costs. If our profitability is adversely affected because of these additional costs, it could have a negative effect on the trading price of our common stock.

Future sales of our common stock may depress our stock price.

After completion of this offering, we will have shares of common stock outstanding. The shares sold in this offering, or shares if the underwriters' over-allotment is exercised in full, will be freely tradable without restriction or further registration under federal securities laws unless purchased by our "affiliates" as such term is used in Rule 144 of the Securities Act of 1933, as amended (the "Securities Act"), and additional shares of common stock outstanding after completion of this offering will be eligible for sale in the public market as of the date of this prospectus. After the lock-up agreements pertaining to this offering expire 180 days from the date of this prospectus, up to an additional shares of our common stock will be eligible for sale in the public market, in some cases subject to volume limitations and other restrictions under Rule 144 of the Securities Act, of which are held by executive officers, directors and their affiliates. If our existing common stockholders sell substantial amounts of common stock in the public market, or if the market perceives that these sales may occur, the market price of our common stock may decline, including below the initial public offering price.

The above information assumes the effectiveness of the lock-up agreements under which our officers, directors and certain principal stockholders have agreed not to sell or otherwise dispose of their shares of common stock. Janney Montgomery Scott LLC may, in its sole discretion and at any time without notice, release all or any portion of the securities subject to lock-up agreements. In considering any request to release shares subject to a lock-up agreement, Janney Montgomery Scott LLC will consider the facts and circumstances relating to a request at the time of that request. See "Shares Eligible for Future Sale."

In addition, as soon as practicable after the completion of this offering, we intend to file a registration statement under the Securities Act covering shares of common stock issuable upon exercise of options or other equity incentives granted or to be granted under our 2008 Long-Term Incentive Plan. Shares registered under this registration statement will be available for sale in the open market, subject to applicable vesting restrictions and the contractual lock-up agreements described above. If these additional shares are sold, or if it is perceived that they will be sold, in the public market, the trading price of our common stock could decline. See "Shares Eligible for Future Sale."

Our management team may invest or spend a portion of the net proceeds of this offering in ways in which you may not agree or in ways that may not yield a return.

We intend to use a portion of the net proceeds of this offering to repay our indebtedness under our line of credit with Wells Fargo Bank, make capital expenditures, fund potential future acquisitions and for general corporate purposes. Our management will have considerable discretion in the application of the net proceeds to purposes other than debt repayment, and you will not have the opportunity, as part of your investment decision, to assess whether the proceeds are being applied or allocated appropriately. The net proceeds may be used for corporate purposes that do not increase our operating results or market value. Until the net proceeds are used, they may be placed in investments that do not produce significant income.

Anti-takeover provisions under Delaware law could delay or discourage a takeover that stockholders may consider favorable.

Because we are a Delaware corporation, we are governed by the provisions of Section 203 of the Delaware General Corporation Law, which may prohibit certain business combinations with stockholders owning 15% or more of our outstanding voting stock. This and other provisions under Delaware law could

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THE REORGANIZATION

Our operations are currently conducted through Global Water Resources, LLC, a Delaware limited liability company, and a number of wholly-owned subsidiaries, all of which are Arizona "C" corporations. Global Water Management, LLC currently provides management services to our water and wastewater utilities as a commonly controlled entity. Global Water Resources, Inc. has no operating history and was formed for the purpose of acquiring 100% of the limited liability company interests in Global Water Resources, LLC and in Global Water Management, LLC, currently held by various investors, including certain executive officers, directors and employees of the Company, pursuant to a reorganization (the "Reorganization") described below. Prior to the Reorganization, Global Water Resources, LLC will have 10,000 common limited liability interests and 10,000 preferred limited liability interests outstanding, and Global Water Management, LLC will have 10,000 common limited liability interests and 10,000 preferred limited liability interests outstanding. Global Water Management, LLC and Global Water Resources, LLC have the same investors and the investors hold their common and preferred limited liability interests in each entity in the same relative proportions.

The owners of Global Water Management, LLC will contribute their common limited liability company interests in that company to Global Water Resources, LLC. Thereafter, the owners of Global Water Resources, LLC will contribute their common limited liability company interests in that company to Global Water Resources, Inc., in exchange for common stock of Global Water Resources, Inc., in effect incorporating the business of Global Water Resources, LLC. The acquisition of Global Water Management, LLC will improve our ability to allocate management expenses among our utility subsidiaries in accordance with applicable state regulatory requirements.

The number of shares of Global Water Resources, Inc. common stock that will be issued in exchange for common limited liability company interests of Global Water Resources, LLC will be calculated by (i) multiplying the total combined market value of Global Water Resources, LLC and Global Water Management, LLC by the percentage of Global Water Resources, Inc. that the investors in Global Water Resources, LLC and Global Water Management, LLC will own after the initial public offering, and (ii) dividing the resulting amount by the initial public offering price for the Global Water Resources, Inc. common stock.

In addition, the preferred limited liability company interests in each of Global Water Resources, LLC and Global Water Management, LLC will be redeemed as described below.

Under Arizona utility regulations, the Reorganization, and the initial public offering, must be approved by the ACC. On May 13, 2008, we filed a notice of intent with the ACC requesting approval of the Reorganization and the initial public offering. The notice of intent is currently under review by the Commission. We cannot sell our shares to the public without approval from the ACC.

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BUSINESS

Introduction

We are a water resource management company that provides water, wastewater and recycled water utility services. Recycled water is highly treated and purified wastewater that is distributed throughout the communities we serve for a variety of non-potable uses through a separate distribution system of purple pipes. We call our integrated approach "Total Water Management," or "TWM," a term which we use to mean managing the entire water cycle, both to conserve water and to maximize its total economic value. Our application of TWM has proven to be effective as a means of water scarcity management that promotes sustainable communities in areas where management expects growth to outpace existing potable water supply.

We currently own and operate 16 water and wastewater utilities in strategically targeted communities in metropolitan Phoenix, Arizona. We have grown significantly since our formation in 2003, with total revenues increasing from $4.9 million to $25.8 million from 2004 to 2007 and service connections increasing from 8,145 to 38,682 from December 31, 2004 to December 31, 2007, with the potential capacity in our planning areas to serve approximately two million service connections in the future.

Our objective is to become the largest investor-owned operator of integrated water and wastewater utilities in areas of the arid western U.S. where water scarcity management is necessary for long-term economic sustainability and growth.

Our growth strategy involves the elements listed below:

- acquiring or forming utilities in the path of prospective population growth;
- expanding our service areas geographically and organically growing our customer base;
- deploying our TWM approach into these utilities and service areas;
- structuring and operating related unregulated businesses; and
- replicating our business model in areas of water scarcity.

U.S. Water and Wastewater Industry

Overview

The U.S. water and wastewater industry has three main segments: (i) utility, which involves supplying water, wastewater and water recycling services to consumers; (ii) general products and services, which involves providing water- and wastewater-related products and services to water and wastewater utilities and other customers on a contract basis; and (iii) water resource management, which involves production and monetization of water as a commodity through the trading of rights and credits.

The utility segment includes municipal systems, which are owned and operated by local governments or governmental subdivisions, and investor-owned systems. Growth of service providers in the utility segment is principally achieved through acquisitions of other water and wastewater systems and organic growth of the population served by such providers.

The utility segment is characterized by high barriers to entry, including high capital spending requirements. Investor-owned water and wastewater utilities also face required regulatory approval processes, which may involve obtaining relevant operating approvals, including certificates of public convenience and necessity or similar authorizations (CC&Ns) from state public utility commissions or other entities engaged in economic regulation of public utilities (PUCs). Investor-owned water and wastewater systems are generally economically regulated by the PUCs in the states in which they operate. The federal government and the states also regulate environmental, health and safety and water quality matters for both investor-owned and government-owned water and wastewater utilities.

The general products and services segment includes engineering and consulting companies and numerous other fee-for-service businesses. These include the building, financing and operating of water and wastewater

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Intelligence Water Reuse Markets 2005-2015, A Global Assessment and Forecast, approximately $25.1 billion is projected for investment in recycled water distribution internationally over the next ten years.

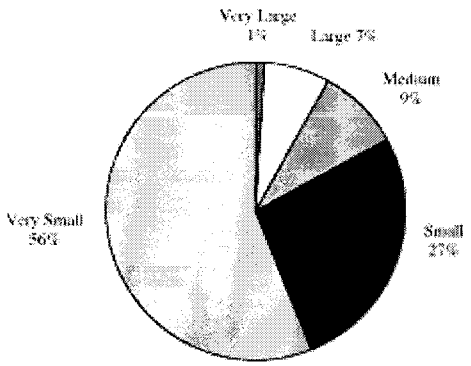
Recycled water is created by taking wastewater and applying advanced tertiary treatment to create a high quality, non-potable water source. The use of recycled water for non-potable applications has the potential to reduce demand for potable water by up to approximately 40% as opposed to conventional wastewater discharge methods.

Fragmentation and Consolidation

The utility segment of the U.S. water and wastewater industry is highly fragmented, with approximately 53,000 water systems and approximately 16,000 wastewater systems, according to the EPA. As shown in the charts below, the majority of the approximately 53,000 water systems are very small, serving a population of 500 or less. Government-owned systems make up the vast majority of the U.S. water and wastewater utility segment, accounting for approximately 84% of all water systems in the U.S. and approximately 98% of all wastewater systems in the U.S. Investor-owned water and wastewater systems account for the remainder of the water and wastewater systems in the U.S.

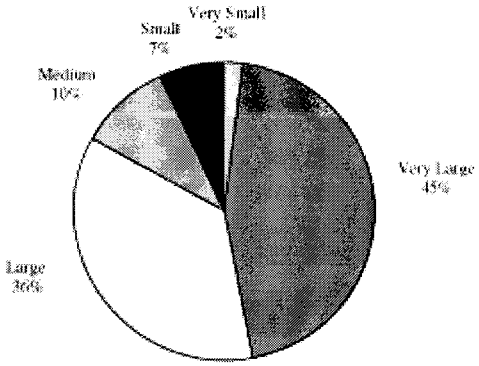
The following charts set forth the total U.S. water industry by system type and the total population served by system type, respectively, for 2005:

Number of United States Water Systems by Type:*



Total Water Systems: 52,837

United States Population Served by Water System Type:*



Total Population Serviced: 282 million

Legend:
Very Small - 500 or less | Small - 501 to 3,300 | Medium - 3,301 to 10,000 | Large - 10,001 to 100,000 | Very Large - 100,001 or more

*Note: Includes only community water systems, defined as a public system that supplies water to the same population year around
Source: EPA, Drinking and Ground Water Statistics, 2005

This large number of relatively small water and wastewater utilities results in inefficiencies in the marketplace, since smaller utilities may not have the operating expertise, financial and technological capability or economies of scale to provide services or raise capital as efficiently as larger utilities. These inefficiencies may lead to industry consolidation in the future, as the investor-owned utilities acquire smaller, local water and wastewater systems. Investor-owned utilities that have greater access to capital are generally more capable of addressing increasingly stringent environmental and human health standards, navigating a wide variety of regulatory processes and making mandated and other necessary infrastructure upgrades to both water and wastewater systems.

Large investor-owned utilities that are able to spread overhead expenses over a larger customer base reduce the costs to serve each customer. Since many administrative and support activities can be efficiently centralized

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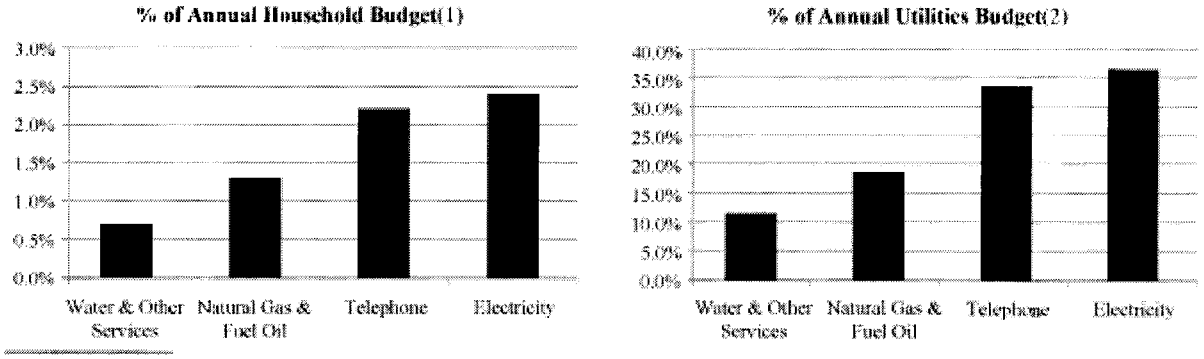
to gain economies of scale and sharing of best practices, companies that participate in industry consolidation have the potential to improve operating efficiencies, lower unit costs and improve service at the same time.

Water and Wastewater Rates

Investor-owned water and wastewater utilities generate operating revenue from customers based on rates that are established by PUCs through a rate-setting process that may include public hearings, evidentiary hearings and the submission by the utility of evidence and testimony in support of the requested level of rates. In evaluating a rate case, state PUCs typically focus on five areas: (i) the amount and prudence of investment in facilities considered "used and useful" in providing public service; (ii) the operating and maintenance costs and taxes associated with providing the service (typically by making reference to a representative 12-month period of time, known as a test year); (iii) the appropriate rate of return; (iv) the tariff or rate design that allocates operating revenue requirements equitably across the customer base; and (v) the quality of service the utility provides, including issues raised by customers. For most consumers, water and wastewater bills make up a relatively small percentage of household expenditures compared to other utility services.

The following chart sets forth the relative cost of water in the U.S. as a percentage of total household utility expenditures:



(1) 2004 Bureau of Labor Statistics (assumes four person households)
(2) United States Department of Labor-Consumer Expenditures Survey 2004-2005 (assumes four person households)

Many municipal water and wastewater systems do not adequately account for their infrastructure investment needs and charge rates below cost, which effectively subsidizes water and wastewater services for their consumers. As a result, they generate insufficient revenue to finance infrastructure investments and in some cases, operations and maintenance costs as well, and will need to increase their rates absent other sources of funding. Large investor-owned utilities' rates are premised upon a pricing approach that recovers the full cost of water and wastewater services. The elimination of rate subsidies (explicit or otherwise) would also signal the value of water to consumers and play an important role in demand-side management, encouraging conservation of water. New, investor-owned systems that do not require integration with existing facilities, also known as "green field" systems, typically incorporate full cost pricing from initiation of services.

Public-Private Partnerships

Capital expenditures related to municipal water supply, treatment and distribution and wastewater collection and treatment facilities are typically funded by water and wastewater rates, taxes or the issuance of bonds. However, raising large amounts of funds is challenging for municipal water utilities, which impacts their ability to increase capital spending. In order to meet their capital spending challenges, many municipalities are examining a combination of privatizations and partnerships with the private sector. Privatization involves a transfer of responsibility for, and ownership of, the utility from the municipality to the private sector. Partnerships between municipalities and the private sector ("public-private partnerships") include design, build, operate contracts; build, own, operate and transfer contracts; and own, leaseback and

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approach because it provides a partnering platform which promotes economic development, reduces their traditional dependence on bond financing and ensures long term water sustainability.

Our competitive advantage facilitates the execution of our growth strategy. Demand for our TWM-based platform generates new business opportunities and a high success rate in bids for new territories. Our proven conservation methods lead to successful permitting for more connections in expanded and new service areas.

Market Opportunities

Opportunities for Growth in Our Existing Service Areas

Our existing service areas present significant opportunities for organic growth of our business. Because we are based in one of the fastest growing states in the U.S. and operate utilities in high growth areas of that state, our organic growth potential is significant compared to traditional investor-owned water utilities, which we believe have relatively limited prospects for organic growth and rely primarily on acquisitions to fuel customer growth. We have secured regulatory approval to provide water and wastewater services in large, growing service areas, where we have built infrastructure ahead of development. We believe this positions us for significant organic growth for the foreseeable future.

Regional Planning Areas. We have two large regional planning areas totaling 378 square miles. Our Maricopa-Casa Grande regional planning area encompasses 244 square miles that includes the cities of Maricopa and Casa Grande, located south of Phoenix. That area is served primarily by our Santa Cruz and Palo Verde utility subsidiaries. Our West Valley regional planning area encompasses 134 square miles in western Maricopa County near the town of Buckeye, west of the Hassayampa River. That area is served primarily by our Water Utility of Greater Tonopah subsidiary for water service and by our Hassayampa Utility Company subsidiary for wastewater service. We believe there is significant opportunity for organic growth due to future development in our Maricopa-Casa Grande and West Valley regional planning areas.

Population Growth. Our Maricopa-Casa Grande regional planning area is located in Pinal County. Pinal County is rapidly changing from primarily rural to an area of suburbanization. According to a 2006 U.S. Census estimate, Pinal County grew by 51% from a population of 180,000 in 2000 to 271,000 in 2006, making it the sixth fastest growing county in the U.S. and the fastest growing county in Arizona in terms of percentage population growth. A Pinal County Small Area Transportation study conducted in 2006 estimates that the population of Pinal County will grow to 1.9 million by 2025.

Our West Valley regional planning area is located in Maricopa County. Maricopa County gained 696,000 residents between 2000 and 2006, the largest numerical increase of any county in the U.S. during this period according to U.S. Census data. Maricopa County is now the fourth largest county in the U.S., with 3.8 million residents. The Maricopa Association of Governments projects that this population will grow to approximately 4.5 million by 2025.

Service Connection Growth. Each new resident requires both a water and wastewater service connection. We estimate that each square mile of regional planning area represents 2,240 potential water connections and 2,240 potential wastewater connections.

Opportunities for Further Consolidation and Expansion

We are actively pursuing strategic expansion opportunities in Arizona in both our regulated and unregulated businesses. For example, we recently received approval for a utility service area near Eloy, Arizona, which is located between Tucson and Phoenix. Eloy is located at the junction of two major interstate highways and is in the heart of Arizona's "Sun Corridor," which is expected to attract significant long-term growth. We are actively pursuing a 100-square mile regional planning area associated with this new service area.

In addition to Arizona's attractive growth prospects as described above, we believe Idaho and Nevada present attractive long-term growth prospects. According to U.S. Census data, Idaho's population is projected to grow by 29.8%, or an average of 1.5% per year, from 2010 to 2030, and Nevada's population is projected

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to grow by 59.2%, or an average of 3.0% per year, over the same period. We believe the regulatory environment in each state will be receptive to our emphases on water conservation, regional planning and collaborative regulatory relationships.

Although our acquisition experience and current plans focus primarily on Arizona and on new opportunities in Idaho and Nevada, our business model is replicable in other geographic areas as well. Our relationships with developers and builders have introduced us to other areas of the U.S. in which prospective population and economic growth and water conservation awareness could form a suitable basis for our Total Water Management model. International awareness of water conservation and related initiatives has also become increasingly prevalent. We believe this increasing awareness provides an opportunity for us to expand internationally, although we have no present plans in that regard. See "—Our Strengths—Replicable Total Water Management Business Model.

Our Strengths

Well-Positioned for Long-Term Growth

We have a proven ability to acquire and integrate high growth, accretive utilities, through which we have captured additional service territories that will serve as a base for future revenue. We have acquired 13 regulated water and wastewater utilities during the past four years, and our integration of their operations, management, infrastructure, technology and employees with ours. We believe this experience presents a strong platform for further expansion and that our success to date also engenders positive relationships and credibility with regulators, municipalities, developers and customers in both existing and prospective service areas.

The utilities we have acquired are located in geographic areas that present significant opportunities for long-term revenue growth. The following chart shows the estimated potential number of service connections within the regional planning areas that will be served by our acquired or formed utilities, assuming maximum buildout, 3.5 homes per acre and two service connections per home. See "—Market Opportunities—Opportunities for Growth in Our Existing Service Areas" and "—our Regulated Utilities—Acquisition History."

Regional Planning Areas	Square Miles	Estimated Potential Homes	Estimated Potential Service Connections
Maricopa-Casa Grande (includes Global Water — Santa Cruz Water Company, Global Water — Palo Verde Utilities Company, 387 Domestic Water Improvement District, 387 Wastewater Improvement District, Francisco Grande and CP Water)	244	546,560	1,093,120
Eloy Region(1) (includes Picacho Cove Water Company and Picacho Cove Utilities Company)	66	147,840	295,680
West Valley (includes Water Utility of Greater Tonopah, Hassayampa Utilities Company and Balterra Sewer Company)	134	300,160	600,320
Totals	**444**	**994,560**	**1,989,120**

(1) Proposed regional planning area in negotiation.

Demonstrated Ability to Align Green and Socially Responsible Practices into our Profitable Growth Company

We have developed a profitable model that encourages and promotes resource conservation. We have integrated proven technologies into a water scarcity management platform that provides a socially responsible

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman
WILLIAM A. MUNDELL
Commissioner
JEFF HATCH-MILLER
Commissioner
KRISTIN K. MAYES
Commissioner
GARY PIERCE
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA-AMERICAN WATER COMPANY ANTHEM/AGUA FRIA WASTEWATER, AN ARIZONA CORPORATION,FOR A DETERMINATION OF THE CURRENT FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES BASED THEREON FOR UTILITY SERVICE BY ITS ANTHEM WATER AND ATHEM/AGUA FRIA WASTERWATER DISTRICTS.	)	DOCKET NO. WS-01303A-06-0403

SURREBUTTAL

TESTIMONY

OF

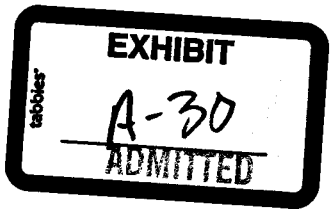
GERALD BECKER

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 17, 2007



ARIZONA-AMERICAN WATER COMPANY - ANTHEM/AGUA FRIA WASTEWATER DISTRICT Schedule GWB-11
Docket No. WS-01303A-06-0403
Test Year Ended December 9, 2005

OPERATING INCOME ADJUSTMENT #1 - CORPORATE EXPENSE ALLOCATION

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED	[B] ADJ #1	[C] STAFF RECOMMENDED
1	Labor	$ 70,313		$ 70,313
2	Salaries & Wages - Officers, Directors	-	-	-
3	Employee Pension and Benefits	134,836		134,836
4	Purchased Wastewater Treatment			-
5	Waste Disposal	-	-	-
6	Fuel and Power	-	-	-
7	Fuel for Power Production	-	-	-
8	Chemicals	-	-	-
9	Materials & Supplies O & M	-	-	-
10	Management Fees	827,789	(86,077)	741,712
11	Customer Accounting	91,310		91,310
12	Rents	55,250	(1,070)	54,180
13	Gen'l Office Expense	148,858	(4,583)	144,275
14	Contractual Services - Testing	-	-	-
15	Contractual Services - Other	-	-	-
16	Rental Of Building/Real Property	-	-	-
17	Rental Of Equipment	-	-	-
18	Transportation Expenses	-	-	-
19	Insurance - Vehicle	-	-	-
20	Insurance - General Liability	-	-	-
21	Insurance - Workman's Compensation	-	-	-
22	Insurance - Other Than Group	92,795	(9,740)	83,055
23	Telephone	-	-	-
24	Postage	-	-	-
25	Maintenance	158,133	(655)	157,478
26	Training, Travel, and Meals	-	-	-
27	Dues	-	-	-
28	Regulatory Comm. Exp. - Rate Case	-	-	-
29	Miscellaneous	228,375	(6,475)	221,900
30	Depreciation & Amortization Expense			-
31	Taxes Other Than Income	-	-	-
32	Property Taxes	-	-	-
33	Income Tax		-	-
34	**Totals**	**$ 1,807,659**	**$ (108,600)**	**$ 1,699,059**

Liberty Water	12725 W. Indian School Rd. Suite D101 Avondale, AZ 85392		
Asset Retirement Policy	Proc. #:	**8010-800-000-002**	
Description: Retirement of Assets from Plant in Service	Revision #:	1	Page: 1 of 2

Original	Jun 28, 2010	Document Created	Peter Eichler

Description

From time to time, assets are removed or replaced prior to the end of their useful life. This policy governs the accounting treatment of asset retirements and how they are to be recorded on the utility books.

Regulatory References

NARUC Uniform System of Accounts, pages 31-33

Other References

Handy-Whitman Index

Procedure

A new line item has been added to the FWO form which requires the identification of assets. At the time of initiating a project, the following section must now be completed on the form:

WILL THERE BE ASSETS GREATER THAN $5,000 THAT ARE CURRENTLY IN SERVICE REMOVED AS A RESULT OF THIS PROJECT? IF YES, PLEASE DETAIL THE SPECIFIC ASSETS THAT WILL BE REMOVED:

1. Original Cost of Plant to be removed (if known):
2. What is the replacement cost of the plant being removed (if original cost not known)?
3. Original Work Order of Plant to be removed (if known):
4. Is the Plant being removed reusable?
5. What is the year of original installation of the plant being removed?

Accounting Entry required:

The recording of asset retirements will occur in tracking accounts for statistical purposes, as they occur. The following entry shall occur. The amount of the entry shall be book cost.

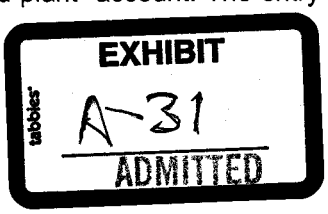
Dr. Accumulated Depreciation – Retired Plant
Cr. Retired Fixed Assets

In addition, depreciation expense on retired fixed assets should be tracked as well through the following entry, which shall occur from the time of retirement, until the end of the useful life of the asset:

Dr. Depreciation expense - retired plant
Cr. Depreciation expense – retired plant

At the end of every calendar year, a manual adjusting entry must occur to depreciation expense in the amount of the total debits or total credits in the "Depreciation Expense – retired plant" account. The entry shall be:

Dr. Accumulated Depreciation – plant
Cr. Depreciation Expense



Salvage Value, Removal Costs, and other items in the course of retirement

Any other costs incurred or recovered (via salvage value) in the course of retirement shall be charged or credited against the accumulated depreciation account, consistent with instructions found in section 27(2) of the NARUC Uniform System of Accounts, page 32.

Book Cost:

The book cost of any plant item retired should be determined by referring to the original invoice. If an item cannot be easily distinguished on an invoice, an estimate may be used of original book cost by using an estimate of the replacement value (requires an up to date quote) and adjusting for inflation to the original installation date by using the inflation data in the Handy-Whitman index (2009 version attached for reference).

The Handy Whitman index provides an inflation adjusted value with a base year of 1973. For example, as seen on page W-5-8 line 9, an item located within a utility that is part of the Plateau region with a value of $100 in 1973 would have a value of $501 on January 1, 2009. Similarly, if an item were to have a current day replacement cost of $100, the book value would be deemed to be $19.96 (calculated as $100/(501/100)) for retirement purposes.

Please note that utilities located in Arizona are deemed to be part of the "Plateau region" while utilities in Texas are deemed to be part of the "South West region".

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2010

July 12 - 2010 - **Algonquin Power & Utilities Corp. announces dates for 2010 second quarter financial results release and conference call**

June 23 - 2010 - **Algonquin Power & Utilities Corp. Announces Results of Annual and Special Meeting of Shareholders**

June 9 - 2010 - **Algonquin Power & Utilities Corp. Announces Adopts Shareholder Rights Plan**

June 2 - 2010 - **Algonquin Power & Utilities Corp. Announces date for Annual and Special Meeting**

May 7 - 2010 - **Algonquin Power & Utilities Corp. Declares Second Quarter 2010 Dividend**

May 6 - 2010 - **Algonquin Power & Utilities Corp. Announces 2010 First Quarter Financial Results**
For additional information click here

April 21 - 2010 - **Algonquin Power & Utilities Corp. Announces Commencement of Construction of Phase I of the Red Lily Wind Project**
Click Here for the Fact Sheet

April 16 - 2010 - **Algonquin Power & Utilities Corp. announces dates for 2010 first quarter financial results release and conference call**

March 29 - 2010 - **Algonquin Power & Utilities Corp. Announces Acquisition of 19th Water Utility System**
Click Here for the Fact Sheet

March 22 - 2010 - **Algonquin Power & Utilities Corp. Declares First Quarter 2010 Dividend**

March 4 - 2010 - **Algonquin Power & Utilities Corp. Announces 2009 Fourth Quarter and Year End Financial Results**
For additional information click here

February 9 - 2010 - **Algonquin Power & Utilities Corp. announces dates for 2009 fourth quarter and year end financial results release and conference call**

January 13 - 2010 - **Algonquin Power & Utilities Corp. Announces Completion of Acquisition of 36.8 MW of Hydroelectric Generating Assets**

Algonquin Power & Utilities Corp. announces dates for 2010 second quarter financial results release and conference call

OAKVILLE, Ontario- July 12th, 2010 – Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN) today announced plans to release 2010 second quarter financial results the afternoon of Thursday, August 12, 2010. APUC will hold an earnings conference call at 10:00 a.m. eastern time on Friday, August 13, 2010, hosted by Chief Executive Officer Ian Robertson and Chief Financial Officer David Bronicheski.

Conference call details are as follows:

Date: Friday, August 13, 2010
Start Time: 10:00 a.m. eastern
Phone Number: Toll free within North America: 1-800-814-4859 or Local 416-644-3414.
Conference ID#: 4327246

For those unable to attend the live call, a digital recording will be available for replay two hours after the call by dialing 1-877-289-8525 or 416-640-1917 access code 4327246# from August 13, 2010 until August 20, 2010.

About Algonquin Power & Utilities Corp.
Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of approximately $1 billion of clean renewable electric generation and sustainable utility distribution assets in North America. Algonquin Power Co., APUC's electric generation subsidiary, includes 45 renewable energy facilities and 14 thermal energy facilities representing more than 480 MW of installed capacity. Liberty Water Co., APUC's water utility subsidiary, provides regulated utility services to more than 70,000 customers with a portfolio of 19 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A and AQN.DB.B.

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EXHIBIT
ADMITTED

Algonquin Power & Utilities Corp. Announces Results of Annual and Special Meeting of Shareholders

OAKVILLE, Ontario- June 23rd, 2010 – Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN) is pleased to announce that at its annual and special meeting (the "Meeting") held on June 23, 2010, shareholders re-appointed KPMG LLP as auditors of APUC, approved all special resolutions put before them at the Meeting and elected to the Board of Directors of APUC, Messrs. Chris Ball, Chris Huskilson, Chris Jarratt, Ken Moore, Ian Robertson and George Steeves.

The special resolutions passed at the Meeting include approval of the issuance of shares in respect of the internalization of management, approval of the shareholder rights plan, and approval of APUC's stock option plan, all of which are outlined in the Notice of Meeting and Information Circular dated May 20, 2010 that is available on SEDAR and on APUC's website at www.algonquinpowerandutilities.com.

ABOUT ALGONQUIN POWER & UTILITIES CORP.
Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of approximately $1 billion of clean renewable electric generation and sustainable utility distribution assets in North America. Algonquin Power Co., APUC's electric generation subsidiary, includes 45 renewable energy facilities and 14 thermal energy facilities representing more than 480 MW of installed capacity. Liberty Water Co., APUC's water utility subsidiary, provides regulated utility services to more than 70,000 customers with a portfolio of 19 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A and AQN.DB.B.

CAUTION REGARDING FORWARD LOOKING INFORMATION
Certain statements included in this news release may contain information that is forward-looking within the meaning of certain securities laws. These statements are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection. Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include including those set out in the management's discussion and analysis section of APUC's 2009 annual report and APUC's Annual Information Form dated March 31, 2010. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

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Algonquin Power & Utilities Corp. Announces Adopts Shareholder Rights Plan

OAKVILLE, Ontario- June 9th, 2010 – Algonquin Power & Utilities Corp. ("APUC") today announced that its Directors have adopted a Shareholder Rights Plan (the "Rights Plan").

The Rights Plan was adopted by the Directors on June 9, 2010 and was adopted to ensure the fair treatment of shareholders in connection with any take-over offer for APUC, and to provide the Directors and shareholders with additional time to fully consider any unsolicited take-over bid. The Rights Plan will also provide the Directors more time to pursue, if appropriate, other alternatives to maximize shareholder value.

The Rights Plan is subject to regulatory approval and is subject to approval by shareholders at APUC's annual and special meeting of shareholders, which will be held in Oakville on June 23, 2010. If approved by shareholders, the Rights Plan will have an initial term of 3 years. APUC is not adopting the Rights Plan in response to any specific proposal to acquire control of APUC. The Rights Plan is similar to plans adopted by other Canadian companies and approved by their shareholders.

The Rights Plan is not intended to prevent take-over bids, but to ensure their proper evaluation. Under the Rights Plan, those bids that meet certain requirements intended to protect the interests of all shareholders are deemed to be "Permitted Bids". Permitted Bids must be made by way of a take-over bid circular prepared in compliance with applicable securities laws and remain open for not less than sixty days.

Under the Rights Plan, Rights have been issued and attached to all shares of APUC issued and outstanding as of the close of business on June 9, 2010. Rights will be issued upon any future issuance of any shares of APUC that occurs prior to the Separation Time (as defined in the Rights Plan).

In the event a take-over bid does not meet the Permitted Bid requirements of the Rights Plan, the Rights will entitle shareholders, other than any shareholder or shareholders making the take-over bid, to purchase additional shares in APUC at a substantial discount to the market value at the time.

ABOUT ALGONQUIN POWER & UTILITIES CORP.
Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of approximately $1 billion of clean renewable electric generation and sustainable utility distribution assets in North America. APCo, APUC's electric generation subsidiary, includes 45 renewable energy facilities and 14 thermal energy facilities representing more than 480 MW of installed capacity. Liberty Water Co., APUC's water utility subsidiary, provides regulated utility services to more than 70,000 customers with a portfolio of 19 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based

regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A and AQN.DB.B.

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Algonquin Power & Utilities Corp. Announces date for Annual and Special Meeting

OAKVILLE, Ontario- June 2nd, 2010 – Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN) today announced the date of the annual and special meeting of its shareholders.

Meeting Details:
Date: June 23, 2010
Time: 4:00 p.m. Eastern Time
Location: Homewood Suites, 2095 Winston Park Drive, Oakville, ON

The Notice of Meeting and Management Information Circular outlining the matters to be dealt with at the meeting are available **here.**

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Algonquin Power & Utilities Corp. Declares Second Quarter 2010 Dividend

OAKVILLE, Ontario- May 7th, 2010 Algonquin Power & Utilities Corp. ("APUC") (TSX:AQN) of Oakville, Ontario announced today that its Directors have declared a dividend on its shares. The dividend is $0.06 per share payable on July 15, 2010 to the shareholders of record on June 30, 2010 for the period from April 1, 2010 to June 30, 2010. For Canadian resident shareholders, dividends declared are considered as "eligible dividends" for purposes of the dividend tax credit rules contained in the Income Tax Act (Canada).

About Algonquin Power & Utilities Corp.
Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of approximately $1 billion of clean, renewable electric generation and sustainable utility distribution assets in North America. APCo, APUC's electric generation subsidiary, includes 45 renewable energy facilities and 14 thermal energy facilities representing more than 480 MW of installed capacity. Liberty Water Co., APUC's water utility subsidiary, provides regulated utility services to more than 70,000 customers with a portfolio of 19 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A and AQN.DB.B.

Caution Regarding Forward-Looking Information
Certain statements included in this news release may contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. These statements are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments. Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include those set out in the management's discussion and analysis section of APUC's 2009 annual report, first quarter 2010 report, and APUC's Annual Information Form dated March 31, 2010. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

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Algonquin Power & Utilities Corp. Announces 2010 First Quarter Financial Results

OAKVILLE, Ontario- May 6th, 2010 - Algonquin Power & Utilities Corp. (TSX: AQN), today announced financial results for the first quarter ended March 31, 2010. On October 27, 2009, Algonquin Power Income Fund became a wholly owned subsidiary of Algonquin Power & Utilities Corp. (collectively "APUC"), maintaining the same operations and business activities, but under a new corporate structure. Year-over-year results will be as compared to the results of Algonquin Power Income Fund in the relevant period.

For the first quarter of 2010, revenue was $45.9 million as compared to $52.2 million in the first quarter of 2009 and $43.4 in the fourth quarter of 2009. The decrease in revenue is primarily the result of the outage at the Energy-from-Waste facility and the lower than average wind resources in many areas of North America which impacted APCo's Renewable Energy division.

Adjusted earnings before interest, taxes, depreciation, and amortization ("Adjusted EBITDA") was $17.9 million in the first quarter of 2010 as compared to $21.1 million in the first quarter of 2009 and $18.0 in the fourth quarter of 2009. The decrease in Adjusted EBITDA is primarily related to lower earnings from operations.

APUC reported net earnings in the first quarter of 2010 of $3.5 million or $0.04 per share as compared to net earnings of $4.2 million or $0.05 per share for the first quarter of 2009 and a net loss of $1.4 million or $0.03 per share in the fourth quarter of 2009.

Adjusted net earnings in the first quarter of 2010 were $3.0 million or $0.03 per share as compared to adjusted net earnings of $7.9 million or $0.10 per share in the first quarter of 2009 and $11.5 million or $0.14 per share in the fourth quarter of 2009. APUC uses adjusted net earnings to assess the net earnings of APUC without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, and interest rate swaps as these are primarily non-cash items that are not reflective of the performance of the underlying business of APUC.

Performance Summary for the first quarter of 2010:

- Revenue of $45.9 million in Q1 2010 as compared to $52.2 million in Q1 2009.
- Adjusted EBITDA of $17.9 million in Q1 2010 as compared to $21.1 million in Q1 2009.
- Adjusted net earnings of $3.0 million or $0.03 per share in Q1 2010 as compared to adjusted net earnings of $7.9 million or $0.10 per share in Q1 2009.
- Net earnings of $3.5 million or $0.04 per share in Q1 2010 as compared to net earnings of $4.2 million or $0.05 per share in Q1 2009.

"While April results show a return to more normal wind conditions at our St. Leon facility, the earnings impact of the refurbishment of our Energy-from-Waste facility will continue to be felt during Q2. Nevertheless, we are confident that our committed 2010 growth initiatives including the previously announced electric utility acquisition, construction of Red Lily Phase I and Liberty Water rate case applications remain on track to deliver full year 2011 earnings per share in line with our targeted dividend payout ratio of 75% to 100%", commented Ian Robertson, Chief Executive Officer of APUC.

APUC's financial information and analysis are available **here.**

APUC will hold an earnings conference call at 10:00 a.m. eastern time on Friday, May 7, 2010, hosted by Chief Executive Officer Ian Robertson and Chief Financial Officer David Bronicheski.

Conference call details are as follows:

Date: Friday, May 7, 2010
Start Time: 10:00 a.m. eastern
Phone Number: Toll free within North America: 1-877-974-0445 or local 416-644-3416.
Conference ID#: 4283874

For those unable to attend the live call, a digital recording will be available for replay two hours after the call by dialing 1-877-289-8525 or 416-640-1917 access code 4283874# from May 7, 2010 until May 14, 2010.

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Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of approximately $1 billion of clean renewable electric generation and sustainable utility distribution assets in North America. APCo, APUC's electric generation subsidiary, includes 45 renewable energy facilities and 14 thermal energy facilities representing more than 480 MW of installed capacity. Liberty Water Co., APUC's water utility subsidiary, provides regulated utility services to more than 70,000 customers with a portfolio of 19 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A and AQN.DB.B.

Caution Regarding Forward Looking Information
Certain statements included in this news release contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. These statements are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments. Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include those set out in the management's discussion and analysis section of

APUC's 2009 annual report and APUC's Annual Information Form dated March 31, 2010. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

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Algonquin Power & Utilities Corp. Announces Commencement of Construction of Phase I of the Red Lily Wind Project

OAKVILLE, Ontario- April 21st, 2010 Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN) is pleased to announce the commencement of construction of the 26.4 MW Phase I Red Lily Wind Project ("Red Lily I") in south-eastern Saskatchewan with the execution of a turbine supply agreement with Vestas Canadian Wind Technology Inc., receipt of all required permits and satisfaction of all conditions for project financing.

The project is owned by Concord Pacific Group who will make an equity investment of approximately $19 million in the development of the project. Total capital investment for the project is expected to be $67.5 million. In addition to the $19 million of equity investment, the project costs will be financed with $31 million of senior debt provided by Integrated Private Debt Fund II LP and $17.5 million of senior and subordinated debt provided by Algonquin Power Co. ("APCo"). APCo will provide services to and will receive fees for the development, construction, operation and supervision of the project. In addition, APCo has been granted an option to subscribe for a 75% equity interest in the project in exchange for its subordinated debt commitment, exercisable five years following commissioning of the project.

Red Lily I, initially developed by Gaia Power Inc., will consist of 16 Vestas V82 wind turbine generators, which have been procured and are awaiting shipment from a Canadian storage location. Red Lily I enjoys an excellent wind resource with annual gross revenues of $7.5 million expected in the first year of production and $8 million expected in the second year. The power purchase agreement with SaskPower is for 25 years and includes a 2% annual increase throughout the term of the agreement. Commissioning of the project is expected to occur in early 2011.

"The construction of Red Lily I demonstrates APUC's continuing contribution to the clean, renewable energy business and reinforces APUC's strategic focus on increasing earnings per share which will contribute to growing dividends and capital appreciation for our shareholders", commented Ian Robertson, Chief Executive Officer of APUC. "We are very pleased to be extending our renewable power investment into Saskatchewan. The local support for the project is overwhelming and both APCo and Concord Pacific look forward to continuing to work within the Regional Municipalities of both Martin and Moosomin on this and future projects".

In addition to the effort focused on completing Red Lily I, APCo, together with the owner, has secured additional land rights for a second phase of the project, which, should it proceed, would provide an additional 106 MW of generating capacity.

Click Here for the Fact Sheet

ABOUT ALGONQUIN POWER & UTILITIES CORP.

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ABOUT CONCORD PACIFIC GROUP Concord Pacific Group is a Canadian organization developing multi-phased, master planned residential communities. Its developments include Concord Pacific Place in Vancouver, British Columbia, Concord CityPlace in Toronto, Ontario, and Concord Park Place in North York.

CAUTION REGARDING FORWARD LOOKING INFORMATION

Certain statements included in this news release contain information that is forward-looking within the meaning of certain securities laws, including information and statements regarding prospective results of operations, financial position or cash flows. These statements are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments. Since forward-looking statements relate to future events and conditions, by their very nature they require making assumptions and involve inherent risks and uncertainties. APUC cautions that although it is believed that the assumptions are reasonable in the circumstances, these risks and uncertainties give rise to the possibility that actual results may differ materially from the expectations set out in the forward-looking statements. Material risk factors include including those set out in the management's discussion and analysis section of APUC's 2009 annual report and APUC's Annual Information Form dated March 31, 2010. Given these risks, undue reliance should not be placed on these forward-looking statements, which apply only as of their dates. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

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Algonquin Power & Utilities Corp. announces dates for 2010 first quarter financial results release and conference call

OAKVILLE, Ontario- April 16th, 2010 Algonquin Power & Utilities Corp. ("APUC") (TSX: AQN) today announced plans to release 2010 first quarter financial results the afternoon of Thursday, May 6, 2010. APUC will hold an earnings conference call at 10:00 a.m. eastern time on Friday, May 7, 2010, hosted by Chief Executive Officer Ian Robertson and Chief Financial Officer David Bronicheski.

Conference call details are as follows:

Date: Friday, May 7, 2010
Start Time: 10:00 a.m. eastern
Phone Number: Toll free within North America: 1-877-974-0445 or local 416-644-3416.
Conference ID#: 4283874

For those unable to attend the live call, a digital recording will be available for replay two hours after the call by dialing 1-877-289-8525 or 416-640-1917 access code 4283874# from May 7, 2010 until May 14, 2010.

About Algonquin Power & Utilities Corp.
Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of approximately $1 billion of clean renewable electric generation and sustainable utility distribution assets in North America. Algonquin Power Co., APUC's electric generation subsidiary, includes 45 renewable energy facilities and 14 thermal energy facilities representing more than 480 MW of installed capacity. Liberty Water Co., APUC's water utility subsidiary, provides regulated utility services to more than 70,000 customers with a portfolio of 19 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A and AQN.DB.B. Visit Algonquin Power & Utilities Corp. on the web at www.AlgonquinPowerandUtilities.com.

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Algonquin Power & Utilities Corp. Announces Acquisition of 19th Water Utility System

OAKVILLE, Ontario- March 29nd, 2010 Algonquin Power & Utilities Corp. (TSX: AQN) ("APUC") is pleased to announce that its wholly owned subsidiary Liberty Water Co. ("Liberty Water") has completed the acquisition of an additional water distribution and wastewater collection system (the "Galveston System") for a total purchase price of $2,000,000. Located near Galveston, Texas, the Galveston System provides water distribution and waste water collection to approximately 260 equivalent residential connections. Liberty Water is expected to earn a return on and of the net asset value of the Galveston System ($2,000,000) equivalent to that provided by the Texas Commission on Environmental Quality of approximately 12% after application of regulatory taxes.

"The earnings and cash flow accretion generated by these long lived, utility grade water distribution and wastewater collection assets are consistent with Liberty Water's objective of accretively expanding its water utility asset base and supports APUC's commitment to providing total shareholder return through a combination of predictable and growing earnings and dividends together with capital appreciation" commented Ian Robertson, the Chief Executive Officer of APUC. "The operation and administration of the Galveston System will capitalize on economies of scale from Liberty Water's regional office located in Tyler, Texas" he continued.

ABOUT ALGONQUIN POWER & UTILITIES CORP.
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Click Here for the Fact Sheet

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Algonquin Power & Utilities Corp. Declares First Quarter 2010 Dividend

OAKVILLE, Ontario- March 22nd, 2010 Algonquin Power & Utilities Corp. ("Algonquin") (TSX.AQN) of Oakville, Ontario announced today that its Directors have declared a dividend on its shares. The dividend is $0.06 per share payable on April 15, 2010 to the shareholders of record on March 31, 2010 for the period from January 01, 2010 to

March 31, 2010. For Canadian resident shareholders, dividends declared are considered as "eligible dividends" for purposes of the dividend tax credit rules contained in the Income Tax Act (Canada).

Algonquin currently has 93,661,913 common shares outstanding.

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Algonquin Power & Utilities Corp. Announces 2009 Fourth Quarter and Year End Financial Results

OAKVILLE, Ontario- March 4th, 2010 Algonquin Power & Utilities Corp. (TSX: AQN), today announced financial results for the fourth quarter and year ended December 31, 2009. On October 27, 2009, Algonquin Power Income Fund became a wholly owned subsidiary of Algonquin Power & Utilities Corp., maintaining the same operations and business activities, but under a corporate structure with Algonquin Power Income Fund's unitholders becoming shareholders of the new Algonquin Power & Utilities Corp. (collectively "APUC").

APUC ended the year having completed several significant accomplishments. The change in business form from an income trust structure to a corporate structure will facilitate APUC's long term growth as it now focuses on providing total shareholder return through a combination of dividends and capital appreciation realized through the successful execution of its business strategies. Major growth initiatives accomplished in the year included the announcement of the acquisition of a regulated electricity distribution utility in California, serving over 47,000 customers, which is expected to close later in 2010. APUC also grew its renewable power portfolio with the announcement of the acquisition of 36.8 MW of hydroelectric generating assets in New Brunswick and Maine which closed on January 12, 2010.

For the fourth quarter of 2009, revenue was $43.4 million as compared to $56.5 million in the fourth quarter of 2008 and $45.1 in the third quarter of 2009. The decrease in revenue is due to reduced average energy rates and lower demand for steam at the Sanger and Windsor Locks facilities in the Thermal Energy division and lower weighted average energy rates and lower average hydrology and wind resources in the Renewable Energy division. In addition, revenue decreased as a result of a stronger Canadian dollar as compared to the same period in 2008.

Adjusted earnings before interest, taxes, depreciation, and amortization ("Adjusted EBITDA") was $18.0 million in the fourth quarter of 2009 as compared to $23.3 million in the fourth quarter of 2008 and $20.3 in the third quarter of 2009. The decrease in Adjusted EBITDA is primarily related to lower gas prices and reduced demand for steam at APUC's thermal energy facilities and lower average energy rates earned by the U.S. renewable energy facilities.

Adjusted net earnings in the fourth quarter of 2009 were $11.5 million or $0.14 per share as compared to adjusted net earnings of $8.8 million or $0.12 per share in the fourth quarter of 2008 and $13.1 million or $0.09 per share in the third quarter of 2009. APUC uses adjusted net earnings to assess the net earnings of APUC without the effects of gains or losses on foreign exchange, foreign exchange forward contracts, and interest rate swaps as these are primarily non-cash items that are not reflective of the performance of the underlying business of APUC.

APUC reported a net loss in the fourth quarter of 2009 of $1.4 million or $0.03 per share as compared to a net loss of $21.1 million or $0.28 per share for the fourth quarter of 2008 and net earnings of $13.1 million or $0.17 per share in the third quarter of 2009. .

Performance Summary for the fourth quarter of 2009:

- Revenue of $43.4 million in Q4 2009 as compared to $56.5 million in Q4 2008.
- Adjusted EBITDA of $18.0 million in Q4 2009 as compared to $23.3 million in Q4 2008.
- Adjusted net earnings of $11.5 million or $0.14 per share in Q4 2009 as compared to adjusted net earnings of $8.8 million or $0.12 per share in Q4 2008.
- Net loss of $1.4 million or $0.03 per share in Q4 2009 as compared to a net loss of $21.1 million or $0.28 per share in Q4 2008.

Performance Summary for the year ended December 31, 2009:

- Revenue of $187.3 million for the year 2009 as compared to $213.8 million in 2008.
- Adjusted EBITDA of $79.4 million for the year 2009 as compared to $90.0 million in 2008.
- Adjusted net earnings of $30.5 million or $0.38 per share in 2009 as compared to adjusted net earnings of $18.9 million or $0.25 per share in 2008.
- Net earnings of $31.3 million or $0.39 per share in 2009 as compared to a net loss of $19.0 million or $0.25 per share in 2008.

"APUC is pleased at the breadth and scope of the significant changes which have occurred through 2009, with the

organization finishing the year looking dramatically different than when it entered the year," commented Ian Robertson, Chief Executive Officer of APUC. "Despite the volatility in the capital markets and wavering global economic environment in 2009, APUC achieved several major goals we had set for ourselves including positioning the company for growth in 2010 by strengthening our balance sheet through our $86 million dollar financing of common shares and convertible debentures in December. APUC is optimistic that the diversification of its portfolio, coupled with the impact of its committed growth initiatives, will serve the organization well in 2010."

Click **here** for APUC's financial information and analysis.

APUC will hold an earnings conference call at 10:00 a.m. eastern time on Friday, March 5, 2010, hosted by Chief Executive Officer Ian Robertson and Chief Financial Officer David Bronicheski.

Conference call details are as follows:

Date: Friday, March 5, 2010
Start Time: 10:00 a.m. eastern
Phone Number: Toll free within North America: 1-877-974-0446 or local 416-644-3418.
Conference ID#: 4224434

For those unable to attend the live call, a digital recording will be available for replay two hours after the call by dialing 1-877-289-8525 or 416-640-1917 access code 4224434# from March 5, 2010 until March 12, 2010.

About Algonquin Power & Utilities Corp.
Through its distinct operating subsidiaries, APUC owns and operates a diversified portfolio of clean renewable electric generation and sustainable utility distribution businesses throughout North America. APUC's electric generation subsidiary, carrying on business as Algonquin Power Co., includes 45 renewable energy facilities and 11 high efficiency thermal energy facilities representing more than 450 MW of installed capacity. Through its wholly owned subsidiary, Liberty Water Co., APUC provides regulated utility services to more than 70,000 customers across 18 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, APUC is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. APUC and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the aggressive pursuit of accretive acquisition opportunities. APUC's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A, and AQN.DB.B. Visit Algonquin Power & Utilities Corp. on the web at www.AlgonquinPowerandUtilities.com.

Forward-Looking Information
This news release may contain certain information that is future-oriented, including information and statements regarding prospective results of operations, financial position or cash flows. These statements and information are forward-looking, and are based on factors or assumptions that were applied in drawing a conclusion or making a forecast or projection, including assumptions based on historical trends, current conditions and expected future developments, and other factors believed to be appropriate in the circumstances. Although the forward-looking statements and information are based upon management's current expectations and assumptions, they are subject to numerous risks and uncertainties, including those set out in the management's discussion and analysis section of APUC's 2008 annual report, APUC's Annual Information Form dated March 31, 2009, and APUC's Management Information Circular dated March 20, 2009. Readers are cautioned that such risks and uncertainties may cause APUC's actual results to vary materially from those expressed in, or implied by, the forward-looking statements and information. Any forward-looking statements or information contained in this news release are made as of the date hereof for the purpose of providing readers with APUC's expectations for the coming financial period(s), and may not be appropriate for other purposes. Other than as specifically required by law, APUC undertakes no obligation to update any forward-looking statements or information to reflect new information, subsequent or otherwise.

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Algonquin Power & Utilities Corp. announces dates for 2009 fourth quarter and year end financial results release and conference call

OAKVILLE, Ontario- February 9th, 2010 Algonquin Power & Utilities Corp. ("Algonquin") (TSX: AQN) today announced plans to release 2009 fourth quarter and year end financial results the afternoon of Thursday, March 4, 2010. Algonquin Power will hold an earnings conference call at 10:00 a.m. eastern time on Friday, March 5, 2010, hosted by Chief Executive Officer Ian Robertson and Chief Financial Officer David Bronicheski.

Conference call details are as follows:

Date: Friday, March 5, 2010
Start Time: 10:00 a.m. eastern
Phone Number: Toll free within North America: 1-877-974-0446 or local 416-644-3418.
Conference ID#: 4224434

For those unable to attend the live call, a digital recording will be available for replay two hours after the call by dialing 1-877-289-8525 or 416-640-1917 access code 4224434# from March 5, 2010 until March 12, 2010.

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Algonquin Power & Utilities Corp. Announces Completion Of Acquisition Of 36.8 MW Of Hydroelectric Generation Assets

TORONTO, ONTARIO – January 13, 2010 – Algonquin Power & Utilities Corp. ("Algonquin") (TSX: AQN) is pleased to announce that it has completed the acquisition of 36.8 MW of electrical generating assets (the "Hydro Assets") previously announced on November 10, 2009, located in New Brunswick and Maine from Integrys Energy Services Inc. after satisfying the conditions of the acquisition including regulatory approval. Through the purchase of shares and assets, Algonquin has acquired three hydroelectric generating stations, most notably the 34.5MW Tinker Hydroelectric station located on the Aroostook River near the Town of Perth-Andover, New Brunswick. Additionally, Algonquin acquired five thermal generating stations and certain regulated NB ISO transmission lines located in proximity to the generating facilities. Due to confidentiality provisions with the seller, the purchase price has not been disclosed. For additional information on the acquired assets, please refer to the fact sheet posted on Algonquin's website. The acquisition has been financed with $20 million of new equity and the balance with a portion of the long term convertible debentures from the offering of Algonquin shares and
debentures that was completed on December 2, 2009. " We are very pleased with the recent acquisition of these long lived, utility grade Hydro Assets" stated Ian Robertson, Chief Executive Officer. "We believe this acquisition is accretive and will help us grow earnings from our portfolio of renewable and clean energy generating assets".

ABOUT ALGONQUIN POWER & UTILITIES CORP.
Through its distinct operating subsidiaries, Algonquin owns and operates a diversified portfolio of clean renewable electric generation and sustainable utility distribution businesses throughout North America. Algonquin's electric generation subsidiary includes 42 renewable energy facilities and 11 high efficiency thermal energy facilities representing more than 400 MW of installed capacity. Through its wholly owned subsidiary, Liberty Water Co., Algonquin provides regulated utility services to more than 70,000 customers across 18 water distribution and wastewater treatment utility systems. Pursuant to a previously announced agreement, Algonquin is committed to acquiring the California based regulated utility electric distribution and generation assets of NV Energy which serve approximately 47,000 retail electricity distribution customers. Algonquin and its operating subsidiaries deliver continuing growth through an expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the aggressive pursuit of accretive acquisition opportunities. Algonquin's common shares and convertible debentures are traded on the Toronto Stock Exchange under the symbols AQN, AQN.DB, AQN.DB.A, and AQN.DB.B. Visit Algonquin Power & Utilities Corp. on the web at www.AlgonquinPower.com.
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Mat. G

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SANDRA D. KENNEDY
BOB STUMP

ARIZONA CORPORATION COMMISSION

ERNEST G. JOHNSON
Executive Director

EXHIBIT
R-2
ADMITTED

November 17, 2009

Ms. Julie Baldwin
Development Services Coordinator
Algonquin Water Services, L.L.C.
12725 West Indian School Road
Suite D101
Avondale, Arizona 85392

Dear Ms. Baldwin:

The enclosed Main Extension Agreement between Bella Vista Water Company and Sierra Vista Regional health Center / LXA #7034 has met the provisions of A.A.C. R14-2-406, or company approved tariffs, and is approved, excepting those provisions, if any, not within the jurisdiction of the Arizona Corporation Commission.

A copy of this agreement will remain on file in the Utilities Division's Central Files.

Sincerely,

Vicki Wallace

Vicki Wallace
Executive Consultant
Utilities Division

VW:tdp

Enclosures

THIS WATER LINE EXTENSION AGREEMENT ("Agreement"), entered into this 4th day of August, 2009 by and between BELLA VISTA WATER COMPANY, an Arizona public service corporation, (hereinafter referred to as "Utility"), and SIERRA VISTA REGIONAL HEALTH CENTER, INC., an Arizona corporation, (hereinafter referred to as "Developer")(individually, a "Party" and collectively, "Parties"), in respect of the construction of utility infrastructure necessary to extend and provide water utility service to the Sierra Vista Regional Health Center Service Building, a commercial land parcel owned by the Developer in Cochise County, Arizona as shown in **Exhibit "A"** (hereinafter called the "Development").

RECITALS

WHEREAS, Utility represents and warrants to Developer that it is a public service corporation, and holds a Certificate of Convenience and Necessity (the "CC&N") granted by the Arizona Corporation Commission ("Commission"), together with other required permits and governmental approvals authorizing it to serve the public with water utility service in certain parts of Cochise County, Arizona; and

WHEREAS, Developer desires that water utility service be extended to the Development, which consists of approximately 75.31 acres of commercial development located in Sierra Vista, in Cochise County, Arizona. A legal description and map of the proposed Development are attached hereto in **Exhibit "A"** and incorporated herein by reference for all purposes; and

WHEREAS, the Development is located within the Utility's CC&N, and Utility is willing to extend water utility service to the Development subject to the terms of this Agreement; and

WHEREAS, the Utility does not presently have onsite water distribution facilities within the Development and Developer is prepared to construct and then convey such facilities all at his sole unrecoverable expense as may be provided for herein; and

WHEREAS, the Utility does not presently have sufficient or appropriate off-site facilities to convey the water to the Development and the Developer is prepared to either: i) construct such facilities and convey them to the Utility and/or, ii) provide the advance funding to Utility so that Utility may construct such off-site facilities (an In-Kind Advance or Money Advance and together Advance) and in either case the cost thereof shall be subject to a partial refunding to the Developer over time as may be provided for herein; and

WHEREAS, Developer is willing to transfer to the Utility legal title to: i) all on-site facilities within the Development, ii) all offsite facilities that are necessary to extend water utility service to the Development which it undertakes to construct, subject to the terms and conditions set forth hereinafter; and

Calculation of Advance. Based on the estimated costs for Facilities and Capacity Costs contained in Paragraph I.C, and Deposit in Paragraph I.D, and subject to receiving invoices pursuant to Paragraph VI.A totaling at least the estimated cost plus applicable Administrative Costs, the total refundable estimated Advance by Developer is **$24,465.60**, subject to adjustment as provided for in this Agreement. If the actual Advance is less than the estimated Advance, the Advance shall be the lesser amount, to the extent supported by invoices provided pursuant to Paragraphs I.D and VI.A. If the actual Advance is more than the estimated Advance, the Advance shall be the greater amount, to the extent supported by invoices provided pursuant to Paragraphs I.D and VI.A.

Time of Payment. The payment of the funds under this Agreement shall be made as follows:

1. Developer shall submit as the initial Deposit for the Utility's total estimated Administrative Costs the sum of **$5,000** upon execution of this Agreement.

2. If the Deposit is greater than $5,500, Utility shall compute the unexpended portion of the Deposit, if applicable, and refund any such amount over $5,000 within sixty (60) days of Utility's Final Acceptance of the Facilities pursuant to Paragraph IV.F. All other amounts shall be added to the Advance.

3. Upon completion of the construction of the Facilities to be performed by Developer, Developer shall provide the documentation required by Paragraphs III, IV, V, and VI of this Agreement.

4. Developer shall either pay the estimated Capacity Costs upon execution of the Agreement in the amount of **$5,792.60**, or post a LOC in the amount of **$5,792.60** within ten (10) calendar days upon execution this Agreement.

C. Income Taxes. In the event it is determined by Congress, the Internal Revenue Service, the Arizona Legislature or the Arizona Department of Revenue that all or a portion of the cost estimates in **Exhibit "C"** is taxable income to the Utility as of the date of this Agreement, or upon receipt of said costs or facilities by the Utility, Developer will pay to the Utility funds equal to the applicable income taxes for the Utility's state and federal tax liability on all funds contributed pursuant to this Agreement. These funds shall be payable by Developer to the Utility within thirty (30) days after the Utility provides to Developer written notice of such taxes, along with reasonable supporting documentation.

D. Computation of Refund. The Utility shall refund to Developer the Advance by making annual payments (each an "**Advance Refund Payment**" and collectively, the "**Advance Refund Payments**") on or before the 31st day of August of each year. Each Advance Refund Payment shall be equal to ten percent (10%) of the gross annual operating revenues, exclusive of any taxes or pass-through costs by Utility, from the sale of water utility services to bona fide customers of Utility within the Development. Any other amounts to be refunded by the Utility to

Initials

Developer pursuant to this Agreement, including without limitation, the amount of any income taxes pursuant to Paragraph VII.C, shall be in addition to the Advance Refund Payments, and shall be paid contemporaneously with each Advance Refund Payment. The Utility shall continue to pay Advance Refund Payments for a period of ten (10) years. Utility retains the right to refund all or any portion of the outstanding Advance balance to Developer at any time prior to the termination of refunds made pursuant to this Agreement, and to extend the refund period prior to the expiration of the initial 10-year term, upon proper notice to the Developer. Any amount of the Advance that has not been refunded to Developer at the end of the refund period, or extended refund period, shall become a contribution in aid of construction.

E. Maximum Refund; Interest on Advance; Limitation on Revenues. The sum total of the Advance Refund Payments shall in no event exceed the amount of the Advance, as adjusted. No interest shall be paid by the Utility on any amounts to be refunded to Developer pursuant to this Agreement.

F. Transfer of Facilities. In the event of the sale, conveyance or transfer by the Utility, pursuant to the approval of the Commission, of any portion of its water system, including the Facilities, the Utility's obligation hereto shall cease (except as to any payment which is then due), conditioned upon the transferee assuming, and agreeing to pay Developer, any sums becoming payable to Developer thereafter in accordance with the provisions of this Agreement.

G. Assignment; Utility's Right of First Refusal. Developer may assign this Agreement, or any of its rights and obligations hereunder, to another party, including another company under the same corporate umbrella, provided that such assignment is made in connection with the sale of the Development and further provided that Developer first receives written consent of such assignment from Utility prior to the effective date of the assignment, which consent shall not be unreasonably withheld; provided, however, that Developer acknowledges that Utility may, in its sole discretion, require that the assignee agree in writing to fully perform Developer's obligations hereunder to be bound by this Agreement and to require that the assignee demonstrate financial ability to assume Developer's obligations hereunder. Before selling, assigning or otherwise transferring to any third party Developer's right to the receipt of the Advance Refund Payments or any other payment from the Utility pursuant to this Agreement, Developer shall first give the Utility, or its assigns, reasonable opportunity to purchase the same at the same price and upon the same terms as contained in any bona fide offer which Developer has received from any third person or persons which Developer desires to accept. Upon such assignment, the Utility shall make all refunds under the Agreement to the Developer's assignee.

VIII. RISK; LIABILITY; INSURANCE

A. Risk. Developer shall carry on all work required hereunder at its own risk until Completion and will, in case of accident, destruction or injury to the work or material before Completion, replace or repair forthwith the work or materials so injured, damaged or destroyed, in accordance with the Approved Plans, to the reasonable satisfaction of the Utility and at Developer's own expense.

Initials

BEFORE THE ARIZONA CORPORATION C . .

Arizona Corporation Commission
DOCKETED
NOV 27 2007
DOCKETED BY

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-06-0463
IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. TO REVIEW AND REVISE ITS PURCHASED GAS ADJUSTOR.	DOCKET NO. G-04204A-06-0013
IN THE MATTER OF THE INQUIRY INTO THE PRUDENCE OF THE GAS PROCUREMENT PRACTICES OF UNS GAS, INC.	DOCKET NO. G-04204A-05-0831

DECISION NO. 70011

OPINION AND ORDER

DATES OF HEARING: April 16, 17, 18, 19, 20, 24, and 25, 2007.

PLACE OF HEARING: Phoenix, Arizona

ADMINISTRATIVE LAW JUDGE: Dwight D. Nodes

IN ATTENDANCE: Mike Gleason, Chairman
Kristin K. Mayes, Commissioner

APPEARANCES: Mr. Michael W. Patten and Mr. Timothy Sabo, ROSHKA, DEWULF & PATTEN, P.L.C. and Ms. Michelle Livengood, UNISOURCE ENERGY SERVICES, on behalf of Applicant;

Mr. Scott S. Wakefield, Chief Counsel, on behalf of the Residential Utility Consumer Office;

Ms. Cynthia Zwick, Executive Director, Arizona Community Action Association;

Mr. Marshall Magruder, in propria persona; and

Mr. Keith Layton and Ms. Maureen Scott, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

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

Deduction of Customer Advances

The final issue raised in UNS's trilogy of CWIP-related issues is its plea that the Commission should not reduce rate base to recognize funds received for customer advances, if the Commission rejects UNS's request for CWIP or, alternatively, for post-test-year plant. The Company concedes that such advances are typically deducted from rate base because they represent customer-supplied capital. However, UNS contends that it has received approximately $4 million in customer advances related to the $7 million in CWIP plant investment (Ex. A-28 at 27). Thus, according to UNS, the net impact on rates (if the requested $7 million of CWIP were to be included in rate base) is $3 million, based on the net of the $7 million offset by $4 million in advances.

UNS argues that it is inherently unfair to exclude the advances from rate base if the plant associated with those advances is not yet in service and not included in rate base. UNS claims that the purpose of deducting advances (*i.e.*, recognizing customer-supplied capital) is not furthered when

the plant is not in service. The Company also contends that the deduction of advances in this case would discourage utilities from seeking advances to offset infrastructure capital costs.

Both Staff and RUCO oppose the Company's recommendation. Staff witness Ralph Smith states that because advances represent non-investor-supplied capital, they should be reflected as a deduction to rate base. He stated that Staff is not aware of any instance in which CWIP was excluded for a major utility in Arizona and customer advances were not reflected as a deduction to rate base. Mr. Smith also cites to A.A.C. R14-2-103, Appendix B, Schedule B-1, which he claims requires companies to reflect advances as a deduction from rate base (Ex. S-27 at 15-16).

RUCO witness Marylee Diaz Cortez agreed with Staff's recommendation regarding advances. She testified that the Commission has historically excluded CWIP from rate base and recognized contributions (advances) as a deduction from rate base and that UNS is being afforded (under RUCO's and Staff's recommendations) the same rate base treatment as every other utility in Arizona (RUCO Ex. 6 at 8). Ms. Diaz Cortez claims that it is only the Company's proposal to include CWIP which creates a mismatch, because UNS failed to include the additional revenues the construction projects generate (*Id.* at 8-9).

We agree with Staff and RUCO that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNS not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base. The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.

As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNS's CWIP-related proposals are entirely

consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

Geographic Information System

UNS seeks to include in rate base $897,068 for expenses incurred during 2003 and 2004 to install a Geographic Information System ("GIS"). The GIS is a global positioning system that allows UNS to locate existing service lines. UNS witness Gary Smith testified that the Company installed the GIS in response to a Commission Pipeline Safety audit that recommended a complete mapping of the UNS system. He described several benefits of the GIS, including improved response times, better informed decisions regarding adding system infrastructure, and increased accuracy for field staff (Ex. A-15 at 6-7).

According to Staff witness Ralph Smith, the GIS costs should not be included in rate base because they were non-recurring expenses that were largely incurred outside of the test year. He explained that, according to internal Company memos, UNS initially decided to treat the GIS as a capitalized investment, but later determined that capitalization of the costs was inappropriate under Generally Accepted Accounting Principles ("GAAP"). Mr. Smith stated that, under GAAP, the GIS costs were required to be expensed during the period in which they were incurred and, since they were incurred prior to the test year, are not properly includable in rates (Ex. S-27 at 16-18).

RUCO also opposes inclusion of the GIS expenses in rates. RUCO witness Marylee Diaz Cortez stated that because UNS failed to obtain from the Commission an accounting order to treat the GIS expenses as a regulatory asset, which would be eligible for future rate recovery consideration, the Company is not entitled to recover those costs in this rate proceeding (RUCO Ex. 5 at 11-12; RUCO Ex. 6 at 9-10). RUCO argues that regardless of the Company's increased productivity claims, its failure to properly account for the GIS costs precludes recovery in UNS's rate base.

We agree with Staff and RUCO that the GIS costs are not properly recoverable as a regulatory asset in this proceeding. As described by Staff witness Ralph Smith, the GIS costs were required by GAAP to be expensed, and the vast majority of those costs were incurred prior to the test year and are non-recurring in nature (Ex. S-25 at 12-17). Further, the Company's failure to seek an accounting order from the Commission when the costs were incurred renders them unrecoverable as a regulatory

BEFORE THE ARIZONA CORPORATION C

COMMISSIONERS

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

Arizona Corporation Commission
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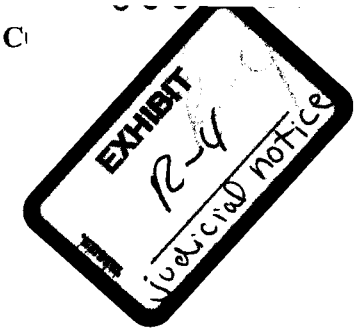


IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND REQEUST FOR APPROVAL OF RELATED FINANCING.	DOCKET NO. E-04204A-06-0783 DECISION NO. 70360 **OPINION AND ORDER**

DATES OF HEARING:	September 10, 11, 12, 13, 14, 20, 21, and October 2, 2007.
PLACE OF HEARING:	Phoenix, Arizona
ADMINISTRATIVE LAW JUDGE:	Teena Wolfe[1]
IN ATTENDANCE:	William A Mundell, Commissioner Kristin A. Mayes, Commissioner
APPEARANCES:	Mr. Michael W. Patten and Mr. Jason Gellman, ROSHKA, DEWULF & PATTEN, PLC, on behalf of UNS Electric, Inc.; Ms. Michelle Livengood on behalf of Unisource Energy Services; Mr. Daniel Pozefsky, on behalf of the Residential Utility Consumer Office; Mr. Marshall Magruder, in propria persona; and Ms. Maureen Scott, Senior Attorney, and Mr. Kevin Torrey, Staff Attorney, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

[1] Administrative Law Judge Teena Wolfe conducted the hearing in this case and Administrative Law Judge Dwight Nodes drafted the Recommended Opinion and Order.

Deduction of Customer Advances

The final issue raised by UNSE related to the allowance of CWIP is the Company's request that the Commission not reduce rate base to recognize funds received for customer advances, if the Commission rejects UNSE's request for CWIP or, alternatively, for post-test-year plant. The Company concedes that such advances are typically deducted from rate base because they represent customer-supplied capital. However, UNSE contends that it has received approximately $1.9 million in customer advances related to the $10.8 million in CWIP plant investment (Ex. A-35 at 19).

UNSE argues that it is inherently unfair to exclude the advances from rate base if the plant associated with those advances is not yet in service and not included in rate base. UNSE claims that the purpose of deducting advances (*i.e.*, recognizing customer-supplied capital) is not furthered when the plant is not in service. The Company also contends that the deduction of advances in this case would discourage utilities from seeking advances to offset infrastructure capital costs.

Staff opposed the Company's recommendation. Staff witness Ralph Smith stated that because advances represent non-investor-supplied capital, they should be reflected as a deduction to rate base. He stated that Staff is not aware of any instance in which CWIP was excluded for a major utility in Arizona and customer advances were not reflected as a deduction to rate base. Mr. Smith also cited to A.A.C. R14-2-103, Appendix B, Schedule B-1, which he claims requires companies to reflect advances as a deduction from rate base. Finally, Mr. Smith testified that the Company's computation of AFUDC does not reduce the project balance, on which the AFUDC rate is applied, for customer advances. Rather, UNSE records customer advances in a liability account (Ex. S-58 at 17; Tr. 1039-41).

Consistent with our treatment of this issue in the UNS Gas rate case, we agree with Staff that advances represent customer-supplied funds that are properly deducted from the Company's rate base. Indeed, the Commission's own rules contemplate that such a deduction is required, as Staff witness Smith testified. Had UNSE not requested the inclusion of CWIP in rate base, a ratemaking treatment that is only afforded under extraordinary circumstances (and apparently has not occurred for more than 20 years), there would presumably not have been an issue raised by the Company with respect to an alleged "mismatch" between exclusion of CWIP and deducting advances from rate base.

The Company's attempt to frame this issue as one in which it is being treated in a discriminatory manner is unpersuasive.

As we have stated in prior cases, regulated utility companies control the timing of their rate case filings and should not be heard to complain when their chosen test periods do not coincide with the completion of plant that may be considered used and useful and therefore properly included in rate base. We believe our conclusions regarding UNSE's CWIP-related proposals are entirely consistent with the treatment that has been afforded to other utility companies regulated by the Commission and provide a result that is fair to both the Company and its customers.

AFUDC Accrual on New Construction Projects

UNSE witness Grant proposed that, even if the Commission grants its request for inclusion of CWIP in rate base, the Company should be permitted to continue accruing AFUDC on all eligible construction projects on a going-forward basis (Ex. A-35, at 35-6). Given our denial of the Company's CWIP proposal, this issue becomes a moot point.

Accumulated Deferred Income Taxes

Based on its recommendations in this case, Staff adjusted rate base by $161,555 to account for removal of accumulated deferred income tax ("ADIT") related to its recommendation regarding the Company's Supplemental Executive Retirement Plan ("SERP"), and removal of the ADIT related to stock-based compensation (Ex. S-58 at 19-20). Staff claims that UNSE did not contest these ADIT adjustments, which Staff asserts are necessary to reconcile rate base with the components of operating income adjustments.

In its brief, UNSE does not dispute the ADIT issues raised by Staff, which are reconciliation adjustments flowing through from several operating income issues and are addressed below. However, the Company does take issue with RUCO's proposed adjustments related to ADIT for Contributions in Aid of Construction ("CIAC") and for Administrative and General ("A&G") expenses (Ex. A-7 at 11-12).

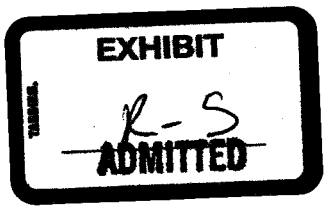
RUCO witness Marylee Diaz Cortez recommended removal of $888,390 from UNSE's rate base based on her claim that the Company failed to follow the NARUC Uniform System of Accounts ("USOA") requirement to include CIAC in Account 271 (RUCO Ex. 10-11). With respect to ADIT

Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment 3

Exhibit
Schedule B-2
Page 5
Witness: Bourassa

Deferred Income Tax as of March 31, 2009

Line No.		Adjusted Book Value[1]	Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
6	Plant-in-Service	$ 28,165,701								
7	Accum. Deprec.	(12,057,912)								
8	CIAC	(542,445)								
9	Fixed Assets	$ 15,565,344	$ 9,232,954	100.0%	$ (6,332,390)	38.6%		-		(2,444,232)
10	AIAC		6,781,443	100.0%	$ 6,781,443	38.6%		$ 2,617,561		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	38.6%		$ -		
12							$ -	$ 2,617,561	$ -	$ (2,444,232)
13										
14					Net Asset (Liability)		$ 173,329			
15										
16	Factor						1.00000			
17										
18	Allocated DIT Asset (Liability)						$ 173,329			
19										
20	DIT Asset (Liability) per books						$ 101,160			
21										
22	Adjustment to DIT						$ (72,169)			
23										
24	[1] Adjusted - per B-2, page 2									
25										
26										



Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
Original Cost Rate Base Proforma Adjustments
Adjustment 3

Exhibit
Rebuttal Schedule B-2
Page 5
Witness: Bourassa

Line No.											
1	Deferred Income Tax as of March 31, 2009										
2											
3											
4		Adjusted		Probability of Realization of Future	Deductible TD (Taxable TD) Expected to	Tax	Future Tax Asset		Future Tax Liability	
5		Book Value	Tax Value	Tax Benefit	be Realized	Rate[5]	Current	Non Current	Current	Non Current
6	Plant-in-Service	$ 26,610,749 [1]								
7	Accum. Deprec.	(10,528,021) [1]								
8	CIAC	(4,472,325) [3]						-		(1,282,539)
9	Fixed Assets	$ 11,610,403	$ 8,287,666 [2]	100.0%	$ (3,322,737)	38.6%		$ 710,533		
10	AIAC		6,136,045 [4]	30.0%	$ 1,840,813 [4]	38.6%		$ -		
11	Tax Benefits from O.L. Carry Forward			100.0%	$ -		$ -	$ 710,533	$ -	$ (1,282,539)
12										
13										
14	Allocated DIT Asset (Liability)						$ (572,006)			
15										
16	DIT Asset (Liability) per Direct						$ 173,329			
17										
18	Adjustment to DIT						$ 745,335			
19										
20	[1] Adjusted per Rebuttal Schedule B-2, page 2									
21										
22	[2] Tax Basis as of March 31, 2009									
23								$ 18,314,641		
24	Unadjusted Cost Basis per 2008 Tax Return (Fiscal Year Ended 12/31/2008)									
25	Adjustments:							656,307		
26	Land not on tax return depreciation repor							(9,166,130)		
27	Tax accumulated depreciation through 12/31/2008							(254,979)		
28	Tax depreciation from 1/1/2009 to 3/31/2009 for assets added before 12/31/2008.							(1,490,506)		
29	Bonus Depreciation/Section 179 deductions through 12/31/2008							947,275		
30	Assets added after 12/31/2008 (net of affiliate profit, AIAC, CIAC;							(4,736)		
31	Tax depreciation for assets added after 12/31/2008 thru 3/31/2009 (Estimated 25 yr S.L. half-year convention							(118,409)		
32	Bonus depreciation for assets added after 12/31/2008 thru 3/31/2009 (Estimated)							101,011		
33	B-2 Adjustments to plant-in-service (PTY Plant of $110,057 and plant retirement of $12,000							(3,496)		
34	Tax accumulated depreciation from B-2 adjustments to plant-in-service							(229,194)		
35	Affiliate profit removed through 2008							17,533		
36	Tax accumulated depreciation related to affiliate profit through 200							(1,333,228)		
37	Proposed retirements per B-2							1,162,419		
38	Estimated tax depreciation on B- 2 proposed retirement							(80,055)		
39	Proposed B-2 adjustments (AFUDC)							4,214		
40	Estimated Tax depreciation on B- 2 proposed adjustments (AFUDC							(144,623)		
41	Proposed B-2 adjustments (McClain acquistion costs							9,943		
42	Estimated Tax depreciation on B- 2 proposed adjustments (McClain acquisition costs							(100,321)		
43	Timing difference through 2008							$ 8,287,666		
44	Net tax value as of March 31, 2009									
45										
46	[3] CIAC (including impact of change to probability of realization)									
47							$ 542,445			
48	Gross CIAC per B-2						(326,777)			
49	Less: Pre-1996 CIAC					$ (230,570)				
50	A.A per B-2					191,996				
51	A.A on Pre-1996 CIAC						(38,574)			
52	A.A. on Post 1996 CIAC							$ 177,094		
53	Net CIAC before unrealized AIAC									
54										
55	Unrealized AIAC Componen						$ 6,136,045			
56	Adjusted Net AIAC (see footnote 5 below)						70.0%			
57	Unrealized AIAC Component % (1-Realized AIAC Component							$ 4,295,231		
58	Addition to CIAC							$ 4,472,325		
59	Total realizable CIAC									
60										
61	[4] AIAC (including impact of change in probability of realization)						$ 6,781,443			
62	AIAC per B-2						(645,398)			
63	Less: Pre-1996 AIAC included for book and tax purpose							$ 6,136,045		
64	Net AIAC before unrealized portion							$ (4,295,231)		
65	Less: Unrealized AIAC (from Note 4, above							$ 1,840,813		
66	Net realizable AIAC									
67										
68	[5] Effective tax rates Per C-3 schedule									
69										

Bella Vista Water Co., Inc.
Northern Sunrise Water Company Inc.
Southern Sunrise Water Company Inc.

W-02465A-09-0411, W-20453A-09-0412, W-20454A-09-0413,
W-02465A-09-0414, W-20453A-09-0414 and W-20454A-09-0414

Thomas J. Bourassa
Rejoinder Testimony
(Rate Base, Income Statement And Rate Design)
July 7, 2010

Exhibit
TB-RJ2

Bella Vista Water Company (Consolidated)
Test Year Ended March 31, 2009
ACCUMULATED DEFERRED INCOME TAXES
BASED UPON RUCO'S PROPOSED RATE BASE COMPONENTS (PIS, A/D, AIAC AND CIAC)

Line No.											
1	Deferred Income Tax as of March 31, 2009										
2											
3											
4		Adjusted		Probability of Realization of Future	Deductible TD (Taxable TD) Expected to	Tax	Future Tax Asset		Future Tax Liability	
5		Book Value	Tax Value	Tax Benefit	be Realized	Rate[5]	Current	Non Current	Current	Non Current
6	Plant-in-Service	$ 26,605,855 [1]								
7	Accum. Deprec.	(10,552,073) [1]								
8	CIAC	(5,871,343) [3]								
9	Fixed Assets	$ 10,182,439	$ 8,287,666 [2]	100.0%	$ (1,894,773)	38.6%		-		(731,361)
10	AIAC		6,136,045 [4]	7.2%	$ 441,795 [4]	38.6%		$ 170,528		
11	Tax Benefits from O.L. Carry Forward			100.0%	$ -			$ -		
12							$ -	$ 170,528	$ -	$ (731,361)
13										
14	Allocated DIT Asset (Liability)						$ (560,833)			

[1] Adjusted per Rebuttal Schedule B-2, page 2

[2] Tax Basis as of March 31, 2009

Unadjusted Cost Basis per 2008 Tax Return (Fiscal Year Ended 12/31/2008)		$ 18,314,641
Adjustments:		
Land not on tax return depreciation repor		656,307
Tax accumulated depreciation through 12/31/2008		(9,166,130)
Tax depreciation from 1/1/2009 to 3/31/2009 for assets added before 12/31/2008.		(254,979)
Bonus Depreciation/Section 179 deductions through 12/31/2008		(1,490,506)
Assets added after 12/31/2008 (net of affiliate profit, AIAC, CIAC)		947,275
Tax depreciation for assets added after 12/31/2008 thru 3/31/2009 (Estimated 25 yr S.L. half-year convention		(4,736)
Bonus depreciation for assets added after 12/31/2008 thru 3/31/2009 (Estimated)		(118,409)
B-2 Adjustments to plant-in-service (PTY Plant of $110,057 and plant retirement of $12,000)		101,011
Tax accumulated depreciation from B-2 adjustments to plant-in-service		(3,496)
Affiliate profit removed through 2008		(229,194)
Tax accumulated depreciation related to affilitate profit through 2008		17,533
Proposed retirements per B-2		(1,333,228)
Estimated tax depreciation on B- 2 proposed retirement		1,162,419
Proposed B-2 adjustments (AFUDC)		(80,055)
Estimated Tax depreciation on B- 2 proposed adjustments (AFUDC		4,214
Proposed B-2 adjustments (McClain acquistion costs)		(144,623)
Estimated Tax depreciation on B- 2 proposed adjustments (McClain acqusition costs		9,943
Timing difference through 2008		(100,321)
Net tax value as of March 31, 2009		$ 8,287,666

[3] CIAC (including impact of change to probability of realization)

Gross CIAC per B-2		$ 542,445	
Less: Pre-1996 CIAC		(326,777)	
A.A per B-2	$ (230,570)		
A.A on Pre-1996 CIAC	191,996		
A.A. on Post 1996 CIAC		(38,574)	
Net CIAC before unrealized AIAC			$ 177,094
Unrealized AIAC Componen			
Adjusted Net AIAC (see footnote 5 below)		$ 6,136,045	
Unrealized AIAC Component % (1-Realized AIAC Component		92.8%	
Addition to CIAC			$ 5,694,250
Total realizable CIAC			$ 5,871,343

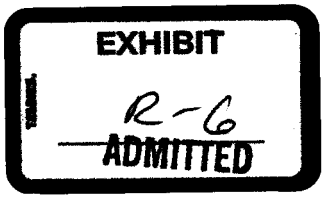
[4] AIAC (including impact of change in probability of realization)

AIAC per B-2		$ 6,781,443	
Less: Pre-1996 AIAC included for book and tax purposes		(645,398)	
Net AIAC before unrealized portion			$ 6,136,045
Less: Unrealized AIAC (from Note 4, above			$ (5,694,250)
Net realizable AIAC			$ 441,795

[5] Effective tax rates Per C-3 schedule

BELLA VISTA WATER COMPANY, INC.

DOCKET NO. W-02465A-09-0411 ET AL.



DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 12, 2010

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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

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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 the applications for permanent changes in rates filed by three water systems owned by Liberty Water Company ("Liberty Water")[1]: Bella Vista Water Company, Inc. ("BVWC" or the "Company"), Northern Sunrise Water Company, Inc. ("NSWC")[2], and Southern Sunrise Water Company, Inc. ("SSWC")[3]. The three applications were filed with the Arizona Corporation Commission (ACC or Commission) on August 31, 2009. On September 1, 2009, BVWC filed a motion to consolidate the three applications into a joint application. On November 9, 2009, the Administrative Law Judge ("ALJ") assigned to the case issued a Procedural Order that consolidated the three applications into a joint application ("Joint Application"). The Company has chosen the operating period ended March 31, 2009 for the test year ("Test Year") in this proceeding. The Company has also elected not to perform a reconstruction cost new less depreciation study and is proposing that its original cost rate base be treated as its fair value rate base for ratemaking purposes. Therefore there is no need to perform a separate analysis to determine a fair value rate of return on a fair value rate base.

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[1] Based on documents provided to ACC Staff and RUCO during the recent Litchfield Park Services Company proceeding (Staff data request JMM 7.3, dated October 23, 2009), Algonquin Water Resources of America, Inc., the entity that held the BVWC, NSWC and SSWC systems at the time of the August 31, 2009 filing, changed its name to Liberty Water Company on April 27, 2009.

[2] W-20453A-09-0412

[3] W-20454A-09-0413

Q. Are you providing cost of capital testimony for each of the three Liberty Water systems on a stand alone basis?

A. No. In this round of testimony I am providing cost of capital testimony on a consolidated basis. As explained in the direct testimony of RUCO Director Jodi Jerich, RUCO will present schedules on a stand alone basis when RUCO's direct testimony on rate design is filed on April 23, 2010. At that time I will provide my capital structure recommendations for BVWC, NSWC and SSWC on a stand alone basis.

Q. Please describe Liberty Water.

A. Liberty Water is a wholly owned subsidiary of an entity known as Algonquin Power & Utilities Corp., which is listed on the Toronto Stock Exchange (ticker symbol AQN)[4]. In addition to BVWC, NSWC and SSWC, Liberty Water also owns and operates four other ACC regulated utilities: Black Mountain Sewer Corporation, which provides wastewater service to the Boulders Community in Carefree just north of Scottsdale; Gold Canyon Sewer Company, which is located east of Apache Junction; Litchfield Park Services Company, situated on the west side of the Phoenix metropolitan area; and Rio Rico Utilities, Inc., located just north of Nogales on the border between Arizona and Mexico.

[4] Algonquin Power & Utilities Corp. was previously organized as a Canadian-based mutual fund known as Algonquin Power Income Fund prior to a conversion that occurred during the last half of 2009. Algonquin Power Income Fund was also listed on the Toronto Stock Exchange (ticker symbol APF.UN).

Q. Please explain your role in RUCO's analysis of the Joint Application.

A. I reviewed the Joint 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 capital structure, my direct testimony will present my recommended cost of common equity (the Company has no preferred stock) and my recommended cost of long-term debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Joint 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 and rate base?

A. No. The majority of those aspects of the case will be addressed in the direct testimony of RUCO witness Rodney L. Moore. RUCO witness Timothy J. Coley will provide testimony on the issues of accumulated deferred income taxes and cost allocations.

Q. Will RUCO be presenting direct testimony on the rate design issues I this case?

A. Yes. Mr. Moore will provide direct testimony on RUCO's recommended rate design, which is scheduled to be filed on April 23, 2010. As previously indicated, Ms. Jerich will address the policy issues related to rate design.

Q. What areas will you address in your testimony?

A. I will address the cost of capital issues associated with the case based on the Company-proposed consolidation.

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 return 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 the Company 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 the Company'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, 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 range of 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 350 basis points lower than the 12.50 percent cost of equity capital being proposed by the Company.

Capital Structure – I am recommending that the Commission adopt the Company-proposed capital structure, which is comprised of 21.08 percent long-term debt and 78.92 percent common equity.

Cost of Debt – I am recommending that the Commission adopt the Company-proposed cost of debt of 6.27 percent, which is the average weighted cost of debt of BVWC's various loans

Weighted Average Cost of Capital – Based on the results of my recommended capital structure, I am recommending an 8.42 percent cost of capital for the Company, which is the weighted cost of my recommended costs of long-term debt and common equity. My recommended weighted average cost of capital is 277 basis points lower than the 11.19 percent weighted average cost of capital being proposed by the Company.

Q Why do you believe that RUCO's recommended 8.42 percent weighted average cost of capital is an appropriate rate of return for the Company to earn on its invested capital?

A. The 8.42 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 BVWC, 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 BVWC?

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 side of the range of results derived 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"). The results of my DCF and CAPM analyses are summarized on page 3 of my Schedule WAR-1.

Discounted Cash Flow (DCF) Method

Q. Please explain the DCF method that you used to estimate the Company'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 the Company's cost of equity capital.

Q. In determining the rate of future dividend growth for the Company, 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.[5]

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%

[5] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

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 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[6] 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.[7] 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

[6] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[7] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

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.

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,[8] 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

[8] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

accrues to a current shareholder, and

v = funds raised from the sale of stock as a fraction of existing equity.

and v = 1 - [(BV) ÷ (MP)]

where: BV = book value per share of common stock, and

MP = the market price per share of common stock.

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[9], 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 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 the Company?

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 BVWC, NSWC and SSWC. Consequently it was necessary

[9] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

to create a proxy by analyzing publicly traded water companies and LDC's with similar risk characteristics.

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 the Company?

A. The three water companies used in the proxy are publicly traded on the New York Stock Exchange ("NYSE"). All three 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 January 22, 2010 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. However, in prior proceedings I have also included a fourth water provider known as Southwest Water Company ("SWWC") which is traded over the counter through the National Association of Securities Dealers Automated Quotation System ("NASDAQ").

Q. Why did you exclude SWWC from your sample in this proceeding?

A. On March 3, 2010 SWWC announced that it had entered into a definitive merger agreement to be acquired for approximately $275 million in cash, or $11.00 per share (almost 2.5 times SWWC's 2009 book value per share), by institutional investors advised by J.P. Morgan Asset Management and Water Asset Management L.L.C. As a result of this situation, the Company's stock price is being driven by the offer price and is no longer suitable for use in my sample.

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") and Aqua America, Inc. ("WTR"). Each of these water companies face the same types of risk that the Company 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. 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 were used in the Joint Application?

A. The Company's cost of equity witness, Mr. Thomas J. Bourassa, used the same water companies included in my proxy. Mr. Bourassa also used

three other water companies in his cost of capital analysis[10] 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 three water companies that I used in my proxy. Consequently, as in the case of Southwest Water Company, 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 the Company?

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.

[10] 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.[11]

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

[11] Docket No. G-04204A-06-0463

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 the water utilities and 2005 to 2009 for the LDC's. 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 the water utilities and the same data projections over 2010, 2011 and 2013-15 for 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 percent over the 2004 to 2008 time frame reflects an up and down pattern of growth that ranged from a low of 1.01 percent in 2004 to a high of 3.79 percent during 2007. Value Line is predicting that growth will increase steadily from 3.05 percent in 2008, to 6.37 percent by the end of the 2012-14 time frame. After weighing Value Line's projections on earnings, I believe that a 6.25% rate of 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 18.60 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 7.99 percent (6.25 percent internal + 1.74 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 6.67 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 5.64 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 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 6.67 percent estimate exceeds Zacks' average long-term EPS projection of 6.23 percent and Value Line's growth projection of 5.58 percent (which is an average of EPS, DPS and BVPS). My 6.67 percent estimate is 101 basis points higher than the 5.66 percent average of Value Line's historical and projected data averaged with the consensus opinions published by Zacks. My 6.67 percent growth estimate is also 111 basis points higher than Value Line's 5.56 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 6.50 percent to 8.00 percent book return on common equity over the 2009 to 2014 period. On

balance, I would say my 6.67 percent estimate is a good 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 5.64 percent estimate falls between the average 5.98 percent long-term EPS consensus projections published by Zacks, and the 4.34 percent Value Line projected estimate (which is an average of EPS, DPS and BVPS). As can also be seen on Schedule WAR-6, the 5.64 percent estimate that I have calculated is 44 basis points lower than the 6.08 percent average of the 5-year historic EPS, DPS and BVPS means of Value Line. In fact, my 6.45 percent estimate is 36 basis points higher than the combined 5.28 percent Value Line and Zacks averages displayed in Schedule WAR-6. In the case of the LDC's I would say that my 5.64 percent estimate, which is lower than Zacks' estimates but higher than Value Line's forecasts, is also a reasonable 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 January 22, 2010 Ratings and Reports water utility industry update and Value Line's March 12, 2010 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 February 1, 2010 to March 26, 2010.

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 9.93 percent for the water utilities and 9.90 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[12], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for

[12] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

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.[13] In this regard, CAPM can help an investor to 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:

[13] 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 market; and if a stock's beta is less than 1.0, its returns are less volatile or riskier than the overall stock market.

$$k = r_f + [ß (r_m - r_f)]$$

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

$r_m - r_f$ = 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,[14] a real rate

[14] 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

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 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 January 5, 2010 through March 26, 2010 (Attachment D). This resulted in a risk-free (r_f) rate of return of 2.36 percent.

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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.

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 January 22, 2010 for the water companies and March 12, 2010 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 0.80 with an average beta of 0.73. 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 0.66.

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 5.44 percent for the water companies and 5.13 percent for the natural gas LDC's. My calculation using an arithmetic mean results in an average expected return of 6.83 percent for the water companies and 6.39 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)	9.93%
DCF (Natural Gas Sample)	9.90%
CAPM (Water Sample)	5.44% – 6.83%
CAPM (Natural Gas)	5.13% – 6.39%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 5.13 percent to 9.93 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 side of the range of estimates obtained from my DCF and CAPM analyses. My final estimate takes into consideration reports on the improving state of the national economy which began in the later part of 2009, a rejuvenated stock market and reports in the financial press which anticipate Federal Reserve actions to raise interest rates. I also weighed

information on Arizona's current rate of unemployment in making my final cost of equity estimate.

Q. Can you provide some examples of the reports that you noted above that influenced your common equity estimate of 9.00 percent?

A. Yes. Value Line analysts cited 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 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[15] that "Federal Reserve officials are thinking mostly these days about how to unwind the unprecedented stimulus they've pumped into the economy" and that eventually will mean raising interest rates. Mr. Hilsenrath quoted former Fed governor Frederic Mishkin, a former Federal Reserve 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." Based on the information obtained from these sources, I began increasing my cost of equity recommendations to reflect an improving economy, an improved stock market and the increased possibility of higher interest rates in the coming 12 month period.

Q. Have the trends in the national economy and the stock market continued since the latter part of 2009?

A. Yes. As of March 26, 2010, Value Line's analysts are estimating that the national economy, which grew by 5.9% during the fourth quarter of 2009, will increase by 2.50 percent to 3.00 percent during the first quarter of 2010. Value Line expects that increases in consumer spending and

[15] Hilsenrath, Jon, "WSJ Fed's Path to Higher Interest Rates Begins to Take Shape" The Wall Street Journal, November 2, 2009

business equipment will offset further weakness in homebuilding. For the most part, stock market indices (e.g. the Dow Jones Industrial Average and the S&P 500 Index) have remained at levels at or above where they were during November of 2009.

Q. How is Arizona faring in terms of unemployment during this period of economic recovery?

A. According to a U.S. Bureau of Labor Statistics news release on March, 26, 2010, unemployment in Arizona had increased from 8.30 percent in February 2009 to 9.50 percent in February 2010.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 12.50 percent cost of equity capital proposed by the Company is 350 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[16] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

[16] 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.

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 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.'[17]

[17] 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.[18] 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.[19]

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[18] McKinnon, John D. and Greg IP, "Fed Raises Rates by a Quarter Point," The Wall Street Journal, September 22, 2004.

[19] 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[20]. 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[21]. 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."

[20] Browning, E.S, "Not Too Fast, Not Too Slow...," The Wall Street Journal Online Edition, August 21, 2006.

[21] 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."[22]

Q. What has been the state of the economy since 2007?

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

[22] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

unchanged at 5.25 percent.[23] 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.[24] 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, [25] 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.

[23] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

[24] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[25] 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).[26] 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[27]. 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. Over the course of 2009, the FOMC elected not to make any changes in the federal funds rate. During this same period of time, the Federal Reserve

[26] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

[27] 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

purchased over $1 trillion in mortgage-backed securities and U.S. Treasury instruments from banks in order to inject liquidity into the U.S. financial system. In testimony offered to the House Financial Services Committee on Wednesday, February 24, 2010, Chairman Bernanke stated that the Fed would continue to keep rates low over the next several months.[28] The Fed chief further stated that the Federal Reserve is actively looking at what tools to use once the economy will need higher interest rates. Of particular concern at this point in time is how the fed will drain the excess reserves that banks have accumulated, as a result of the aforementioned purchases of mortgage-backed securities and U.S. Treasuries, in order to avoid unwanted inflation.

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), currently stands at 0.75 percent from 0.50 percent in 2009 (one of the few rates that the fed has increased over the past year).

[28] Di Leo, Luca and Tom Barkley, "Bernanke: Low Rates Still Needed" The Wall Street Journal, February 24, 2010

Q. What has been the trend in other leading interest rates over the last year?

A. As of March 17, 2010, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have dropped from their 2009 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 3065). The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[29], 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 79 basis points from 1.57 percent, in March 2009, to 2.36 percent as of March 17, 2010. As noted above, the 30-Year Treasury constant maturity rate increased from 3.42 percent over the past year to 4.56 percent. Still 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).

[29] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

Q. What is the current outlook for the economy?

A. Value Line's analysts are forecasting for moderate growth over the coming year. As I noted earlier in my testimony Value line's analysts had this to say in the March 26, 2010 edition of Value Line's Selection and Opinion publication:

> **Growth probably will moderate significantly in the current quarter, following a late 2009 surge.** In all, we estimate that the economy — which grew by 5.9% during the final three months last year — will gain 2.5%-3.0% over the first three months of 2010, with increases in consumer spending and business equipment offsetting further weakness in homebuilding.

Value Line's analysts went on to explain

> **Meanwhile, the likely sequential deceleration in growth this quarter requires an explanation.** That is because much of the 5.9% gain in fourth-quarter (2009) gross domestic product growth was inventory driven—as that period saw a sharp lessening in inventory drawdowns. Further help on this front is probable in 2010, as manufacturers add to their depleted stockpiles (thus boosting production and GDP in the process), albeit at a slower rate. Meanwhile, consumers, although constrained by tight credit conditions and wealth considerations (reflecting lower home prices), may still boost spending modestly in 2010. We also expect business investment to rise in 2010, possibly helping GDP to gain close to 3% this year.

Value Line's analysts also stated

> **Some trouble spots remain.** For openers, the housing market is still under duress, with foreclosures and repossessions unlikely to ease much anytime soon, while home prices may do no better than tread water for some time. Homebuilding is also near the recession lows. Then, there is the employment outlook. Here, gains are likely this year, although, for now, non-farm payrolls are still falling.

Value Line's analysts went on to say

> **We expect a moderate business recovery for the most part.** As noted, we think GDP will rise by close to 3% this year, with a similar gain likely in 2011. A so called V-shaped recovery is

> unlikely, given tight credit, sluggish spending by consumers, and weak housing demand.

Q. How are water utilities faring in the current economic environment?

A. Although, as always, there are concerns regarding long-term infrastructure requirements, water utilities are being viewed as they normally are during better economic times according to Value Line analyst Andre J. Costanza. In the January 22, 2010 quarterly update on the water utility industry Mr. Costanza stated the following:

> 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.

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 the Company?

A. I believe that my recommended 9.00 percent cost of equity will provide the Company with a reasonable rate of return on invested capital when economic data on interest rates (that are low by historical standards), the current situation in 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 on the high side of the range of results I obtained from both the DCF and CAPM models, has produced such a return.

CAPITAL STRUCTURE AND COST OF DEBT

Q. Please describe the Company-proposed capital structure.

A. The Company-proposed capital structure is comprised of 78.92 percent common equity and 21.08 percent long-term debt.

Q. How does the Company-proposed capital structure compare with the capital structures of the water and gas utilities that comprise your samples?

A. The Company-proposed capital structure, comprised of 78.92 percent equity capital is clearly heavier in equity than the capital structures of the water and gas utilities in my samples and would be perceived by investors as having lower risk overall. The lower level of debt in the Company's capital structure would indicate lower financial risk and would justify a downward adjustment to the cost of common equity derived from my sample companies that had average capital structures of approximately 49.00 percent common equity and 51 percent debt in the case of water, and approximately 54.00 percent equity and 46.00 percent debt in the case of natural gas.

Q. Why have you decided not to recommend a hypothetical capital structure in this round of testimony given the fact that the Company-proposed capital structure contains less debt than the utilities in your sample?

A. In recent years I have attempted, for the most part, to recommend hypothetical capital structures for utilities that have extreme levels of debt or equity in their capital structures. In the case of Liberty Water systems I have recommended hypothetical capital structures in cases where imprudent capital structures comprised of 100 percent equity were being proposed. While a higher level of lower cost debt would be desirable in this case, I believe that the fact that the Company-proposed consolidated capital structure, which is comprised of 21.08 percent long-term debt, eliminates the need for a hypothetical capital structure. My capital structure recommendations may change in later testimony when the stand alone systems are examined.

Q. Did you make any direct downward adjustment to your recommended cost of common equity that takes into consideration the higher level of equity contained in the Company-proposed capital structure?

A. No. While a good argument could be made for such an adjustment, I believe my recommended 9.00 percent cost of equity would cover any investor concerns regarding unique business risk associated with the consolidation of BVWC, NSWC and SSWC.

Q. What cost of long-term debt are you recommending?

A. I am recommending that the Commission adopt the Company-proposed cost of debt of 6.27 percent, which is an average of the weighted costs of BVWC's various loans agreements.

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. As explained earlier, the Company has proposed a weighted average cost of capital of 11.19 percent which is 277 basis points higher than the 8.42 percent weighted cost that I am recommending.

COMMENTS ON THE COMPANY-PROPOSED COST OF EQUITY CAPITAL

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 12.50 percent. His 12.50 percent cost of equity capital is 350 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 proposed cost of common equity for the Company?

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 11.2 percent indicated cost of equity, and a future growth estimate which produces a 13.00 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 21.0 percent using a current market risk premium. His average CAPM result is 15.6 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 prior to August 31, 2009 and consequently much of the data that he used in his analysis is now seven months old. 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	$33.21	$33.95	- $0.74
CWT	$36.51	$38.35	- $1.84
WTR	$17.00	$17.47	- $0.47

Q. What are the differences between your constant growth DCF results and Mr. Bourassa's constant growth models?

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 annual dividend yields of 3.63 percent to 3.69 percent are 37 to 43 basis points higher than my average dividend yield of 3.26 percent. The current dividend yield of the three utilities that our samples have in common (based on my 8-week average adjusted closing prices listed above) would be 3.07 or 19 basis points lower than my 3.26 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 7.61 percent to 9.26 percent are 94 to 259 basis points higher than my average growth estimate of 6.67 percent. However, 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 regarding historical DPS 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 while his average DCF result relying on DPS historical growth of 6.90 percent is higher than the current yields of investment grade bonds, the growth results of four of the utilities in his sample were lower than the yields on investment grade bonds. A review of my Attachment D will show that, as of March 17, 2009, Mr. Bourassa's 6.90 percent DCF result relying on historical DPS growth is 150 to 56 basis points higher than the yields of A-rated corporate bonds and Baa/BBB rated utility bonds which ranged from 5.40 percent to 6.34 percent. Essentially Mr. Bourassa is making the argument that only one element of growth, in this case DPS growth, should be selectively ignored if it depresses an overall growth rate that also includes EPS and BVPS.

Q. Do you agree with Mr. Bourassa?

A. No. I believe that all elements of growth should be considered in calculating a growth component for the DCF. This is what I've done to arrive at my DCF growth estimates.

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 0.82 has also fallen since his testimony was filed, and his current market risk premium figure of 19.8 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 2.36 percent yield on a 5-year treasury rate whereas Mr. Bourassa relied on a 4.80 percent average of forecasted 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. His 4.80 percent risk-free rate is based on analysts' estimates forecasts for 2011 and 2012 and is 24 basis points higher than the current

yield on a 30-year Treasury bond which I believe is a better indicator of future yields on that instrument.

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 0.79 as opposed to the 0.82 used in his CAPM analysis and the 0.73 used in my CAPM analysis using a sample of water utilities. Since Mr. Bourassa's direct testimony was filed in August 2009, the betas for California Water Service Group, Connecticut Water Service, Inc. and Middlesex Water Company dropped from 0.80, 0.85 and 1.00 to 0.75, 0.80 and 0.95 respectively, indicating lower risk, in terms of beta, for these companies.

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 2009 SBBI Yearbook). Mr. Bourassa relied on a 6.5 percent historical risk premium (which also relied on Morningstar data) and a 19.8 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 19.8 percent current market risk premium?

A. No. Mr. Bourassa's 19.8 percent market risk premium is clearly excessive and only represents a snapshot in time. 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 24.01 percent. His 19.8 percent risk premium is the difference between the 24.01 percent DCF result and the 4.26 percent 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 12.50 percent cost of common equity for the Company?

A. Mr. Bourassa's proposed 12.50 percent cost of common equity represents his own judgment and relies on the results of the midpoints of the ranges of estimates he obtained from his DCF and CAPM models.

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, Liberty Water, the entity that owns BVWC, NSWC and SSWC, is a wholly owned subsidiary of Algonquin Power Income Fund, a large publicly traded corporation 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 the Company might face?

A. Yes. As I stated earlier in my testimony, I believe that the amount of equity contained in my recommended capital structure, which is higher than the percentage of equity contained in my utility samples, and the fact that I have not made any downward adjustment to my recommended 9.00 percent cost of equity mitigates any perceived business risk that investors might believe the Company 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 BVWC, NSWC or SSWC constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on BVWC, NSWC and SSWC?

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

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 Public Service Company	E-01345A-08-0172	Rate Increase
Johnson Utilities, LLC	WS-02987A-08-0180	Rate Increase
Arizona-American Water Company	W-01303A-08-0227 et al.	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
Far West Water & Sewer Company	WS-03478A-08-0608	Interim 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
Rio Rico Utilities, Inc.	WS-02676A-08-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase

ATTACHMENT A

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.

INDUSTRY TIMELINESS: 74 (of 98)

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.

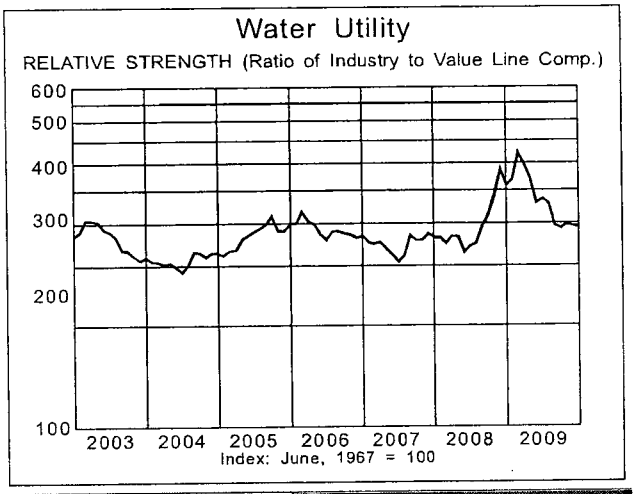
Conclusion

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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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)

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

	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	© VALUE LINE PUB., INC.	12-14
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		
	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%*

% 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

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%*

Calendar	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*

Calendar	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*

Calendar	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*

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	70
Earnings Predictability	70

(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.

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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)

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

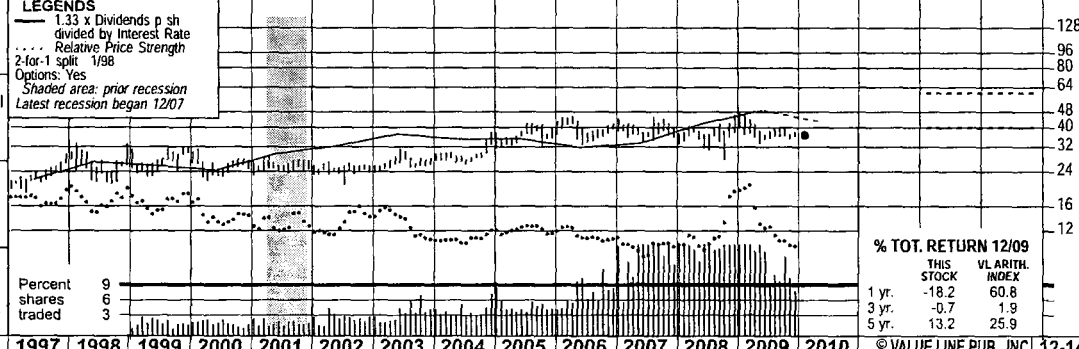
Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	83	76	56
to Sell	81	85	75
Hld's(000)	10000	10018	9635

	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

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

Target Price Range 2012 | 2013 | 2014



% 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	2.63	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%
						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%

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)

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%

Calendar	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

Calendar	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

Calendar	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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AQUA AMERICA NYSE-WTR

RECENT PRICE 17.57 | P/E RATIO 20.9 (Trailing: 23.7 Median: 25.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 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)

2012-14 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+70%)	14%
Low	20	(+15%)	3%

Insider Decisions

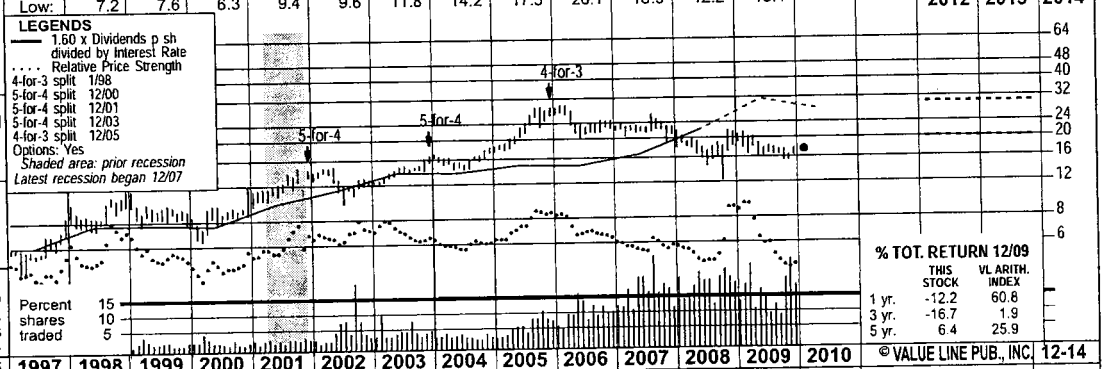
	F	M	A	M	J	J	A	S	O
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	130	117	88
to Sell	134	136	118
Hld's(000)	63551	61341	60196

	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

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



Target Price Range 2012 | 2013 | 2014
64
48
40
32
24
20
16
12
8
6

% 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%*
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%*

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)

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%*

Calendar	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*

Calendar	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*

Calendar	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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ATTACHMENT B

After a difficult year in 2009, the Natural Gas Utility Industry will likely begin on its road to recovery. The economic environment is improving, which should ease some of the pressures these companies endured over the past 12 months. These utilities have done their best to stave off these challenges through a variety of strategies. Despite the hard times, many of these stocks offer attractive dividend yields, which may interest income-oriented investors.

Macroeconomic Climate

Natural Gas Utilities generally offer fairly predictable cash flows, solid balance sheets, and good yields. Therefore, when times are tough, investor interest in these defensive equities picks up. However, when the stock market rallies, investors tend to flock to issues that have the potential for greater returns. On point, natural gas utility stocks have not performed well over the past year. Indeed, the difficult economic environment weighed on this group in 2009. Reduced industrial demand, weakness in the housing market, and conservative spending all hurt results. Additionally, bill collection has become tougher due to high unemployment levels. In response, these companies have scaled back their spending and increased their marketing in an effort to weather these challenges. All told, investor confidence appears to be picking up, which suggests the worst may be behind these companies.

Regulation

This group is regulated by state commissions that determine the return on equity these stocks can realize. Consequently, rate cases remain key to this sector's performance. If a company does not have adequate relief, its budget can become stretched. On the other hand, a rate that is too generous can give utilities too much upside at the expense of its customers. State commissions are constantly working to keep a balance between shareholder and customer interests. These decisions are carefully monitored by investors due to their impact on stock valuations. A positive decision can significantly improve a company's prospects, while a negative one can limit its near-term outlook. Thus, interested investors should pay close attention to the regulatory environment.

INDUSTRY TIMELINESS: 82 (of 97)

Weather

Colder-than-normal weather of late may have provide a boost to natural gas prices due to lower supply. However, now that the peak heating season is in the rear-view mirror, these utilities will likely post weak results as they enter a seasonably slow time of year. Therefore, we look for these companies to focus on cost management to strengthen their results during the warmer months.

Business Strategy

A strategy that is becoming increasingly common is nonregulated businesses. These ventures allow firms to diversify their operations and gain income that is not subject to regulatory authorities. While these operations are often more risky, they generally offer a greater potential for returns.

Conservation is also becoming a noticeably important theme in this sector. Governments are encouraging these utilities to partake in energy-efficiency programs by offering incentives. This way companies can participate without hurting their profitability. All told, we think these initiatives will continue to gain momentum going forward.

Dividends

Income-oriented accounts may want to consider some of the equities in this industry. Indeed, these equities on average have better dividend yields (4.2%) compared to the *Value Line* median (2.0%). Most notably, *NiSource*, *AGL Resources*, *Atmos Energy* and *Laclede Group* all stand out for their hearty payouts.

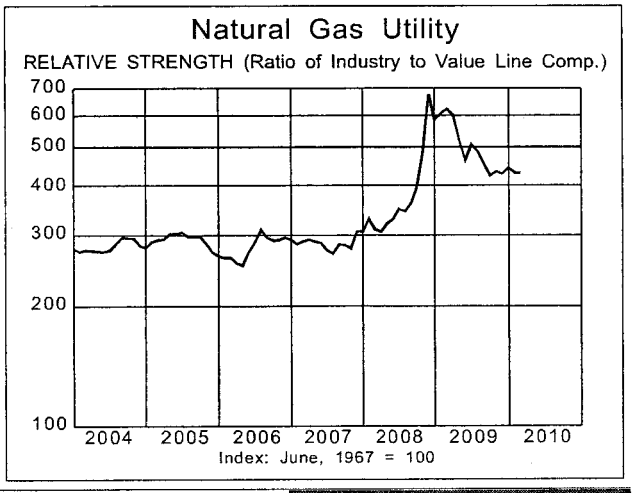
Conclusion

Natural Gas Utility stocks have fallen near the bottom of our Industry spectrum for Timeliness. Accordingly, short-term investors would probably do best to find a group with better prospects over the coming six to 12 months.Longer-term, we expect these businesses to rebound. An improved economic environment, coupled with stronger pricing, should boost results across this sector over the coming years. In sum, we think patient investors will find a few issues in this sector that offer enticing total-return potential over the 2013-2015 time frame.

Richard Gallagher

Composite Statistics: Natural Gas Utility

2006	2007	2008	2009	2010	2011		13-15
38273	38528	44207	*45500*	*47000*	*48500*	Revenues ($mill)	*54750*
1553.3	1562.4	1694.2	*1775*	*1850*	*1925*	Net Profit ($mill)	*2250*
35.3%	33.9%	35.7%	*36.0%*	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
4.0%	4.1%	3.8%	*3.9%*	*3.9%*	*4.0%*	Net Profit Margin	*4.1%*
51.2%	50.4%	50.6%	*51.0%*	*51.0%*	*51.0%*	Long-Term Debt Ratio	*52.0%*
48.7%	49.5%	49.4%	*48.0%*	*48.0%*	*48.0%*	Common Equity Ratio	*46.0%*
30847	32263	32729	*33250*	*34750*	*36250*	Total Capital ($mill)	*42000*
32543	33936	35342	*36750*	*38500*	*40250*	Net Plant ($mill)	*48250*
6.6%	6.5%	6.8%	*6.5%*	*6.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.2%	9.8%	10.5%	*10.0%*	*10.5%*	*10.0%*	Return on Shr. Equity	*10.0%*
10.2%	9.8%	10.5%	*10.0%*	*10.5%*	*10.0%*	Return on Com Equity	*10.0%*
4.0%	3.7%	4.3%	*4.0%*	*4.5%*	*4.0%*	Retained to Com Eq	*4.5%*
61%	62%	59%	*60%*	*62%*	*61%*	All Div'ds to Net Prof	*65%*
15.6	16.6	13.9		*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
.84	.88	.83				Relative P/E Ratio	*.85*
3.9%	3.7%	4.2%				Avg Ann'l Div'd Yield	*4.6%*
327%	336%	358%	*375%*	*375%*	*375%*	Fixed Charge Coverage	*400%*



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AGL RESOURCES NYSE-AGL

RECENT PRICE **37.00** | P/E RATIO **12.5** (Trailing: 12.8 Median: 14.0) | RELATIVE P/E RATIO **0.74** | DIV'D YLD **4.8%** | **VALUE LINE**

TIMELINESS **3** Raised 2/12/10
SAFETY **2** New 7/27/90
TECHNICAL **3** Lowered 2/12/10
BETA .75 (1.00 = Market)

2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+60%)	13%
Low	45	(+20%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	1	1	2
to Sell	0	2	0	0	1	0	0	2	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	110	124	112
to Sell	107	96	99
Hld's(000)	45714	45662	45741

	2008	2009	2010
High:	39.1	37.5	37.2
Low:	24.0	24.0	34.3

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07

Target Price Range 2013 | 2014 | 2015

% TOT. RETURN 2/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	37.9	101.8
3 yr.	3.3	0.8
5 yr.	31.6	30.1

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	*29.90*	*34.35*	*36.10*	Revenues per sh [A]	*40.35*
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	*5.95*	*5.05*	*5.30*	"Cash Flow" per sh	*5.75*
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	2.89	*2.95*	*3.10*	Earnings per sh [A B]	*3.40*
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*	*1.80*	Div'ds Decl'd per sh [C]	*1.92*
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	*6.15*	*4.45*	*4.50*	Cap'l Spending per sh	*5.30*
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	*22.95*	*24.10*	*25.45*	Book Value per sh [D]	*29.95*
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	*77.50*	*78.50*	*79.00*	Common Shs Outst'g [E]	*80.50*
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	11.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.99	.84	.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.73			Relative P/E Ratio	*1.00*
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%	5.4%			Avg Ann'l Div'd Yield	*3.8%*
607.4	1049.3	868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	*2695*	*2850*	Revenues ($mill) [A]	*3250*
71.1	82.3	103.0	132.4	153.0	193.0	212.0	211.0	207.6	*260*	*230*	*245*	Net Profit ($mill)	*275*
34.3%	40.7%	36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	*30.0%*	*35.0%*	*35.0%*	Income Tax Rate	*38.0%*
11.7%	7.8%	11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	*11.2%*	*8.6%*	*8.6%*	Net Profit Margin	*8.4%*
45.9%	61.3%	58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	*53.0%*	*54.0%*	*52.0%*	Long-Term Debt Ratio	*51.0%*
48.3%	38.7%	41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	*48.0%*	*50.0%*	*48.0%*	Common Equity Ratio	*49.0%*
1286.2	1736.3	1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	*3750*	*3800*	*4200*	Total Capital ($mill)	*4900*
1637.5	2058.9	2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	*2900*	*3080*	*3250*	Net Plant ($mill)	*3900*
7.4%	6.5%	8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	*7.0%*	*7.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
10.2%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	*14.5%*	*12.0%*	*12.0%*	Return on Shr. Equity	*11.0%*
11.5%	12.3%	14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	*14.5%*	*12.0%*	*12.0%*	Return on Com Equity	*11.0%*
3.2%	4.2%	7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	*7.0%*	*5.0%*	*5.5%*	Retained to Com Eq	*5.0%*
72%	65%	52%	53%	49%	52%	52%	58%	60%	*50%*	*58%*	*57%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $2576.0 mill. **Due in 5 Yrs** $543.0 mill.
LT Debt $1974.0 mill. **LT Interest** $90.0 mill.
(Total interest coverage: 4.5x)

Leases, Uncapitalized Annual rentals $28.0 mill.
Pension Assets-12/09 $303.0 mill.
Oblig. $463.0 mill.

Pfd Stock None

Common Stock 77,543,821 shs.
as of 1/29/10
MARKET CAP: $2.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/09
Cash Assets	21.0	16.0	26.0
Other	1790.0	2026.0	1974.0
Current Assets	1811.0	2042.0	2000.0
Accts Payable	172.0	202.0	237.0
Debt Due	580.0	866.0	602.0
Other	893.0	915.0	933.0
Current Liab.	1645.0	1983.0	1772.0
Fix. Chg. Cov.	391%	416%	472%

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 2.3 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.

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	4.0%	15.5%	*2.5%*
"Cash Flow"	6.0%	6.5%	*3.0%*
Earnings	7.0%	8.5%	*3.5%*
Dividends	4.0%	8.0%	*2.5%*
Book Value	7.0%	10.0%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	973	467	369	685	2494
2008	1012	444	539	805	2800
2009	995	377	307	638	2317
2010	*1020*	*450*	*475*	*750*	*2695*
2011	*1075*	*475*	*500*	*800*	*2850*

Calendar	EARNINGS PER SHARE [B] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	1.29	.40	.17	.86	2.72
2008	1.16	.30	.28	.97	2.71
2009	1.55	.26	.16	.92	2.89
2010	*1.50*	*.30*	*.25*	*.90*	*2.95*
2011	*1.41*	*.36*	*.33*	*1.00*	*3.10*

Calendar	QUARTERLY DIVIDENDS PAID [C] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	.43	1.72
2010	.44				

AGL Resources reported better-than-anticipated fourth quarter profit. Earnings of $0.92 a share topped our estimate of $0.78 a share. A good performance in the company's unregulated businesses offset disappointing results in AGL's gas utility operations. For the full year, the utility posted a solid bottom-line showing ($2.89 a share), thanks to strong results in the March period. However, a year-over-year decline in customers weighed on the top line ($2.3 billion).

The company provided positive guidance for 2010. Management expects share net to come in between $2.95 and $3.05 this year. We have increased our estimate by a nickel, matching the low end of this range. We look for results across AGL's operations to perform mostly in line with 2009's showing except at the company's wholesale services business, which should post improved results. Moreover, AGL will probably focus on new projects to offset the decline in customers due to the weak residential real estate market. Furthermore, the company recently added two new pipeline projects that began commercial operation recently, which should provide a boost to results over the coming months.

The board raised AGL's quarterly payout by a penny (or 2.3%) to $0.44 a share. Accordingly, income-oriented accounts may want to take note of these shares. Indeed, this stock's yield (4.8%) is above average for a natural gas utility.

Long-term prospects appear to be promising. The company reached a legal settlement, which will allow it to expand its presence on Jefferson Island. Moreover, a few rate cases should come into play in the near term, which if approved, would bolster results over the long haul. Additionally, AGL recently launched a new energy services business that targets large-scale clients. This should contribute to profits in the years ahead.

These shares are neutrally ranked for Timeliness. But this stock may be of interest to patient investors. Indeed, the issue is attractive on a risk-adjusted basis (Safety: 2) for total-return potential over the 3- to 5-year pull, based on our projections of steady earnings growth and modest dividend increases.

Richard Gallagher *March 12, 2010*

(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 April. (C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2009: $418 million, $5.44/share. (E) In millions.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	75
Earnings Predictability	95

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ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE 28.05 | P/E RATIO 12.5 (Trailing: 13.1 Median: 15.0) | RELATIVE P/E RATIO 0.74 | DIV'D YLD 4.8% | VALUE LINE

TIMELINESS 3 Lowered 9/11/09
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Raised 10/16/09
BETA .65 (1.00 = Market)

2013-15 PROJECTIONS

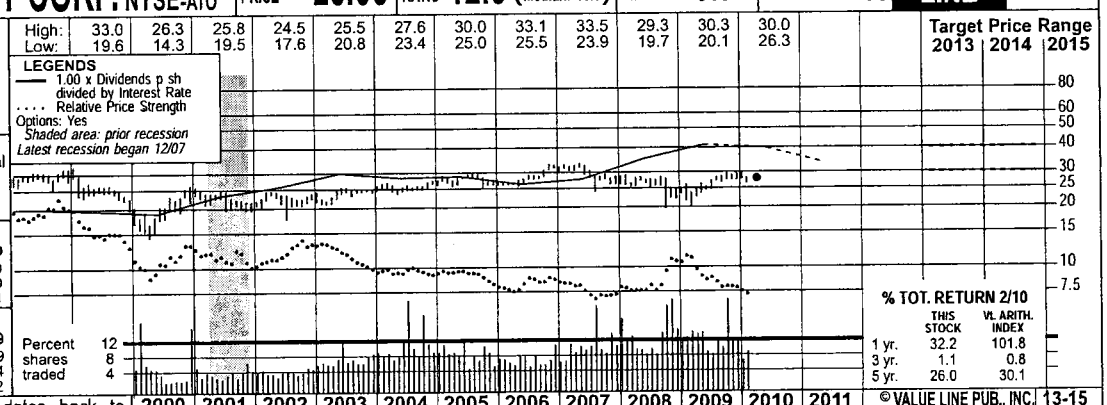
	Price	Gain	Ann'l Total Return
High	40	(+45%)	13%
Low	30	(+5%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	1	0	0	1	0
to Sell	0	0	0	0	3	0	0	1	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	108	107	79
to Sell	122	115	124
Hld's(000)	53874	54285	55892



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.

CAPITAL STRUCTURE as of 12/31/09
Total Debt $2349.3 mill. **Due in 5 Yrs** $685.0 mill.
LT Debt $2159.5 mill. **LT Interest** $130.0 mill.
(LT interest earned: 2.8x; total interest coverage: 2.8x)
Leases, Uncapitalized Annual rentals $17.8 mill.
Pfd Stock None
Pension Assets-9/09 $301.1 mill.
Oblig. $380.0 mill.
Common Stock 93,054,189 shs.
as of 1/28/10
MARKET CAP: $2.6 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2008	2009	12/31/09
Cash Assets	46.7	111.2	174.8
Other	1238.4	717.7	1111.8
Current Assets	1285.1	828.9	1286.6
Accts Payable	395.4	207.4	578.8
Debt Due	351.3	72.7	189.8
Other	460.4	457.3	413.8
Current Liab.	1207.1	737.4	1182.4
Fix. Chg. Cov.	450%	416%	435%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	9.5%	10.0%	.5%
"Cash Flow"	3.5%	6.0%	4.5%
Earnings	4.0%	4.5%	5.5%
Dividends	2.0%	1.5%	2.0%
Book Value	7.0%	7.0%	3.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
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	650.6	4969.1
2010	1292.9	*1650*	*900*	*757.1*	*4600*
2011	*1065*	*1835*	*1045*	*855*	*4800*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
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.17	1.97
2010	1.00	*1.32*	*.05*	*d.12*	*2.25*
2011	*.97*	*1.36*	*.03*	*d.01*	*2.35*

Calendar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	.335	1.33
2010	.335				

	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
	26.61	35.36	22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	*48.95*	*50.00*	Revenues per sh A	*68.20*
	3.01	3.03	3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	*4.70*	*4.90*	"Cash Flow" per sh	*5.40*
	1.03	1.47	1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	*2.25*	*2.35*	Earnings per sh A B	*2.70*
	1.14	1.16	1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	*1.34*	*1.36*	Div'ds Decl'd per sh C ■	*1.45*
	2.36	2.77	3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	*5.60*	*5.70*	Cap'l Spending per sh	*6.70*
	12.28	14.31	13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	*24.50*	*24.95*	Book Value per sh	*27.80*
	31.95	40.79	41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	*94.00*	*96.00*	Common Shs Outst'g D	*110.00*
	18.9	15.6	15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*13.0*
	1.23	.80	.83	.76	.84	.86	.73	.84	.82	.82			Relative P/E Ratio	*.85*
	5.9%	5.1%	5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%			Avg Ann'l Div'd Yield	*4.1%*
	850.2	1442.3	950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	*4600*	*4800*	Revenues ($mill) A	*7500*
	32.2	56.1	59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	*210*	*225*	Net Profit ($mill)	*300*
	36.1%	37.3%	37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	*38.5%*	*38.5%*	Income Tax Rate	*40.5%*
	3.8%	3.9%	6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	*4.6%*	*4.7%*	Net Profit Margin	*4.0%*
	48.1%	54.3%	53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	*49.0%*	*49.0%*	Long-Term Debt Ratio	*49.0%*
	51.9%	45.7%	46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	*51.0%*	*51.0%*	Common Equity Ratio	*51.0%*
	755.7	1276.3	1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	*4520*	*4700*	Total Capital ($mill)	*6000*
	982.3	1335.4	1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	*4745*	*5050*	Net Plant ($mill)	*6100*
	6.5%	5.9%	6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	*9.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
	8.2%	9.6%	10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	*9.0%*	*9.5%*	Return on Com Equity	*10.0%*
	NMF	2.1%	1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
	112%	79%	82%	70%	77%	73%	63%	65%	65%	68%	*60%*	*58%*	All Div'ds to Net Prof	*53%*

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three 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 2009 gas volumes: 282 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2009 depreciation rate 3.6%. Has around 4,700 employees. Officers and directors own approximately 1.6% of common stock (12/09 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 got off to a strong start in fiscal 2010, which ends on September 30th, as first-quarter earnings per share were around 20% higher than the year-earlier tally. For one thing, the natural gas marketing segment enjoyed a substantial increase in unrealized margins, brought about, to a certain extent, by a narrowing of spreads between current cash prices and forward natural gas prices. Furthermore, results for the natural gas utility were aided partially by higher rates in the Mid-Tex, Louisiana, and West Texas service areas. That unit also benefited from a 7% rise in throughput, as colder temperatures boosted consumption. Finally, the regulated transmission and storage operation experienced a drop in operating expenses because of a decreased level of pipeline maintenance activity.

We expect the momentum to continue during the remaining three quarters. As a result, the bottom line stands to advance about 14%, to $2.25 a share, in fiscal 2010. Assuming further expansion in operating margins, share net may reach $2.35 next year. That would be a much slower rate of growth due to the difficult comparison.

Steady, though unexciting, earnings gains appear to be in store for the company in the next three to five years. The utility is one of the nation's largest natural gas-only distributors, now serving over three million customers across 12 states. Moreover, the unregulated segments (contributing between 15% and 35% to net income annually on a historical basis) possess healthy prospects. Lastly, management may return to its successful strategy of purchasing less-efficient utilities and shoring up their profitability through expense-reduction initiatives, rate relief, and aggressive marketing. (Future acquisitions are excluded from our figures, however.) In Atmos' current configuration, annual share-net growth could be in the mid-single-digit range over the 2013-2015 period.

On a risk-adjusted basis, total return potential is appealing. Meanwhile, these good-quality shares are ranked to perform in line with the broader market in the year ahead.

Frederick L. Harris, III *March 12, 2010*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '00, 12¢; '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢. Next egs. rpt. due early May. (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	90

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LACLEDE GROUP NYSE-LG

RECENT PRICE 33.81 | P/E RATIO 13.8 (Trailing: 13.4 / Median: 14.0) | RELATIVE P/E RATIO 0.81 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 5 Lowered 2/5/10
SAFETY 2 Raised 6/20/03
TECHNICAL 1 Raised 2/5/10
BETA .60 (1.00 = Market)

2013-15 PROJECTIONS

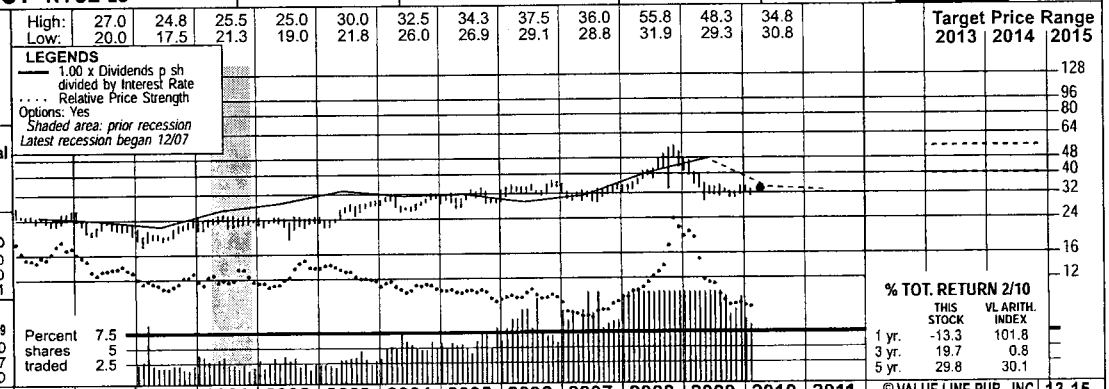
	Price	Gain	Ann'l Total Return
High	55	(+65%)	16%
Low	40	(+20%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	2	1	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	0	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	70	71	60
to Sell	81	81	67
Hld's(000)	11043	10569	10660



1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	85.49	*72.90*	*76.10*	Revenues per sh	*96.15*
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	4.56	*4.15*	*4.35*	"Cash Flow" per sh	*5.20*
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	2.92	*2.45*	*2.60*	Earnings per sh A B	*3.00*
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*	*1.61*	Div'ds Decl'd per sh C■	*1.75*
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	2.36	*2.45*	*2.55*	Cap'l Spending per sh	*3.15*
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	23.32	*23.90*	*24.30*	Book Value per sh D	*27.70*
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	22.17	*22.50*	*23.00*	Common Shs Outst'g E	*26.00*
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	13.4	*Bold figures are*		Avg Ann'l P/E Ratio	*16.0*
1.08	1.04	.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.88	*Value Line*		Relative P/E Ratio	*1.05*
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%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*
566.1	1002.1	755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	*1640*	*1750*	Revenues ($mill) A	*2500*
26.0	30.5	22.4	34.6	36.1	40.1	50.5	49.8	57.6	64.3	*55.0*	*60.0*	Net Profit ($mill)	*80.0*
35.2%	32.7%	35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
4.6%	3.0%	3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	*3.4%*	*3.4%*	Net Profit Margin	*3.2%*
45.2%	49.5%	47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	*42.5%*	*43.0%*	Long-Term Debt Ratio	*47.0%*
54.5%	50.2%	52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	*57.5%*	*57.0%*	Common Equity Ratio	*53.0%*
519.2	574.1	546.6	605.0	737.4	707.9	798.9	784.5	876.1	906.3	*935*	*980*	Total Capital ($mill)	*1360*
575.4	602.5	594.4	621.2	646.9	679.5	763.8	793.8	823.2	855.9	*870*	*915*	Net Plant ($mill)	*1230*
6.7%	6.9%	6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	*7.0%*	*7.5%*	Return on Total Cap'l	*7.5%*
9.1%	10.5%	7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	*10.0%*	*10.5%*	Return on Shr. Equity	*11.0%*
9.1%	10.5%	7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	*10.0%*	*10.5%*	Return on Com Equity	*11.0%*
.2%	1.8%	NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	*3.5%*	*4.0%*	Retained to Com Eq	*5.0%*
98%	83%	113%	74%	73%	72%	59%	63%	56%	53%	*64%*	*62%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $509.5 mill. **Due in 5 Yrs** $180.0 mill.
LT Debt $364.3 mill. **LT Interest** $20.0 mill.
(Total interest coverage: 4.3x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/09 $223.7 mill.
Oblig. $378.0 mill.

Pfd Stock None
Common Stock 22,262,436 shs.
as of 1/28/10

MARKET CAP: $750 million (Small Cap)

CURRENT POSITION ($MILL.)	2008	2009	12/31/09
Cash Assets	14.9	74.6	80.0
Other	547.0	294.2	396.7
Current Assets	561.9	368.8	476.7
Accts Payable	159.6	72.8	135.1
Debt Due	216.1	129.8	145.2
Other	103.5	96.5	127.5
Current Liab.	479.2	299.1	407.8
Fix. Chg. Cov.	377%	420%	400%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	12.0%	12.5%	.5%
"Cash Flow"	3.5%	8.5%	3.5%
Earnings	5.0%	10.5%	2.5%
Dividends	1.0%	2.0%	2.5%
Book Value	4.0%	6.5%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
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	251.9	1895.2
2010	491.2	*550*	*350*	*248.8*	*1640*
2011	*460*	*625*	*410*	*255*	*1750*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2007	.89	.97	.43	.03	2.31
2008	.99	1.39	.41	d.14	2.64
2009	1.42	1.40	.31	d.22	2.92
2010	1.03	*1.30*	*.35*	*d.23*	*2.45*
2011	*1.00*	*1.41*	*.41*	*d.22*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	.385	1.54
2010	.395				

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 2009: 1.07 mill. Revenue mix for regulated operations: residential, 65%; commercial and industrial, 24%; transportation, 1%; other, 10%. Has around 1,762 employees. Officers and directors own approximately 8% of common shares (1/10 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.

Laclede Group's share net plummeted 27% in the opening quarter of fiscal 2010, compared to the same period a year earlier. (Years end September 30th.) The shortfall occurred primarily because Laclede Energy Resources suffered from a substantial reduction in margins on sales of natural gas, reflecting narrower price differentials. On a positive note, results for Laclede Gas were boosted nicely by the sale of propane in the wholesale market, and, to a lesser degree, higher net investment income.

We expect more of the same during the remainder of the year. Consequently, the company's bottom line for fiscal 2010, as a whole, stands to drop about 16%, to $2.45 a share. But assuming a better performance from Laclede Energy Resources, share net may advance 6%, to $2.60, the following year. Note that our figures do not include a pending rate case (discussed below).

A rate case was filed with the Missouri Public Service Commission. Laclede seeks a net revenue increase of $52.6 million annually, to help offset the rising costs of providing natural gas service to its customers. Of course, there is no guarantee that the measure will be approved, or that the full amount requested will be received.

The company stands to register unspectacular results in the coming three to five years. The customer base for Laclede Gas will probably continue to expand at a moderate rate, since the service territory is in a mature phase. Laclede Energy Resources offers promising growth opportunities, but has contributed just a small portion to total profits on a historical basis. A major acquisition could help to offset this, but it seems that management has no such plans in the works, at this juncture.

The good-quality stock offers a generous amount of current dividend income, which is well covered by the company's earnings. But our projections indicate that additional increases in the distribution will be moderate. That is largely because of the utility's unexciting expansion prospects. Meanwhile, the shares of Laclede are ranked 5 (Lowest) for Timeliness.

Frederick L. Harris, III *March 12, 2010*

(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 April. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '09: $488.3 mill., $22.03/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 **37.33** | P/E RATIO **14.4** (Trailing: 16.4 / Median: 15.0) | RELATIVE P/E RATIO **0.85** | DIV'D YLD **3.6%** | **VALUE LINE**

TIMELINESS 4 Lowered 10/9/09
SAFETY 1 Raised 9/15/06
TECHNICAL 2 Raised 2/12/10
BETA .65 (1.00 = Market)

2013-15 PROJECTIONS

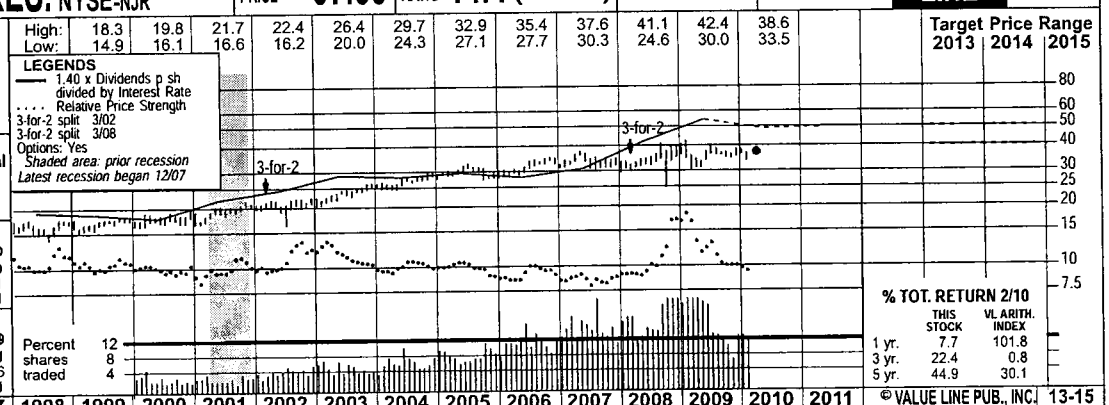
	Price	Gain	Ann'l Total Return
High	50	(+35%)	11%
Low	40	(+5%)	6%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	3	0	0	0	1
to Sell	0	0	0	0	4	0	0	0	1

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	87	89	71
to Sell	88	88	76
Hld's(000)	23324	24695	24351



1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	62.34	*65.50*	*73.15*	Revenues per sh [A]	*79.55*
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	3.16	*3.50*	*3.75*	"Cash Flow" per sh	*3.20*
.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	2.40	*2.60*	*2.75*	Earnings per sh [B]	*3.20*
.68	.68	.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	*1.36*	*1.45*	Div'ds Decl'd per sh [C] ■	*1.52*
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	1.81	*1.80*	*1.95*	Cap'l Spending per sh	*2.00*
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	16.59	*17.50*	*17.65*	Book Value per sh [D]	*19.45*
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	41.59	*42.00*	*41.00*	Common Shs Outst'g [E]	*40.00*
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	14.9	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
.85	.79	.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.98			Relative P/E Ratio	*.95*
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%	3.5%			Avg Ann'l Div'd Yield	*3.8%*
1164.5	2048.4	1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	*2750*	*3000*	Revenues ($mill) [A]	*3185*
47.9	52.3	56.8	65.4	71.6	74.4	78.5	65.3	113.9	101.0	*110*	*115*	Net Profit ($mill)	*125*
37.8%	38.0%	38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	*30.0%*	*35.0%*	Income Tax Rate	*40.0%*
4.1%	2.6%	3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	*4.0%*	*4.0%*	Net Profit Margin	*4.0%*
47.0%	50.1%	50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	*41.5%*	*42.0%*	Long-Term Debt Ratio	*42.5%*
52.9%	49.9%	49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	*58.5%*	*58.0%*	Common Equity Ratio	*57.5%*
620.1	706.2	732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	1144.8	*1260*	*1250*	Total Capital ($mill)	*1350*
730.6	743.9	756.4	852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	*1085*	*1100*	Net Plant ($mill)	*1150*
9.0%	8.5%	8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	*9.5%*	*10.0%*	Return on Total Cap'l	*10.5%*
14.6%	14.8%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	*15.0%*	*16.0%*	Return on Shr. Equity	*16.5%*
14.6%	14.9%	15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	*15.0%*	*16.0%*	Return on Com Equity	*16.5%*
5.4%	6.1%	6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	7.2%	*7.0%*	*7.5%*	Retained to Com Eq	*8.5%*
63%	59%	56%	51%	49%	50%	50%	64%	40%	50%	*52%*	*52%*	All Div'ds to Net Prof	*48%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $666.4 mill. **Due in 5 Yrs** $157.7 mill.
LT Debt $438.4 mill. **LT Interest** $15.8 mill.
Incl. $9.9 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/08 $100.6 mill.
Oblig. $133.8 mill.
Pfd Stock None

Common Stock 41,417,220 shs.
as of 2/2/10
MARKET CAP: $1.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2008	2009	12/31/09
Cash Assets	42.6	36.2	10.3
Other	1067.1	648.0	777.9
Current Assets	1109.7	684.2	788.2
Accts Payable	61.7	44.4	34.8
Debt Due	238.3	149.9	228.0
Other	594.0	361.9	373.6
Current Liab.	894.0	556.2	636.4
Fix. Chg. Cov.	780%	711%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	14.5%	6.0%	*1.5%*
"Cash Flow"	6.0%	5.5%	*5.5%*
Earnings	8.0%	7.5%	*6.5%*
Dividends	4.5%	6.0%	*5.5%*
Book Value	8.5%	10.5%	*4.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
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	412.6	2592.5
2010	609.6	*925*	*615.4*	*600*	*2750*
2011	*670*	*990*	*680*	*660*	*3000*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2007	.70	.19	.60	.06	1.55[F]
2008	1.31	1.86	d.10	d.39	2.70
2009	.77	1.71	.03	d.12	2.40
2010	.66	*1.85*	*.10*	*d.01*	*2.60*
2011	*.70*	*1.90*	*.15*	*Nil*	*2.75*

Calendar	QUARTERLY DIVIDENDS PAID [C E ■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.24	.24	.24	.24	.96
2007	.253	.253	.253	.253	1.01
2008	.267	.28	.28	.28	1.11
2009	.31	.31	.31	.31	1.24
2010	.34				

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 486,529 customers at 9/30/09 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2009 volume: 133 bill. cu. ft. (5% firm, 95% interruptible industrial and electric utility, 3% off-system and capacity release). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2009 dep. rate: 2.2%. Has 613 empls. Off./dir. own about 1.5% 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 posted lower-than-expected top-and bottom-line results for the December interim. Both the utility and nonutility operations experienced declining revenues. This stemmed from lower transportation volumes, and weak demand as a result of oversupply, particularly in the Northeast. However, strategic initiatives helped to reduce expenses and moderate the effects of diminished volumes on profitability. Those cost cuts boosted contributions from the New Jersey Natural Gas (NJNG) unit. And the mid-stream asset division got a significant boost in earnings, reflecting the commencing of operations at the Steckman Ridge facility. Still, coupled with a weak showing at the NJR Energy Services unit, the bottom line fell 14.3% during the first fiscal quarter of 2010. However,

We have left our 2010 earnings estimate unchanged for the time being. Solid contributions from NJNG as a result of new customer accounts (about 1,440 so far this year) and benefits from the Steckman Ridge storage facility are anticipated, putting our earnings target within reach. Also, we have introduced a 2011 share-net estimate of $2.75 a share.

The balance sheet is supportive. Cash reserves fell almost 72% during the December period. This was likely a result of stock and debt repurchases. Over that timeframe, the board of directors voted to increase the existing share-repurchase agreement by two million shares, bringing the total authorization to 8.75 million. Since the inception of the plan in 1996, NJR has bought back about 6.5 million shares. Meantime, the company trimmed its debt load roughly 4%. This move should help to minimize interest expenses.

These shares may appeal to income-seeking accounts, due to a recent dividend hike. Too, the top rank for Safety and high mark for Price Stability will probably appease even the most conservative investors. However, the recent sideways price movement and lackluster earnings figures have resulted in a below-average Timeliness rank. Thus, we look for NJR to lag the broader market in the year ahead. Growth in new hook-ups is still positive, but is slower than it was during last decade's real estate boom.

Bryan J. Fong *March 12, 2010*

(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 April.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2009: $391.0 million, $9.21/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 42.72 | P/E RATIO 14.4 (Trailing: 14.4 Median: 15.0) | RELATIVE P/E RATIO 0.85 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 3 Raised 11/13/09
SAFETY 3 Lowered 6/17/05
TECHNICAL 2 Raised 2/12/10
BETA .70 (1.00 = Market)

2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+50%)	14%
Low	40	(-5%)	3%

Insider Decisions

	A	M	J	J	A	S	O	N	D
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

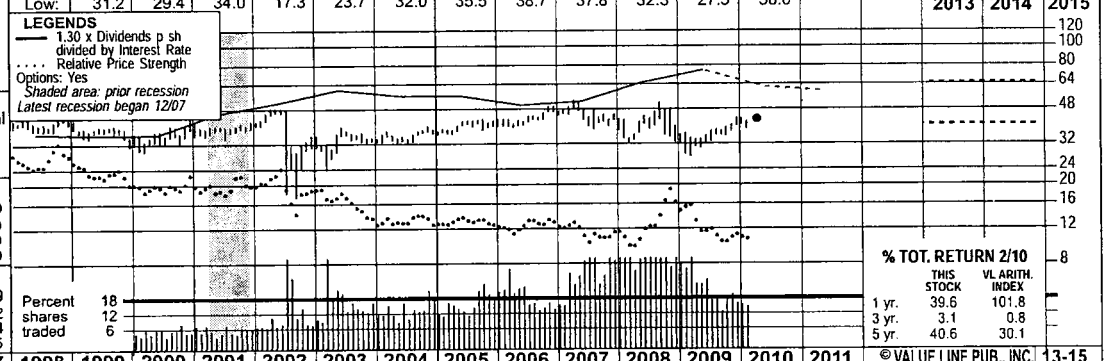
Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	92	105	92
to Sell	126	103	104
Hld's(000)	25772	25968	24945

High: 42.9 43.9 42.4 49.0 39.3 39.7 43.0 49.9 53.7 52.0 43.4 43.2
Low: 31.2 29.4 34.0 17.3 23.7 32.0 35.5 38.7 37.8 32.3 27.5 38.0

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

Target Price Range 2013 | 2014 | 2015



% TOT. RETURN 2/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	39.6	101.8
3 yr.	3.1	0.8
5 yr.	40.6	30.1

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	58.62	*60.45*	*62.65*	Revenues per sh	*76.90*
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	7.32	*7.15*	*7.60*	"Cash Flow" per sh	*8.70*
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	2.98	2.63	2.97	*2.75*	*3.10*	Earnings per sh [A]	*3.30*
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*	*1.86*	Div'ds Decl'd per sh [B]■	*1.86*
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	4.87	*5.80*	*6.25*	Cap'l Spending per sh	*6.80*
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	22.93	*23.70*	*24.95*	Book Value per sh	*29.20*
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	45.25	*45.50*	*45.50*	Common Shs Outst'g [C]	*45.50*
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	11.8	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*16.0*
.82	.88	.78	.82	.92	.83	.77	.66	.72	.90	.84	.92	.81	.80	.91	.78			Relative P/E Ratio	*1.05*
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%	5.3%			Avg Ann'l Div'd Yield	*3.9%*
2298.1	2544.1	1897.4	2662.7	2739.7	3357.8	2960.0	3176.3	3776.6	2652.1	*2750*	*2850*	Revenues ($mill)	*3500*
136.4	136.3	128.0	93.1	98.1	101.1	128.3	135.2	119.5	135.5	*125*	*205*	Net Profit ($mill)	*150*
34.8%	33.5%	31.0%	35.2%	31.8%	28.3%	26.3%	26.6%	27.0%	32.5%	*27.0%*	*27.0%*	Income Tax Rate	*27.0%*
5.9%	5.4%	6.7%	3.5%	3.6%	3.0%	4.3%	4.3%	3.2%	5.1%	*4.6%*	*5.0%*	Net Profit Margin	*4.3%*
32.7%	37.8%	35.1%	39.6%	39.8%	37.4%	36.3%	30.9%	31.5%	32.4%	*32%*	*28%*	Long-Term Debt Ratio	*24%*
66.7%	61.7%	64.5%	60.3%	60.1%	62.5%	63.7%	69.0%	68.4%	67.6%	*68%*	*72%*	Common Equity Ratio	*76%*
1061.2	1180.1	1128.9	1251.5	1246.0	1297.7	1370.7	1368.0	1421.1	1535.9	*1575*	*1585*	Total Capital ($mill)	*1750*
1729.6	1768.6	1796.8	2484.2	2549.8	2659.1	2714.1	2757.3	2858.6	2939.1	*3050*	*3200*	Net Plant ($mill)	*3650*
13.7%	12.3%	12.2%	8.3%	8.8%	9.4%	10.9%	11.2%	9.7%	10.0%	*9.0%*	*10.0%*	Return on Total Cap'l	*9.5%*
19.1%	18.6%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	13.1%	*11.5%*	*12.5%*	Return on Shr. Equity	*11.5%*
19.2%	18.7%	17.5%	12.3%	13.1%	12.5%	14.7%	14.3%	12.3%	13.1%	*11.5%*	*12.5%*	Return on Com Equity	*11.5%*
8.5%	7.9%	6.5%	1.5%	2.1%	2.3%	5.2%	5.4%	3.6%	4.9%	*4.0%*	*5.0%*	Retained to Com Eq	*5.0%*
56%	58%	63%	88%	84%	81%	65%	62%	71%	63%	*67%*	*60%*	All Div'ds to Net Prof	*56%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $992.8 mill. **Due in 5 Yrs** $569.0 mill.
LT Debt $498.8 mill. **LT Interest** $6.5 mill.
(Total interest coverage: 6.1x)

Pension Assets-12/09 $364 mill. **Oblig.** $306 mill.

Pfd Stock $.1 mill. **Pfd Div'd** None

Common Stock 45,245,188 shares
as of 2/17/10
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/09
Cash Assets	91.9	95.5	133.7
Other	931.9	1243.4	869.6
Current Assets	1023.8	1338.9	1003.3
Accts Payable	564.5	411.3	353.9
Debt Due	350.0	789.9	494.0
Other	227.9	466.8	320.2
Current Liab.	1142.4	1668.0	1168.1
Fix. Chg. Cov.	543%	461%	569%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	7.0%	5.0%	*1.5%*
"Cash Flow"	3.0%	4.0%	*3.5%*
Earnings	1.5%	3.5%	*2.5%*
Dividends	2.5%	--	*Nil*
Book Value	3.0%	5.0%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	325.6	768.1	2652.1
2010	*1125*	*465*	*340*	*820*	*2750*
2011	*1175*	*475*	*350*	*850*	*2850*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	1.04	.40	.32	1.22	2.98
2008	.91	.64	.03	1.05	2.63
2009	.96	.50	.30	1.21	2.97
2010	*.90*	*.50*	*.35*	*1.00*	*2.75*
2011	*1.00*	*.56*	*.40*	*1.14*	*3.10*

Calendar	QUARTERLY DIVIDENDS PAID [B]■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	.465	1.86
2010					

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. 2009 gas delivered: 475.9 Bcf, incl. 217.1 Bcf from transportation. 2009 gas sales (258.8 bcf): residential, 78%; commercial, 20%; industrial, 2%. 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's gas distribution business has allowed it to sustain good bottom-line momentum. The utility reported earnings of $1.21 a share in the December period. Management attributed the better-than-expected showing to strong performances in the aforementioned business and its other energy-related operations. Moreover, the recent rate relief has provided a boost to results in recent months. What's more, the company locked in some profits through its investment in energy prices. However, the shipping segment turned in weak results due to lower volumes as a result of the weakness in the global economy. For the full year, Nicor reported share net of $2.97, which was impressive given the tough operating environment.

The Illinois Commerce Commission approved a bad debt recovery mechanism. The company implemented an instrument that allows it to annually collect the difference between its bad debt expense and a predetermined benchmark, which is payable in the following year. This year Nicor will recover $32 million for bad debt from previous years. Investors should note that we will be excluding this number from our estimates.

The company's prospects for 2010 appear subpar. We look for share net to pull back in the year ahead. The gas distribution business should continue to perform well. However, we expect the shipping business and the company's other energy-related operations to fall short of their 2009 performance. Accordingly, we estimate earnings will decline 7% to $2.75 a share. Additionally, we are introducing our share-net target for 2011. We look for the bottom line to rebound to $3.10 a share as the shipping business should improve along with the global economy.

Nicor stock offers an attractive dividend yield. Indeed, GAS' yield (4.4%) is just above average for a natural gas utility. Thus, income-oriented accounts may want to take a look here.

That said, this equity is ranked to track the market over the coming six to 12 months. What's more, it has below-average total-return potential at present. Therefore, we recommend most investors stay on the sidelines until prospects improve.

Richard Gallagher *March 12, 2010*

(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 late April.
(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 45.85 | P/E RATIO 17.0 (Trailing: 16.6 Median: 16.0) | RELATIVE P/E RATIO 1.00 | DIV'D YLD 3.7% | VALUE LINE

TIMELINESS 4 Lowered 3/12/10
SAFETY 1 Raised 3/18/05
TECHNICAL 2 Raised 2/12/10
BETA .60 (1.00 = Market)

2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	12%
Low	55	(+20%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	1
Options	0	0	0	0	0	0	0	0	2
to Sell	0	1	1	1	2	0	0	2	3

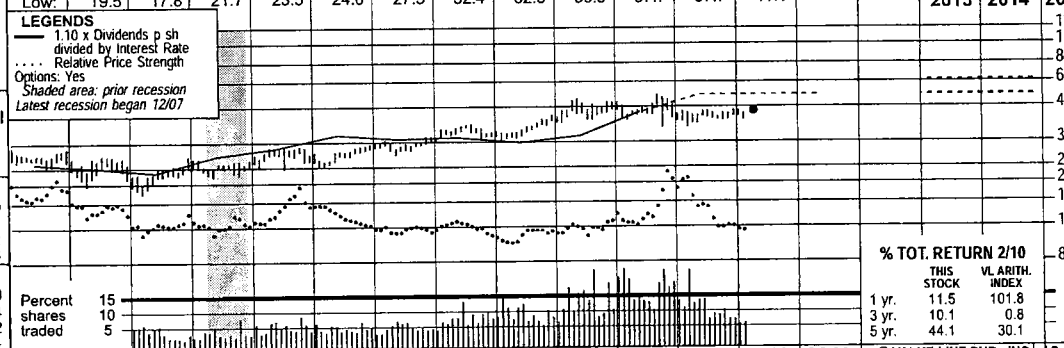
Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	67	78	64
to Sell	93	69	82
Hld's(000)	15126	15387	15134

	2013	2014	2015
High:	27.9	27.5	26.8
Low:	19.5	17.8	21.7

Target Price Range 2013 | 2014 | 2015

LEGENDS
1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded area: prior recession
Latest recession began 12/07



% TOT. RETURN 2/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	11.5	101.8
3 yr.	10.1	0.8
5 yr.	44.1	30.1

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	38.18	*35.85*	*35.55*	Revenues per sh	*48.20*
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	5.12	*5.25*	*5.45*	"Cash Flow" per sh	*6.40*
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	2.77	*2.80*	*2.95*	Earnings per sh A	*3.50*
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*	*1.78*	Div'ds Decl'd per sh B■	*2.16*
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	5.09	*7.70*	*6.20*	Cap'l Spending per sh	*4.50*
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	24.88	*26.10*	*27.45*	Book Value per sh	*31.75*
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	26.53	*26.60*	*26.60*	Common Shs Outst'g C	*28.00*
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	15.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*17.0*
.85	.86	.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.02			Relative P/E Ratio	*1.15*
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%	3.7%			Avg Ann'l Div'd Yield	*3.6%*
532.1	650.3	641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	*950*	*1025*	Revenues ($mill)	*1350*
47.8	50.2	43.8	46.0	50.6	58.1	65.2	74.5	68.5	73.5	*74.5*	*80.0*	Net Profit ($mill)	*98.0*
35.9%	35.4%	34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	*37.0%*	*37.0%*	Income Tax Rate	*37.0%*
9.0%	7.7%	6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.0%	*7.9%*	*7.8%*	Net Profit Margin	*7.3%*
45.1%	43.0%	47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	*50%*	*51%*	Long-Term Debt Ratio	*50%*
50.9%	53.2%	51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	*50%*	*49%*	Common Equity Ratio	*50%*
887.8	880.5	937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	*1400*	*1500*	Total Capital ($mill)	*1800*
934.0	965.0	995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	*1800*	*1900*	Net Plant ($mill)	*2200*
6.7%	6.9%	5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.0%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
9.8%	10.0%	8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.1%	*11.0%*	*11.0%*	Return on Shr. Equity	*9.0%*
10.0%	10.2%	8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.1%	*11.0%*	*11.0%*	Return on Com Equity	*9.0%*
3.1%	3.5%	1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	4.7%	*4.5%*	*4.5%*	Retained to Com Eq	*3.5%*
70%	67%	79%	72%	69%	63%	59%	52%	59%	58%	*60%*	*60%*	All Div'ds to Net Prof	*62%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $738.7 mill. **Due in 5 Yrs** $145 mill.
LT Debt $601.7 mill. **LT Interest** $34.0 mill.

(Total interest coverage: 3.9x)

Pension Assets-12/08 $201 mill.
Oblig. $308 mill.
Pfd Stock None

Common Stock 26,533,028 shares
as of 2/23/10
MARKET CAP $1.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	2009
Cash Assets	6.1	6.9	8.4
Other	268.8	474.1	319.8
Current Assets	274.9	481.0	328.2
Accts Payable	119.7	94.4	123.7
Debt Due	148.1	248.0	137.0
Other	122.1	208.9	131.9
Current Liab.	389.9	551.3	392.6
Fx. Chg. Cov.	408%	393%	395%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	9.0%	9.0%	*2.5%*
"Cash Flow"	3.5%	6.5%	*3.5%*
Earnings	5.0%	8.0%	*5.0%*
Dividends	2.0%	3.0%	*6.0%*
Book Value	3.5%	3.5%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	394.1	183.2	124.2	331.7	1033.2
2008	387.7	191.3	109.7	349.2	1037.9
2009	437.3	149.3	116.8	309.3	1012.7
2010	*375*	*135*	*110*	*330*	*950*
2011	*400*	*145*	*125*	*355*	*1025*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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.25	1.18	2.77
2010	*1.70*	*.11*	*d.29*	*1.28*	*2.80*
2011	*1.77*	*.11*	*d.27*	*1.34*	*2.95*

Calendar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	.415	1.60
2010	.415				

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 668,000 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, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. 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 2009 results reflected some unusual items. The company earned $15 million pretax from its commodity cost-sharing arrangement in Oregon, under which Northwest retains some of the difference between actual and forecast gas costs, with the majority going to the rate payers. That windfall was partially offset by higher pension, healthcare, incentive bonus, and severance costs. Customer growth was just below 1% last year, compared with an average of around 3% annually for many years through 2007, as the recession flattened housing starts. All told, earnings would have been around $2.60-$2.65 a share in 2009, excluding the unusual items.

We anticipate a normal year in 2010. Thanks to much-lower natural gas prices, Northwest is lowering its residential gas prices by around 10% this year. That and the incipient economic recovery should produce better customer growth than in 2009. Operating costs should remain moderate, owing to a roughly 20% headcount reduction since 2005. Pension and bonus expenses should decline, unless the latter rises due to a very good year.

Steady growth is likely next year. We expect the recovery in customer growth and industrial gas use to continue. Polls indicate that gas is favored over electricity for home heating by a three to one margin in Portland, and returning prosperity should increase conversions to gas from other fuels. Costs should remain moderate, as last year's new union contract provides for more workforce flexibility and caps payroll and healthcare costs at 3% annually depending on inflation. Finally, the Gill Ranch gas storage project in California is scheduled to open late this year and ought to contribute to results in 2011.

A new pipeline could boost earnings noticeably by 2013-2015. Northwest owns half of the proposed Palomar pipeline, which would provide Portland a needed second source of gas. If both halves are built, the company's investment would be around $400 million. Though that would entail raising some equity, it would lift earnings beyond our forecast, which excludes the project for now.

These high-quality shares offer good risk adjusted total-return potential.

Sigourney B. Romaine *March 12, 2010*

(A) Diluted earnings per share. Excludes nonrecurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢. Next earnings report due early May.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions, adjusted for 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 26.38 | P/E RATIO 16.0 (Trailing: 15.8 Median: 17.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 4.2% | VALUE LINE

TIMELINESS 3 Raised 6/15/07
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 2/12/10
BETA .65 (1.00 = Market)

2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	15%
Low	30	(+15%)	8%

Insider Decisions

	A	M	J	J	A	S	O	N	D
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	75	78	78
to Sell	123	96	82
Hld's(000)	34611	33567	33498

	High:	18.3	19.7	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	27.4
	Low:	14.3	11.8	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9

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

Target Price Range 2013 | 2014 | 2015

Percent shares traded 7.5 5 2.5

% TOT. RETURN 2/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	11.7	101.8
3 yr.	15.5	0.8
5 yr.	34.1	30.1

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	22.36	*23.60*	*24.50*	Revenues per sh [A]	*27.75*
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	3.01	*2.90*	*2.95*	"Cash Flow" per sh	*3.25*
.68	.73	.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	*1.65*	*1.70*	Earnings per sh [AB]	*1.95*
.51	.54	.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	*1.11*	*1.15*	Div'ds Decl'd per sh [C■]	*1.27*
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	1.76	*.65*	*.55*	Cap'l Spending per sh	*1.45*
5.68	6.16	6.53	6.95	7.45	7.86	8.25	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	*12.95*	*13.40*	Book Value per sh [D]	*14.70*
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	73.27	*72.00*	*71.50*	Common Shs Outst'g [E]	*69.00*
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	15.4	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*18.0*
1.03	.92	.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.02			Relative P/E Ratio	*1.50*
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%	4.1%			Avg Ann'l Div'd Yield	*3.3%*
						830.4	1107.9	832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	*1700*	*1750*	Revenues ($mill) [A]	*1915*
						64.0	65.5	62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	*119*	*120*	Net Profit ($mill)	*135*
						34.7%	34.6%	33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	26.5%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						7.7%	5.9%	7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	*7.0%*	*7.0%*	Net Profit Margin	*7.0%*
						46.1%	47.6%	43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	*44.5%*	*45.5%*	Long-Term Debt Ratio	*47.0%*
						53.9%	52.4%	56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	*55.5%*	*54.5%*	Common Equity Ratio	*53.0%*
						978.4	1069.4	1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	*1680*	*1760*	Total Capital ($mill)	*1915*
						1072.0	1114.7	1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	*2350*	*2375*	Net Plant ($mill)	*2450*
						8.3%	7.9%	7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	*8.5%*	*8.5%*	Return on Total Cap'l	*8.5%*
						12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	*13.0%*	*12.5%*	Return on Shr. Equity	*13.0%*
						12.1%	11.7%	10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	*13.0%*	*12.5%*	Return on Com Equity	*13.0%*
						3.5%	3.0%	1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	*4.0%*	*4.0%*	Retained to Com Eq	*5.0%*
						71%	75%	83%	74%	66%	68%	74%	70%	69%	64%	*67%*	*67%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 10/31/09
Total Debt $1098.5 mill. Due in 5 Yrs $220.0 mill.
LT Debt $732.5 mill. LT Interest $55.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.5x)

Pension Assets-10/09 $184.3 mill.
Oblig. $195.3 mill.

Pfd Stock None

Common Stock 73,295,803 shs.
as of 12/11/09
MARKET CAP: $1.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	10/31/09
Cash Assets	7.5	7.0	7.6
Other	427.8	593.8	505.6
Current Assets	435.3	600.8	513.2
Accts Payable	143.6	132.3	115.4
Debt Due	195.0	436.5	366.0
Other	85.9	112.7	118.8
Current Liab.	424.5	681.5	600.2
Fix. Chg. Cov.	309%	341%	316%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	7.5%	8.0%	*2.0%*
"Cash Flow"	5.5%	6.5%	*2.5%*
Earnings	5.0%	6.5%	*4.0%*
Dividends	5.0%	4.5%	*3.5%*
Book Value	5.0%	4.5%	*3.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
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	180.3	222.8	1638.1
2010	*795*	*470*	*195*	*240*	*1700*
2011	*805*	*480*	*210*	*255*	*1750*

Fiscal Year Ends	EARNINGS PER SHARE [A B] Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
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.06	1.67
2010	*1.15*	*.75*	*d.10*	*d.15*	*1.65*
2011	*1.16*	*.77*	*d.09*	*d.14*	*1.70*

Calendar	QUARTERLY DIVIDENDS PAID [C■] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.23	.24	.24	.24	.95
2007	.24	.25	.25	.25	.99
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27				

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 952,469 customers in North Carolina, South Carolina, and Tennessee. 2009 revenue mix: residential (48%), commercial (28%), industrial (8%), other (16%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 65.7% of revenues. '09 deprec. rate: 3.4%. Estimated plant age: 8.4 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,821 employees. Officers & directors own about 1.3% of common stock (1/10 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 likely posted a modest earnings advance for the first quarter of fiscal 2010 (ended January 31st). *The company was expected to issue financial results shortly after this report went to press.* Top line volumes probably advanced in the low single-digit range, thanks to additional customer accounts, and a firming up in natural gas pricing. Meantime, system throughput ought to have advanced a couple of percentage points as a result of colder-than-normal weather patterns. Margins likely continued to benefit from last year's rate-case increases in North Carolina and lower operations and maintenance expenses. On balance, profits probably rose approximately 5% over that time frame. However,

We trimmed $0.20 off our 2010 share-net estimate. PNY has proposed rate reductions for customers in North and South Carolina, due to the declining cost of wholesale gas prices. The proposal would lower residential billing rates in each state by roughly 5%. If it is passed, the new rates will have gone into effect on March 1st. Meantime, diminished contributions from the Southstar divestiture are also factored into our reduced estimates.

The company sold half of its Southstar Energy holdings. PNY received $57.5 million ($0.42 a share) from AGL Resources for a 15% stake in Southstar. That deal closed during the January interim and should provide a nice boost to cash. The downside is that earnings contributions from those holdings were starting to pick up, but due to the diminished stake, will now fall by roughly 50%.

We have introduced our 2011 revenue and earnings estimates of $1.75 billion and $1.70 a share, respectively. Continued growth in customer accounts, and the benefits from existing joint ventures should all contribute to the anticipated rebound in the top and bottom lines.

These neutrally ranked shares may appeal to income-oriented accounts. The equity offers a decent dividend yield, when compared to other utilities covered in the *Value Line Investment Survey.* Meantime, solid dividend-growth prospects, an Above-Average Safety rank (2), and a top mark for Price Stability (100) are all pluses.

Bryan J. Fong *March 12, 2010*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring charge: '97, 2¢. Next earnings report due early May. 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 2009: $31.6 million, 43¢/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

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SOUTH JERSEY INDS. NYSE-SJI

RECENT PRICE 40.49 | P/E RATIO 15.7 (Trailing: 17.0 Median: 14.0) | RELATIVE P/E RATIO 0.92 | DIV'D YLD 3.3% | VALUE LINE

TIMELINESS 3 Lowered 8/14/09
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 2/19/10
BETA .60 (1.00 = Market)

2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+35%)	11%
Low	40	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
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	2	0	2	0	0	0	3

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	73	70	63
to Sell	70	78	72
Hld's(000)	16545	15858	15611

	High:	15.4	15.1	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	40.6
	Low:	10.8	12.3	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: Yes
Shaded area: prior recession
Latest recession began 12/07

Target Price Range 2013 | 2014 | 2015

% TOT. RETURN 2/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	14.5	101.8
3 yr.	26.7	0.8
5 yr.	66.9	30.1

1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	28.37	*31.45*	*32.80*	Revenues per sh	*37.15*
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	3.44	*3.60*	*3.90*	"Cash Flow" per sh	*4.45*
.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	2.38	*2.65*	*2.80*	Earnings per sh [A]	*3.30*
.72	.72	.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	*1.34*	*1.40*	Div'ds Decl'd per sh [B] ■	*1.60*
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	*3.65*	*2.40*	*2.50*	Cap'l Spending per sh	*2.85*
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	18.27	*19.35*	*20.00*	Book Value per sh [C]	*22.85*
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	29.80	*31.00*	*32.00*	Common Shs Outst'g [D]	*35.00*
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	15.0	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*14.0*
1.06	.82	.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	.99			Relative P/E Ratio	*.95*
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%	3.4%			Avg Ann'l Div'd Yield	*3.5%*
515.9	837.3	505.1	696.8	819.1	921.0	931.4	956.4	962.0	845.4	*975*	*1050*	Revenues ($mill)	*1300*
24.7	26.8	29.4	34.6	43.0	48.6	72.0	61.8	67.7	71.1	*80.0*	*90.0*	Net Profit ($mill)	*115*
43.1%	42.2%	41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	36.7%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
4.8%	3.2%	5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	*8.2%*	*8.6%*	Net Profit Margin	*8.8%*
54.1%	57.0%	53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	36.5%	*40.0%*	*40.0%*	Long-Term Debt Ratio	*38.5%*
37.6%	35.9%	46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	*60.0%*	*60.0%*	Common Equity Ratio	*61.5%*
443.5	516.2	512.5	608.4	675.0	710.3	801.1	839.0	848.0	857.4	*1000*	*1065*	Total Capital ($mill)	*1300*
562.2	607.0	666.6	748.3	799.9	877.3	920.0	948.9	982.6	1073.1	*1075*	*1110*	Net Plant ($mill)	*1300*
7.4%	6.9%	7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	*9.2%*	*9.0%*	*9.5%*	Return on Total Cap'l	*9.5%*
12.1%	12.1%	12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	*13.5%*	*14.0%*	Return on Shr. Equity	*14.5%*
14.8%	12.8%	12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	*13.5%*	*14.0%*	Return on Com Equity	*14.5%*
4.8%	3.5%	4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	*6.5%*	*7.0%*	Retained to Com Eq	*7.5%*
67%	76%	62%	57%	52%	50%	37%	48%	49%	51%	*52%*	*50%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $544.5 mill. **Due in 5 Yrs** $113.2 mill.
LT Debt $312.8 mill. **LT Interest** $18.0 mill.
(Total interest coverage: 5.9x)

Pension Assets-12/09 $105.9 mill.
Oblig. $149.0 mill.

Pfd Stock none

Common Stock 29,812,932 common shs.
as of 2/22/10

MARKET CAP: $1.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/09
Cash Assets	11.7	5.8	3.8
Other	316.6	429.3	364.6
Current Assets	328.3	435.1	368.4
Accts Payable	101.2	120.2	123.9
Debt Due	118.4	237.6	231.7
Other	108.7	142.1	123.2
Current Liab.	328.3	499.9	478.8
Fix. Chg. Cov.	476%	598%	585%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '06-'08 to '13-'15
Revenues	6.0%	3.0%	*2.0%*
"Cash Flow"	8.5%	10.0%	*4.0%*
Earnings	11.5%	13.0%	*5.5%*
Dividends	3.5%	6.0%	*6.5%*
Book Value	9.0%	11.0%	*5.0%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	127.1	221.6	845.4
2010	*400*	*150*	*140*	*285*	*975*
2011	*420*	*160*	*160*	*310*	*1050*

Calendar	EARNINGS PER SHARE [A] Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2007	1.30	.21	d.05	.63	2.09
2008	1.32	.26	.04	.67	2.27
2009	1.46	.15	d.06	.83	2.38
2010	*1.45*	*.20*	*.10*	*.90*	*2.65*
2011	*1.50*	*.25*	*.10*	*.95*	*2.80*

Calendar	QUARTERLY DIVIDENDS PAID [B] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	--	.225	.225	.470	.92
2007	--	.245	.245	.515	1.01
2008	--	.270	.270	.568	1.11
2009	--	.298	.298	.628	1.22
2010	--				

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 should continue to report healthy results going forward. The company appears well-positioned in the markets that it serves. Revenues and share earnings should advance at a good clip for 2010 and 2011.

Utility South Jersey Gas continues to experience modest growth in its customer base, despite softness in the housing construction market. Natural gas remains very popular in its service territory. Much of the recent growth can be attributed to conversions to natural gas from other fuel sources. SJG's recent gas main extension project in Cape May County, as well as aggressive marketing efforts in other parts of its service territory without natural gas service, have been well received. As a result, the utility expects to add over 3,000 customers from conversions this year. Elsewhere,

Performance from the company's Wholesale Energy business should also remain solid. It currently has significant gas storage capacity and pipeline capacity under management, both of which afford opportunities to lock in attractive margins resulting from volatility in market pricing. In addition, this unit ought to benefit from its position in the Marcellus Shale acreage. Leaseholder St. Mary Land & Exploration Company has already drilled two wells on SJI's property, and expects to drill two more in 2010. The company expects to begin recognizing a royalty and working interest revenue stream from these wells in the current year.

South Jersey Gas is seeking higher rates. The utility petitioned the New Jersey Board of Public Utilities for a $35 million increase (roughly 7%) in operating revenues. This marks SJG's first base rate filing in seven years. The company cited the need to recover infrastructure investments of $466 million made over the past six years. Any increase would not become effective until late 2010.

These neutrally ranked shares don't stand out at present. The issue earns high marks for Safety, Price Stability, and Earnings Predictability. But it offers below average, though fairly well-defined, total-return potential for the coming years, based on the modest bottom-line growth we envision to 2013-2015.

Michael Napoli, CFA *March 12, 2010*

(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 May.

(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	85

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SOUTHWEST GAS NYSE-SWX

RECENT PRICE 29.56 | P/E RATIO 14.6 (Trailing: 14.9 Median: 19.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 3.4% | VALUE LINE

TIMELINESS 3 Raised 5/23/08
SAFETY 3 Lowered 1/4/91
TECHNICAL 2 Raised 2/26/10
BETA .75 (1.00 = Market)

2013-15 PROJECTIONS

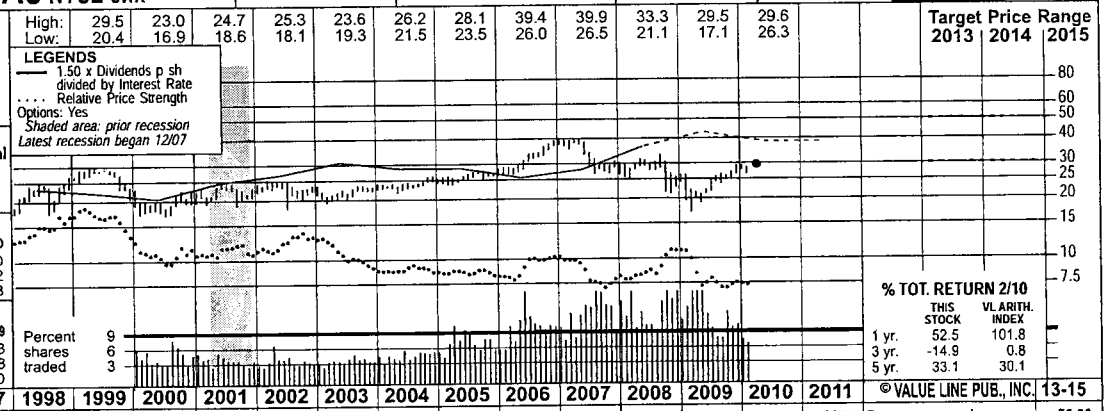
	Price	Gain	Ann'l Total Return
High	50	(+70%)	16%
Low	30	(Nil)	4%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	2	2
to Sell	0	0	1	0	3	1	1	3	3

Institutional Decisions

	1Q2009	2Q2009	3Q2009
to Buy	83	86	73
to Sell	71	71	68
Hld's(000)	32859	32802	33100



1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
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	42.00	*42.95*	*44.70*	Revenues per sh	*56.00*
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	6.15	*6.40*	*6.80*	"Cash Flow" per sh	*7.50*
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	1.94	*2.05*	*2.20*	Earnings per sh A	*2.65*
.80	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	*1.00*	*1.05*	Div'ds Decl'd per sh B■†	*1.20*
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	*4.80*	*5.65*	*6.40*	Cap'l Spending per sh	*8.50*
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	24.46	*26.10*	*27.65*	Book Value per sh	*30.00*
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	45.09	*46.00*	*47.00*	Common Shs Outst'g C	*50.00*
14.0	NMF	NMF	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	*15.0*
.92	NMF	NMF	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.80			Relative P/E Ratio	*1.00*
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%	4.0%			Avg Ann'l Div'd Yield	*3.0%*
1034.1	1396.7	1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	*1975*	*2100*	Revenues ($mill)	*2800*
38.3	37.2	38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.4	*95.0*	*110*	Net Profit ($mill)	*135*
26.2%	34.5%	32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	*34.0%*	*35.0%*	*36.0%*	Income Tax Rate	*36.0%*
3.7%	2.7%	2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	*4.8%*	*5.2%*	Net Profit Margin	*4.8%*
60.2%	56.2%	62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	*51.0%*	*50.0%*	Long-Term Debt Ratio	*48.5%*
35.8%	39.6%	34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	*49.0%*	*50.0%*	Common Equity Ratio	*51.5%*
1489.9	1417.6	1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2372.0	*2450*	*2600*	Total Capital ($mill)	*2925*
1686.1	1825.6	1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	*3125*	*3200*	Net Plant ($mill)	*3600*
4.6%	5.1%	4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	*5.5%*	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
6.5%	6.0%	5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
7.2%	6.6%	6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	*8.0%*	*8.5%*	Return on Com Equity	*9.0%*
2.4%	1.9%	1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.0%	*4.0%*	*4.5%*	Retained to Com Eq	*5.0%*
67%	71%	70%	72%	49%	65%	42%	44%	63%	49%	*48%*	*45%*	All Div'ds to Net Prof	*44%*

CAPITAL STRUCTURE as of 12/31/09
Total Debt $1270.7 mill. **Due in 5 Yrs** $496.3 mill.
LT Debt $1269.4 mill. **LT Interest** $85.0 mill.
(Total interest coverage: 2.6x)
Leases, Uncapitalized Annual rentals $5.0 mill.
Pension Assets-12/09 $418.5 mill.
Oblig. $648.6 mill.
Pfd Stock None

Common Stock 45,228,164 shs.
as of 2/17/10

MARKET CAP: $1.3 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2007	2008	12/31/09
Cash Assets	32.0	26.4	65.3
Other	470.5	411.7	352.3
Current Assets	502.5	438.1	417.6
Accts Payable	220.7	191.4	158.9
Debt Due	47.1	62.8	1.3
Other	260.1	255.7	314.0
Current Liab.	527.9	509.9	474.2
Fix. Chg. Cov.	229%	224%	251%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	6.0%	4.5%	*2.0%*
"Cash Flow"	4.5%	3.5%	*4.0%*
Earnings	7.0%	9.0%	*8.0%*
Dividends	0.5%	1.0%	*5.5%*
Book Value	4.5%	5.0%	*4.5%*

Calendar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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	317.5	498.8	1893.8
2010	*715*	*415*	*335*	*510*	*1975*
2011	*740*	*440*	*360*	*560*	*2100*

Calendar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
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.18	1.02	1.94
2010	*1.20*	*Nil*	*d.20*	*1.05*	*2.05*
2011	*1.25*	*Nil*	*d.15*	*1.10*	*2.20*

Calendar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.205	.205	.205	.205	.82
2007	.205	.215	.215	.215	.85
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250			

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. 2009 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.2 billion therms. Sold PriMerit Bank, 7/96. Has 4,450 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 89193. Telephone: 702-876-7237. Internet: www.swgas.com.

Southwest Gas began 2010 on a sound note, despite a challenging operating environment. The bottom line should further benefit from higher rates in the company's service territories (discussed below) and improved cost controls. Modest customer growth should also help. Overall, we anticipate a moderate bottom-line advance at Southwest Gas for the current year. Growth will probably continue from 2011 onward. The company has reduced its capital expenditures, given the current low-growth environment. The southwest was one of the nation's hardest hit regions during the housing crisis. Even so, Southwest Gas continues to upgrade and expand its distribution system, and we expect investment in operations will gradually rebound in the coming years.

The company is benefiting from recent rate relief. Southwest Gas has realized higher rates in Nevada, California, and Arizona. In addition, SWX now has improved rate design in Nevada that allows it to more aggressively encourage conservation by its customers. The company's focus on procuring rate relief and improving rate design is important, as such approved revenue increases help it to cope with growth in operating expenses.

The board has recently approved a dividend increase of roughly 5%. Starting with the June payout, the quarterly dividend is now $0.25 per share. This follows other dividend hikes in recent years. We find this pattern encouraging and expect it to continue.

But the stock is not without risk. Warmer-than-usual temperatures during the winter months can hurt profitability at Southwest Gas. Also, the company will probably incur greater costs as it continues to expand operations. Moreover, insufficient, or lagging, rate relief can also hurt performance.

These shares remain neutrally ranked for year-ahead relative price performance. Looking further out, we anticipate solid bottom-line growth at the company over the pull to 2013-2015. Income-oriented accounts may find this issue's dividend growth prospects attractive. That said, total return potential for the coming years is not particularly compelling, from the present quotation.

Michael Napoli, CFA *March 12, 2010*

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	75

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Excl. loss from disc. ops.: '95, 75¢. Totals may not sum due to rounding. Next egs. report due late April/early May. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

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WGL HOLDINGS NYSE-WGL

RECENT PRICE 33.53 | P/E RATIO 14.6 (Trailing: 13.7 Median: 15.0) | RELATIVE P/E RATIO 0.86 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 4 Lowered 11/27/09
SAFETY 1 Raised 4/2/93
TECHNICAL 2 Raised 2/12/10
BETA .65 (1.00 = Market)

2013-15 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+35%)	11%
Low	35	(+5%)	5%

Insider Decisions

	A	M	J	J	A	S	O	N	D
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	1	0	1
to Sell	0	2	0	0	1	0	1	1	2

Institutional Decisions

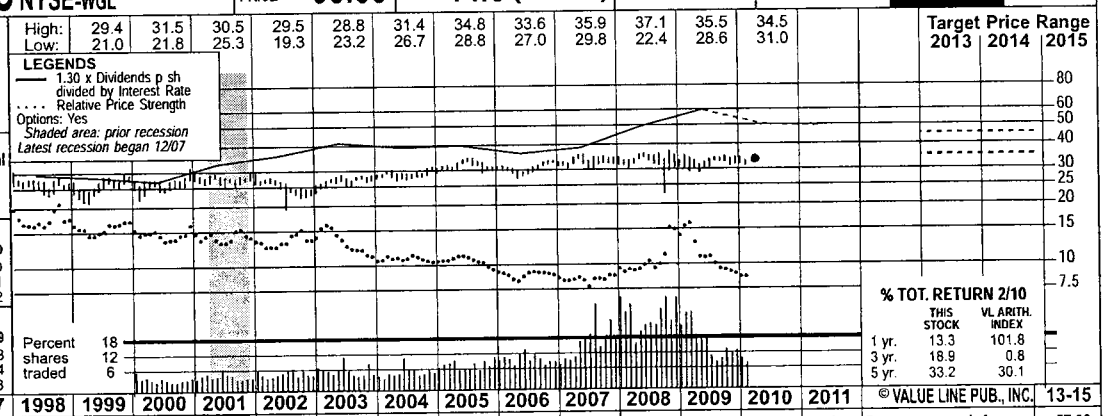
	1Q2009	2Q2009	3Q2009
to Buy	97	85	78
to Sell	96	98	74
Hld's(000)	30919	31333	31643

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	© VALUE LINE PUB., INC.	13-15
High:	29.4	31.5	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	34.5								
Low:	21.0	21.8	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0								
	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	53.98	53.00	54.00	Revenues per sh [A]	57.30
	2.43	2.51	2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.20	4.35	"Cash Flow" per sh	4.70
	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	2.09	2.44	2.53	2.30	2.45	Earnings per sh [B]	2.70
	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	1.55	Div'ds Decl'd per sh [C] ■	1.67
	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	2.77	3.00	2.50	Cap'l Spending per sh	2.50
	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	21.89	22.65	23.55	Book Value per sh [D]	26.75
	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	50.14	50.00	50.00	Common Shs Outst'g [E]	50.00
	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	12.6	Bold figures are Value Line estimates		Avg Ann'l P/E Ratio	15.0
	.92	.85	.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.83			Relative P/E Ratio	1.00
	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%	4.6%			Avg Ann'l Div'd Yield	4.1%
							1031.1	1446.5	1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2650	2700	Revenues ($mill) [A]	2865
							84.6	89.9	55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115	125	Net Profit ($mill)	135
							36.1%	39.6%	34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	37.0%	38.0%	Income Tax Rate	38.0%
							8.2%	6.2%	3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.5%	4.5%	Net Profit Margin	4.8%
							43.1%	41.7%	45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	36.0%	35.0%	Long-Term Debt Ratio	34.0%
							54.8%	56.3%	52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	62.5%	63.5%	Common Equity Ratio	64.5%
							1299.2	1400.8	1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1810	1855	Total Capital ($mill)	2075
							1460.3	1519.7	1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2330	2395	Net Plant ($mill)	2600
							7.9%	7.9%	5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.5%	8.0%	Return on Total Cap'l	8.0%
							11.4%	11.0%	7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	10.0%	10.5%	Return on Shr. Equity	10.5%
							11.7%	11.2%	7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	10.5%	11.0%	Return on Com Equity	11.0%
							3.7%	3.8%	NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.5%	4.0%	Retained to Com Eq	4.0%
							69%	67%	112%	56%	65%	62%	69%	66%	57%	57%	65%	63%	All Div'ds to Net Prof	61%

% TOT. RETURN 2/10

	THIS STOCK	VL ARITH. INDEX
1 yr.	13.3	101.8
3 yr.	18.9	0.8
5 yr.	33.2	30.1

Target Price Range 2013 | 2014 | 2015



CAPITAL STRUCTURE as of 12/31/09
Total Debt $871.9 mill. Due in 5 Yrs $256.7 mill.
LT Debt $612.8 mill. LT Interest $40.4 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)
Pension Assets-9/09 $550.0 mill. Oblig. $678.1 mill.
Preferred Stock $28.2 mill. Pfd. Div'd $1.3 mill.

Common Stock 50,302,721 shs. as of 1/29/10

MARKET CAP: $1.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2008	2009	12/31/09
Cash Assets	6.2	7.9	13.6
Other	736.1	675.6	852.1
Current Assets	742.3	683.5	865.7
Accts Payable	243.1	213.5	271.3
Debt Due	347.0	266.5	259.2
Other	158.4	154.6	244.5
Current Liab.	748.5	634.6	775.0
Fix. Chg. Cov.	490%	533%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '07-'09 to '13-'15
Revenues	9.0%	6.5%	1.0%
"Cash Flow"	4.0%	4.0%	2.0%
Earnings	4.0%	5.5%	2.5%
Dividends	1.5%	2.0%	3.0%
Book Value	4.0%	5.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) [A] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2007	732.9	1119.9	467.5	325.7	2646.0
2008	751.6	1020.0	464.7	391.9	2628.2
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1050	455	417.6	2650
2011	740	1060	465	435	2700

Fiscal Year Ends	EARNINGS PER SHARE [A B] Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
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.25	2.53
2010	1.01	1.55	.05	d.31	2.30
2011	1.05	1.58	.07	d.25	2.45

Cal-endar	QUARTERLY DIVIDENDS PAID [C] ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2006	.333	.338	.338	.338	1.35
2007	.34	.34	.34	.34	1.36
2008	.34	.36	.36	.36	1.42
2009	.36	.37	.37	.37	1.47
2010	.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 (1,064,071 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 7.7% of common stock; Off./dir. less than 1% (1/10 proxy). Chrmn. & CEO: Terry D. McCallister. 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 is off to a so-so start in fiscal 2010 (began October 1st). Revenues declined 12% in the first quarter. This stemmed from diminished volumes at the regulated utility business due to soft pricing and customer conservation. But this was partially offset by rising volumes at the non-utility operations. Meantime, the design-build unit did not make meaningful contributions to the bottom line this past quarter as profitability fell into negative territory. Still, decreases in the cost of gas minimized the bottom-line decline to roughly 2%, which was better than we had expected. Nonetheless,

For the time being, we have left our 2010 earnings estimate unchanged. We look for the top line to register a low single-digit decline this year. This ought to stem from the continued depressed natural gas prices. Still, despite weak revenue volumes, the regulated utility segment has seen a 10,300 increase in active meters over the past 12 months. Meantime, the retail energy marketing segment has been experiencing higher realized margins and more-favorable weather patterns. On balance, we expect share net to contract about 9% this year.

WGL's balance sheet and overall financial position appear to be improving. The company's cash reserves increased approximately 74% so far this year, giving way to a nice financial cushion. Meantime, the debt levels remain at easily serviceable levels.

We have introduced our 2011 top- and bottom-line estimates of $2.7 billion and $2.45 a share, respectively. The regional economy is starting to show initial signs of a recovery. As the company continues on that road, efficiency initiatives, additional customers, and clean energy programs will only help to bolster its profitability and send earnings higher.

These shares are ranked to lag the broader market in the coming year. However, the stock price has remained stable throughout the financial market turmoil and all-but-officially ended recession. This bears out its Above-Average Safety rank and high mark for Price Stability. These features, coupled with an attractive dividend yield, may appeal to conservative income-oriented accounts.

Bryan J. Fong *March 12, 2010*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late April. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available. (D) Includes deferred charges and intangibles. '09: $386.7 million, $7.71/sh. (E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	95

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ATTACHMENT C

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AMERICAN STS WTR CO (NYSE)

Scottrade

AWR	34.36	+ 0.29	(0.85%)	Vol. 44,470	14:40 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.

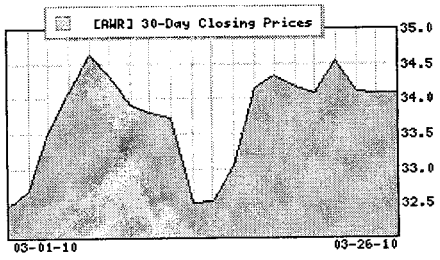
General Information

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	12/31/09
Next EPS Date	05/10/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	34.07
52 Week High	37.42
52 Week Low	30.82
Beta	0.36
20 Day Moving Average	100,403.80
Target Price Consensus	39.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.94	4 Week	0.30
12 Week	-3.78	12 Week	-8.03
YTD	-3.78	YTD	-8.03

Share Information

Shares Outstanding (millions)	18.55
Market Capitalization (millions)	632.14
Short Ratio	10.23
Last Split Date	06/10/2002

Dividend Information

Dividend Yield	3.05%
Annual Dividend	$1.04
Payout Ratio	0.63
Change in Payout Ratio	-0.02
Last Dividend Payout / Amount	02/10/2010 / $0.26

EPS Information

Current Quarter EPS Consensus Estimate	0.27
Current Year EPS Consensus Estimate	1.88
Estimated Long-Term EPS Growth Rate	4.00
Next EPS Report Date	05/10/2010

Consensus Recommendations

Current (1=Strong Buy, 5=Strong Sell)	1.80
30 Days Ago	1.80
60 Days Ago	1.80
90 Days Ago	1.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.17	vs. Previous Year	-55.00%	vs. Previous Year	2.50%
Trailing 12 Months:	20.77	vs. Previous Quarter	-66.67%	vs. Previous Quarter:	-14.97%
PEG Ratio	4.54				

Price Ratios		ROE		ROA	
Price/Book	1.75	12/31/09	8.64	12/31/09	2.70

Price/Cash Flow	9.94	09/30/09	10.03 09/30/09	3.06
Price / Sales	1.75	06/30/09	9.40 06/30/09	2.83
Current Ratio		**Quick Ratio**	**Operating Margin**	
12/31/09	0.96	12/31/09	0.94 12/31/09	8.28
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
Net Margin		**Pre-Tax Margin**	**Book Value**	
12/31/09	13.39	12/31/09	13.39 12/31/09	19.42
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
Inventory Turnover		**Debt-to-Equity**	**Debt to Capital**	
12/31/09	52.94	12/31/09	0.85 12/31/09	45.97
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

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CALIFORNIA WTR SVC GROUP (NYSE)

Scottrade

CWT	37.30	▲0.49	(1.33%)	Vol. 71,437	14:42 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.

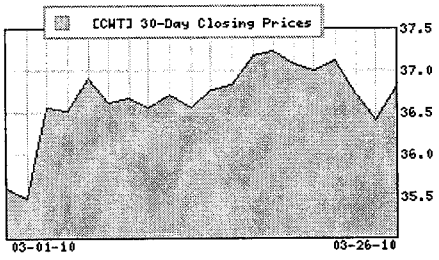
General Information

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	12/31/09
Next EPS Date	04/28/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	36.81
52 Week High	42.85
52 Week Low	33.49
Beta	0.37
20 Day Moving Average	100,958.70
Target Price Consensus	42.8



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.59	4 Week	-2.87
12 Week	-0.03	12 Week	-4.44
YTD	-0.03	YTD	-4.44

Share Information		Dividend Information	
Shares Outstanding (millions)	20.76	Dividend Yield	3.23%
		Annual Dividend	$1.19
Market Capitalization (millions)	764.36	Payout Ratio	0.61
Short Ratio	6.69	Change in Payout Ratio	-0.14
Last Split Date	01/26/1998	Last Dividend Payout / Amount	02/04/2010 / $0.30

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.11	Current (1=Strong Buy, 5=Strong Sell)	1.50
Current Year EPS Consensus Estimate	2.00	30 Days Ago	1.50
Estimated Long-Term EPS Growth Rate	6.70	60 Days Ago	1.50
Next EPS Report Date	04/28/2010	90 Days Ago	1.50

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	18.44	vs. Previous Year	-11.43%	vs. Previous Year	6.81%
Trailing 12 Months:	18.88	vs. Previous Quarter	-67.02%	vs. Previous Quarter:	-23.17%
PEG Ratio	2.77				

Price Ratios		ROE		ROA	
Price/Book	1.82	12/31/09	9.86	12/31/09	2.70
Price/Cash Flow	9.18	09/30/09	10.18	09/30/09	2.81
Price / Sales	1.70	06/30/09	10.94	06/30/09	3.12
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	0.84	12/31/09	0.79	12/31/09	9.02
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	14.55	12/31/09	14.55	12/31/09	20.28
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	33.46	12/31/09	0.89	12/31/09	47.08
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

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AQUA AMERICA INC (NYSE)

Scottrade

WTR	17.35	▲0.15	(0.87%)	Vol. 502,127	14:43 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.

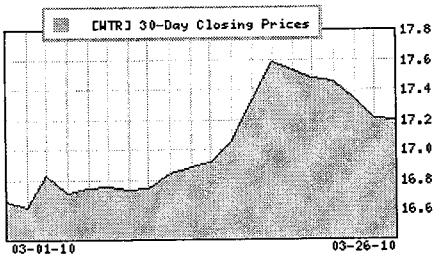
General Information

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	12/31/09
Next EPS Date	05/11/2010

Price and Volume Information

Zacks Rank	2
Yesterday's Close	17.20
52 Week High	20.37
52 Week Low	15.39
Beta	0.18
20 Day Moving Average	725,876.25
Target Price Consensus	22.17



% Price Change		% Price Change Relative to S&P 500	
4 Week	0.47	4 Week	-4.88
12 Week	-1.77	12 Week	-6.11
YTD	-1.77	YTD	-6.11

Share Information		Dividend Information	
Shares Outstanding (millions)	136.68	Dividend Yield	3.37%
		Annual Dividend	$0.58
Market Capitalization (millions)	2,350.90	Payout Ratio	0.74
		Change in Payout Ratio	0.08
Short Ratio	20.67	Last Dividend Payout / Amount	02/11/2010 / $0.14
Last Split Date	12/02/2005		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.16	Current (1=Strong Buy, 5=Strong Sell)	1.67
Current Year EPS Consensus Estimate	0.88	30 Days Ago	1.62
Estimated Long-Term EPS Growth Rate	8.00	60 Days Ago	1.62
Next EPS Report Date	05/11/2010	90 Days Ago	1.62

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	19.57	vs. Previous Year	5.26%	vs. Previous Year	5.04%
Trailing 12 Months:	22.05	vs. Previous Quarter	-20.00%	vs. Previous Quarter:	-7.15%
PEG Ratio	2.45				

Price Ratios	ROE	ROA

Price/Book	2.11	12/31/09	9.64	12/31/09	2.90
Price/Cash Flow	10.69	09/30/09	9.66	09/30/09	2.93
Price / Sales	3.51	06/30/09	9.95	06/30/09	3.04
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	0.60	12/31/09	0.56	12/31/09	15.56
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	25.68	12/31/09	25.68	12/31/09	8.14
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	27.81	12/31/09	1.25	12/31/09	55.55
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

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AGL RESOURCES INC (NYSE)

Scottrade

AGL	38.35	+0.35	(0.92%)	Vol. 133,800	14:49 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.

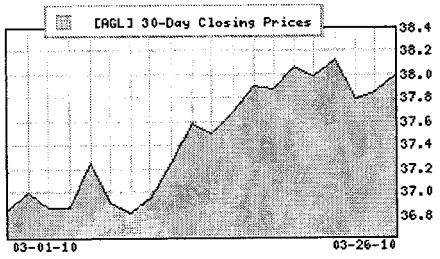
General Information

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	12/31/09
Next EPS Date	04/28/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	38.00
52 Week High	38.48
52 Week Low	26.00
Beta	0.42
20 Day Moving Average	184,215.00
Target Price Consensus	38.29



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.60	4 Week	-0.97
12 Week	4.20	12 Week	-0.40
YTD	4.20	YTD	-0.40

Share Information		Dividend Information	
Shares Outstanding (millions)	78.01	Dividend Yield	4.63%
		Annual Dividend	$1.76
Market Capitalization (millions)	2,964.38	Payout Ratio	0.60
Short Ratio	3.05	Change in Payout Ratio	0.01
Last Split Date	12/04/1995	Last Dividend Payout / Amount	02/17/2010 / $0.44

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.52	Current (1=Strong Buy, 5=Strong Sell)	2.11
Current Year EPS Consensus Estimate	2.98	30 Days Ago	2.11
Estimated Long-Term EPS Growth Rate	4.50	60 Days Ago	2.11
Next EPS Report Date	04/28/2010	90 Days Ago	2.11

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.75	vs. Previous Year	-5.15%	vs. Previous Year	-20.75%
Trailing 12 Months:	13.15	vs. Previous Quarter	475.00%	vs. Previous Quarter:	107.82%
PEG Ratio	2.83				

Price Ratios		ROE		ROA	
Price/Book	1.62	12/31/09	12.53	12/31/09	3.48
Price/Cash Flow		09/30/09		09/30/09	

	7.74		13.00		3.58
Price / Sales	1.28	06/30/09	13.60	06/30/09	3.68
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	1.13	12/31/09	0.75	12/31/09	9.58
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	16.57	12/31/09	16.57	12/31/09	23.50
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	2.98	12/31/09	1.09	12/31/09	52.04
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

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ATMOS ENERGY CORP (NYSE)

Scottrade

ATO	28.41	+0.10	(0.35%)	Vol. 314,868	15:03 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.

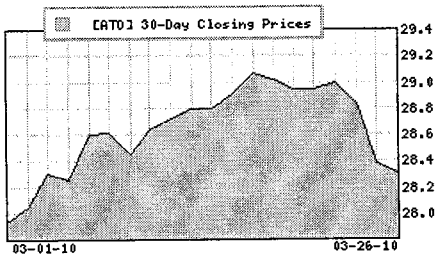
General Information

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	12/31/09
Next EPS Date	04/22/2010

Price and Volume Information

Zacks Rank	2
Yesterday's Close	28.31
52 Week High	30.32
52 Week Low	22.52
Beta	0.51
20 Day Moving Average	285,066.91
Target Price Consensus	30.42



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.10	4 Week	-2.39
12 Week	-3.71	12 Week	-7.96
YTD	-3.71	YTD	-7.96

Share Information		Dividend Information	
Shares Outstanding (millions)	92.93	Dividend Yield	4.73%
		Annual Dividend	$1.34
Market Capitalization (millions)	2,630.91	Payout Ratio	0.71
Short Ratio	3.16	Change in Payout Ratio	0.06
Last Split Date	05/17/1994	Last Dividend Payout / Amount	02/23/2010 / $0.34

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.40	Current (1=Strong Buy, 5=Strong Sell)	2.50
Current Year EPS Consensus Estimate	2.19	30 Days Ago	2.50
Estimated Long-Term EPS Growth Rate	5.00	60 Days Ago	2.50
Next EPS Report Date	04/22/2010	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	12.96	vs. Previous Year	-14.46%	vs. Previous Year	-24.67%
Trailing 12 Months:	14.90	vs. Previous Quarter	987.50%	vs. Previous Quarter:	98.72%
PEG Ratio	2.59				

Price Ratios		
Price/Book	1.17	12/31/09
Price/Cash Flow	6.34	09/30/09
Price / Sales	0.58	06/30/09

Current Ratio		
12/31/09	1.09	12/31/09
09/30/09	1.12	09/30/09
06/30/09	1.24	06/30/09

Net Margin		
12/31/09	7.02	12/31/09
09/30/09	5.86	09/30/09
06/30/09	5.55	06/30/09

Inventory Turnover		
12/31/09	10.50	12/31/09
09/30/09	10.42	09/30/09
06/30/09	11.62	06/30/09

ROE		
7.98	12/31/09	2.70
8.58	09/30/09	2.85
9.14	06/30/09	2.99

Quick Ratio		
0.75	12/31/09	3.86
0.65	09/30/09	3.72
0.74	06/30/09	3.37

Pre-Tax Margin		
7.02	12/31/09	24.30
5.86	09/30/09	23.59
5.55	06/30/09	23.82

Debt-to-Equity		
0.96	12/31/09	48.88
1.00	09/30/09	49.92
0.99	06/30/09	49.75

ROA		
7.98	12/31/09	2.70
8.58	09/30/09	2.85
9.14	06/30/09	2.99

Operating Margin		
0.75	12/31/09	3.86
0.65	09/30/09	3.72
0.74	06/30/09	3.37

Book Value		
7.02	12/31/09	24.30
5.86	09/30/09	23.59
5.55	06/30/09	23.82

Debt to Capital		
0.96	12/31/09	48.88
1.00	09/30/09	49.92
0.99	06/30/09	49.75

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LACLEDE GROUP INC (NYSE)

Scottrade

LG	33.66	▲0.22	(0.66%)	Vol. 33,227	14:58 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.

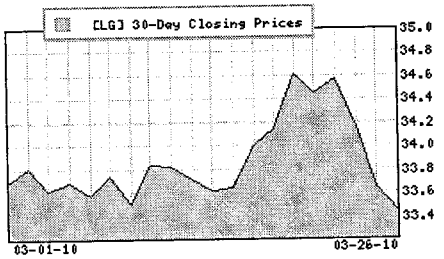
General Information

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	12/31/09
Next EPS Date	04/22/2010

Price and Volume Information

Zacks Rank	2
Yesterday's Close	33.44
52 Week High	39.90
52 Week Low	29.26
Beta	0.04
20 Day Moving Average	118,960.35
Target Price Consensus	35



% Price Change		% Price Change Relative to S&P 500	
4 Week	1.98	4 Week	-3.45
12 Week	-0.98	12 Week	-5.35
YTD	-0.98	YTD	-5.35

Share Information		Dividend Information	
Shares Outstanding (millions)	22.26	Dividend Yield	4.72%
Market Capitalization (millions)	744.44	Annual Dividend	$1.58
Short Ratio	7.19	Payout Ratio	0.63
Last Split Date	03/08/1994	Change in Payout Ratio	0.01
		Last Dividend Payout / Amount	03/09/2010 / $0.40

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.31	Current (1=Strong Buy, 5=Strong Sell)	3.00
Current Year EPS Consensus Estimate	2.48	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	3.00	60 Days Ago	2.80
Next EPS Report Date	04/22/2010	90 Days Ago	2.80

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.48	vs. Previous Year	-27.46%	vs. Previous Year	-27.15%
Trailing 12 Months:	13.27	vs. Previous Quarter	568.18%	vs. Previous Quarter:	94.96%
PEG Ratio	4.49				

Price Ratios		ROE		ROA	
Price/Book	1.40	12/31/09	10.57	12/31/09	3.16

Price/Cash Flow	7.32	09/30/09	12.30	09/30/09	3.63
Price / Sales	0.43	06/30/09	12.78	06/30/09	3.71
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	1.17	12/31/09	0.90	12/31/09	3.26
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	4.89	12/31/09	4.89	12/31/09	23.89
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	13.49	12/31/09	0.69	12/31/09	40.66
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

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NEW JERSEY RES (NYSE)

Scottrade

NJR	37.86	0.33	(0.88%)	Vol. 109,233	15:03 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.

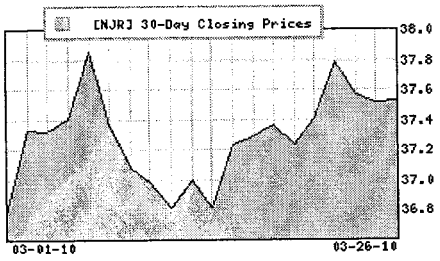
General Information

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	12/31/09
Next EPS Date	04/28/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	37.53
52 Week High	40.61
52 Week Low	30.79
Beta	0.13
20 Day Moving Average	217,149.59
Target Price Consensus	42.67



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.05	4 Week	-2.44
12 Week	0.35	12 Week	-4.08
YTD	0.35	YTD	-4.08

Share Information		Dividend Information	
Shares Outstanding (millions)	41.42	Dividend Yield	3.62%
		Annual Dividend	$1.36
Market Capitalization (millions)	1,554.38	Payout Ratio	0.60
Short Ratio	9.23	Change in Payout Ratio	0.08
Last Split Date	03/04/2008	Last Dividend Payout / Amount	03/11/2010 / $0.34

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.86	Current (1=Strong Buy, 5=Strong Sell)	1.64
Current Year EPS Consensus Estimate	2.52	30 Days Ago	1.64
Estimated Long-Term EPS Growth Rate	7.00	60 Days Ago	1.67
Next EPS Report Date	04/28/2010	90 Days Ago	1.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.88	vs. Previous Year	-14.47%	vs. Previous Year	-23.93%
Trailing 12 Months:	16.61	vs. Previous Quarter	641.67%	vs. Previous Quarter:	47.74%
PEG Ratio	2.13				

Price Ratios			ROE			ROA	
Price/Book	2.16	12/31/09		13.27	12/31/09		4.05
Price/Cash Flow	11.94	09/30/09		13.90	09/30/09		4.15
Price / Sales	0.65	06/30/09		12.20	06/30/09		3.58
Current Ratio			**Quick Ratio**			**Operating Margin**	
12/31/09	1.24	12/31/09		0.71	12/31/09		3.99
09/30/09	1.23	09/30/09		0.68	09/30/09		3.89
06/30/09	1.23	06/30/09		0.88	06/30/09		2.98
Net Margin			**Pre-Tax Margin**			**Book Value**	
12/31/09	4.00	12/31/09		4.00	12/31/09		17.39
09/30/09	1.21	09/30/09		1.21	09/30/09		16.42
06/30/09	5.66	06/30/09		5.66	06/30/09		17.11
Inventory Turnover			**Debt-to-Equity**			**Debt to Capital**	
12/31/09	9.39	12/31/09		0.61	12/31/09		37.75
09/30/09	10.06	09/30/09		0.66	09/30/09		39.77
06/30/09	9.78	06/30/09		0.63	06/30/09		38.82

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NICOR INC (NYSE) — Scottrade

GAS	42.25	▲ 0.21	(0.50%)	Vol. 333,478	15:03 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.

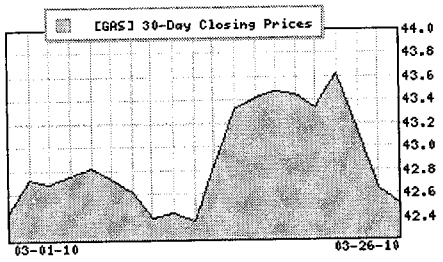
General Information

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	12/31/09
Next EPS Date	04/23/2010

Price and Volume Information

Zacks Rank	2
Yesterday's Close	42.04
52 Week High	43.75
52 Week Low	30.28
Beta	0.38
20 Day Moving Average	358,605.50
Target Price Consensus	41.4



% Price Change		% Price Change Relative to S&P 500	
4 Week	2.06	4 Week	-3.37
12 Week	0.97	12 Week	-3.48
YTD	0.97	YTD	-3.48

Share Information		Dividend Information	
Shares Outstanding (millions)	45.24	Dividend Yield	4.38%
		Annual Dividend	$1.86
Market Capitalization (millions)	1,923.36	Payout Ratio	0.63
Short Ratio	6.06	Change in Payout Ratio	-0.08
Last Split Date	04/27/1993	Last Dividend Payout / Amount	12/29/2009 / $0.47

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.34	Current (1=Strong Buy, 5=Strong Sell)	3.13
Current Year EPS Consensus Estimate	3.05	30 Days Ago	3.13
Estimated Long-Term EPS Growth Rate	3.70	60 Days Ago	3.13
Next EPS Report Date	04/23/2010	90 Days Ago	2.86

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	13.96	vs. Previous Year	15.24%	vs. Previous Year	-26.20%
Trailing 12 Months:	14.31	vs. Previous Quarter	303.33%	vs. Previous Quarter:	135.90%
PEG Ratio	3.81				

Price Ratios		ROE		ROA	
Price/Book	1.85	12/31/09	13.40	12/31/09	3.11

Price/Cash Flow	5.80	09/30/09	12.88	09/30/09	2.88
Price / Sales	0.73	06/30/09	11.78	06/30/09	2.59
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	0.86	12/31/09	0.74	12/31/09	5.11
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	7.56	12/31/09	7.56	12/31/09	22.94
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	17.32	12/31/09	0.48	12/31/09	32.44
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

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NORTHWEST NAT GAS CO (NYSE)

Scottrade

NWN	47.06	0.64	(1.38%)	Vol. 45,622	15:06 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.

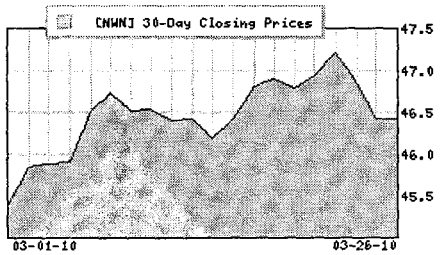
General Information

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	12/31/09
Next EPS Date	04/23/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	46.42
52 Week High	47.34
52 Week Low	39.58
Beta	0.25
20 Day Moving Average	98,283.05
Target Price Consensus	49.5



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.52	4 Week	-0.09
12 Week	3.06	12 Week	-1.49
YTD	3.06	YTD	-1.49

Share Information		Dividend Information	
Shares Outstanding (millions)	26.53	Dividend Yield	3.58%
		Annual Dividend	$1.66
Market Capitalization (millions)	1,231.66	Payout Ratio	0.58
Short Ratio	20.31	Change in Payout Ratio	-0.01
Last Split Date	09/09/1996	Last Dividend Payout / Amount	01/27/2010 / $0.41

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.75	Current (1=Strong Buy, 5=Strong Sell)	1.86
Current Year EPS Consensus Estimate	2.70	30 Days Ago	1.86
Estimated Long-Term EPS Growth Rate	5.70	60 Days Ago	1.86
Next EPS Report Date	04/23/2010	90 Days Ago	1.86

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.19	vs. Previous Year	-5.60%	vs. Previous Year	-11.39%
Trailing 12 Months:	16.34	vs. Previous Quarter	572.00%	vs. Previous Quarter:	164.81%
PEG Ratio	3.03				

Price Ratios	ROE	ROA

Price/Book	1.86	12/31/09	11.46	12/31/09	3.25
Price/Cash Flow	8.92	09/30/09	11.87	09/30/09	3.33
Price / Sales	1.22	06/30/09	11.51	06/30/09	3.26
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	0.84	12/31/09	0.63	12/31/09	7.42
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	12.03	12/31/09	12.03	12/31/09	24.89
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	8.47	12/31/09	0.91	12/31/09	47.69
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

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PIEDMONT NAT GAS INC (NYSE)

Scottrade

PNY	27.15	▲0.02	(0.07%)	Vol. 232,056	15:06 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.

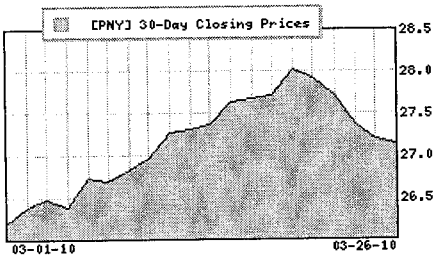
General Information

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	01/31/10
Next EPS Date	06/04/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	27.13
52 Week High	28.04
52 Week Low	21.65
Beta	0.21
20 Day Moving Average	266,102.41
Target Price Consensus	26.71



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.03	4 Week	-0.56
12 Week	1.42	12 Week	-3.06
YTD	1.42	YTD	-3.06

Share Information		Dividend Information	
Shares Outstanding (millions)	73.38	Dividend Yield	4.13%
		Annual Dividend	$1.12
Market Capitalization (millions)	1,990.80	Payout Ratio	0.63
		Change in Payout Ratio	-0.07
Short Ratio	13.35	Last Dividend Payout / Amount	03/23/2010 / $0.28
Last Split Date	11/01/2004		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	0.72	Current (1=Strong Buy, 5=Strong Sell)	2.86
Current Year EPS Consensus Estimate	1.59	30 Days Ago	2.88
Estimated Long-Term EPS Growth Rate	6.30	60 Days Ago	2.88
Next EPS Report Date	06/04/2010	90 Days Ago	2.57

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	17.06	vs. Previous Year	3.64%	vs. Previous Year	-13.58%
Trailing 12 Months:	15.86	vs. Previous Quarter	2,000.00%	vs. Previous Quarter:	202.34%
PEG Ratio	2.69				

Price Ratios		ROE		ROA	
Price/Book	2.01	01/31/10	13.10	01/31/10	4.03
Price/Cash Flow	8.81	10/31/09	12.94	10/31/09	3.92
Price / Sales	1.30	07/31/09	12.13	07/31/09	3.64
Current Ratio		**Quick Ratio**		**Operating Margin**	
01/31/10	0.95	01/31/10	0.78	01/31/10	8.20
10/31/09	0.85	10/31/09	0.67	10/31/09	7.50
07/31/09	0.99	07/31/09	0.76	07/31/09	6.59
Net Margin		**Pre-Tax Margin**		**Book Value**	
01/31/10	16.91	01/31/10	16.91	01/31/10	13.53
10/31/09	12.50	10/31/09	12.50	10/31/09	12.69
07/31/09	12.89	07/31/09	12.89	07/31/09	12.99
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
01/31/10	10.95	01/31/10	0.74	01/31/10	42.46
10/31/09	10.02	10/31/09	0.79	10/31/09	44.12
07/31/09	10.20	07/31/09	0.84	07/31/09	45.54

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SOUTH JERSEY INDS INC (NYSE)

Scottrade

SJI	41.50	▲0.21	(0.51%)	Vol. 126,678	15:19 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.

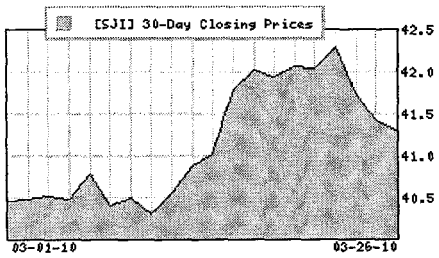
General Information

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	12/31/09
Next EPS Date	05/10/2010

Price and Volume Information

Zacks Rank	2
Yesterday's Close	41.29
52 Week High	42.35
52 Week Low	33.04
Beta	0.21
20 Day Moving Average	91,396.00
Target Price Consensus	47.86



% Price Change		% Price Change Relative to S&P 500	
4 Week	3.56	4 Week	-1.95
12 Week	8.15	12 Week	3.37
YTD	8.15	YTD	3.37

Share Information		Dividend Information	
Shares Outstanding (millions)	29.81	Dividend Yield	3.20%
		Annual Dividend	$1.32
Market Capitalization (millions)	1,230.98	Payout Ratio	0.55
Short Ratio	9.59	Change in Payout Ratio	0.03
Last Split Date	07/01/2005	Last Dividend Payout / Amount	03/08/2010 / $0.33

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.45	Current (1=Strong Buy, 5=Strong Sell)	1.50
Current Year EPS Consensus Estimate	2.62	30 Days Ago	1.43
Estimated Long-Term EPS Growth Rate	11.60	60 Days Ago	1.43
Next EPS Report Date	05/10/2010	90 Days Ago	1.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	15.77	vs. Previous Year	23.88%	vs. Previous Year	-17.18%
Trailing 12 Months:	17.35	vs. Previous Quarter	1,483.33%	vs. Previous Quarter:	74.45%
PEG Ratio	1.36				

Price Ratios	ROE	ROA

Price/Book	2.26	12/31/09	13.23	12/31/09	4.14
Price/Cash Flow	11.11	09/30/09	12.53	09/30/09	3.86
Price / Sales	1.46	06/30/09	13.17	06/30/09	4.06
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	0.77	12/31/09	0.55	12/31/09	8.42
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	11.06	12/31/09	11.06	12/31/09	18.28
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	6.63	12/31/09	0.57	12/31/09	36.48
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

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SOUTHWEST GAS CORP (NYSE)

Scottrade

SWX	30.12	-0.15	(0.50%)	Vol. 127,488	15:07 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.

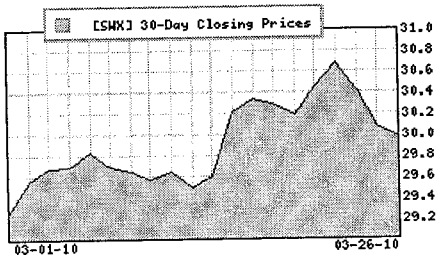
General Information

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	12/31/09
Next EPS Date	04/23/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	29.97
52 Week High	30.70
52 Week Low	18.96
Beta	0.73
20 Day Moving Average	178,980.75
Target Price Consensus	31.2



% Price Change		% Price Change Relative to S&P 500	
4 Week	4.86	4 Week	-0.72
12 Week	5.05	12 Week	0.41
YTD	5.05	YTD	0.41

Share Information		Dividend Information	
Shares Outstanding (millions)	45.29	Dividend Yield	3.17%
Market Capitalization (millions)	1,357.43	Annual Dividend	$0.95
Short Ratio	8.02	Payout Ratio	0.41
Last Split Date	N/A	Change in Payout Ratio	-0.11
		Last Dividend Payout / Amount	02/11/2010 / $0.24

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.38	Current (1=Strong Buy, 5=Strong Sell)	2.43
Current Year EPS Consensus Estimate	2.12	30 Days Ago	2.43
Estimated Long-Term EPS Growth Rate	7.00	60 Days Ago	2.43
Next EPS Report Date	04/23/2010	90 Days Ago	2.43

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.14	vs. Previous Year	43.66%	vs. Previous Year	-2.08%
Trailing 12 Months:	12.86	vs. Previous Quarter	466.67%	vs. Previous Quarter:	57.10%
PEG Ratio	2.02				

Price Ratios		ROE		ROA	
Price/Book	1.22	12/31/09	9.25	12/31/09	2.68

Price/Cash Flow	4.95	09/30/09	7.97	09/30/09	2.28
Price / Sales	0.72	06/30/09	5.70	06/30/09	1.63
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	0.88	12/31/09	0.88	12/31/09	5.29
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
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	6.97	12/31/09	6.97	12/31/09	24.51
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	-	12/31/09	1.06	12/31/09	49.31
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

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WGL HLDGS INC (NYSE)

Scottrade

WGL	34.76	▲ 0.26	(0.75%)	Vol. 110,436	15:08 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.

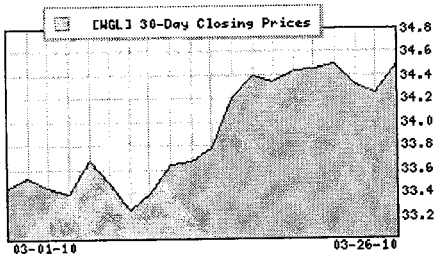
General Information

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	12/31/09
Next EPS Date	04/28/2010

Price and Volume Information

Zacks Rank	
Yesterday's Close	34.50
52 Week High	34.98
52 Week Low	28.59
Beta	0.18
20 Day Moving Average	214,144.91
Target Price Consensus	36.25



% Price Change		% Price Change Relative to S&P 500	
4 Week	5.02	4 Week	-0.57
12 Week	2.86	12 Week	-1.68
YTD	2.86	YTD	-1.68

Share Information		Dividend Information	
Shares Outstanding (millions)	50.30	Dividend Yield	4.26%
		Annual Dividend	$1.47
Market Capitalization (millions)	1,735.45	Payout Ratio	0.58
		Change in Payout Ratio	-0.06
Short Ratio	13.35	Last Dividend Payout / Amount	01/06/2010 / $0.37
Last Split Date	05/02/1995		

EPS Information		Consensus Recommendations	
Current Quarter EPS Consensus Estimate	1.56	Current (1=Strong Buy, 5=Strong Sell)	2.67
Current Year EPS Consensus Estimate	2.31	30 Days Ago	2.60
Estimated Long-Term EPS Growth Rate	-	60 Days Ago	2.67
Next EPS Report Date	04/28/2010	90 Days Ago	2.67

Fundamental Ratios

P/E		EPS Growth		Sales Growth	
Current FY Estimate:	14.94	vs. Previous Year	-1.94%	vs. Previous Year	-11.45%
Trailing 12 Months:	13.69	vs. Previous Quarter	504.00%	vs. Previous Quarter:	76.20%
PEG Ratio	-				

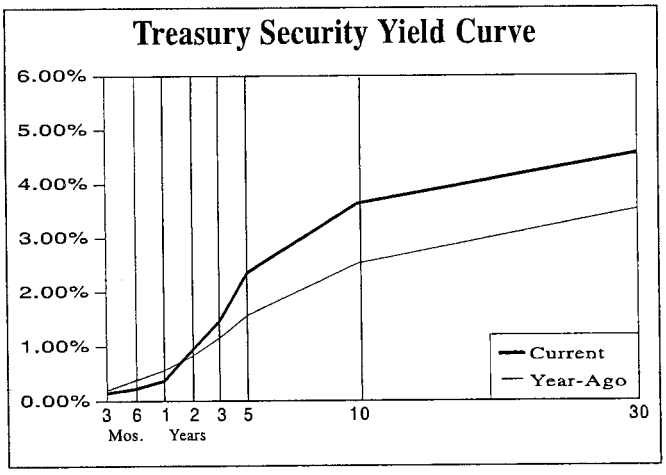
Price Ratios	ROE	ROA

Price/Book	1.54	12/31/09	11.26	12/31/09	3.76
Price/Cash Flow	7.62	09/30/09	11.44	09/30/09	3.78
Price / Sales	0.67	06/30/09	11.67	06/30/09	3.84
Current Ratio		**Quick Ratio**		**Operating Margin**	
12/31/09	1.12	12/31/09	0.83	12/31/09	4.86
09/30/09	1.08	09/30/09	0.67	09/30/09	4.72
06/30/09	1.17	06/30/09	0.82	06/30/09	5.26
Net Margin		**Pre-Tax Margin**		**Book Value**	
12/31/09	7.15	12/31/09	7.15	12/31/09	22.42
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
Inventory Turnover		**Debt-to-Equity**		**Debt to Capital**	
12/31/09	11.28	12/31/09	0.54	12/31/09	34.66
09/30/09	9.89	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

ATTACHMENT D

Selected Yields

	Recent (3/17/10)	3 Months Ago (12/16/09)	Year Ago (3/18/09)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.16	0.12	0.49
3-month LIBOR	0.27	0.25	1.29
Bank CDs			
6-month	0.25	0.31	0.84
1-year	0.44	0.54	1.05
5-year	1.99	1.95	2.07
U.S. Treasury Securities			
3-month	0.15	0.03	0.20
6-month	0.23	0.16	0.38
1-year	0.37	0.37	0.56
5-year	2.36	2.33	1.57
10-year	3.64	3.60	2.53
10-year (inflation-protected)	1.38	1.26	1.31
30-year	4.57	4.52	3.53
30-year Zero	4.84	4.74	3.54



	Recent (3/17/10)	3 Months Ago (12/16/09)	Year Ago (3/18/09)
Mortgage-Backed Securities			
GNMA 6.5%	2.00	3.33	3.59
FHLMC 6.5% (Gold)	1.51	1.85	3.15
FNMA 6.5%	2.29	1.81	3.28
FNMA ARM	2.93	2.41	3.60
Corporate Bonds			
Financial (10-year) A	5.08	5.32	7.52
Industrial (25/30-year) A	5.65	5.73	6.07
Utility (25/30-year) A	5.75	5.74	5.90
Utility (25/30-year) Baa/BBB	6.24	6.45	7.51
Foreign Bonds (10-Year)			
Canada	3.47	3.41	2.70
Germany	3.11	3.20	3.22
Japan	1.36	1.27	1.31
United Kingdom	4.01	3.89	3.11
Preferred Stocks			
Utility A	5.52	5.71	6.25
Financial A	6.53	6.67	9.76
Financial Adjustable A	5.47	5.47	5.47
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.33	4.19	5.03
25-Bond Index (Revs)	4.92	4.93	5.83
General Obligation Bonds (GOs)			
1-year Aaa	0.27	0.29	0.57
1-year A	1.10	1.24	0.67
5-year Aaa	1.44	1.56	2.39
5-year A	2.44	2.73	2.99
10-year Aaa	2.99	3.12	3.45
10-year A	4.04	4.14	3.95
25/30-year Aaa	4.44	4.47	4.98
25/30-year A	5.48	5.41	5.98
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.76	4.74	6.00
Electric AA	4.74	4.72	6.10
Housing AA	5.57	5.58	6.35
Hospital AA	5.06	5.13	6.30
Toll Road Aaa	4.81	4.77	6.15

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	3/10/10	2/24/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1163123	1192272	-29149	1098926	1035752	907736
Borrowed Reserves	101275	102895	-1620	136615	200733	334538
Net Free/Borrowed Reserves	1061848	1089377	-27529	962311	835019	573199

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/1/10	2/22/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1712.9	1718.4	-5.5	6.3%	9.3%	9.9%
M2 (M1+savings+small time deposits)	8526.6	8537.8	-11.2	0.8%	2.5%	1.9%

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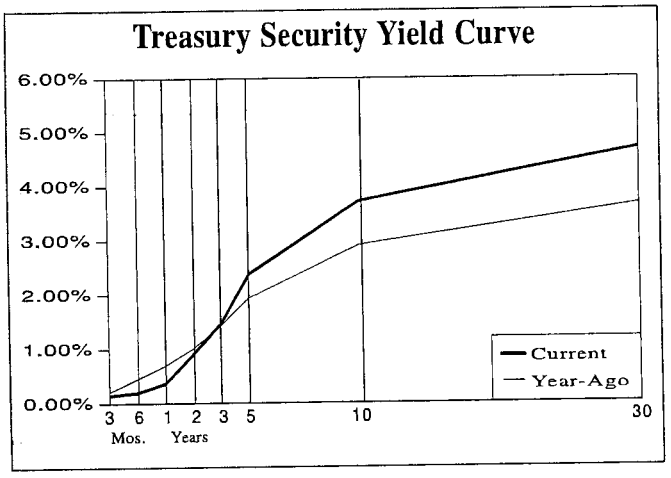
Selected Yields

	Recent (3/10/10)	3 Months Ago (12/09/09)	Year Ago (3/11/09)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.14	0.12	0.75
3-month LIBOR	0.26	0.26	1.33
Bank CDs			
6-month	0.25	0.31	0.84
1-year	0.44	0.54	1.05
5-year	1.99	1.95	2.07
U.S. Treasury Securities			
3-month	0.15	0.02	0.22
6-month	0.20	0.14	0.45
1-year	0.37	0.27	0.70
5-year	2.38	2.15	1.94
10-year	3.72	3.43	2.91
10-year (inflation-protected)	1.47	1.27	2.01
30-year	4.69	4.42	3.66
30-year Zero	4.97	4.63	3.56



	Recent (3/10/10)	3 Months Ago (12/09/09)	Year Ago (3/11/09)
Mortgage-Backed Securities			
GNMA 6.5%	2.09	3.22	4.21
FHLMC 6.5% (Gold)	1.67	1.94	3.58
FNMA 6.5%	2.43	1.95	3.73
FNMA ARM	2.93	2.41	3.60
Corporate Bonds			
Financial (10-year) A	5.22	5.34	7.38
Industrial (25/30-year) A	5.81	5.68	6.18
Utility (25/30-year) A	5.86	5.71	6.05
Utility (25/30-year) Baa/BBB	6.35	6.32	7.50
Foreign Bonds (10-Year)			
Canada	3.54	3.31	2.92
Germany	3.15	3.14	3.07
Japan	1.31	1.25	1.32
United Kingdom	4.08	3.67	3.09
Preferred Stocks			
Utility A	5.54	6.08	6.96
Financial A	6.28	7.17	11.44
Financial Adjustable A	5.46	5.54	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.34	4.24	4.96
25-Bond Index (Revs)	4.93	4.98	5.80
General Obligation Bonds (GOs)			
1-year Aaa	0.28	0.33	0.57
1-year A	1.03	1.25	0.67
5-year Aaa	1.45	1.47	2.30
5-year A	2.45	2.67	2.55
10-year Aaa	3.01	3.07	3.30
10-year A	4.02	4.04	3.83
25/30-year Aaa	4.44	4.47	4.87
25/30-year A	5.48	5.41	5.91
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.76	4.74	5.90
Electric AA	4.75	4.61	5.95
Housing AA	5.54	5.65	6.25
Hospital AA	5.06	5.17	6.30
Toll Road Aaa	4.81	4.77	6.00

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/24/10	2/10/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1192276	1119426	72850	1092703	1009425	889600
Borrowed Reserves	102895	126874	-23979	151648	216902	352598
Net Free/Borrowed Reserves	1089381	992552	96829	941055	792523	537002

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/22/10	2/15/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1718.5	1715.6	2.9	8.6%	10.1%	10.4%
M2 (M1+savings+small time deposits)	8537.6	8527.3	10.3	1.2%	3.3%	2.3%

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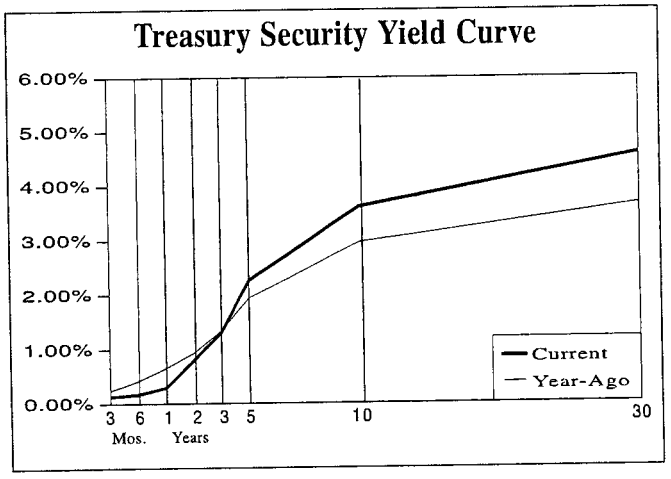
Selected Yields

	Recent (3/03/10)	3 Months Ago (12/02/09)	Year Ago (3/04/09)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.16	0.13	0.79
3-month LIBOR	0.25	0.26	1.28
Bank CDs			
6-month	0.25	0.31	0.84
1-year	0.44	0.54	1.04
5-year	1.99	2.21	2.07
U.S. Treasury Securities			
3-month	0.14	0.04	0.25
6-month	0.18	0.14	0.43
1-year	0.30	0.26	0.66
5-year	2.27	2.09	1.94
10-year	3.62	3.31	2.97
10-year (inflation-protected)	1.44	1.10	2.03
30-year	4.59	4.25	3.67
30-year Zero	4.86	4.46	3.55



	Recent (3/03/10)	3 Months Ago (12/02/09)	Year Ago (3/04/09)
Mortgage-Backed Securities			
GNMA 6.5%	2.17	3.02	4.19
FHLMC 6.5% (Gold)	1.84	2.06	4.13
FNMA 6.5%	2.26	1.93	4.15
FNMA ARM	2.93	2.41	3.60
Corporate Bonds			
Financial (10-year) A	5.16	5.26	8.50
Industrial (25/30-year) A	5.70	5.58	6.23
Utility (25/30-year) A	5.79	5.58	5.93
Utility (25/30-year) Baa/BBB	6.28	6.25	7.16
Foreign Bonds (10-Year)			
Canada	3.42	3.26	3.02
Germany	3.14	3.16	3.14
Japan	1.34	1.26	1.31
United Kingdom	4.03	3.59	3.64
Preferred Stocks			
Utility A	5.94	5.68	7.62
Financial A	6.73	7.16	12.59
Financial Adjustable A	5.53	5.53	5.53
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.36	4.33	4.87
25-Bond Index (Revs)	4.94	5.03	5.76
General Obligation Bonds (GOs)			
1-year Aaa	0.27	0.34	0.57
1-year A	1.04	1.31	0.67
5-year Aaa	1.49	1.56	2.30
5-year A	2.49	2.77	2.90
10-year Aaa	3.02	3.11	3.29
10-year A	4.07	4.08	3.79
25/30-year Aaa	4.44	4.47	4.86
25/30-year A	5.48	5.46	5.86
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.76	4.76	5.90
Electric AA	4.75	4.64	6.00
Housing AA	5.62	5.70	6.25
Hospital AA	5.06	5.20	6.20
Toll Road Aaa	4.81	4.79	6.05

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/24/10	2/10/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1192276	1119424	72852	1092703	1009425	889600
Borrowed Reserves	102895	126874	-23979	151648	216902	352598
Net Free/Borrowed Reserves	1089381	992550	96831	941054	792523	537001

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/15/10	2/8/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1715.6	1697.8	17.8	7.9%	7.6%	9.8%
M2 (M1+savings+small time deposits)	8526.9	8486.2	40.7	0.7%	2.7%	2.3%

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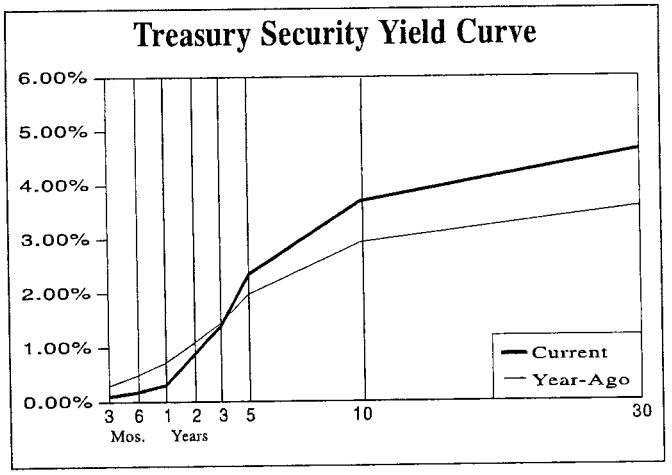
Selected Yields

	Recent (2/24/10)	3 Months Ago (11/24/09)	Year Ago (2/25/09)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.15	0.11	0.43
3-month LIBOR	0.25	0.26	1.26
Bank CDs			
6-month	0.25	0.34	0.85
1-year	0.45	0.57	1.05
5-year	1.99	2.21	2.07
U.S. Treasury Securities			
3-month	0.11	0.03	0.30
6-month	0.18	0.13	0.49
1-year	0.31	0.26	0.72
5-year	2.35	2.09	1.99
10-year	3.69	3.30	2.93
10-year (inflation-protected)	1.50	1.14	1.92
30-year	4.64	4.25	3.59
30-year Zero	4.90	4.43	3.46



	Recent (2/24/10)	3 Months Ago (11/24/09)	Year Ago (2/25/09)
Mortgage-Backed Securities			
GNMA 6.5%	2.39	2.97	3.79
FHLMC 6.5% (Gold)	2.03	1.82	3.74
FNMA 6.5%	2.81	1.80	3.65
FNMA ARM	2.98	2.42	3.90
Corporate Bonds			
Financial (10-year) A	5.33	5.19	8.78
Industrial (25/30-year) A	5.74	5.52	6.16
Utility (25/30-year) A	5.85	5.52	5.95
Utility (25/30-year) Baa/BBB	6.34	6.22	7.12
Foreign Bonds (10-Year)			
Canada	3.45	3.29	2.95
Germany	3.14	3.25	2.99
Japan	1.33	1.30	1.31
United Kingdom	4.08	3.66	3.46
Preferred Stocks			
Utility A	5.94	6.02	6.08
Financial A	6.73	6.90	12.58
Financial Adjustable A	5.52	5.52	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.38	4.35	4.89
25-Bond Index (Revs)	4.97	5.04	5.70
General Obligation Bonds (GOs)			
1-year Aaa	0.32	0.35	0.57
1-year A	1.08	1.32	0.67
5-year Aaa	1.55	1.65	1.98
5-year A	2.58	2.86	2.24
10-year Aaa	3.11	3.18	3.03
10-year A	4.11	4.10	3.53
25/30-year Aaa	4.46	4.49	4.81
25/30-year A	5.51	5.48	5.85
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.79	4.79	5.85
Electric AA	4.78	4.77	5.90
Housing AA	5.65	5.72	6.20
Hospital AA	5.07	5.19	6.25
Toll Road Aaa	4.84	4.84	5.95

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/10/10	1/27/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1119425	1063402	56023	1071837	974870	868086
Borrowed Reserves	126874	125300	1574	168048	233876	369577
Net Free/Borrowed Reserves	992551	938102	54449	903789	740994	498509

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/8/10	2/1/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1696.9	1691.8	5.1	1.3%	5.0%	8.0%
M2 (M1+savings+small time deposits)	8484.8	8470.8	14.0	-1.1%	1.6%	1.9%

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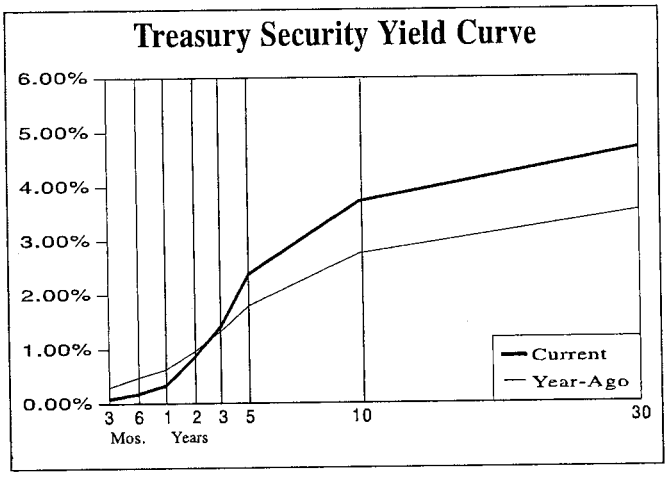
Selected Yields

	Recent (2/17/10)	3 Months Ago (11/18/09)	Year Ago (2/18/09)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.16	0.14	0.52
3-month LIBOR	0.25	0.27	1.25
Bank CDs			
6-month	0.25	0.34	0.87
1-year	0.45	0.58	1.20
5-year	1.97	2.23	2.14
U.S. Treasury Securities			
3-month	0.09	0.02	0.30
6-month	0.18	0.14	0.48
1-year	0.34	0.28	0.63
5-year	2.38	2.19	1.80
10-year	3.73	3.36	2.76
10-year (inflation-protected)	1.44	1.15	1.61
30-year	4.70	4.30	3.55
30-year Zero	4.96	4.47	3.43
Mortgage-Backed Securities			
GNMA 6.5%	2.99	3.03	4.05
FHLMC 6.5% (Gold)	1.75	2.03	3.92
FNMA 6.5%	2.61	1.99	3.78
FNMA ARM	2.98	2.42	3.90
Corporate Bonds			
Financial (10-year) A	5.41	5.21	8.33
Industrial (25/30-year) A	5.85	5.52	6.14
Utility (25/30-year) A	5.93	5.51	5.74
Utility (25/30-year) Baa/BBB	6.44	6.24	7.07
Foreign Bonds (10-Year)			
Canada	3.47	3.41	2.86
Germany	3.19	3.29	2.99
Japan	1.33	1.31	1.26
United Kingdom	4.03	3.68	3.39
Preferred Stocks			
Utility A	5.40	5.68	6.03
Financial A	7.14	7.14	13.57
Financial Adjustable A	5.52	5.52	5.52



	Recent (2/17/10)	3 Months Ago (11/18/09)	Year Ago (2/18/09)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.34	4.40	4.89
25-Bond Index (Revs)	4.96	5.02	5.67
General Obligation Bonds (GOs)			
1-year Aaa	0.31	0.42	0.55
1-year A	1.10	1.38	0.65
5-year Aaa	1.55	1.82	1.85
5-year A	2.59	3.00	2.15
10-year Aaa	3.12	3.27	2.90
10-year A	4.10	4.18	3.40
25/30-year Aaa	4.45	4.49	4.72
25/30-year A	5.50	5.48	5.72
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.77	4.78	5.80
Electric AA	4.76	4.79	5.90
Housing AA	5.63	5.72	6.15
Hospital AA	5.03	5.19	6.10
Toll Road Aaa	4.83	4.91	5.95

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	2/10/10	1/27/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1119423	1063401	56022	1071836	974870	868086
Borrowed Reserves	126874	125300	1574	168048	233876	369577
Net Free/Borrowed Reserves	992549	938101	54448	903789	740994	498509

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	2/1/10	1/25/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1692.0	1677.0	15.0	3.8%	3.3%	8.4%
M2 (M1+savings+small time deposits)	8471.4	8464.4	7.0	-1.3%	1.1%	1.8%

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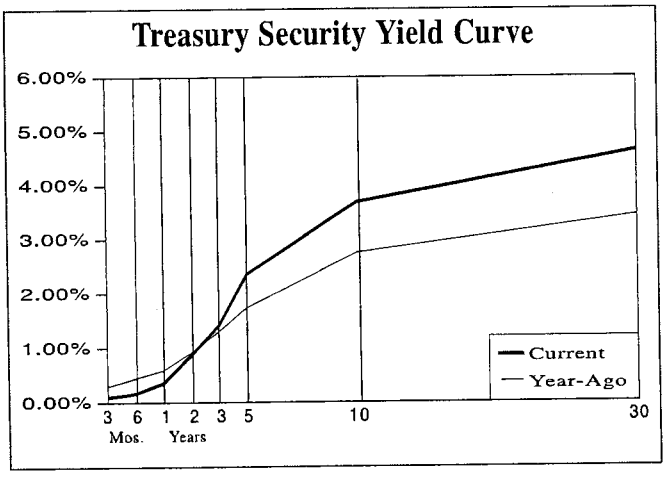
Selected Yields

	Recent (2/10/10)	3 Months Ago (11/10/09)	Year Ago (2/11/09)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.16	0.13	0.48
3-month LIBOR	0.25	0.28	1.23
Bank CDs			
6-month	0.25	0.38	0.89
1-year	0.45	0.62	1.08
5-year	1.97	2.22	2.37
U.S. Treasury Securities			
3-month	0.10	0.06	0.30
6-month	0.17	0.16	0.45
1-year	0.36	0.30	0.60
5-year	2.36	2.29	1.75
10-year	3.69	3.47	2.75
10-year (inflation-protected)	1.31	1.25	1.60
30-year	4.63	4.41	3.44
30-year Zero	4.88	4.58	3.31



	Recent (2/10/10)	3 Months Ago (11/10/09)	Year Ago (2/11/09)
Mortgage-Backed Securities			
GNMA 6.5%	3.10	3.43	4.02
FHLMC 6.5% (Gold)	2.05	2.28	3.62
FNMA 6.5%	2.03	2.43	3.63
FNMA ARM	2.98	2.42	3.89
Corporate Bonds			
Financial (10-year) A	5.40	5.26	8.09
Industrial (25/30-year) A	5.75	5.58	5.94
Utility (25/30-year) A	5.80	5.64	5.60
Utility (25/30-year) Baa/BBB	6.34	6.32	7.00
Foreign Bonds (10-Year)			
Canada	3.44	3.50	2.94
Germany	3.20	3.34	3.19
Japan	1.34	1.44	1.31
United Kingdom	3.93	3.76	3.61
Preferred Stocks			
Utility A	5.98	5.74	6.01
Financial A	6.87	6.86	11.01
Financial Adjustable A	5.51	5.51	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.36	4.41	4.96
25-Bond Index (Revs)	4.96	5.01	5.74
General Obligation Bonds (GOs)			
1-year Aaa	0.31	0.42	0.55
1-year A	1.17	1.37	0.65
5-year Aaa	1.58	1.93	1.76
5-year A	2.63	3.10	2.02
10-year Aaa	3.12	3.35	2.84
10-year A	4.10	4.24	3.34
25/30-year Aaa	4.43	4.49	4.71
25/30-year A	5.48	5.53	5.75
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.80	4.80	5.75
Electric AA	4.74	4.78	5.80
Housing AA	5.63	5.78	6.10
Hospital AA	5.03	5.19	6.15
Toll Road Aaa	4.81	4.80	5.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/27/10	1/13/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1063393	1004703	58690	1063241	946974	855998
Borrowed Reserves	125300	164979	-39679	185403	249615	385808
Net Free/Borrowed Reserves	938093	839724	98369	877837	697359	470190

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/25/10	1/18/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1677.1	1664.9	12.2	-0.0%	3.8%	8.0%
M2 (M1+savings+small time deposits)	8464.3	8458.3	6.0	-1.6%	0.2%	1.7%

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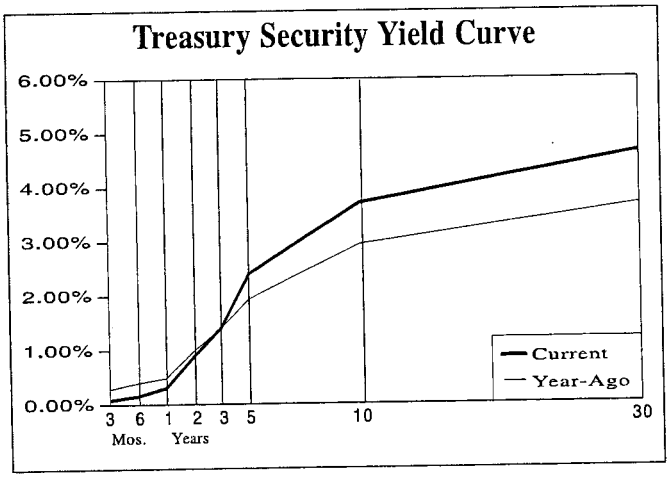
Selected Yields

	Recent (2/03/10)	3 Months Ago (11/04/09)	Year Ago (2/04/09)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.17	0.16	0.55
3-month LIBOR	0.25	0.28	1.24
Bank CDs			
6-month	0.25	0.38	0.87
1-year	0.45	0.62	1.29
5-year	1.97	2.22	2.41
U.S. Treasury Securities			
3-month	0.09	0.04	0.29
6-month	0.16	0.15	0.40
1-year	0.31	0.33	0.49
5-year	2.40	2.38	1.94
10-year	3.71	3.52	2.94
10-year (inflation-protected)	1.22	1.39	1.78
30-year	4.64	4.40	3.68
30-year Zero	4.87	4.55	3.55
Mortgage-Backed Securities			
GNMA 6.5%	3.10	3.52	4.28
FHLMC 6.5% (Gold)	2.29	2.31	4.17
FNMA 6.5%	2.25	2.43	4.14
FNMA ARM	2.98	2.42	3.89
Corporate Bonds			
Financial (10-year) A	5.46	5.35	8.03
Industrial (25/30-year) A	5.76	5.59	6.15
Utility (25/30-year) A	5.80	5.71	6.00
Utility (25/30-year) Baa/BBB	6.41	6.39	7.27
Foreign Bonds (10-Year)			
Canada	3.43	3.48	3.12
Germany	3.22	3.32	3.36
Japan	1.36	1.41	1.36
United Kingdom	3.92	3.79	3.77
Preferred Stocks			
Utility A	5.59	5.59	6.02
Financial A	6.69	7.12	10.79
Financial Adjustable A	5.50	5.51	5.51



	Recent (2/03/10)	3 Months Ago (11/04/09)	Year Ago (2/04/09)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.39	4.39	5.16
25-Bond Index (Revs)	4.99	4.95	5.89
General Obligation Bonds (GOs)			
1-year Aaa	0.30	0.43	0.55
1-year A	1.24	1.45	0.65
5-year Aaa	1.62	1.98	1.79
5-year A	2.73	3.13	2.09
10-year Aaa	3.21	3.36	2.90
10-year A	4.16	4.30	3.40
25/30-year Aaa	4.46	4.51	4.82
25/30-year A	5.48	5.56	5.82
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.80	4.71	5.90
Electric AA	4.76	4.76	6.00
Housing AA	5.65	5.83	6.25
Hospital AA	5.03	5.17	6.20
Toll Road Aaa	4.79	4.80	6.05

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/27/10	1/13/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1063393	1004700	58693	1063252	946979	856001
Borrowed Reserves	125300	164979	-39679	185403	249615	385808
Net Free/Borrowed Reserves	938093	839721	98372	877848	697364	470193

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/18/10	1/11/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1665.0	1653.7	11.3	-2.7%	2.2%	7.2%
M2 (M1+savings+small time deposits)	8458.6	8451.5	7.1	-1.2%	0.4%	2.0%

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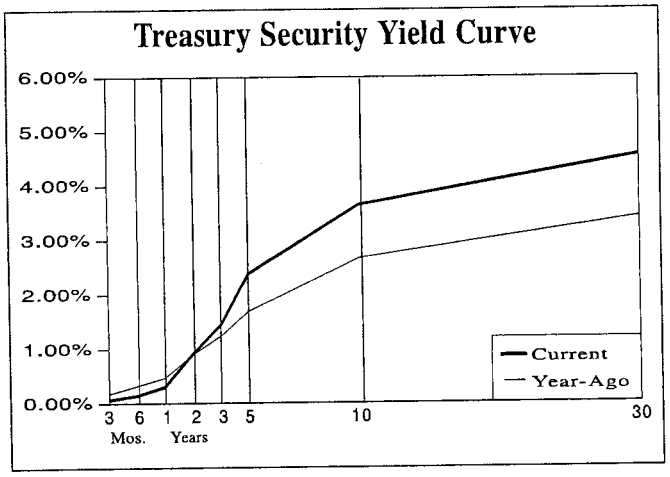
Selected Yields

	Recent (1/27/10)	3 Months Ago (10/28/09)	Year Ago (1/28/09)
TAXABLE			
Market Rates			
Discount Rate	0.50	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.16	0.17	0.45
3-month LIBOR	0.25	0.28	1.17
Bank CDs			
6-month	0.25	0.38	0.88
1-year	0.46	0.62	1.25
5-year	2.00	2.22	2.39
U.S. Treasury Securities			
3-month	0.07	0.06	0.18
6-month	0.15	0.15	0.33
1-year	0.31	0.36	0.47
5-year	2.39	2.33	1.69
10-year	3.65	3.42	2.67
10-year (inflation-protected)	1.24	1.44	1.78
30-year	4.56	4.26	3.42
30-year Zero	4.80	4.39	3.29



	Recent (1/27/10)	3 Months Ago (10/28/09)	Year Ago (1/28/09)
Mortgage-Backed Securities			
GNMA 6.5%	3.05	3.69	3.90
FHLMC 6.5% (Gold)	2.24	2.26	3.50
FNMA 6.5%	2.14	2.44	3.50
FNMA ARM	3.24	2.56	4.27
Corporate Bonds			
Financial (10-year) A	5.49	5.45	7.96
Industrial (25/30-year) A	5.69	5.44	6.18
Utility (25/30-year) A	5.72	5.53	6.10
Utility (25/30-year) Baa/BBB	6.32	6.20	7.04
Foreign Bonds (10-Year)			
Canada	3.35	3.46	2.96
Germany	3.20	3.26	3.23
Japan	1.32	1.43	1.27
United Kingdom	3.88	3.61	3.64
Preferred Stocks			
Utility A	5.58	5.58	5.98
Financial A	6.68	7.12	8.89
Financial Adjustable A	5.50	5.50	5.50
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.30	4.31	5.13
25-Bond Index (Revs)	4.91	4.87	5.82
General Obligation Bonds (GOs)			
1-year Aaa	0.30	0.45	0.55
1-year A	1.23	1.45	0.65
5-year Aaa	1.64	2.07	1.84
5-year A	2.73	3.18	2.14
10-year Aaa	3.25	3.35	3.00
10-year A	4.18	4.33	3.50
25/30-year Aaa	4.43	4.50	5.05
25/30-year A	5.43	5.55	6.05
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.81	4.69	6.05
Electric AA	4.74	4.77	6.10
Housing AA	5.65	5.85	6.40
Hospital AA	5.01	5.15	6.45
Toll Road Aaa	4.86	4.80	6.15

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	1/13/10	12/30/09	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1004700	1059954	-55254	1052310	924156	847856
Borrowed Reserves	164979	163525	1454	205393	268367	401995
Net Free/Borrowed Reserves	839721	896429	-56708	846916	655789	445861

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	1/11/10	1/4/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1655.3	1704.6	-49.3	-4.0%	0.3%	3.8%
M2 (M1+savings+small time deposits)	8452.3	8461.7	-9.4	-0.8%	0.5%	2.0%

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BELLA VISTA WATER COMPANY, INC.
DOCKET NO. W-02465A-09-0411 ET AL.
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BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
COST OF CAPITAL SUMMARY

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 1
PAGE 1 OF 3

WEIGHTED AVERAGE COST OF CAPITAL - CONSOLIDATED

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST RATE	WEIGHTED COST RATE
1	Long-Term Debt	$ 1,697,323	$ -	$ 1,697,323	21.08%	6.27%	1.32%
2	Common Equity	6,354,582	-	6,354,582	78.92%	9.00%	7.10%
3	Total Capitalization	$ 8,051,905	$ -	$ 8,051,905	100.00%		
4	**WEIGHTED AVERAGE COST OF CAPITAL**						**8.42%**

REFERENCES:
COLUMN (A): COMPANY, SCHEDULE D
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINES 1 & 2 / LINE 4
COLUMN (E): LINE 1; SCHEDULE WAR-1, PAGE 2, LINE 2; TESTIMONY WAR
COLUMN (F): COLUMN (D) x COLUMN (E), LINE 4; LINE 1 + LINE 2

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
COST OF CAPITAL SUMMARY

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SCHEDULE WAR - 1
PAGE 2 OF 3

WEIGHTED COST OF LONG-TERM DEBT

LINE NO.	(A) DESCRIPTION	END OF TEST YEAR (B) AMOUNT OUTSTANDING	(C) ANNUAL INTEREST	(D) INTEREST RATE	(E) WEIGHTED COST	END OF PROJECTED YEAR (F) AMOUNT OUTSTANDING	(G) ANNUAL INTEREST	(H) INTEREST RATE	(I) WEIGHTED COST
1	WIFA #1	$ 108,754	$ 6,634	6.10%	0.391%	$ 99,968	$ 6,098	6.10%	0.385%
2	WIFA #2	1,545,436	96,744	6.26%	5.700%	1,455,280	91,101	6.26%	5.751%
3	K-MART	6,140	526	8.57%	0.031%	484	41	8.47%	0.003%
4	BVR/RC-3	13,849	1,011	7.30%	0.060%	9,854	719	7.30%	0.045%
5	BVR/RC-4	16,109	1,113	6.91%	0.066%	12,802	885	6.91%	0.056%
6	BVR-CCCII	7,035	504	7.16%	0.030%	5,645	404	7.16%	0.026%
7	TOTALS	$ 1,697,323	$ 106,532		6.28%	$ 1,584,033	$ 99,248		
8	**WEIGHTED COST OF DEBT**								6.27%

REFERENCES:
COLUMN (A) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (B) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (C) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (D) LINES 1 THRU 6: COLUMN (C) / COLUMN (B)
COLUMN (E) LINES 1 THRU 6 : COLUMN (D) LINES 1 THRU 6 / LINE 7
COLUMN (F) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (G) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (H) LINES 1 THRU 6: COLUMN (C) / COLUMN (B)
COLUMN (I) LINES 1 THRU 6 : COLUMN (H) LINES 1 THRU 6 / LINE 7, LINE 8: SUM OF LINES 1 THRU 6

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
COST OF CAPITAL SUMMARY

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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	9.93%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.90%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**9.92%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.44%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.13%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.83%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**5.95%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.93%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	**9.00%**	TESTIMONY WAR

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
DCF COST OF EQUITY CAPITAL

DOCKET NO. W-02465A-09-0411 ET AL.
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.	3.13%	+	7.99%	=	11.12%
2	CWT	CALIFORNIA WATER SERVICE GROUP	3.23%	+	6.72%	=	9.95%
3	WTR	AQUA AMERICA, INC.	3.41%	+	5.32%	=	8.73%
4	**WATER COMPANY AVERAGE**						**9.93%**
5	AGL	AGL RESOURCES, INC.	4.83%	+	5.26%	=	10.08%
6	ATO	ATMOS ENERGY CORP.	4.81%	+	4.74%	=	9.55%
7	LG	LACLEDE GROUP, INC.	4.82%	+	5.10%	=	9.92%
8	NJR	NEW JERSEY RESOURCES CORPORATION	3.75%	+	8.27%	=	12.01%
9	GAS	NICOR, INC.	4.49%	+	5.19%	=	9.67%
10	NWN	NORTHWEST NATURAL GAS CO.	3.70%	+	4.61%	=	8.31%
11	PNY	PIEDMONT NATURAL GAS COMPANY	4.17%	+	4.50%	=	8.68%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	4.10%	+	9.35%	=	13.45%
13	SWX	SOUTHWEST GAS CORPORATION	3.47%	+	5.12%	=	8.59%
14	WGL	WGL HOLDINGS, INC.	4.47%	+	4.25%	=	8.72%
15	**NATURAL GAS LDC AVERAGE**						**9.90%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
DIVIDEND YIELD CALCULATION

DOCKET NO. W-02465A-09-0411 ET AL.
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.	$1.04	/	$33.21	=	3.13%
2	CWT	CALIFORNIA WATER SERVICE GROUP	1.18	/	36.51	=	3.23%
3	WTR	AQUA AMERICA, INC.	0.58	/	17.00	=	3.41%
4	**WATER COMPANY AVERAGE**						**3.26%**
5	AGL	AGL RESOURCES, INC.	$1.76	/	$36.46	=	4.83%
6	ATO	ATMOS ENERGY CORP.	1.34	/	27.86	=	4.81%
7	LG	LACLEDE GROUP, INC.	1.58	/	32.79	=	4.82%
8	NJR	NEW JERSEY RESOURCES CORPORATION	1.36	/	36.31	=	3.75%
9	GAS	NICOR, INC.	1.86	/	41.45	=	4.49%
10	NWN	NORTHWEST NATURAL GAS CO.	1.66	/	44.82	=	3.70%
11	PNY	PIEDMONT NATURAL GAS COMPANY	1.08	/	25.89	=	4.17%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	1.63	/	39.76	=	4.10%
13	SWX	SOUTHWEST GAS CORPORATION	1.00	/	28.80	=	3.47%
14	WGL	WGL HOLDINGS, INC.	1.48	/	33.09	=	4.47%
15	**NATURAL GAS LDC AVERAGE**						**4.26%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/22/2010 (WATER COMPANIES) AND 03/12/2010 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF CLOSING PRICES FROM 02/01/2010 TO 03/26/2010
STOCK QUOTES OBTAINED THROUGH BIG CHARTS WEB SITE - HISTORICAL QUOTES (www.bigcharts.com).
COLUMN (C): COLUMN (A) ÷ COLUMN (B)

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 4

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AWR	AMERICAN STATES WATER CO.	6.25%	+	1.74%	=	7.99%
2	CWT	CALIFORNIA WATER SERVICE GROUP	6.00%	+	0.72%	=	6.72%
3	WTR	AQUA AMERICA, INC.	5.00%	+	0.32%	=	5.32%
4	**WATER COMPANY AVERAGE**						**6.67%**
5	AGL	AGL RESOURCES, INC.	5.00%	+	0.26%	=	5.26%
6	ATO	ATMOS ENERGY CORP.	4.50%	+	0.24%	=	4.74%
7	LG	LACLEDE GROUP, INC.	4.50%	+	0.60%	=	5.10%
8	NJR	NEW JERSEY RESOURCES CORPORATION	8.00%	+	0.27%	=	8.27%
9	GAS	NICOR, INC.	5.00%	+	0.19%	=	5.19%
10	NWN	NORTHWEST NATURAL GAS CO.	4.25%	+	0.36%	=	4.61%
11	PNY	PIEDMONT NATURAL GAS COMPANY	4.50%	+	0.00%	=	4.50%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	7.50%	+	1.85%	=	9.35%
13	SWX	SOUTHWEST GAS CORPORATION	5.00%	+	0.12%	=	5.12%
14	WGL	WGL HOLDINGS, INC.	4.25%	+	0.00%	=	4.25%
15	**NATURAL GAS LDC AVERAGE**						**5.64%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 4

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	{ [((1.69) + 1) / 2] - 1 }	=	1.74%
2	CWT	CALIFORNIA WATER SERVICE GROUP	1.75%	x	{ [((1.83) + 1) / 2] - 1 }	=	0.72%
3	WTR	AQUA AMERICA, INC.	0.55%	x	{ [((2.15) + 1) / 2] - 1 }	=	0.32%
4	**WATER COMPANY AVERAGE**						**0.92%**
5	AGL	AGL RESOURCES, INC.	1.00%	x	{ [((1.51) + 1) / 2] - 1 }	=	0.26%
6	ATO	ATMOS ENERGY CORP.	3.50%	x	{ [((1.14) + 1) / 2] + 1 }	=	0.24%
7	LG	LACLEDE GROUP, INC.	3.25%	x	{ [((1.37) + 1) / 2] - 1 }	=	0.60%
8	NJR	NEW JERSEY RESOURCES CORPORATION	0.50%	x	{ [((2.07) + 1) / 2] - 1 }	=	0.27%
9	GAS	NICOR, INC.	0.50%	x	{ [((1.75) + 1) / 2] - 1 }	=	0.19%
10	NWN	NORTHWEST NATURAL GAS CO.	1.00%	x	{ [((1.72) + 1) / 2] - 1 }	=	0.36%
11	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((2.00) + 1) / 2] - 1 }	=	0.00%
12	SJI	SOUTH JERSEY INDUSTIES, INC.	3.50%	x	{ [((2.06) + 1) / 2] - 1 }	=	1.85%
13	SWX	SOUTHWEST GAS CORPORATION	2.25%	x	{ [((1.10) + 1) / 2] + 1 }	=	0.12%
14	WGL	WGL HOLDINGS, INC.	0.01%	x	{ [((1.46) + 1) / 2] - 1 }	=	0.00%
15	**NATURAL GAS LDC AVERAGE**						**0.39%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/22/2010 (WATER COMPANIES) AND 03/12/2010 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
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	0.4541		9.50%		4.31%		18.60	7.51%
8			2010	0.4750		10.50%		4.99%		19.00	4.80%
9			2012-14	0.5308		12.00%		6.37%	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	0.4070		10.00%		4.07%		21.00	1.35%
18			2010	0.4333		10.50%		4.55%		21.25	1.27%
19			2012-14	0.5192		12.00%		6.23%	2.00%	23.00	2.11%
20											
21	WTR	AQUA AMERICA, INC.	2004	0.4219		10.70%		4.51%	5.89	127.18	
22			2005	0.4366		11.20%		4.89%	6.30	128.97	
23			2006	0.3714		10.00%		3.71%	6.96	132.33	
24			2007	0.3239		9.70%		3.14%	7.32	133.40	
25			2008	0.3014		9.30%		2.80%	7.82	135.37	
26			GROWTH 2004 - 2008					3.81%	10.00%		1.57%
27			2009	-5.8750		10.00%		NMF		136.30	0.69%
28			2010	0.3444		10.50%		3.62%		137.00	0.60%
29			2012-14	0.4400		12.00%		5.28%	6.00%	139.00	0.53%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 01/22/2010
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, 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

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
DIVIDEND GROWTH COMPONENTS

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 5
PAGE 2 OF 4

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.	2005	0.4758		12.90%		6.14%	19.29	77.70	
2			2006	0.4559		13.20%		6.02%	20.71	77.70	
3			2007	0.3971		12.70%		5.04%	21.74	76.40	
4			2008	0.3801		12.60%		4.79%	21.48	76.90	
5			2009	0.4048		14.50%		5.87%	22.95	77.50	
6			GROWTH 2005 - 2009					5.57%	10.00%		-0.06%
7			2010	0.4034		12.00%		4.84%		78.50	1.29%
8			2011	0.4194		12.00%		5.03%		79.00	0.96%
9			2013-15	0.4353		11.00%		4.79%	5.00%	80.50	0.76%
10											
11	ATO	ATMOS ENERGY CORP.	2005	0.2791		8.50%		2.37%	19.90	80.54	
12			2006	0.3700		9.80%		3.63%	20.16	81.74	
13			2007	0.3402		8.70%		2.96%	22.01	89.33	
14			2008	0.3500		8.80%		3.08%	22.60	90.81	
15			2009	0.3299		8.30%		2.74%	23.52	92.55	
16			GROWTH 2005 - 2009					2.96%	7.00%		3.54%
17			2010	0.4044		9.00%		3.64%		94.00	1.57%
18			2011	0.4213		9.50%		4.00%		96.00	1.85%
19			2013-15	0.4630		10.00%		4.63%	3.50%	110.00	3.51%
20											
21	LG	LACLEDE GROUP, INC.	2005	0.2789		10.90%		3.04%	17.31	21.17	
22			2006	0.4093		12.50%		5.12%	18.85	21.36	
23			2007	0.3723		11.60%		4.32%	19.79	21.65	
24			2008	0.4356		11.80%		5.14%	22.12	21.99	
25			2009	0.4760		12.40%		5.90%	23.32	22.17	
26			GROWTH 2005 - 2009					4.70%	6.50%		1.16%
27			2010	0.3592		10.00%		3.59%		22.50	1.49%
28			2011	0.3808		10.50%		4.00%		23.00	1.85%
29			2013-15	0.4167		11.00%		4.58%	4.00%	26.00	3.24%
30											
31	NJR	NEW JERSEY RESOURCES CORPORATION	2005	0.4859		17.00%		8.26%	10.60	41.32	
32			2006	0.4866		12.60%		6.13%	15.00	41.44	
33			2007	0.3484		10.10%		3.52%	15.50	41.61	
34			2008	0.5889		15.70%		9.25%	17.28	42.06	
35			2009	0.4833		14.60%		7.06%	16.59	41.59	
36			GROWTH 2005 - 2009					6.84%	10.50%		0.16%
37			2010	0.4769		15.00%		7.15%		42.00	0.99%
38			2011	0.4727		16.00%		7.56%		41.00	-0.71%
39			2013-15	0.5250		16.50%		8.66%	4.50%	40.00	-0.78%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/12/2010
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2005 - 2009

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
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.	2005	0.1806		12.50%		2.26%	18.36	44.18	
2			2006	0.3519		14.70%		5.17%	19.43	44.90	
3			2007	0.3758		14.30%		5.37%	20.58	45.90	
4			2008	0.2928		12.30%		3.60%	21.55	45.13	
5			2009	0.3737		13.10%		4.90%	22.93	45.25	
6			GROWTH 2005 - 2009					4.26%	5.00%		0.60%
7			2010	0.3236		11.50%		3.72%		45.50	0.55%
8			2011	0.4000		12.50%		5.00%		45.50	0.28%
9			2013-15	0.4364		11.50%		5.02%	5.00%	45.50	0.11%
10											
11	NWN	NORTHWEST NATURAL GAS CO.	2005	0.3744		9.90%		3.71%	21.28	27.58	
12			2006	0.4085		10.90%		4.45%	22.01	27.24	
13			2007	0.4783		12.50%		5.98%	22.52	26.41	
14			2008	0.4086		10.90%		4.45%	23.71	26.50	
15			2009	0.4224		11.10%		4.69%	24.88	26.53	
16			GROWTH 2005 - 2009					4.66%	3.50%		-0.97%
17			2010	0.4000		11.00%		4.40%		26.60	0.26%
18			2011	0.3966		11.00%		4.36%		26.60	0.13%
19			2013-15	0.3829		9.00%		3.45%	5.00%	28.00	1.08%
20											
21	PNY	PIEDMONT NATURAL GAS COMPANY	2005	0.3106		11.50%		3.57%	11.53	76.70	
22			2006	0.2578		11.00%		2.84%	11.83	74.61	
23			2007	0.2929		11.90%		3.49%	11.99	73.23	
24			2008	0.3087		12.40%		3.83%	12.11	73.26	
25			2009	0.3593		13.20%		4.74%	12.67	73.27	
26			GROWTH 2005 - 2009					3.69%	4.50%		-1.14%
27			2010	0.3273		13.00%		4.25%		72.00	-1.73%
28			2011	0.3235		12.50%		4.04%		71.50	-1.22%
29			2013-15	0.3487		13.00%		4.53%	3.00%	69.00	-1.19%
30											
31	SJI	SOUTH JERSEY INDUSTIES, INC.	2005	0.4971		12.40%		6.16%	13.50	28.98	
32			2006	0.6260		16.30%		10.20%	15.11	29.33	
33			2007	0.5167		12.80%		6.61%	16.25	29.61	
34			2008	0.5110		13.10%		6.69%	17.33	29.73	
35			2009	0.4874		13.10%		6.38%	18.27	29.80	
36			GROWTH 2005 - 2009					7.21%	11.00%		0.70%
37			2010	0.4943		13.50%		6.67%		31.00	4.03%
38			2011	0.5000		14.00%		7.00%		32.00	3.63%
39			2013-15	0.5152		14.50%		7.47%	5.00%	35.00	3.27%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/12/2010
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2005 - 2009

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
DIVIDEND GROWTH COMPONENTS

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 5
PAGE 4 OF 4

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	2005	0.3440		6.40%		2.20%	19.10	39.33	
2			2006	0.5859		8.90%		5.21%	21.58	41.77	
3			2007	0.5590		8.50%		4.75%	22.98	42.81	
4			2008	0.3525		5.90%		2.08%	23.49	44.19	
5			2009	0.5103		7.90%		4.03%	24.46	45.09	
6			GROWTH 2005 - 2009					3.66%	5.00%		3.48%
7			2010	0.5122		8.00%		4.10%		46.00	2.02%
8			2011	0.5227		8.50%		4.44%		47.00	2.10%
9			2013-15	0.5472		9.00%		4.92%	4.50%	50.00	2.09%
10											
11	WGL	WGL HOLDINGS, INC.	2005	0.3803		12.00%		4.56%	17.80	48.65	
12			2006	0.3041		12.00%		3.65%	18.86	48.89	
13			2007	0.3445		10.40%		3.58%	19.83	49.45	
14			2008	0.4221		11.60%		4.90%	20.99	49.92	
15			2009	0.4190		11.60%		4.86%	21.89	50.14	
16			GROWTH 2005 - 2009					4.31%	5.00%		0.76%
17			2010	0.3435		10.50%		3.61%		50.00	-0.28%
18			2011	0.3673		11.00%		4.04%		50.00	-0.14%
19			2013-15	0.3815		11.00%		4.20%	4.00%	50.00	-0.06%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 03/12/2010
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6 & 16, SIMPLE AVERAGE GROWTH, 2005 - 2009

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINES 6 & 16, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
GROWTH RATE COMPARISON

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 6

WATER COMPANY SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	AWR	7.99%	4.00%	9.50%	4.50%	4.00%	5.50%	2.00%	5.00%	4.93%	10.23%	2.96%	4.57%
2	CWT	6.72%	6.70%	4.75%	1.50%	3.50%	7.00%	0.50%	6.50%	4.35%	6.81%	0.87%	5.55%
3	WTR	5.32%	8.00%	10.00%	6.50%	6.00%	5.50%	8.00%	10.00%	7.71%	3.34%	8.35%	7.34%
4				8.08%	4.17%	4.50%	6.00%	3.50%	7.17%		6.79%	4.06%	5.82%
5	AVERAGES	6.67%	6.23%		5.58%			5.56%		5.66%		5.56%	

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) VALUE LINE PROJECTED DPS	(C) VALUE LINE PROJECTED BVPS	(D) VALUE LINE HISTORIC EPS	(D) VALUE LINE HISTORIC DPS	(D) VALUE LINE HISTORIC BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) 5 - YEAR COMPOUND HISTORY DPS	(F) 5 - YEAR COMPOUND HISTORY BVPS
1	AGL	5.26%	4.50%	3.50%	2.50%	5.00%	8.50%	8.00%	10.00%	6.00%	3.90%	7.25%	4.44%
2	ATO	4.74%	5.00%	5.50%	2.00%	3.50%	4.50%	1.50%	7.00%	4.14%	3.45%	1.58%	4.27%
3	LG	5.10%	3.00%	2.50%	2.50%	4.00%	10.50%	2.00%	6.50%	4.43%	11.34%	2.80%	7.74%
4	NJR	8.27%	7.00%	6.50%	5.50%	4.50%	7.50%	6.00%	10.50%	6.79%	7.91%	8.04%	11.85%
5	GAS	5.19%	3.70%	2.50%	-	5.00%	3.50%	-	5.00%	3.94%	6.95%	0.00%	5.71%
6	NWN	4.61%	5.70%	5.00%	6.00%	5.00%	8.00%	3.00%	3.50%	5.17%	7.04%	4.93%	3.98%
7	PNY	4.50%	6.30%	4.00%	3.50%	3.00%	6.50%	4.50%	4.50%	4.61%	6.06%	4.13%	2.39%
8	SJI	9.35%	11.60%	5.50%	6.50%	5.00%	13.00%	6.00%	11.00%	8.37%	8.62%	9.14%	7.86%
9	SWX	5.12%	7.00%	8.00%	5.50%	4.50%	9.00%	1.00%	5.00%	5.71%	11.62%	3.75%	6.38%
10	WGL	4.25%	-	2.50%	3.00%	4.00%	5.50%	2.00%	5.00%	3.67%	4.40%	2.73%	5.31%
11				4.55%	4.11%	4.35%	7.65%	3.78%	6.80%		7.13%	4.43%	5.99%
12	AVERAGES	5.64%	5.98%		4.34%			6.08%		5.28%		5.85%	

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 01/22/2010 (WATER COMPANIES) AND 03/12/2010 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 01/22/2010 (WATER COMPANIES) AND 03/12/2010 (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 01/22/2010 (WATER COMPANIES) AND 03/12/2010 (NATURAL GAS LDC's)

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
CAPM COST OF EQUITY CAPITAL

DOCKET NO. W-02465A-09-0411 ET AL.
SCHEDULE WAR - 7
PAGE 1 OF 2

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL						(A)								(B) EXPECTED RETURN
		k	=	r_f	+ [	ß	x	(	r_m	-	r_f	)]	=	
1	AWR	k	=	2.36%	+ [	0.80	x	(	9.60%	-	5.40%	)]	=	5.72%
2	CWT	k	=	2.36%	+ [	0.75	x	(	9.60%	-	5.40%	)]	=	5.51%
3	WTR	k	=	2.36%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.09%
4	**WATER COMPANY AVERAGE**					0.73								**5.44%**
5	ATO	k	=	2.36%	+ [	0.75	x	(	9.60%	-	5.40%	)]	=	5.51%
6	LG	k	=	2.36%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.09%
7	NJR	k	=	2.36%	+ [	0.60	x	(	9.60%	-	5.40%	)]	=	4.88%
8	GAS	k	=	2.36%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.09%
9	NWN	k	=	2.36%	+ [	0.70	x	(	9.60%	-	5.40%	)]	=	5.30%
10	PNY	k	=	2.36%	+ [	0.60	x	(	9.60%	-	5.40%	)]	=	4.88%
11	SJI	k	=	2.36%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.09%
12	SWX	k	=	2.36%	+ [	0.60	x	(	9.60%	-	5.40%	)]	=	4.88%
13	WGL	k	=	2.36%	+ [	0.75	x	(	9.60%	-	5.40%	)]	=	5.51%
14	JRAL GAS LDC AV	k	=	2.36%	+ [	0.65	x	(	9.60%	-	5.40%	)]	=	5.09%
15	**NATURAL GAS LDC AVERAGE**					0.66								**5.13%**

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 02/05/2010 THROUGH 03/26/2010 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 PERI THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOOK.

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
CAPM COST OF EQUITY CAPITAL

DOCKET NO. W-02465A-09-0411 ET A
SCHEDULE WAR - 7
PAGE 2 OF 2

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL						(A)									(B) EXPECTED RETURN
		k	=	r_f	+ [	ß	x	(	r_m	-	r_f	)]	=			
1	AWR	k	=	2.36%	+ [	0.80	x	(	11.70%	-	5.60%	)]	=			7.24%
2	CWT	k	=	2.36%	+ [	0.75	x	(	11.70%	-	5.60%	)]	=			6.94%
3	WTR	k	=	2.36%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=			6.33%
4	**WATER COMPANY AVERAGE**					0.73										**6.83%**
5	ATO	k	=	2.36%	+ [	0.75	x	(	11.70%	-	5.60%	)]	=			6.94%
6	LG	k	=	2.36%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=			6.33%
7	NJR	k	=	2.36%	+ [	0.60	x	(	11.70%	-	5.60%	)]	=			6.02%
8	GAS	k	=	2.36%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=			6.33%
9	NWN	k	=	2.36%	+ [	0.70	x	(	11.70%	-	5.60%	)]	=			6.63%
10	PNY	k	=	2.36%	+ [	0.60	x	(	11.70%	-	5.60%	)]	=			6.02%
11	SJI	k	=	2.36%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=			6.33%
12	SWX	k	=	2.36%	+ [	0.60	x	(	11.70%	-	5.60%	)]	=			6.02%
13	WGL	k	=	2.36%	+ [	0.75	x	(	11.70%	-	5.60%	)]	=			6.94%
14	JRAL GAS LDC AV	k	=	2.36%	+ [	0.65	x	(	11.70%	-	5.60%	)]	=			6.33%
15	**NATURAL GAS LDC AVERAGE**					0.66										**6.39%**

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 SURVEYS "SELECTION & OPINIONS" PUBLICATION FROM 02/05/2010 THROUGH 03/26/2010 WAS USED AS A RISK FREE RATE OF RETURN.

(b) THE RISK PREMIUM (RM - RF) USED THE ARITHMETIC MEAN FOR S&P 500 TOTAL RETURNS OVER THE 1926 - 2008 PERIOD MINUS TOTAL RETURNS ON INTERMEDIATE TREASURIES DURING THE SAMI THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2009 YEARBOO

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. W-02465A-09-0411 ET AL.
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	2009	2.73%	-2.40%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	CURRENT	2.10%	5.60%	3.25%	0.75%	0.00% - 0.25%	0.15%	4.57%	5.75%	6.24%

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 03/26/2010
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY , DATED 03/26/2010

BELLA VISTA WATER COMPANY, INC.
TEST YEAR ENDED MARCH 31, 2009
CAPITAL STRUCTURES OF SAMPLE COMPANIES

DOCKET NO. W-02465A-09-0411 ET AL.
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%

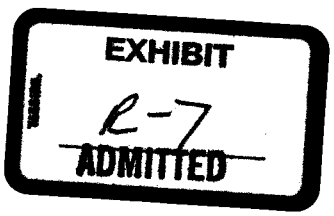
AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES

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:

BELLA VISTA WATER COMPANY, INC.

DOCKET NO. W-02465A-09-0411 ET AL.



SUPPLEMENTAL DIRECT TESTIMONY
(COST OF CAPITAL)

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 23, 2010

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ATTACHMENT A

SCHEDULES WAR

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 supplemental direct testimony.

A. The purpose of my supplemental direct testimony is to present RUCO's recommended weighted average costs of capital for BVWC, NSWC and SSWC on a stand-alone basis.

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

A. Yes, on April 12, 2010, I filed direct testimony with the Commission on RUCO's cost of capital recommendations for BVWC on a consolidated basis.

Q. Are you recommending a separate cost of common equity for each of the three Liberty Water systems?

A. No. I am recommending the same 9.00 percent cost of common equity that I recommended on a consolidated basis. The analysis which produced my recommended 9.00 percent cost of common equity was explained in my direct testimony filed on April 12, 2010 and so there is no need to repeat it in this supplemental direct testimony.

Q. Will RUCO be filing supplemental direct testimony on the rate base and operating income issues as they relate to the three Liberty Water systems on a stand-alone basis?

A. Yes. RUCO analyst Rodney L. Moore will file supplemental direct testimony on the rate base and operating income issues as they relate to the three Liberty Water systems on a stand-alone basis.

Q. Is RUCO filing testimony on rate consolidation and rate design in this proceeding?

A. Yes. RUCO Director Jodi A. Jerich, Esq. and RUCO analyst Rodney L. Moore will provide direct testimony on RUCO's rate consolidation policy and RUCO's recommended rate designs respectively.

Q. How is your supplemental direct testimony organized?

A. My supplemental direct testimony contains five parts: the introduction that I have just presented; a summary of RUCO's recommendations on a stand-alone basis that I am about to present; a section on RUCO's stand-alone capital structure recommendations; a section on RUCO's stand-alone cost of debt recommendations; and, a section on the weighted costs of capital for each of the three Liberty Water systems.

SUMMARY OF RECOMMENDATIONS

Q. What are RUCO's capital structure, cost of debt and weighted average cost of capital recommendations for BVWC, NSWC and SSWC on a stand-alone basis?

A. RUCO is recommending the following capital structure, cost of debt and weighted average cost of capital recommendations for BVWC, NSWC and SSWC on a stand-alone basis:

Bella Vista Water Company

BVWC Capital Structure – For BVWC, I am recommending that the Commission adopt BVWC's proposed capital structure, which is comprised of 27.76 percent long-term debt and 72.24 percent common equity.

BVWC Cost of Debt – For BVWC, I am recommending that the Commission adopt the Company-proposed cost of debt of 6.27 percent, which is the average weighted cost of debt of BVWC's various loans.

BVWC Weighted Average Cost of Capital – Based on the results of my recommended capital structure, I am recommending an 8.24 percent cost of capital for BVWC, which is the weighted cost of my recommended 6.28 percent cost of long-term debt and my recommended 9.00 percent cost of common equity. My recommended weighted average cost of capital for

BVWC is 253 basis points lower than the 10.77 percent weighted average cost of capital being proposed by the Company.

Northern and Southern Sunrise Water Companies

NSWC and SSWC Capital Structures – I am recommending that NSWC's and SSWC's proposed capital structures, which are comprised of 100 percent common equity be rejected by the ACC and that my recommended hypothetical capital structures, which are comprised of 60 percent common equity and 40 percent debt, be adopted by the Commission.

NSWC and SSWC Costs of Debt – For both NSWC and SSWC, 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.

NSWC and SSWC Weighted Average Costs of Capital – Based on the results of my recommended hypothetical capital structures, I am recommending a 7.90 percent cost of capital for both NSWC and SSWC, which is the weighted cost of my recommended costs of common equity and hypothetical debt. My recommended 7.90 percent weighted average costs of capital for NSWC and SSWC are 490 basis points lower than the

12.80 percent weighted average costs of capital being proposed by NSWC and SSWC.

CAPITAL STRUCTURE

Bella Vista Water Company

Q. Please describe BVWC's proposed capital structure.

A. BVWC's proposed capital structure is comprised of 72.24 percent common equity and 27.76 percent long-term debt.

Q. How does BVWC's capital structure compare with the capital structures of the water and gas utilities that comprise your samples?

A. BVWC's capital structure, comprised of 72.24 percent equity capital is clearly heavier in equity than the capital structures of the water and gas utilities in my samples and would be perceived by investors as having lower risk overall. The lower level of debt in the Company's capital structure would indicate lower financial risk and would justify a downward adjustment to the cost of common equity derived from my sample companies that had average capital structures of approximately 49.00 percent common equity and 51.00 percent debt in the case of water, and approximately 54.00 percent equity and 46.00 percent debt in the case of natural gas.

Q. Why have you decided not to recommend a hypothetical capital structure for BVWC given the fact that BVWC's capital structure contains less debt than the utilities in your sample?

A. As I explained in my direct testimony filed on April 12, 2010, in recent years I have attempted, for the most part, to recommend hypothetical capital structures for utilities that have extreme levels of debt or equity in their capital structures. In the case of Liberty Water systems I have recommended hypothetical capital structures in cases where imprudent capital structures comprised of 100 percent equity were being proposed. While a higher level of lower cost debt would be desirable for BVWC, I believe that the fact that my recommended capital structure, which is comprised of 21.08 percent long-term debt, eliminates the need for a hypothetical capital structure in this case.

Q. Did you make any direct downward adjustment to your recommended cost of common equity that takes into consideration the higher level of equity contained in the Company-proposed capital structure?

A. No. While a good argument could be made for such an adjustment, I believe my recommended 9.00 percent cost of equity would cover any investor concerns regarding unique business risk associated with BVWC.

Northern and Southern Sunrise Water Companies

Q. Have you reviewed both NSWC's and SSWC's testimony regarding their proposed capital structures?

A. Yes, I have.

Q. Please describe the capital structures being proposed by NSWC and SSWC.

A. Both NSWC and SSWC are proposing capital structures comprised of 100 percent common equity.

Q. Are the capital structures being proposed by NSWC and SSWC in line with industry averages?

A. No. The capital structures being proposed by NSWC and SSWC are 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, direct testimony filed on April 12, 2010). The capital structures for those utilities averaged 51.4 percent for debt and 48.6 percent for equity.

Q. In terms of risk, how do the capital structures proposed by NSWC and SSWC 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 12.80 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 utilities such as NSWC and SSWC, which have no debt in their capital structures. In the case of a publicly traded company, like those included in my proxy, a company with NSWC's and SSWC's levels 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 both NSWC and SSWC.

Q. What capital structure are you recommending for both NSWC and SSWC?

A. I am recommending a hypothetical capital structure comprised of 60 percent equity and 40 percent debt for both NSWC and SSWC.

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 Liberty Water). 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 both NSWC and SSWC 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 both NSWC and SSWC may face and for that reason I believe a higher level of equity is reasonable.

COST OF DEBT

Bella Vista Water Company

Q. Have you reviewed the various debt instruments that comprise the long-term debt in BVWC's capital structure?

A. Yes.

Q. What cost of long-term debt are you recommending for BVWC?

A. I am recommending that the Commission adopt the 6.27 percent cost of debt being proposed by BVWC, which is the average of the weighted costs of BVWC's various loans agreements.

Northern and Southern Sunrise Water Companies

Q. Are you recommending a hypothetical cost of debt for both NSWC and SSWC?

A. Yes.

Q. What hypothetical cost of debt are you recommending for both NSWC and SSWC?

A. I am recommending a hypothetical cost of debt of 6.26 percent for both NSWC and SSWC.

Q. How did you determine your hypothetical cost of debt for NSWC and SSWC?

A. As can be viewed on page 2 of Schedule WAR-1 for both NSWC and SSWC, 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 in my direct testimony filed on April 11, 2010, 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. Is your recommended hypothetical cost of debt for NSWC and SSWC similar to BVWC's cost of debt?

A. Yes. The 6.26 percent hypothetical cost of debt that I am recommending for NSWC and SSWC is only one basis point lower than BVWC's 6.27 percent cost of debt.

Q. Why do you believe your recommended 6.26 percent hypothetical cost of debt for NSWC and SSWC is reasonable given the recent turbulence in the financial markets?

A. My recommended 6.26 percent hypothetical cost of debt is falls within the current yields of A-rated and Baa/BBB-rated utility bonds that was reported in the April 23, 2010 Value Line Selection and Opinion publication (Attachment A). 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 Liberty Water's parent company's ability to

access capital, it is reasonable to believe that Algonquin Power & Utilities Corp. can obtain debt at a cost in the A-rated to Baa/BBB-rated range of 5.89 percent to 6.35 percent stated above, I believe, for the reasons stated above, my recommended 6.26 percent hypothetical cost of debt is reasonable and there is no need for additional basis point adjustment.

Q. How does your recommended 6.26 percent hypothetical cost of debt for NSWC and SSWC 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.

WEIGHTED AVERAGE COST OF CAPITAL

Bella Vista Water Company

Q. What weighted average cost of capital are you recommending for BVWC?

A. I am recommending an 8.24 percent weighted average cost of capital for BVWC.

Q. How does the Company's proposed weighted cost of capital compare with your recommendation?

A. BVWC has proposed a weighted average cost of capital of 10.77 percent which is 253 basis points higher than the 8.24 percent weighted cost that I am recommending. My cost of capital recommendation for BVWC is consistent with the one that I made for Liberty Water's Litchfield Park Service Company in a case that is now pending before the Commission.

Northern and Southern Sunrise Water Companies

Q. What weighted average cost of capital are you recommending for both NSWC and SSWC?

A. I am recommending a 7.90 percent weighted average cost of capital for both NSWC and SSWC.

Q. How does the weighted average cost of capital being proposed by NSWC and SSWC compare with your recommendation?

A. Both NSWC and SSWC have proposed weighted average costs of capital of 12.80 percent which reflects the total absence of debt financing in their proposed capital structures. The proposed weighted average cost of capital of 12.80 percent for both NSWC and SSWC is 490 basis points higher than the 7.90 percent weighted average cost of capital that I am recommending. I would also point out that my cost of capital recommendations for NSWC and SSWC are consistent with the

recommendations that I made in Liberty Water's Gold Canyon, Black Mountain Sewer Corporation, and Rio Rico Utilities, Inc. rate cases.

Q. Does your silence on any of the issues, matters or findings addressed in the rebuttal testimony of any of the witnesses for BVWC, NSWC or SSWC constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

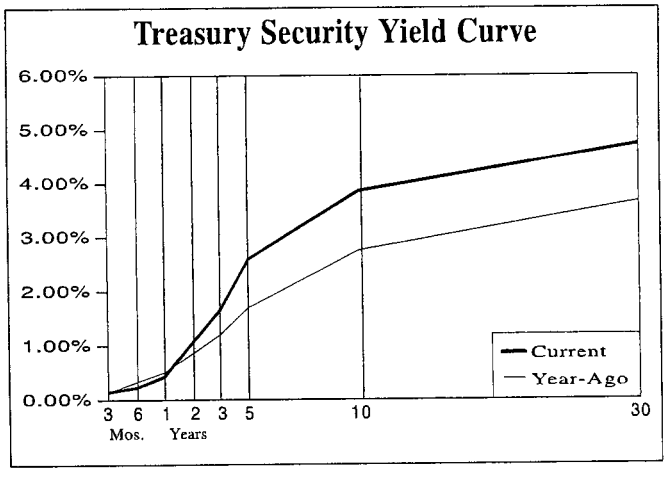
Q. Does this conclude your supplemental direct testimony on the stand-alone cost of capital issues for BVWC, NSWC and SSWC?

A. Yes, it does.

ATTACHMENT A

Selected Yields

	Recent (4/14/10)	3 Months Ago (1/13/10)	Year Ago (4/15/09)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.50	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.20	0.16	0.38
3-month LIBOR	0.30	0.25	1.11
Bank CDs			
6-month	0.25	0.26	0.81
1-year	0.43	0.47	1.02
5-year	1.99	2.02	2.01
U.S. Treasury Securities			
3-month	0.15	0.05	0.14
6-month	0.23	0.14	0.33
1-year	0.43	0.35	0.51
5-year	2.60	2.54	1.70
10-year	3.86	3.79	2.76
10-year (inflation-protected)	1.51	1.31	1.43
30-year	4.73	4.71	3.66
30-year Zero	4.99	4.95	3.66
Mortgage-Backed Securities			
GNMA 6.5%	2.52	3.63	3.39
FHLMC 6.5% (Gold)	1.83	2.41	2.67
FNMA 6.5%	2.14	2.54	2.62
FNMA ARM	2.76	3.24	3.15
Corporate Bonds			
Financial (10-year) A	5.22	5.65	7.61
Industrial (25/30-year) A	5.76	5.87	6.25
Utility (25/30-year) A	5.89	5.89	6.17
Utility (25/30-year) Baa/BBB	6.35	6.49	7.59
Foreign Bonds (10-Year)			
Canada	3.71	3.60	2.94
Germany	3.14	3.30	3.14
Japan	1.38	1.34	1.44
United Kingdom	4.03	3.96	3.26
Preferred Stocks			
Utility A	5.99	5.57	6.36
Financial A	6.60	5.83	7.55
Financial Adjustable A	5.49	5.49	5.49



	Recent (4/14/10)	3 Months Ago (1/13/10)	Year Ago (4/15/09)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.45	4.31	4.92
25-Bond Index (Revs)	4.96	4.96	5.74
General Obligation Bonds (GOs)			
1-year Aaa	0.43	0.31	0.43
1-year A	1.18	1.27	0.53
5-year Aaa	1.87	1.68	1.91
5-year A	2.85	2.77	2.13
10-year Aaa	3.30	3.28	3.09
10-year A	4.27	4.20	3.62
25/30-year Aaa	4.45	4.47	4.71
25/30-year A	5.51	5.41	5.75
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.81	4.83	5.70
Electric AA	4.79	4.74	5.80
Housing AA	5.75	5.70	6.10
Hospital AA	5.15	5.04	6.15
Toll Road Aaa	4.78	4.80	5.85

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/7/10	3/24/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1093777	1103634	-9857	1105760	1072867	937535
Borrowed Reserves	84524	88326	-3802	113453	168251	295198
Net Free/Borrowed Reserves	1009253	1015308	-6055	992307	904616	642338

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	3/29/10	3/22/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1719.7	1718.9	0.8	5.7%	7.6%	10.4%
M2 (M1+savings+small time deposits)	8490.8	8502.5	-11.7	-2.0%	0.3%	1.5%

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BELLA VISTA WATER COMPANY, INC. (STAND-ALONE)
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BELLA VISTA WATER COMPANY, INC. (STAND-ALONE)
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WEIGHTED AVERAGE COST OF CAPITAL - CONSOLIDATED

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST RATE	WEIGHTED COST RATE
1	Long-Term Debt	$ 1,697,323	$ -	$ 1,697,323	27.76%	6.27%	1.74%
2	Common Equity	4,416,118	-	4,416,118	72.24%	9.00%	6.50%
3	Total Capitalization	$ 6,113,441	$ -	$ 6,113,441	100.00%		
4	**WEIGHTED AVERAGE COST OF CAPITAL**						**8.24%**

REFERENCES:
COLUMN (A): COMPANY, SCHEDULE D
COLUMN (B): TESTIMONY, WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COLUMN (C) LINES 1 & 2 / LINE 4
COLUMN (E): LINE 1; SCHEDULE WAR-1, PAGE 2, LINE 2; TESTIMONY WAR
COLUMN (F): COLUMN (D) x COLUMN (E), LINE 4; LINE 1 + LINE 2

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WEIGHTED COST OF LONG-TERM DEBT

		END OF TEST YEAR				END OF PROJECTED YEAR			
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
LINE NO.	DESCRIPTION	AMOUNT OUTSTANDING	ANNUAL INTEREST	INTEREST RATE	WEIGHTED COST	AMOUNT OUTSTANDING	ANNUAL INTEREST	INTEREST RATE	WEIGHTED COST
1	WIFA #1	$ 108,754	$ 6,634	6.10%	0.391%	$ 99,968	$ 6,098	6.10%	0.385%
2	WIFA #2	1,545,436	96,744	6.26%	5.700%	1,455,280	91,101	6.26%	5.751%
3	K-MART	6,140	526	8.57%	0.031%	484	41	8.47%	0.003%
4	BVR/RC-3	13,849	1,011	7.30%	0.060%	9,854	719	7.30%	0.045%
5	BVR/RC-4	16,109	1,113	6.91%	0.066%	12,802	885	6.91%	0.056%
6	BVR-CCCII	7,035	504	7.16%	0.030%	5,645	404	7.16%	0.026%
7	TOTALS	$ 1,697,323	$ 106,532		6.28%	$ 1,584,033	$ 99,248		
8	**WEIGHTED COST OF DEBT**								6.27%

REFERENCES:
COLUMN (A) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (B) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (C) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (D) LINES 1 THRU 6: COLUMN (C) / COLUMN (B)
COLUMN (E) LINES 1 THRU 6 : COLUMN (D) LINES 1 THRU 6 / LINE 7
COLUMN (F) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (G) LINES 1 THRU 6: COMPANY APPLICATION SCHEDULE D-2
COLUMN (H) LINES 1 THRU 6: COLUMN (C) / COLUMN (B)
COLUMN (I) LINES 1 THRU 6 : COLUMN (H) LINES 1 THRU 6 / LINE 7, LINE 8: SUM OF LINES 1 THRU 6

BELLA VISTA WATER COMPANY, INC. (STAND-ALONE)
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COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.93%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.90%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**9.92%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.44%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.13%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.83%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**5.95%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.93%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	**9.00%**	TESTIMONY WAR

NORTHERN SUNRISE WATER COMPANY, INC. (STAND-ALONE)
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WEIGHTED AVERAGE COST OF CAPITAL

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)

NORTHERN SUNRISE WATER COMPANY, INC. (STAND-ALONE)
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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 USED.

NORTHERN SUNRISE WATER COMPANY, INC. (STAND-ALONE)
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COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.93%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.90%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**9.92%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.44%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.13%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.83%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**5.95%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.93%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	**9.00%**	TESTIMONY WAR

SOUTHERN SUNRISE WATER COMPANY, INC. (STAND-ALONE)
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SCHEDULE #

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TEST YEAR ENDED MARCH 31, 2009
COST OF CAPITAL SUMMARY

DOCKET NO. W-02465A-09-0411 ET AL.
SUPPLEMENTAL SCHEDULE WAR - 1
PAGE 1 OF 3

WEIGHTED AVERAGE COST OF CAPITAL

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)

SOUTHERN SUNRISE WATER COMPANY, INC. (STAND-ALONE)
TEST YEAR ENDED MARCH 31, 2009
COST OF CAPITAL SUMMARY

DOCKET NO. W-02465A-09-0411 ET AL.
SUPPLEMENTAL SCHEDULE WAR - 1
PAGE 2 OF 3

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 USED.

SOUTHERN SUNRISE WATER COMPANY, INC. (STAND-ALONE)
TEST YEAR ENDED MARCH 31, 2009
COST OF CAPITAL SUMMARY

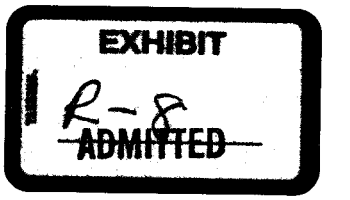
DOCKET NO. W-02465A-09-0411 ET AL.
SUPPLEMENTAL SCHEDULE WAR-1
PAGE 3 OF 3

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.93%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	9.90%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**9.92%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.44%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.13%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.83%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.39%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**5.95%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.93%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	**9.00%**	TESTIMONY WAR

BELLA VISTA WATER COMPANY, INC.

DOCKET NO. W-02465A-09-0411 ET AL.



SURREBUTTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 18, 2010

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

A. Yes, on April 12, 2010, I filed direct testimony with the Commission on RUCO's cost of capital recommendations for BVWC on a consolidated basis. Also, on April 23, 2010, I filed supplemental direct testimony which presented RUCO's recommended weighted average costs of capital for BVWC, NSWC and SSWC on a stand-alone basis.

Q. Please state the purpose of your surrebuttal testimony.

A. The purpose of my surrebuttal testimony is to respond to the rebuttal testimony of BVWC witnesses Greg Sorenson and Thomas J. Bourassa, which was filed on May 25, 2010.

Q. Will RUCO be filing surrebuttal testimony on the rate base and operating income issues in this case?

A. Yes. RUCO analyst Rodney L. Moore and Timothy J. Coley will file surrebuttal testimony on the rate base and operating income issues in this case.

Q. Is RUCO filing surrebuttal testimony on rate consolidation and rate design in this proceeding?

A. Yes. RUCO Director Jodi A. Jerich, Esq. and RUCO analyst Rodney L. Moore will provide surrebuttal testimony on RUCO's rate consolidation policy and RUCO's recommended rate designs respectively.

Q. How is your surrebuttal testimony organized?

A. My surrebuttal testimony contains five parts: the introduction that I have just presented; a summary of RUCO's recommendations on both a stand-alone and a consolidated basis; a comparison of the proposals and recommendations of the Company, ACC Staff and RUCO; a summary of the Company's rebuttal testimony; and my response to the Company's rebuttal positions.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize RUCO's capital structure, cost of debt and weighted average cost of capital recommendations for BVWC, NSWC and SSWC on a stand-alone basis.

A. RUCO is recommending the following capital structure, cost of debt and weighted average cost of capital recommendations for BVWC, NSWC and SSWC on a stand-alone basis:

Bella Vista Water Company

BVWC Capital Structure – For BVWC, I am recommending that the Commission adopt BVWC's proposed capital structure, which is comprised of 27.76 percent long-term debt and 72.24 percent common equity.

BVWC Cost of Debt – For BVWC, I am recommending that the Commission adopt a cost of debt of 6.27 percent, which is the average weighted cost of debt of BVWC's various loans.

BVWC Weighted Average Cost of Capital – Based on the results of my recommended capital structure, I am recommending an 8.24 percent cost of capital for BVWC, which is the weighted cost of my recommended 6.27 percent cost of long-term debt and my recommended 9.00 percent cost of common equity.

Northern and Southern Sunrise Water

NSWC and SSWC Capital Structures – I am recommending that NSWC's and SSWC's proposed capital structures, which are comprised of 100 percent common equity be rejected by the ACC and that my recommended hypothetical capital structures, which are comprised of 60 percent common equity and 40 percent debt, be adopted by the Commission.

NSWC and SSWC Costs of Debt – For both NSWC and SSWC, 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.

NSWC and SSWC Weighted Average Costs of Capital – Based on the results of my recommended hypothetical capital structures, I am recommending a 7.90 percent cost of capital for both NSWC and SSWC, which is the weighted cost of my recommended costs of common equity and hypothetical debt.

Q. Please summarize RUCO's capital structure, cost of debt and weighted average cost of capital recommendations for BVWC, NSWC and SSWC on a consolidated basis.

A. RUCO is recommending the following capital structure, cost of debt and weighted average cost of capital recommendations for BVWC, NSWC and SSWC on a consolidated basis:

Capital Structure – On a consolidated basis, I am recommending that the Commission adopt BVWC's proposed capital structure, which is comprised of 21.08 percent long-term debt and 78.92 percent common equity.

Cost of Debt – On a consolidated basis, I am recommending that the Commission adopt a cost of debt of 6.27 percent, which is the average weighted cost of debt of BVWC's various loans.

Weighted Average Cost of Capital – On a consolidated basis, I am recommending an 8.42 percent cost of capital for BVWC, which is the weighted cost of my recommended 6.27 percent cost of long-term debt and my recommended 9.00 percent cost of common equity.

COMPARISON OF PROPOSALS AND RECOMMENDATIONS

Capital Structure

Q. Please compare the Company-proposed capital structure with RUCO and ACC Staff's recommended capital structures on a consolidated basis.

A. A comparison of the Company-proposed and ACC Staff's, and RUCO's recommended capital structures, on a consolidated basis, are as follows:

	Debt	Equity
Company	22.6%	77.4%
ACC Staff	32.2%	67.8%
RUCO	21.08%	78.92%

Cost of Debt

Q. Please compare the Company-proposed cost of debt with RUCO and ACC Staff's recommended costs of debt on a consolidated basis.

A. The Company-proposed cost of debt and ACC Staff's and RUCO's recommended cost of debt can be seen bellow:

Company	6.28%
ACC Staff	6.30%
RUCO	6.27%

Cost of Equity

Q. Please compare the Company-proposed cost of equity with RUCO's and ACC Staff's recommended costs of equity.

A. The Company-proposed cost of equity and ACC Staff's and RUCO's recommended cost of equity, are as follows:

Company	10.90%
ACC Staff	9.80%
RUCO	9.00%

Weighted Average Cost of Capital

Q. Please compare the Company-proposed weighted average cost of capital with RUCO's and ACC Staff's recommended weighted average cost of capital.

A. The weighted average cost of capital recommendations of the Company, ACC Staff and RUCO are as follows:

Company	9.85%
ACC Staff	8.60%
RUCO	8.42%

As can be seen above, the Company-proposed weighted average cost of capital of 9.85 percent is 43 basis points higher than my recommended 8.42 percent weighted average cost of capital. ACC Staff's recommended weighted average cost of capital is 25 basis points lower than the Company's and 18 basis points higher than my recommendation.

SUMMARY OF REBUTTAL TESTIMONY

Q. Have you reviewed the Company's rebuttal testimony?

A. Yes. I have reviewed the rebuttal testimony of Company witnesses Greg Sorensen and Thomas J. Bourassa, filed on May 25, 2010, which address the cost of capital issues in this case.

Q. Please summarize the Company's rebuttal testimony.

A. Mr. Sorensen takes issue with my recommended cost of debt which I have used in my recommended consolidated capital structures for NSWC and SSWC on a stand-alone basis.

Mr. Bourassa is critical of the utilities used in my proxy groups and the CAPM analysis that I conducted in order to arrive at my recommended cost of common equity in this case. Mr. Bourassa also takes issue with my internal sustainable growth estimates used in my DCF analysis.

RESPONSE TO REBUTTAL TESTIMONY

Q. Have you had an opportunity to review updated data on the sample water and natural gas companies used in your cost of capital analysis?

A. Yes I have reviewed updated Value Line data that has been published since my direct testimony was filed and have concluded that there is no need to revise my cost of common equity estimate.

Q. Have you revised your recommended cost of common equity based on your review of the Company's rebuttal testimony?

A. No.

...

Q. Has Mr. Bourassa made any changes to his recommended cost of equity capital?

A. Yes. Mr. Bourassa has decreased his original recommended cost of common equity from 12.50 percent to the 10.90 percent cost of common equity displayed in the prior section of my testimony.

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

A. Yes. On April 28, 2010, the Federal Reserve decided not to increase or decrease the federal funds rate and kept it between zero and 0.25 percent. According to an article[1] that appeared in The Wall Street Journal on Thursday, April 29, 2010, the Federal Reserve upgraded its assessment of the economy modestly and maintained its commitment to keep interest rates near zero to support the recovery. A second Wall Street Journal article[2] published on June 7, 2010, speculated that current economic conditions, which include the recent financial turmoil in Europe, meager job growth here in the U.S. and low inflation, indicate that the Federal Reserve may not take any action on interest rates over the next year. The article went on to state that the "futures markets see less than a 50-50 chance that the Fed will push the federal funds rate up to 0.5% by December from its current level just below 0.25%." This is being viewed as a major shift since early May when an increase in the federal funds rate

[1] Reddy, Sudeep, "Fed Sees Gains But Signals Rates Will Remain Low," The Wall Street Journal, April 29, 2010.

[2] Hilsenrath, Jon, "Easy Money to Stick Around," The Wall Street Journal, June 7, 2010.

was being viewed as "almost a sure thing." The next FOMC meeting is scheduled for June 22, 2010.

Cost of Debt

Q. What position does Mr. Sorensen take in his rebuttal testimony regarding your recommended hypothetical cost of debt?

A. Mr. Sorensen takes the position that third party lenders would not loan money to the former McLain systems (i.e. NSWC and SSWC) on the same terms that lenders offered to BVWC and that local vendors were demanding payments in cash when Liberty Water acquired NSWC and SSWC.

Q. What is your response to Mr. Sorensen's position?

A. I don't dispute Mr. Sorensen's claim regarding local vendors, however I believe that the situation he has described may have more to do with the former operator of the McLain systems as opposed to Liberty Water. In any case I would view this to be more of an isolated local incident.

Q. Do you have any other comments that you would like to make on this subject?

A. Yes. I find it interesting that this Company, not to mention all of the other Liberty Water subsidiaries that have cases pending before the Commission, has spent endless amounts of time and money defending its

right to recover allocated costs charged by its Parent. In seeking to recover these costs, the Company cites all of the benefits that its Parent provides including the ability to access capital. Yet, when it comes to the subject of debt financing, the Company acts as if its Parent, a large publicly traded entity with access to the capital markets with the ability to obtain debt financing for its subsidiaries, doesn't even exist. I also find it interesting that BVWC's 6.27 percent cost of debt, which was obtained prior to its acquisition by Liberty Water when it was a stand-alone entity, is almost identical to my recommended 6.26 cost of debt (derived from a sample of water providers) used in my hypothetical capital structure for NSWC and SSWC on a stand-alone basis. I'm also puzzled by Mr. Sorensen's position given the fact that the Company's cost of capital consultant is recommending a 6.28 percent cost of debt on a consolidated basis which is only one to two basis points higher than my recommendations.

Q. What is the current yield on Baa/BBB-rated utility bonds?

A. As of June 9, 2010, the yield on Baa/BBB-rated utility bonds is 5.87 percent (Attachment A). This is 40 basis points lower than BVWC's 6.27 percent cost of debt.

...

Q. Have you made any changes to your recommended costs of debt as a result of Mr. Sorensen's testimony?

A. No.

Sample Utilities

Q. Do you still believe that your use of a sample of natural gas LDC's is appropriate to estimate a cost of equity for a water utility despite Mr. Bourassa's arguments?

A. Yes.

Q. Please explain why you believe it is appropriate to use a sample group of natural gas LDC's to estimate the cost of equity capital in a water utility rate case proceeding.

A. For the most part, natural gas LDC's have very similar operating and distribution characteristics with water companies such as BVWC, NSWC and SSWC and are therefore a good proxy for water and wastewater utility cost of capital studies. Their inclusion also provides a larger sample to obtain an estimate from.

Q. Have other analysts used natural gas LDC's as proxies in water utility rate case proceedings before the ACC?

A. Yes, in the Arizona-American Water Company (Arizona-American) rate case that is now pending before the Commission, the cost of capital

witness for Arizona-American also relied on a sample group of natural gas LDC's.

Q. Do you believe that an upward adjustment is needed for your recommended cost of equity given your use of a sample group of LDC's that have a lower average beta than the one calculated for your sample group of water utilities?

A. No. Given the current state of the economy I believe that my recommended 9.00 percent cost of equity is reasonable.

Q. Please explain why you believe that your recommended 9.00 percent cost of equity is reasonable given the current state of the U.S. economy.

A. When the downturn in the economy occurred in late 2008, investors reacted to the situation by pulling their funds out of the equity markets and putting them into U.S. Treasury instruments which were, and still are, yielding next to nothing, in order to avoid any further loss of capital (Attachment A). This situation has been referred to as a "flight to quality." Although fears have subsided over the last year and investors are entering the equity markets again, as evidenced by the upturn in the U.S. stock market, both water and natural gas utilities are still, for the most part, viewed by Value Line's analysts as shelters during times of economic uncertainty. This is mainly because of their healthy dividend yields which range from averages of 2.4 percent to 4.6 percent, for the water and

natural gas industry respectively, compared with a median average of 2.1 percent for all the dividend paying stocks followed by Value Line. Given the uncertainty of the economic recovery that is still under way, I believe that both water and natural gas companies will still hold an attraction for investors as a relatively safe investment in the event that another downturn occurs. For these reasons I believe my recommended 9.00 percent cost of equity is reasonable.

Q. Are there other reasons you can cite as to why you think that a higher return is not needed to attract investors?

A. Yes. One has to take into consideration that the investment community at large is well aware of the fact that regulated utilities, such as the subsidiaries of Liberty Water, are indeed different from non-regulated entities in terms of how they recover their costs. This information is taken into account when institutions and individual investors make their decisions on where to place their funds. The best example of this can be seen in an MSN Money/CNBC article[3] authored by Jon D. Markman, a weekly columnist for CNBC (Attachment B). In his article, Mr. Markman pitched his suggestions for investing in what some believe to be a coming global water shortage. In regard to domestic utilities, Markman had this to say:

[3] Markman, Jon D, "Invest in the Coming Global Water Shortage," MSN.com, January 12, 2005, http://moneycentral.msn.com/content/P102152.asp.

> "Virtually all of the U.S. water utility stocks are regulated by states and counties, which makes them pretty dull. Governmental entities typically give utilities a monopoly in a geographic region, then set their profit margin a smidge above costs. Just about the only distinguishing factor among them are the growth rates of their regions and their ability to efficiently manage their underground pipe and pumping infrastructure."

Q. What is your response to Mr. Bourassa's statements, on page 26 of his rebuttal testimony, that BVWC's cost of equity should be higher given the recent Commission Decisions that authorized equity returns of 10.00 percent and 9.50 percent for Southwest Gas Corporation and UNS Gas, Inc.?

A. While it is true that the Commission awarded the aforementioned returns on common equity to Southwest Gas Corporation and UNS Gas, Inc., I would point out that both of those companies had capital structures that contained more debt, 52.0 percent and 50.1 percent respectively, than the roughly 28.0 percent contained in BVWC's test year capital structure, and the total absence of debt in NSWC's and SSWC's capital structures. I would also point out that the Commission has been awarding lower returns on equity over the past six months.

CAPM Analysis

Q. Please respond to Mr. Bourassa's criticism of your reliance on geometric means in the CAPM model.

A. As I stated in my direct testimony there is an on-going debate over which is the better average to rely on. However, it is important to recognize that

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

The best argument in favor of the geometric mean is that it provides a truer picture of the effects of compounding on the value of an investment when return variability exists. This is particularly relevant in the case of the return on the stock market, which has had its share of ups and downs over the 1926 to 2008 observation period used in my CAPM analysis.

Q. Can you provide an example to illustrate the differences between the two averages?

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

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

(20.0% + -20.0%) ÷ 2 =

(0.0%) ÷ 2 = 0.0%

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

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

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

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

$$(0.9798) - 1 =$$

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

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

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

...

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

A. Yes. Two specific cases that come to mind involved UNS Gas Inc. ("UNSG"). Decision No. 70011, dated November 27, 2007 stated the following:

> "We agree with the Staff and RUCO witnesses that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

The Commission later reaffirmed this position in the most recent UNSG case. Decision No. 71623, dated April 14, 2010 stated the following:

> "We also continue to believe, consistent with our findings in several prior cases, that it is appropriate to consider the geometric returns in calculating a comparable company CAPM because to do otherwise would fail to give recognition to the fact that many investors have access to such information for purposes of making investment decisions."

In both UNSG cases, the ACC Staff witness was Mr. David C. Parcell, who, as I do, consistently relies on both arithmetic and geometric means in our CAPM analyses.

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

A. Yes. In the third edition of their book, Valuation: Measuring and Managing the Value of Companies, authors Tom Copeland, Tim Koller and Jack Murrin ("CKM") make the point that, while the arithmetic mean has been

regarded as being more forward-looking in determining market risk premiums, a true market risk premium may lie somewhere between the arithmetic and geometric averages published in Morningstar's SBBI yearbook.

Q. Please explain.

A. In order to believe that the results produced by the arithmetic mean are appropriate, you have to believe that each return possibility included in the calculation is an independent draw. However research conducted by CKM demonstrates that year-to-year returns are not independent and are actually auto correlated (i.e. a relationship that exists between two or more returns, such that when one return changes, the other, or others, also change), meaning that the arithmetic mean has less credence. CKM also explains two other factors that would make the Morningstar arithmetic mean too high. The first factor deals with the holding period. The arithmetic mean depends on the length of the holding period and there is no "law" that says that holding periods of one year are the "correct" measure. When longer periods (e.g. 2 years, 3 years etc.) are observed, the arithmetic mean drops about 100 basis points. The second factor deals with a situation known as survivor bias. According to CKM, this is a well-documented problem with the Morningstar historical return series in that it only measures the returns of successful firms. That is, those firms that are listed on stock exchanges. The Morningstar historical return

series does not measure the failures, of which there are many. Therefore, the return expectations in the future are likely to be lower than the Morningstar historical averages. After conducting their analysis, CKM conclude that 4.0 percent to 5.5 percent is a reasonable forward-looking market risk premium[4]. Adding my 2.36 percent risk free yield on a 5-year Treasury instrument to these two estimates indicate a cost of equity of 6.36 percent to 7.86 percent which is lower than my recommended cost of equity of 9.00 percent. Given the fact that utilities generally exhibit less risk than industrials, a return in the low end of this range could be considered reasonable.

Q. Is Mr. Bourassa correct in his assertion that you did not use the appropriate inputs to calculate a market risk premium in your CAPM model?

A. No. Despite Mr. Bourassa's assertion, I have used an appropriate Treasury instrument to calculate the risk premium in my CAPM model. The risk premium that I have calculated has also been calculated in the same manner by both ACC Staff and other cost of capital witnesses whose cost of capital recommendations have been adopted by the Commission. Mr. Bourassa's assertion that I should not have used total returns in the market risk premium component of the CAPM is unfounded. While it is true that investors are typically attracted to utility stocks for their

[4] In the 4th edition of Valuation, the authors state on page 306 of the text that 4.5 percent to 5.5 percent is an appropriate range (Attachment C).

income needs, it is simply not rational to think that they would not expect some capital gains as well. The use of income returns totally ignores the fact that bond prices do indeed fluctuate as a result of interest rate changes – as do interest sensitive utility stock prices. For this reason I believe Mr. Bourassa's reliance on income returns is unrealistic at best.

Q. Please address Mr. Bourassa's criticism of your use of a 5-year Treasury yields and intermediate-term securities in your CAPM analysis.

A. Mr. Bourassa believes that long-term treasury instruments, with higher yields, should be used in the CAPM. However, utilities do not apply for rate relief every thirty years and regulators do not set rates for thirty-year periods. The simple fact is that utilities generally apply for rate relief every three to five years and utility investors are aware of this fact. For this reason I believe the use of long-term treasury yields overstate the cost of equity capital.

Q. What is the current yield on a 5-year Treasury instrument?

A. The current yield on a 5-year Treasury instrument is 1.97 percent (Attachment A) which is 39 basis points lower than the 2.36 percent yield that I used in my CAPM analysis.

...

Q. Please comment on Mr. Bourassa's argument that you have ignored the current risk premium?

A. The fact that we are now experiencing an improving economy and a resurgence in the equity markets pretty much makes this argument passé. As I have argued in prior cases, the historical market risk premium that I have relied on takes into account a wide range of economic conditions from 1926 through 2008. In short, the economy is slowly getting back to normal and there is no good reason to believe that the excessive market risk premium of 11.2 percent that Mr. Bourassa is proposing is realistic for setting rates in this case. As I stated earlier, the analysis conducted by CKM concluded that 4.0 percent to 5.5 percent is a reasonable forward-looking market risk premium.

Q. Can you name any other sources that support CKM's conclusion that 4.0 percent to 5.5 percent is a reasonable market risk premium on a forward-looking basis?

A. Yes. During the 39th annual Financial Forum of the Society of Utility and Regulatory Financial Analysts, which was held at Georgetown University in Washington D.C. on April 19 and 20, 2007, I had the opportunity to hear the views of Aswarth Damodaran, Ph. D. and Felicia C. Marston, Ph. D., professors of finance from New York University and the University of Virginia respectively, who have conducted empirical research on this subject. Dr. Damodaran and Dr. Marston supported CKM's 4.0 to 5.5

percent estimates during a panel discussion that provided both professors with the opportunity to explain their research on the equity risk premium and to answer questions from other financial analysts in attendance. Each of the panelists[5] stated that they believed that a reasonable market risk premium fell between 4.0 percent and 5.0 percent when asked to provide estimates based on their research.

Q. If market risk premiums of 4.0 percent to 5.0 percent were used in your CAPM model what would the results be?

A. Using market risk premiums (r_m - r_f) of 4.0 percent to 5.0 percent in my CAPM model, using a proxy of water companies, produces the following expected returns (k):

Water Company Sample using 4.0 percent

$$k = r_f + [ß (r_m - r_f)]$$

$$k = 2.36\% + [0.73 (4.0\%)]$$

$$k = 5.28\%$$

Water Company Sample using 5.0 percent

$$k = r_f + [ß (r_m - r_f)]$$

$$k = 2.36\% + [0.73 (5.0\%)]$$

$$k = 6.01\%$$

[5] Other analysts taking part in the panel discussion included Stephen G. Hill, CRRA, Principal, Hill Associates and moderator Farris M. Maddox, Principal Financial Analyst, Virginia State Corporation Commission.

As can be seen above, my CAPM model, using a water company sample average beta (ß) of 0.73 and the yield on a 5-year Treasury instrument of 2.36 percent for the risk free rate of return (r_f), produces an expected return (k) of 5.28 percent to 6.01 percent. My LDC sample, using an average beta of 0.66, produces expected returns of 5.00 percent to 5.66 percent. All of which makes my recommended 9.00 percent cost of common equity appear to be reasonable.

Q. Do you have any data that supports a 4.00 percent to 5.0 percent equity risk premium during the market crises which unfolded in September of 2008?

A. Yes. In September 2008 Dr. Damodaran, who I noted earlier in my testimony, presented a paper titled Equity Risk Premium (ERP): Determinants, Estimation and Implications, which contained an October update that presented data on the swings in implied equity risk premium that occurred between September 12, 2008 and October 16, 2008. During that time frame, implied equity risk premiums ranged from 4.20 percent to 6.39 percent. The 5.30 percent mean average of that range is only 15 basis points higher than the 5.15 percent average of my market risk premium using both geometric and arithmetic means.

...

Q. Please respond to Mr. Bourasssa's argument that your overall CAPM results are below the current yields on Baa/BBB debt instruments.

A. I am not recommending that the Commission adopt my CAPM results, but I am not recommending that the Commission ignore my CAPM results either. What I am recommending is a cost of common equity of 9.00 percent which is 313 to 357 basis points over the most recent yields of 5.87 percent to 5.43 percent for Baa/BBB-rated and A-rated utility bonds respectively (Attachment A). The results of my CAPM analyses (using both arithmetic and geometric means) are simply reflecting the current environment of low interest rates which cannot be ignored. From the perspective that public utilities have traditionally been viewed as safe investments, and all things being equal, it is not reasonable to believe that their costs of equity capital should be at the 10.90 percent level advocated by Mr. Bourassa.

Q. Isn't it also true that common shareholders bear a higher risk than bond holders and expect a higher return than the yields of utility debt instruments?

A. Yes. I do not disagree on this point. However, the question is how much more of a risk premium is merited for a low risk regulated monopoly such as the Liberty Water subsidiaries included in this filing, particularly at a time when interest rates are still at historic lows.

Q. Do you agree with Mr. Bourassa's characterization of BVWC, NSWC, and SSWC as small water and sewer companies?

A. No. As I stated in my direct testimony each of the three water systems are subsidiaries of Algonquin Power & Utilities Corp., a large publicly traded firm that has direct access to the capital markets. As I explained earlier in my testimony, the Company cannot, on the one hand, say that the allocated overhead costs from Algonquin Power & Utilities Corp. benefits its ratepayers and then, on the other hand, act as if that large publicly traded parent doesn't even exist and make an argument that BVWC, NSWC and SSWC are "small" utilities trying to survive on their own.

DCF Analysis

Q. Please comment on Mr. Bourassa's position that the results of your DCF analysis should be rejected by the Commission because of the method that you used to determine the internal growth rates in your DCF model.

A. The method that I have used to determine internal sustainable growth in the DCF model is identical to the DCF analysis performed by ACC Staff witness Stephen Hill, whose cost of equity recommendation was adopted by the Commission in a prior Southwest Gas proceeding that I cited in my direct testimony. The method is also consistent with the DCF analysis that I performed in a prior Gold Canyon Sewer Company proceeding in which the Commission adopted my recommended cost of capital. I am not aware of any proceeding before the ACC in which Mr. Bourassa's

recommended costs of capital or the methods by which he arrived at those recommendations were adopted by the Commission.

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

A. No, it does not.

Q. Does your silence on any of the issues, matters or findings addressed in the rebuttal testimony of any of the witnesses for BVWC, NSWC or SSWC constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

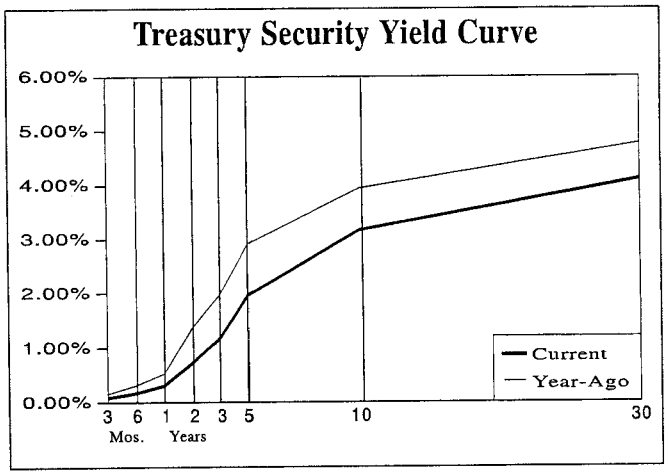
Q. Does this conclude your surrebuttal testimony on BVWC, NSWC and SSWC?

A. Yes, it does.

ATTACHMENT A

Selected Yields

	Recent (6/09/10)	3 Months Ago (3/10/10)	Year Ago (6/10/09)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.50
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25
Prime Rate	3.25	3.25	3.25
30-day CP (A1/P1)	0.37	0.14	0.34
3-month LIBOR	0.54	0.26	0.64
Bank CDs			
6-month	0.41	0.25	0.66
1-year	0.70	0.44	0.87
5-year	2.06	1.99	1.92
U.S. Treasury Securities			
3-month	0.09	0.15	0.17
6-month	0.17	0.20	0.31
1-year	0.31	0.37	0.53
5-year	1.97	2.38	2.92
10-year	3.17	3.72	3.95
10-year (inflation-protected)	1.24	1.47	1.86
30-year	4.11	4.69	4.76
30-year Zero	4.34	4.97	4.84



	Recent (6/09/10)	3 Months Ago (3/10/10)	Year Ago (6/10/09)
Mortgage-Backed Securities			
GNMA 6.5%	1.30	2.09	4.26
FHLMC 6.5% (Gold)	0.99	1.67	3.07
FNMA 6.5%	1.02	2.43	2.91
FNMA ARM	2.97	2.93	2.53
Corporate Bonds			
Financial (10-year) A	4.74	5.22	6.82
Industrial (25/30-year) A	5.30	5.81	6.50
Utility (25/30-year) A	5.43	5.86	6.28
Utility (25/30-year) Baa/BBB	5.87	6.35	7.76
Foreign Bonds (10-Year)			
Canada	3.35	3.54	3.64
Germany	2.57	3.15	3.69
Japan	1.21	1.31	1.55
United Kingdom	3.53	4.08	3.92
Preferred Stocks			
Utility A	6.00	5.54	7.62
Financial A	6.80	6.28	8.63
Financial Adjustable A	5.54	5.46	5.46
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.28	4.34	4.71
25-Bond Index (Revs)	4.81	4.93	5.63
General Obligation Bonds (GOs)			
1-year Aaa	0.31	0.28	0.40
1-year A	1.15	1.03	0.90
5-year Aaa	1.67	1.45	2.14
5-year A	2.56	2.45	2.57
10-year Aaa	3.02	3.01	3.21
10-year A	4.05	4.02	3.57
25/30-year Aaa	4.41	4.44	4.72
25/30-year A	5.51	5.48	5.16
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.74	4.76	5.85
Electric AA	4.78	4.75	5.95
Housing AA	5.65	5.54	6.25
Hospital AA	5.01	5.06	6.20
Toll Road Aaa	4.76	4.81	6.00

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	6/2/10	5/19/10	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1047859	1055070	-7211	1075423	1084060	968858
Borrowed Reserves	73336	76709	-3373	83101	117375	224220
Net Free/Borrowed Reserves	974523	978361	-3838	992321	966685	744638

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	5/24/10	5/17/10	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	1699.7	1683.6	16.1	-5.0%	1.7%	6.5%
M2 (M1+savings+small time deposits)	8573.8	8573.1	0.7	0.6%	1.1%	1.7%

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ATTACHMENT B

Jon Markman

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Posted 1/12/2005

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SuperModels

Invest in the coming global water shortage

Fresh water's getting scarce, and it has no substitutes. For investors in companies that can supply our increasingly thirsty planet, that spells opportunity.

By Jon D. Markman

Ten years ago next Monday, a massive earthquake rolled under the Japanese city of Kobe at dawn, toppling 140,000 buildings, causing 300 major fires, killing more than 5,000 people and leaving 300,000 homeless.

To help cover the story for the L.A. Times, I left my wife to care for our 10-day-old daughter and 2-year-old son and flew into the city with a small team of Los Angeles-based trauma doctors and nurses. We found a surreal, smoking ruin of a city with roads twisted like coils of rope, high-rises tilted at Dr. Seuss angles and thousands of middle-class families jammed into dingy, ice-cold rooms in the few public buildings left standing.

Just as in the tsunami zone of South Asia this month, the immediate health danger, besides a possible outbreak of disease, was a lack of fresh water. More than 75% of the city's water supply was destroyed when underground pipes fractured. As much as they desired pallets of drugs, food, blankets and tents sent from throughout Japan and abroad, the Kobe survivors coveted -- and needed -- clean, bottled water for cooking, drinking and bathing.

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Both incidents are a stark reminder that water is our most precious resource. Because it is seemingly ubiquitous in the United States, it is taken for granted. Massive snowstorms in California this month have loaded up the snowpack that provides water there, and rains in the Southeast are filling reservoirs in that part of the country.

The rest of the world, however, is not so fortunate.

Not making any more water

There is no more fresh water on Earth today than there was a million years ago. Yet today, 6 billion people share it. Since 1950, the world population has doubled, but water use has tripled, notes John Dickerson, an analyst and fund manager based in San Diego. Unlike petroleum, he adds, no technological innovation can ever replace water.

China, which is undergoing a vast rural-to-urban population migration, is emblematic of the places where water has become scarce. It has about as much

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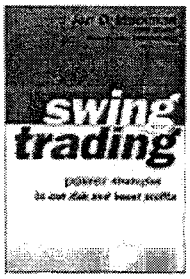

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More...

water as Canada but 100 times more people. Per-capita water reserves are only about a fourth the global average, according to experts. Of its 669 cities, 440 regularly suffer moderate to critical water shortages.

Although not widely appreciated, water has been recognized by conservative investors as an investment opportunity -- and it has rewarded them. Over the past 10 years, the Media General water utilities index is up 133%, double the return of the **Dow Jones Utilities Index** ($UTIL). Over the past five years, water utilities are up 32% -- clobbering the flat returns of both the Dow Jones Utilities and the **Dow Industrials** ($INDU). One of water's key long-term value drivers as an investment, according to Dickerson: Demand is not affected by inflation, recession, interest rates or changing tastes.

Virtually all of the U.S. water utility stocks are regulated by states and counties, which makes them pretty dull. Governmental entities typically give utilities a monopoly in a geographic region, then set their profit margin a smidge above costs. Just about the only distinguishing factor among them are the growth rates of their regions and their ability to efficiently manage their underground pipe and pumping infrastructure. Among the best are **Aqua America** (WTR, news, msgs) of Philadelphia, **Southwest Water** (SWWC, news, msgs) of Los Angeles; **California Water Service Group** (CWT, news, msgs), based in San Jose, Calif.; and **American States Water** (AWR, news, msgs) of San Dimas, Calif.

In a moment, I'll offer a couple of potentially more impactful ways to invest in water, but first let's look a little more broadly at world demand.

Aquifers in India are being sucked dry

The tsunami has focused attention on water demand in South Asia -- and it's a good thing, as it was already reaching critical status in rural areas. Several decades ago, farmers in the Indian state of Gujarat used oxen to haul water in buckets from a few feet below the surface. Now they pump it from 1,000 feet below the surface. That may sound good, but they have been drawing water from the earth to feed a mushrooming population at such a terrific rate that ancient aquifers have been sucked dry -- turning once-fertile fields slowly into sand.

According to New Scientist magazine, farmers using crude oilfield technology in India have drilled 21 million "tube wells" into the strata beneath the fields, and every year millions more wells throughout the region -- all the way to Vietnam -- are being dug to service water-needy crops like rice and sugar cane. The magazine quoted research from the annual Stockholm Water Symposium that the pumps that transformed Indian farming are drawing 200 cubic kilometers of water to the surface each year, while only a fraction is replaced by monsoon

rains. At this rate, the research suggested, groundwater supplies in some areas will be exhausted in five to 10 years, and millions of Indians will see their farmland turned to desert.

In China, the magazine reported, 30 cubic kilometers more water is being pumped to the surface each year than is replaced by rain -- one of the reasons that the country has become dependent on grain imports from the West. This is not just an issue for agriculture. Earlier this year, the Indian state of Kerala ordered the **PepsiCo** (PEP, news, msgs) and **Coca-Cola** (KO, news, msgs) bottling plants closed due to water shortages, costing the companies millions of dollars.

In this country, shareholder activists already are lobbying companies to share water-dependency concerns worldwide with their stakeholders in their financial statements.

Water, water everywhere, but . . .

The central problem is that less than 2% of the world's ample store of water is fresh. And that amount is bombarded by industrial pollution, disease and cyclical shifts in rain patterns. Its increasing scarcity has impelled private companies and countries to attempt to lock up rights to key sources. In an article last month, the Christian Science Monitor suggested that the next decade may see a cartel of water-exporting countries rivaling the Organization of Petroleum Exporting Countries for dominance in the world economy.

"Water is blue gold; it's terribly precious," Maude Barlow, chair of the Council of Canadians, told the Monitor. "Not too far in the future, we're going to see a move to surround and commodify the world's fresh water. Just as they've divvied up the world's oil, in the coming century, there's going to be a grab."

Besides the domestic water utilities listed above -- and similarly plodding foreign utilities such as **United Utilities** (UU, news, msgs) of the United Kingdom, which sports a 6.9% dividend yield, and **Suez** (SZE, news, msgs) of France -- investors interested in the sector can consider a number of variant plays. None are extremely exciting, but my guess is that, over the next few years, some more interesting purification technologies will emerge, along with, perhaps, a vibrant attempt at worldwide industry consolidation.

One current idea is Tennessee-based copper pipe and valve maker **Mueller Industries** (MLI, news, msgs), a $1 billion business with a trailing price/earnings multiple of 15 that is still not expensive despite a 47% run-up in the past year. Its leading outside investor is **Berkshire Hathaway** (BRK.A, news, msgs), the

investment vehicle of legendary investor Warren Buffett.

Another is flow-control products maker **Watts Water Technologies** (WTS, news, msgs), which is a little richer at a $975 million market cap and a trailing P/E multiple of 19, but is still owned by several leading value managers, including Mario Gabelli.

And possibly the most interesting is **Consolidated Water** (CWCO, news, msgs), a $160 million company based in the Cayman Islands that specializes in developing and operating ocean-water desalinization plants and water-distribution systems in areas where natural supplies of drinking water are scarce, such as the Caribbean and South America. It currently supplies water to Belize, Barbados, the British Virgin Islands and the Bahamas, and it has expansion plans. It is the most expensive, but it may also have the greatest growth prospects. Of all of these, it is up the most over the past five years, a relatively steady 355%.

Of course, there is one other benefit to water investing: When these companies say they're going to do a dilutive deal, it's not something to worry about.

Fine Print

Dickerson runs a hedge fund in San Diego strictly focused on water investing, the Summit Water Equity Fund. . . To learn more about Southwest Water, click here. . . . To learn more about California Water Service Group, which runs systems in New Mexico, Hawaii and Washington State, as well as California, click here. . . . To learn more about American States Water, click here. . . To learn more about Mueller, click here, and, for Consolidated Water, click here. . . . Seems like talk is cheap. Since mid-December, the value of the company radio personality Howard Stern is leaving, **Viacom** (VIA.B, news, msgs), has risen 9% while the value of the company he's headed to, **Sirius Satellite Radio** (SIRI, news, msgs), is down 13.5%. . . . For background on the Kobe earthquake, approaching its 10th anniversary, click here and here.

Jon D. Markman is publisher of StockTactics Advisor, an independent weekly investment newsletter, as well as senior strategist and portfolio manager at Pinnacle Investment Advisors. While he cannot provide personalized investment advice or recommendations, he welcomes column critiques and comments at jon.markman@gmail.com; put COMMENT in the subject line. At the time of publication he held positions in the following stocks mentioned in this column: Coca-Cola.

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ATTACHMENT C

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VALUATION

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10

Estimating the Cost of Capital

To value a company using enterprise DCF, we discount free cash flow by the weighted average cost of capital (WACC). The weighted average cost of capital represents the opportunity cost that investors face for investing their funds in one particular business instead of others with similar risk.

The most important principle underlying successful implementation of the cost of capital is consistency between the components of WACC and free cash flow. Since free cash flow is the cash flow available to all financial investors (debt, equity, and hybrid securities), the company's WACC must include the required return for each investor. In addition, the duration and risk of the financial securities used to estimate the WACC must match that of the free cash flow being discounted. To assure consistency, the cost of capital must meet several criteria:

- It must include the opportunity costs from *all* sources of capital—debt, equity, and so on—since free cash flow is available to all investors, who expect compensation for the risks they take.
- It must weight each security's required return by its target market-based weight, not by its historical book value.
- It must be computed after corporate taxes (since free cash flow is calculated in after-tax terms). Any financing-related tax shields not included in free cash flow must be incorporated into the cost of capital or valued separately (as done in the adjusted present value).
- It must be denominated in the same currency as free cash flow.
- It must be denominated in nominal terms when cash flows are stated in nominal terms.

For most companies, discounting free cash flow at the WACC is a simple, accurate, and robust method of corporate valuation. If, however, the

since no single model for estimating the market risk premium has gained universal acceptance, we present the results of various models.

Methods to estimate the market risk premium fall in three general categories:

1. Estimating the future risk premium by measuring and extrapolating historical excess returns.
2. Using regression analysis to link current market variables, such as the aggregate dividend-to-price ratio, to project the expected market risk premium.
3. Using DCF valuation, along with estimates of return on investment and growth, to reverse engineer the market's cost of capital.

None of today's models precisely estimate the market risk premium. Still, based on evidence from each of these models, we believe the market risk premium as of year-end 2003 was just under 5 percent.

Historical market risk premium Investors, being risk-averse, demand a premium for holding stocks rather than bonds. If the level of risk aversion hasn't changed over the last 75 years, then historical excess returns are a reasonable proxy for future premiums (assuming measurement issues, such as survivorship bias, aren't overly problematic). To best measure the risk premium using historical data, follow these guidelines:

- Calculate the premium relative to long-term government bonds.
- Use the longest period possible.
- Use an arithmetic average of longer-dated intervals (such as five years).
- Adjust the result for econometric issues, such as survivorship bias.

Use long-term government bonds When calculating the market risk premium, compare historical market returns with the return on 10-year government bonds. As discussed in the previous section, long-term government bonds better match the duration of a company's cash flows than do short-term bonds.

Use the longest period possible When using historical observations to predict future results, the issue is what length of history to examine. If the market risk premium is stable, a longer history will reduce estimation error. Alternatively, if the premium changes and estimation error is small, a shorter period is better. To determine the appropriate historical period, we consider any trends in the market risk premium compared with the noise associated with short-term estimates.

To test for the presence of a long-term trend, we regress the U.S. market risk premium versus time. Over the last 100 years, no statistically significant trend is observable.[7] Based on regression results, the average excess return has fallen by 3.3 basis points a year, but this result is well below its standard error (leading to a low *t*-statistic). In addition, premiums calculated over subperiods, even as long as 10 years, are extremely noisy. For instance, U.S. stocks outperformed bonds by 18 percent in the 1950s but offered no premium in the 1970s. Given the lack of any discernible trend and the significant volatility of shorter periods, you should use the longest time series possible.

Use arithmetic average of longer-dated intervals When reporting market risk premiums, most data providers report an annual number, such as 6.2 percent per year. But how do they convert a century of data into an annual number? And is an annualized number even important?

Annual returns can be calculated using either an arithmetic average or a geometric average. An arithmetic (simple) average sums each year's observed premium and divides by the number of observations:

$$\text{Arithmetic Average} = \frac{1}{T}\sum_{t=1}^{T}\frac{1+R_m(t)}{1+r_f(t)} - 1$$

A geometric average compounds each year's excess return and takes the root of the resulting product:

$$\text{Geometric Average} = \left(\prod_{t=1}^{T}\frac{1+R_m(t)}{1+r_f(t)}\right)^{1/T} - 1$$

The choice of averaging methodology will affect the results. For instance, between 1903 and 2002, U.S. stocks outperformed long-term government bonds by 6.2 percent per year when averaged arithmetically. Using a geometric average, the number drops to 4.4 percent. This difference is not random; arithmetic averages always exceed geometric averages when returns are volatile.

So which averaging method on historical data best estimates the *expected* future rate of return? To estimate the mean (expectation) for any random variable, well-accepted statistical principles dictate that the arithmetic average is the best unbiased estimator. Therefore, to determine a security's

[7] Some authors, such as Lewellen, argue that the market risk premium does change over time—and can be measured using financial ratios, such as the dividend yield. We address these models separately. J. Lewellen, "Predicting Returns with Financial Ratios," *Journal of Financial Economics*, 74(2) (2004): 209–235.

expected return for one period, the best unbiased predictor is the arithmetic average of many one-period returns. A one-period risk premium, however, can't value a company with many years of cash flow. Instead, long-dated cash flows must be discounted using a compounded rate of return. But when compounded, the arithmetic average will be *biased* upward (too high).

This bias is caused by estimation error and autocorrelation in returns. Let's examine the effect of estimation error first. To estimate the mean of a distribution, statistical theory instructs you to average the observations. In a finite sample, the sample average (R_A) will equal the true mean (μ) plus an error term (ε):

$$R_A = \mu + \varepsilon$$

Sometimes the error term is positive, so the sample average overestimates the true mean, and at other times, the error term is negative. But the average error term equals 0, so the sample average is an unbiased estimator of the true mean.

To value a cash flow *beyond* one period, we must determine the discount factor by raising R_A to a given power. For instance, to estimate a two-period discount rate, we calculate R_A squared. Squaring R_A leads to the following equation:

$$R_A = (\mu + \varepsilon)^2 = \mu^2 + \varepsilon^2 + 2\mu\varepsilon$$

Since the true mean, μ, is a constant and the expectation of ε is 0, the expectation of $2\mu\varepsilon$ equals 0. The expectation of ε^2, however, is not 0, but a positive number (the square of any nonzero number is greater than zero). Therefore, $R_A{}^2$ will be greater than μ^2 (the true mean squared), and a compounded sample average will be too high.

The compounded arithmetic average will also be biased upward when returns are negatively autocorrelated (meaning low returns follow high returns and high returns follow low returns). Although there is disagreement in the academic community, the general consensus is that the aggregate stock market exhibits negative autocorrelation.[8] In this case, the arithmetic mean is biased upward.

[8] Empirical evidence presented by James Poterba, Lawrence Summers, and others indicates that a significant long-term negative autocorrelation exists in stock returns. See J. Poterba and L. Summers, "Mean Reversion in Stock Prices," *Journal of Financial Economics* (October 1988): 27–60. However, subsequent studies by Matthew Richardson and others challenge the statistical significance of earlier studies. See M. Richardson, "Temporary Components of Stock Prices: A Skeptic's View," *Journal of Business and Economic Statistics*, 11 (1993): 199–207.

Exhibit 10.4 Expected Value When Returns Exhibit Negative Autocorrelation

Potential return	Unconditional probability
20%	50%
(10%)	50%

Scenario	Current value	Return in period one	Return in period two	Future value	Expected value when returns are independent		Expected value when returns are negatively autocorrelated	
1	100	1.2	1.2	144	25%	36.0	15%	21.6
2	100	1.2	0.9	108	25%	27.0	35%	37.8
3	100	0.9	1.2	108	25%	27.0	35%	37.8
4	100	0.9	0.9	81	25%	20.3	15%	12.2
					100%	110.3	100%	109.4

To better understand the effect of negative autocorrelation, consider a portfolio that can either grow by 20 percent or fall by 10 percent in a given period (see Exhibit 10.4). Since both returns are equally likely, the one period average return equals 5 percent. In addition, if returns are independently and identically distributed, after two periods there is:

1. A 25 percent probability that an initial investment of $100 will grow to $144
2. A 50 percent probability (two equally probable scenarios) that $100 will grow to $108
3. A 25 percent probability that $100 will shrink to $81

The expected value in two periods equals $110.3, the same as if $100 had grown consistently at the *arithmetic* average of 5 percent for two periods. But if the four scenarios are not equally likely, the expected value in two periods will not equal $110.3. For instance, if there is a 70 percent probability that low returns will be followed by high returns (or vice versa), the expected value in two periods is only $109.4. In this case, compounding the arithmetic mean will lead to an upward bias in expected return.

To correct for the bias caused by estimation error and negative autocorrelation in returns, we have two choices. First, we can calculate multiperiod holding returns directly from the data, rather than compound single-period averages. Using this method, a cash flow received in five years will be discounted by the average five-year market risk premium, not by the annual

Exhibit 10.5 Cumulative Returns for Various Intervals, 1903–2002

percent

		Cumulative returns			Annualized returns	
Arithmetic mean of	Number of observations	U.S. stocks	U.S. government bonds	U.S. excess return	U.S. excess returns	Blume estimator
1-year holding periods	100	11.5	5.3	6.2	6.2	6.2
2-year holding periods	50	24.1	10.9	12.6	6.1	6.1
4-year holding periods	25	49.9	23.7	23.0	5.5	6.0
5-year holding periods	20	68.2	29.5	32.3	5.8	5.9
10-year holding periods	10	165.6	72.1	70.1	5.5	5.6

Source: Ibbotson Associates, McKinsey analysis.

market risk premium compounded five times.[9] In Exhibit 10.5, we present arithmetic averages for holding periods of 1, 2, 4, 5, and 10 years. To avoid placing too little weight on either early or recent observations, we use nonoverlapping returns. The downside of this method is that 5- and 10-year holding periods have very few observations. As shown in the exhibit, the annualized excess return trends downward from 6.2 percent to 5.5 percent as the length of the holding period increases.

Alternatively, researchers have used simulation to show that an estimator proposed by Marshall Blume best adjusts for problems caused by estimation error and autocorrelation of returns:[10]

$$R = \frac{T-N}{T-1} R_A + \frac{N-1}{T-1} R_G$$

where T = Number of historical observations
N = Forecast period
R_A = Arithmetic average
R_G = Geometric average

In the last column of Exhibit 10.5, we report Blume's estimate for the market risk premium. Blume's method generates the same downward-trending estimate of the market risk premium (albeit more smoothly than the raw holding period averages). Based on both estimation techniques, it appears 5.5 percent is a reasonable approximation for *historical* excess returns.

[9] Jay Ritter writes, "There is no theoretical reason why one year is the appropriate holding period. People are used to thinking of interest rates as a rate per year, so reporting annualized numbers makes it easy for people to focus on the numbers. But I can think of no reason other than convenience for the use of annual returns." J. Ritter, "The Biggest Mistakes We Teach," *Journal of Financial Research*, 25 (2002): 159–168.

[10] D. C. Indro and W. Y. Lee, "Biases in Arithmetic and Geometric Averages Premia," *Financial Management*, 26(4) (Winter 1997); M. E. Blume, "Unbiased Estimators of Long Run Expected Rates of Return," *Journal of the American Statistical Association*, 69(347) (September 1974).

Survivorship bias Other statistical difficulties exist with historical risk premiums. According to one argument,[11] even properly measured historical premiums can't predict future returns, because the observable sample will include only countries with strong historical returns. Statisticians refer to this phenomenon as survivorship bias. The U.S. market outperformed all others during the twentieth century, averaging 4.3 percent in real terms (deflating by the wholesale price index) versus a median of 0.8 percent for other countries.[12] A concurring study[13] notes that the –100 percent returns from China, Russia, and Poland are too often ignored in discussions of stock market performance.

Since it is unlikely that the U.S. stock market will replicate its performance over the next century, we adjust downward the historical arithmetic average market risk premium. Using data from Philippe Jorion and William Goetzmann, we find that between 1926 and 1996, the U.S. arithmetic annual return exceeded the median return on a set of 11 countries with continuous histories dating to the 1920s by 1.9 percent in real terms, or 1.4 percent in nominal terms. If we subtract a 1 percent to 2 percent survivorship bias from the long-term arithmetic average of 5.5 percent, the difference implies the future range of the U.S. market risk premium should be 3.5 to 4.5 percent.

Market risk premium regressions Although we find no long-term trend in the historical risk premium, many argue that the market risk premium is predictable using observable variables, such as the aggregate dividend-to-price ratio, the aggregate book-to-market ratio, or the aggregate ratio of earnings to price.

The use of current financial ratios to estimate the expected return on stocks is well documented and dates back to Charles Dow in the 1920s. The concept has been tested by many authors.[14] To predict the market risk premium using financial ratios, excess market returns are regressed against a financial ratio, such as the market's aggregate dividend-to-price ratio:

$$R_m - r_f = \alpha + \beta \ ln\left(\frac{\text{Dividend}}{\text{Price}}\right) + \varepsilon$$

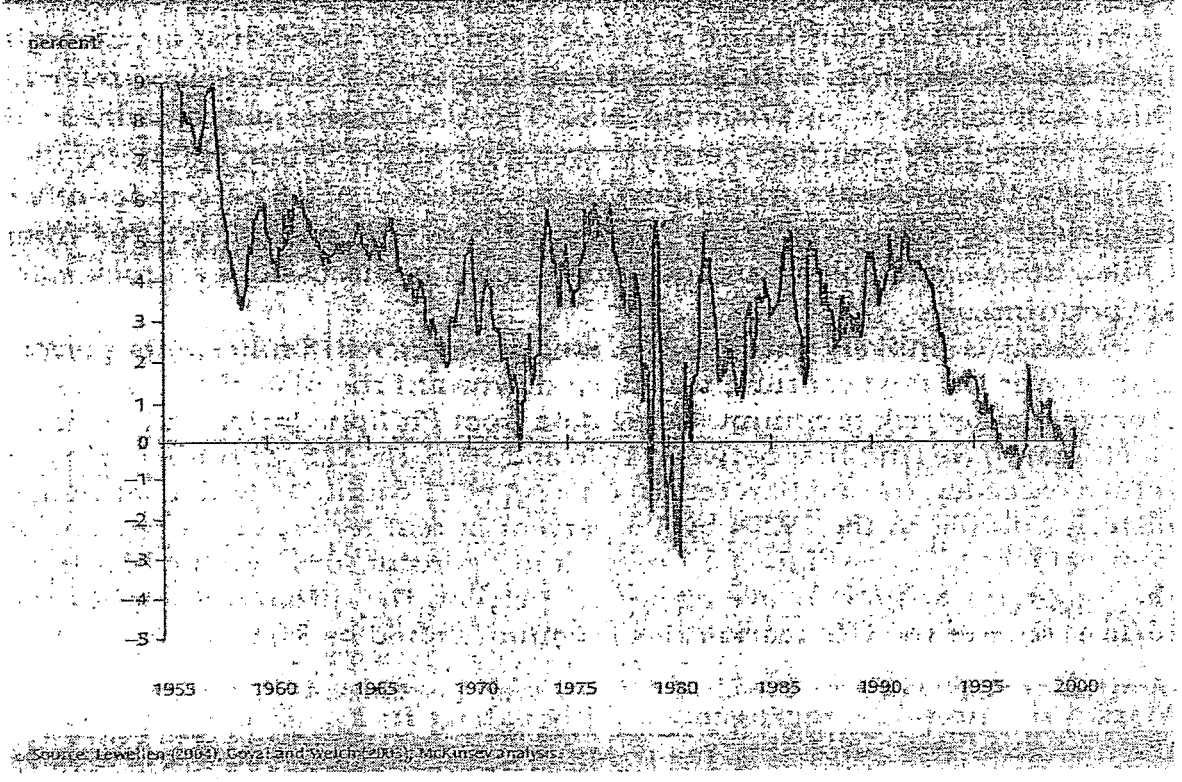
[11] S. Brown, W. Goetzmann, and S. Ross, "Survivorship Bias," *Journal of Finance* (July 1995): 853–873.

[12] P. Jorion and W. Goetzmann, "Global Stock Markets in the Twentieth Century," *Journal of Finance*, 54(3) (June 1999): 953–974.

[13] Elroy Dimson, Paul Marsh, and Michael Staunton, *Triumph of the Optimists* (Princeton: Princeton University Press, 2002).

[14] E. Fama and K. French, "Dividend Yields and Expected Stock Returns," *Journal of Financial Economics*, 22(1) (1988): 3–25; R. F. Stambaugh, "Predictive Regressions," *Journal of Financial Economics*, 54(3) (1999): 375–421; and J. Lewellen, "Predicting Returns with Financial Ratios," *Journal of Financial Economics*, 74(2) (2004): 209–235.

Exhibit 10.6 Expected Market Risk Premium Based on Dividend Yield



Source: Lewellen (2004), Goyal and Welch (2003), McKinsey analysis.

Using advanced regression techniques unavailable to earlier authors, Jonathan Lewellen found that dividend yields *do* predict future market returns. But as shown in Exhibit 10.6, the model has a major drawback: the risk premium prediction can be negative (as it was in the late 1990s). Other authors question the explanatory power of financial ratios, arguing that a financial analyst relying solely on data available at the time would have done better using unconditional historical averages (as we did in the last section) in place of more sophisticated regression techniques.[15]

Forward-looking models A stock's price equals the present value of its dividends. Assuming dividends are expected to grow at a constant rate, we can rearrange the growing perpetuity to solve for the market's expected return:

$$P = \frac{\text{DIV}}{k_e - g} \quad \text{converts to} \quad k_e = \frac{\text{DIV}}{P} + g$$

In the previous section, we reviewed regression models that compare market returns (k_e) to the dividend-price ratio (DIV/P). Using a simple re-

[15] A. Goyal and I. Welch, "Predicting the Equity Premium with Dividend Ratios," *Management Science*, 4, 9(5) (2003): 639–654.

gression, however, ignores valuable information and oversimplifies a few market realities. First, the dividend-price yield itself depends on the expected growth in dividends (g), which simple regressions ignore (the regression's intercept is determined by the data). Second, dividends are only one form of corporate payout. Companies can use free cash flow to repurchase shares or hold excess cash for significant periods of time; consider Microsoft, which accumulated more than $50 billion in liquid securities before paying its first dividend.

Using the principles of discounted cash flow, along with estimates of growth, various authors have attempted to reverse engineer the market risk premium. Two studies used analyst forecasts to estimate growth,[16] but many argue that analyst forecasts focus on the short term and are severely upward biased. Fama and French use long-term dividend growth rates as a proxy for future growth, but they focus on dividend yields, not on available cash flow.[17] Alternatively, our own research has focused on *all* cash flow available to equity holders, as measured by a modified version of the key value driver formula (detailed in Chapter 3):[18]

$$k_e = \frac{\text{Earnings}\left(1 - \frac{g}{\text{ROE}}\right)}{P} + g \quad \text{such that} \quad \text{CF}_e = \text{Earnings}\left(1 - \frac{g}{\text{ROE}}\right)$$

Based on this formula, we used the long-run return on equity (13 percent) and the long-run growth in real GDP (3.5 percent) to convert a given year's S&P 500 median earnings-to-price ratio into the cost of equity.[19]

Exhibit 10.7 on page 306 plots the nominal and real expected market returns between 1962 and 2002. The results are striking. After stripping out inflation, the expected market return (*not* excess return) is remarkably constant, averaging 7.0 percent. For the United Kingdom, the real market return is slightly more volatile, averaging 6.0 percent. Based on these results, we estimate the current market risk premium by subtracting the current real long-term risk-free rate from the real equity return of 7.0 percent (for U.S. markets). At year-end 2003, the yield on a U.S. Treasury inflation-protected security (TIPS) equaled 2.1 percent. Subtracting 2.1

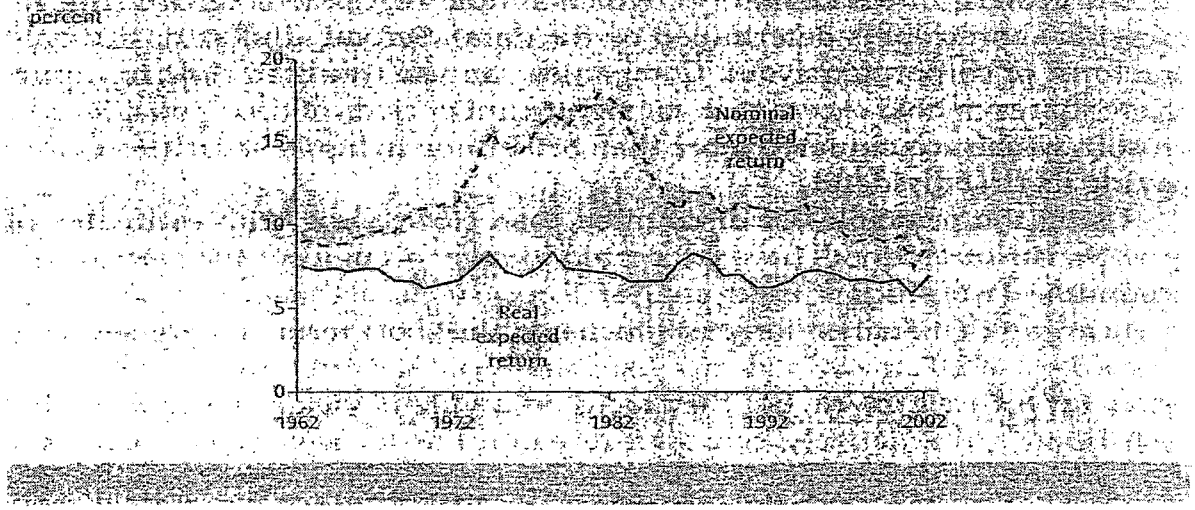
[16] J. Claus and J. Thomas, "Equity Premia as Low as Three Percent? Evidence from Analysts' Earnings Forecasts for Domestic and International Stocks," *Journal of Finance*, 56(5) (October 2001): 1629–1666; and W. R. Gebhardt, C. M. C. Lee, and B. Swaminathan, "Toward an Implied Cost of Capital," *Journal of Accounting Research*, 39(1) (2001): 135–176.

[17] Eugene F. Fama and Kenneth R. French, "The Equity Premium," Center for Research in Security Prices Working Paper No. 522 (April 2001).

[18] Marc H. Goedhart, Timothy M. Koller, and Zane D. Williams, "The Real Cost of Equity," *McKinsey on Finance* (Autumn 2002): 11–15.

[19] Using a two-stage model (i.e., short-term ROE and growth rate projections, followed by long-term estimates) did not change the results in a meaningful way.

Exhibit 10.7 Real and Nominal Expected Market Returns



percent from 7.0 percent gives an estimate of the risk premium at just under 5 percent.

Although many in the finance profession disagree about how to measure the market risk premium, we believe 4.5 to 5.5 percent is an appropriate range. Historical estimates found in most textbooks (and locked in the mind of many), which often report numbers near 8 percent, are too high for valuation purposes because they compare the market risk premium versus short-term bonds, use only 75 years of data, and are biased by the historical strength of the U.S. market.

Estimating beta According to the CAPM, a stock's expected return is driven by beta, which measures how much the stock and market move together. Since beta cannot be observed directly, we must *estimate* its value. To do this, we first measure a raw beta using regression and then improve the estimate by using industry comparables and smoothing techniques. The most common regression used to estimate a company's raw beta is the market model:

$$R_i = \alpha + \beta R_m + \varepsilon$$

In the market model, the stock's return (not price) is regressed against the market's return.

In Exhibit 10.8, we plot 60 months of Home Depot stock returns versus S&P 500 returns between 1999 and 2003. The solid line represents the "best

BELLA VISTA WATER COMPANY, INC.

DOCKET NO. W-02465A-09-0411 ET AL.

DIRECT TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 12, 2010

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INTRODUCTION

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

A. My name is Rodney L. Moore. I am a Public Utilities Analyst V with the Residential Utility Consumer Office ("RUCO"), located at 1110 West Washington Street, 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 case 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 revenue requirement recommendations regarding Bella Vista Water Company's ("BVWC" or "Company") application for an increase in its water rates. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended March 31, 2009 ("Test Year").

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 the rate base, operating income and revenue requirements. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of three sets of data requests, and the review and analysis of Company responses to Commission Staff data requests.

Q. Does RUCO support the Company's request to consolidate operations and the transfer of utility assets of Bella Vista Water Company, Inc., Northern Sunrise Water Company, Inc ("NSWC"). and Southern Sunrise Water Company, Inc. ("SSWC") into Bella Vista Water Company, Inc.?

A. RUCO will address its position on rate consolidation in its testimony that is due April 23, 2010.

Q. Are you providing testimony for each of the three Liberty Water systems (BVWC, NSWC and SSWC) on a stand-alone basis?

A. No. In this round of testimony, I am providing testimony on a consolidated basis. As explained in the direct testimony of RUCO Director Jodi Jerich, RUCO will present schedules on a stand-alone basis when RUCO's direct testimony on rate design is filed on April 23, 2010. At that time, I will provide my recommendations on a stand-alone basis.

Q. What areas will you address in your testimony?

A. I will address issues, on a consolidated basis, related to revenue requirement, rate base, operating income and rate design. RUCO's witness Timothy J. Coley will provide an analysis of the rate base adjustment associated with the accumulated deferred income taxes as presented on Schedule RLM-5 and the operating income adjustment associated with the central office cost allocation expenses as presented on Schedule RLM-11. RUCO's witness William A. Rigsby will provide an analysis of the cost of capital as presented on Schedule RLM-14. On April 23, 2010, Mr. Rigsby will provide a cost of capital analysis for each system in support of stand-alone rates.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring a separate set of Schedules numbered RLM-1 through RLM-14. My rate design testimony and Schedules numbered RLM-RD1 and RLM-RD2 will be filed on April 23, 2010.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and revenue requirement addressed in your testimony.

A. My testimony addresses the following issues:

Rate Base

Post Test Year Gross Plant-In-Service and Accumulated Depreciation – This adjustment reflects changes in recorded plant costs from budget to the actual amounts.

Customer Deposits – This adjustment reflects updated information to decrease meter deposits.

Accumulated Deferred Income Taxes – RUCO witness Timothy Coley will sponsor this adjustment.

Operating Income

Test Year Depreciation Expense – This adjustment corrects a Company calculation error by including all depreciation expenses in the summation.

Property Tax Expense - This adjustment reflects property tax expense based on RUCO's calculation of adjusted and proposed operating revenues.

Miscellaneous Operating Expenses – These adjustments remove unnecessary operating expenses not required for the provisioning of water service and/or remove test year expenses deemed atypical and non-recurring.

Central Office Cost Allocations - RUCO witness Timothy Coley will sponsor this adjustment.

Rate Case Expense - This adjustment is based on RUCO's determination of the fair and reasonable cost to Bella Vista ratepayers for this application process.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

Rate Design and Proof of Recommended Revenue

On April 23, 2010, I will be filing separate direct testimony on my recommended rate design that is generally consistent with the Company's proposed consolidated rate design, but reflects RUCO's recommended revenue requirement and provides proof that the design will produce the appropriate revenue requirement.

REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, RUCO is recommending that the Company's revenue requirement not exceed the following levels:

BVWC	RUCO	DIFFERENCE
$5,672,485	$4,919,615	($752,870)

RUCO's recommended increase in Fair Value Rate Base ("FVRB") is based on the Company's Original Cost Rate Base ("OCRB") and is summarized on Schedule RLM-1:

BVWC	RUCO	DIFFERENCE
$8,628,612	$7,286,645	($1,341,967)

RUCO's recommended required operating income is shown on Schedule RLM-1 as:

BVWC	RUCO	DIFFERENCE
$965,542	$613,796	($351,746)

RUCO's recommended revenue requirement percentage increase versus the Company's proposal is as follows:

BVWC	RUCO	DIFFERENCE
36.29 %	18.20 %	-18.09 %

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

RATE BASE

Rate Base Adjustment Summary

Q. Is RUCO recommending any changes to the Company's proposed rate base?

A. Yes. My adjustments to rate base are exhibited on Schedule RLM-3, columns A through G. Based on my analysis I made two adjustments to the rate base as filed by the Company.

Q. Does RUCO accept BVWC's request to use the Company's OCRB as the FVRB?

A. Yes. RUCO accepts the Company's request that the OCRB be used as the fair value rate base ("FVRB").

Q. Please describe your rate base adjustments.

A. My review, analysis and adjustments are explained below.

Rate Base Adjustment No. 1 – Post Test Year Gross Plant-In-Service and Accumulated Depreciation

Q. Please explain the basis for your adjustment to the post test year gross plant-in-service and the accumulated depreciation.

A. My plant-in-service analysis from the prior rate case to the end of the Test Year mirrored the Company's filing; however, the Company acknowledged in its response to Staff data request MSJ 5-2 there were updated costs for

the plant additions and retirements to reflect actual costs incurred. RUCO reviewed BVWC's response and made the appropriate adjustments.

Q. Please explain the total effect of your Adjustment No. 1 on the rate base.

A. As shown on Schedule RLM-3, column (B), and with supporting Schedule RLM-5, these adjustments decrease gross utility plant in service by $1,940 and accumulated depreciation by $3,610 for a net reduction in the adjusted test year rate base of $5,550.

Rate Base Adjustment No. 2 – Customer Deposits

Q. Please explain the basis for your adjustment to the customer deposits.

A. The Company acknowledged in its response to RUCO data request 2.1 that the actual amount of the customer deposits was less than the amount recorded in the application. RUCO reviewed BVWC's response and made the appropriate adjustments to reflect actual customer deposits.

As shown on Schedule RLM-3, column (C), this adjustment increased adjusted test year rate base by $121,861.

Rate Base Adjustment No. 3 – Accumulated Deferred Income Taxes

Q. Please explain how this adjustment to accumulated deferred income taxes was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley, please refer to his testimony for clarification.

Based on Mr. Coley's testimony and as shown on Schedule RLM-3, column (D), and with supporting Schedule RLM-4 this adjustment decreased adjusted test year rate base by $1,458,278.

OPERATING INCOME

Operating Income Adjustment Summary

Q. Is RUCO recommending any changes to the Company's proposed operating expenses?

A. Yes. Based on my analysis of the Company's adjustments to its historical test year operating income, I have made six adjustments to the Company-proposed level of operating income. The adjustments are exhibited on Schedule RLM-7, columns A through H.

Operating Income Adjustment No. 1 – Test Year Depreciation Expense

Q. Please explain your adjustment to the test year depreciation expense.

A. This adjustment reflects a Company acknowledged computation error, which failed to include all depreciation expenses in BVWC's total.

As shown on Schedule RLM-7, column (B), with supporting documentation on Schedule RLM-8, this adjustment increased the adjusted test year operating expenses by $32,214.

Operating Income Adjustment No. 2 – Property Tax Computation

Q. Did RUCO use the same methodology used by BVWC to calculate property tax expenses?

A. Yes. RUCO calculated property tax expense using two times the adjusted revenues for the year ending March 31, 2009, and one year of revenues at proposed rates. The assessed value (21 percent of full cash value) was then multiplied by the property tax rate to determine adjusted property tax expense. The difference between the Company and RUCO's property tax expense is a result of RUCO's lower level of adjusted and proposed operating revenues.

As shown on Schedule RLM-7, column (C), with supporting documentation on Schedule RLM-9 this adjustment decreased the adjusted test year operating expenses by $9,408.

Operating Income Adjustment No. 3 – Miscellaneous Expense

Q. Please explain your adjustment to the test year miscellaneous expenses.

A After an analysis of the Company's response to Staff data request CSB 1-32, I determined there were test year expenditures not required for the

provision of water service or were abnormal and atypical for considerations as a reasonable recurring test year expense. Therefore, I disallowed their inclusion as acceptable test year operating expenses.

My adjustment removed unnecessary expenditures for charitable donations and a Company Christmas party.

As shown on Schedule RLM-7, column (E), with supporting documentation on Schedule RLM-10, this adjustment decreased test year expenses by $2,500.

Operating Income Adjustment No. 4 – Central Office Cost Allocations

Q. Please explain how this adjustment to the allocation of central office costs was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley, please refer to his testimony for clarification.

Based on Mr. Coley's testimony and as shown on Schedule RLM-7, column (F), this adjustment decreased adjusted test year rate base by $144,927.

Operating Income Adjustment No. 5 – Rate Case Expense

Q. Please explain the adjustment to the rate case expense.

A. RUCO made a determination of the expense to ratepayers for costs incurred by the Company for filing this rate case application.

Q. What level of rate case expense had Bella Vista requested?

A. Bella Vista is requesting $400,000 in rate case expense normalized over three years for a test year expense of $133,333.

Q. Please explain the basis for determining the appropriate level of rate case expense.

A. My adjustment consists of two elements. First, I analyzed the actual rate case expenses incurred to the date of this filing. As of the end of February 2010, the Company has incurred $59,206.

Second, I analyzed a Company-provided estimate of similar remaining costs to be expended for the duration of the Black Mountain Sewer Company ("BMSC") proceeding. In the BMSC preceding the Company estimated $130,000. Because this matter will be heard in Tucson, I have added an additional $10,000 as a per diem allowance to reflect costs associated with conducting the Hearing out of town.

Q. Based on this analysis, what level of rate case expense are you recommending as the financial burden on the ratepayers?

A. As shown on Schedule RLM-7, column (F) and supporting Schedule RLM-12, I recommended total rate case expenses of $200,000 normalized over three years. This adjustment decreased the adjusted test year expenses by $66,667.

Operating Income Adjustment No. 6 – Income Taxes

Q. Please explain RUCO's adjustment to BVWC's income tax expenses.

A. This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

Q. Does RUCO's recommended level of income tax expense reflect an interest deduction using a synchronized interest calculation?

A. Yes.

As shown on Schedules RLM-7, column (K) and supporting Schedule RLM-13, this adjustment increased the adjusted test year expenses by $80,763.

COST OF CAPITAL

Q. Has RUCO conducted a cost of capital analysis for BVWC?

A. Yes. RUCO witness William A. Rigsby has filed testimony on the cost of capital issues associated with the case. His recommended capital structure and weighted average cost of capital is exhibited on Schedule RLM-14.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX 1

Qualifications of Rodney Lane Moore

EDUCATION: Athabasca University
Bachelor's Degree in Business Administration - 1993

EXPERIENCE: Public Utilities Analyst V
Residential Utility Consumer Office
Phoenix, Arizona 85007
May 2001 - Present

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

Auditor
Arizona Corporation Commission
Phoenix, Arizona 85007
October 1999 - May 2001

My duties include review and analysis of financial records and other documents of regulated utilities for accuracy, completeness, and reasonableness. I am also responsible for the preparation of work papers and Schedules resulting in testimony and/or reports regarding utility applications for increase in rates, financings, and other matters. Extensive use of Microsoft Excel and Word, spreadsheet modeling and financial statement analysis.

RESUME OF RATE CASE AND REGULATORY PARTICIPATION

Utility Company	Docket No.
Rio Verde Utilities, Inc	WS-02156A-00-0321
Black Mountain Gas Company	G-03703A-01-0283
Green Valley Water Company	W-02025A-01-0559
New River Utility Company	W-01737A-01-0662

Utility Company	Docket No.
Dragoon Water Company	W-01917A-01-0851
Roosevelt Lake Resort, Inc.	W-01958A-02-0283
Southwest Gas Company	G-01551A-02-0425
Arizona-American Water Company	W-01303A-02-0867 et al.
Rio Rico Utilities, Inc.	WS-02676A-03-0434
Qwest Corporation	T-01051B-03-0454
Chaparral City Water Company	W-02113A-04-0616
Southwest Gas Company	G-01551A-04-0876
Arizona-American Water Company	W-01303A-05-0405
Far West Water and Sewer Company	WS-03478A-05-0801
Gold Canyon Sewer Company	SW-02519A-06-0015
Arizona-American Water Company	WS-01303A-06-0403
UNS Gas, Inc.	G-04204A-06-0463 et al.
UNS Electric, Inc.	E-04204A-06-0783
Tucson Electric Power Company	E-01933A-07-0402
Southwest Gas Company	G-01551A-07-0504
Arizona Water Company	W-01445A-08-0440
Arizona-American Water Company	W-01303A-08-0227 et al.
Johnson Utilities, LLC	WS-02987A-08-0180
Black Mountain Sewer Corporation	SW-02361A-08-0609
Arizona-American Water Company	W-01303A-09-0343 et al.
Global Water Company	SW-20445A-09-0077 et al.

Bella Vista Water Company
Docket No. W-02453A-09-0414 et al.
Test Year Ended March 31, 2009

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RLM-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
RLM-5	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
RLM-6	1	OPERATING INCOME
RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
RLM-11	1	OPERATING INCOME ADJUSTMENT NO. 4 - CENTRAL OFFICE COST ALLOCATION
RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSES
RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 6 - INCOME TAX EXPENSE
RLM-14	1	COST OF CAPITAL

Bella Vista Water Company
Docket No. W-02453A-09-0414 et al.
Test Year Ended March 31, 2009

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 8,628,612	$ 7,286,645
2	Adjusted Operating Income (Loss)	$ 38,170	$ 148,696
3	Current Rate Of Return (L2 / L1)	0.44%	2.04%
4	Required Operating Income (L5 X L1)	$ 965,542	$ 613,796
5	Required Rate Of Return On Fair Value Rate Base	11.19%	8.42%
6	Operating Income Deficiency (L4 - L2)	$ 927,371	$ 465,101
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6286	1.6286
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 1,510,349	$ 757,479
9	Adjusted Test Year Revenue	$ 4,162,136	$ 4,162,136
10	Proposed Annual Revenue (L8 + L9)	$ 5,672,485	$ 4,919,615
11	Required Percentage Increase In Revenue (L8 / L9)	36.29%	18.20%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RLM-2, RLM-6, And RLM-14

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REVENUE REQUIREMENT - CONT'D
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. RLM-1, Col. (B), L4)	$ 613,796			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. RLM-1, Col. (B), L2)	148,696			
13	Required Increase In Operating Income (L11 - L12)		$ 465,101		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 325,355			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	32,976			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 292,378		
17	Total Required Increase In Revenue (L13 + L16)		$ 757,479		
				RUCO Recommended	
	CALCULATION OF INCOME TAX:				
18	Revenue (Sch. RLM-1, Col. (B), L10)			$ 4,919,615	
19	Operating Expense Excluding Income Tax (RLM-6, Col. (E), L28 - L27)			(3,980,464)	
20	Synchronized Interest (Col. (C), L37)			(96,239)	
21	Arizona Taxable Income (L18 + L19 + L20)			$ 842,912	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 58,734
24	Fed. Taxable Income (L21 - L23)			$ 784,178	
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%			152,720	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 266,620
31	Combined Federal And State Income Tax (L23 + L30)				$ 325,355
32	Test Year Combined Income Tax, RUCO As Adjusted (RLM-6, Col. (C), L24)				$ 32,976
33	RUCO Adjustment (L31 - L32) (See RLM-6, Col. (D), L24)				$ 292,378
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. RLM-2, Col. (H), L15)			$ 7,286,645	
36	Weighted Avg. Cost Of Debt (Sch. RLM-14, Col. (F), L1)			1.32%	
37	Synchronized Interest (L35 X L36)			$ 96,239	

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 28,165,701	$ (1,940)	$ 28,163,761
2	Accumulated Depreciation	(12,057,912)	(3,610)	(12,061,522)
3	Net Utility Plant In Service (L1 + L2)	$ 16,107,789	$ (5,550)	$ 16,102,239
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (542,445)	$ -	$ (542,445)
6	Accumulated Amortization Of CIAC	230,987	-	230,987
7	NET CIAC (L5 + L6)	$ (311,458)	$ -	$ (311,458)
8	Customer Meter Deposits	$ (559,605)	$ 134,361	$ (425,244)
9	Customer Hydrant Meter Deposits	$ -	$ (12,500)	$ (12,500)
10	Deferred Income Taxes & Credits	$ 173,329	$ (1,458,278)	$ (1,284,949)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 8,628,612	$ (1,341,967)	$ 7,286,645

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

Bella Vista Water Company
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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) INTENT'NLY LEFT BLANK	(F) INTENT'NLY LEFT BLANK	(G) INTENT'NLY LEFT BLANK	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 28,165,701	$ (1,940)	$ -	$ -	$ -	$ -	$ -	$ 28,163,761
2	Accumulated Depreciation	(12,057,912)	(3,610)	-	-	-	-	-	(12,061,522)
3	Net Utility Plant In Service (L1 + L2)	$ 16,107,789	$ (5,550)	$ -	$ -	$ -	$ -	$ -	$ 16,102,239
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (542,445)	$ -	$ -	$ -	$ -	$ -	$ -	$ (542,445)
6	Accumulated Amortization Of CIAC	230,987	-	-	-	-	-	-	230,987
7	NET CIAC (L5 + L6)	$ (311,458)	$ -	$ -	$ -	$ -	$ -	$ -	$ (311,458)
8	Customer Meter Deposits	$ (559,605)	$ -	$ 134,361	$ -	$ -	$ -	$ -	$ (425,244)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ (12,500)	$ -	$ -	$ -	$ -	$ (12,500)
10	Deferred Income Taxes & Credits	$ 173,329	$ -	$ -	$ (1,458,278)	$ -	$ -	$ -	$ (1,284,949)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 8,628,612	$ (5,550)	$ 121,861	$ (1,458,278)	$ -	$ -	$ -	$ 7,286,645

References:

Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Testimony Of RUCO Witness Tim Coley and Schedule RLM-5)
Column (E): Intentionally Left Blank
Column (F): Intentionally Left Blank
Column (G): Intentionally Left Blank
Column (H): Sum Of Columns (A), (B), (C), (D), (E) & (F)

Bella Vista Water Company
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POST TEST YEAR PLANT SCHEDULE
YEAR ENDED JUNE 30, 2008

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) RUCO T/Y PLANT AS ADJUSTED	(B) RUCO POST TY ADJM'TS PLANT ADDITIONS	(C) RUCO POST TY ADJM'TS PLANT RETIRMENTS	(D) TOTAL PLANT VALUE	(E) ACC. DEP.	(F) NET PLANT VALUE
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise Cost	961	-	-	961	-	961
3	303	Land and Land Rights	688,011	-	-	688,011	-	688,011
4	304	Structures and Improvements	1,929,428	-	-	1,929,428	(401,914)	1,527,514
5	305	Collecting and Impounding Res.	51,378	-	-	51,378	(2,059)	49,319
6	306	Lake River and Other Intakes	-	-	-	-	-	-
7	307	Wells and Springs	1,300,212	-	-	1,300,212	(532,200)	768,011
8	308	Infiltration Galleries and Tunnels	-	-	-	-	-	-
9	309	Supply Mains	3,798	-	-	3,798	(104)	3,694
10	310	Power Generation Equipment	1,293	-	-	1,293	(75)	1,218
11	311	Electric Pumping Equipment	2,777,250	-	-	2,777,250	(2,527,613)	249,638
12	320	Water Treatment Equipment	109,639	-	-	109,639	(50,073)	59,566
13	320.1	Water Treatment Equipment	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2,709,163	-	-	2,709,163	(822,901)	1,886,263
16	330.1	Storage tanks	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	12,722,170	104,507	(8,390)	12,818,287	(4,104,951)	8,713,336
19	333	Services	1,500,252	-	-	1,500,252	(837,916)	662,336
20	334	Meters	1,517,711	-	-	1,517,711	(1,492,936)	24,774
21	335	Hydrants	970,159	-	-	970,159	(284,597)	685,562
22	336	Backflow Prevention Devices	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	114,540	-	-	114,540	(8,753)	105,786
24	340	Office Furniture and Fixtures	202,929	-	-	202,929	(170,545)	32,385
25	340.1	Computers and Software	161,264	-	-	161,264	(117,801)	43,463
26	341	Transportation Equipment	295,224	-	-	295,224	(291,918)	3,305
27	342	Stores Equipment	-	-	-	-	-	-
28	343	Tools and Work Equipment	124,953	-	-	124,953	(124,689)	264
29	344	Laboratory Equipment	-	-	-	-	-	-
30	345	Power Operated Equipment	31,548	-	-	31,548	(5,882)	25,666
31	346	Communications Equipment	444,928	-	-	444,928	(127,515)	317,413
32	347	Miscellaneous Equipment	110,348	-	-	110,348	(104,580)	5,768
33	348	Other Tangible Plant	300,001	-	-	300,001	(52,500)	247,501
34		Rounding	484			484	-	484
		0						
35	TOTAL WASTEWATER PLANT		$ 28,067,644	$ 104,507	$ (8,390)	$ 28,163,761	$ (12,061,522)	$ 16,102,239
36	Company As Filed					28,165,701	$ (12,057,912)	
37	Difference					(1,940)	$ (3,610)	
38	RUCO Adjustment (Line 37) (See RLM-3, Column (B))					(1,940)	$ (3,610)	

References:
Column (A): RUCO Workpapers RLM-4-A(1)
Columns (B) (C): Testimony, RLM
Column (D): Sum Of Columns (A), (B), & (C)
Column (E): Sum Of WP RLM-4-A(1), Column (B) And RLM-4, Column (C)
Column (F): Column (D) + Column (E)

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Schedule RLM-5
Page 1 of 1

ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Allocation	Note (A)	1.5438%
5	Bella Vista ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Test Year Deferred Income Taxes & Credits As Filed	Company Schedule C-1	173,329
9	Decrease In Deferred Income Taxes & Credits	Line 7 - Line 8	$ (1,458,278)
10	RUCO Adjustment (See RLM-3, Column (D), Line 11)	Line 9	$ (1,458,278)

	NOTES:				
11	(A)	Purchase Price of BVWC, NSWC and SSWC	Annual Report	$	15,100,000
12		Algonquin Total Assets	Annual Report	$	978,130,000
13		Ratio Of BVWC, NSWC & SSWC To Algonquin Total A	Line 11 / Line 12		1.5438%
14	(B)	Currency Conversion	moneycentral.com on 04/1/2010		0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

Bella Vista Water Company
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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	Flat Rate Revenues	$ 4,023,022	$ -	$ 4,023,022	$ 757,479	$ 4,780,501
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	139,114	-	139,114	-	139,114
4	TOTAL OPERATING REVENUE	$ 4,162,136	$ -	$ 4,162,136	$ 757,479	$ 4,919,615
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	708	-	708
7	Purchased Power	609,481	-	609,481	-	609,481
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	5,709	-	5,709	-	5,709
10	Materials & Supplies	49,998	-	49,998	-	49,998
11	Outside Services	4,696	-	4,696	-	4,696
12	Outside Services- Legal	41,937	-	41,937	-	41,937
13	Outside Services- Other	1,599,375	(144,927)	1,454,447	-	1,454,447
14	Water Testing	28,184	-	28,184	-	28,184
15	Equipment Rental	6,205	-	6,205	-	6,205
16	Rents	60,600	-	60,600	-	60,600
17	Transportation Expenses	125,122	-	125,122	-	125,122
18	Insurance - General Liability	59,410	-	59,410	-	59,410
19	Insurance - Health and Life	7,290	-	7,290	-	7,290
20	Reg. Comm. Exp.	10,628	-	10,628	-	10,628
21	Reg. Comm. Exp. - Rate Case	133,333	(66,667)	66,667	-	66,667
22	Miscellaneous Expense	92,502	(2,500)	90,002	-	90,002
23	Bad Debt Expense	18,178	-	18,178	-	18,178
24	Depreciation Expense	1,122,442	32,214	1,154,656	-	1,154,656
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	195,954	(9,408)	186,546	-	186,546
27	Income Tax	(47,787)	80,763	32,976	292,378	325,355
28	TOTAL OPERATING EXPENSES	$ 4,123,965	$ (110,525)	$ 4,013,440	$ 292,378	$ 4,305,818
29	OPERATING INCOME (LOSS)	$ 38,170		$ 148,696		$ 613,796

References:

Column (A): Company Schedule C-1
Column (B): RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From RLM-1, Column (B), Line 8 And Income Tax From RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

Bella Vista Water Company
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 CENTRAL OFFICE COST	(F) ADJ # 5 RATE CASE EXPENSES	(G) LEFT BLANK	(H) ADJ # 6 INCOME TAX	(I) RUCO AS ADJT'D
	Revenues:									
1	Flat Rate Revenues	$ 4,023,022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,023,022
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	139,114	-	-	-	-	-	-	-	139,114
4	TOTAL OPR'G REV.	$ 4,162,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,162,136
	Operating Expenses:									
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	-	-	-	-	-	-	708
7	Purchased Power	609,481	-	-	-	-	-	-	-	609,481
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-
9	Chemicals	5,709	-	-	-	-	-	-	-	5,709
10	Materials & Supplies	49,998	-	-	-	-	-	-	-	49,998
11	Outside Services	4,696	-	-	-	-	-	-	-	4,696
12	Outside Services- Legal	41,937	-	-	-	-	-	-	-	41,937
13	Outside Services- Other	1,599,375	-	-	-	(144,927)	-	-	-	1,454,447
14	Water Testing	28,184	-	-	-	-	-	-	-	28,184
15	Equipment Rental	6,205	-	-	-	-	-	-	-	6,205
16	Rents	60,600	-	-	-	-	-	-	-	60,600
17	Transportation Expenses	125,122	-	-	-	-	-	-	-	125,122
18	Insurance - General Liability	59,410	-	-	-	-	-	-	-	59,410
19	Insurance - Health and Life	7,290	-	-	-	-	-	-	-	7,290
20	Reg. Comm. Exp.	10,628	-	-	-	-	-	-	-	10,628
21	Reg. Comm. Exp. - Rate Case	133,333	-	-	-	-	(66,667)	-	-	66,667
22	Miscellaneous Expense	92,502	-	-	(2,500)	-	-	-	-	90,002
23	Bad Debt Expense	18,178	-	-	-	-	-	-	-	18,178
24	Depreciation Expense	1,122,442	32,214	-	-	-	-	-	-	1,154,656
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-
26	Property Taxes	195,954	-	(9,408)	-	-	-	-	-	186,546
27	Income Tax	(47,787)	-	-	-	-	-	-	80,763	32,976
29	TOTAL OPR'G EXP.	$ 4,123,965	$ 32,214	$ (9,408)	$ (2,500)	$ (144,927)	$ (66,667)	$ -	$ 80,763	$ 4,013,440
30	OPR'G INC. (LOSS)	$ 38,170								$ 148,696

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8
Column (C): Testimony, RLM And Schedule RLM-9
Column (D): Testimony, RLM And Schedule RLM-10
Column (E): Testimony, TLC And Schedule RLM-11
Column (F): Testimony, RLM And Schedule RLM-12
Column (G): Intentionally Left Blank
Column (H): Testimony, RLM And Schedule RLM-13
Column (I): Sum Of Columns (A) Thru (H)

Bella Vista Water Company
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Test Year Ended March 31, 2009

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	961	0.00%	-
3	303	Land and Land Rights	688,011	0.00%	-
4	304	Structures and Improvements	1,929,428	3.33%	64,250
5	305	Collecting and Impounding Res.	51,378	2.50%	1,284
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	1,300,212	3.33%	43,297
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	3,798	2.00%	76
10	310	Power Generation Equipment	1,293	5.00%	65
11	311	Electric Pumping Equipment	2,777,250	12.50%	347,156
12	320	Water Treatment Equipment	109,639	3.33%	3,651
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	2,709,163	2.22%	60,143
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	12,818,287	2.00%	256,366
19	333	Services	1,500,252	3.33%	49,958
20	334	Meters	1,517,711	8.33%	126,425
21	335	Hydrants	970,159	2.00%	19,403
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	114,540	6.67%	7,640
24	340	Office Furniture and Fixtures	202,929	6.67%	13,535
25	340.1	Computers and Software	161,264	20.00%	32,253
26	341	Transportation Equipment	295,224	20.00%	59,045
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	124,953	5.00%	6,248
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	31,548	5.00%	1,577
31	346	Communications Equipment	444,928	10.00%	44,493
32	347	Miscellaneous Equipment	110,348	10.00%	11,035
33	348	Other Tangible Plant	300,001	10.00%	30,000
34		Rounding	485		10
35	TOTAL WASTEWATER PLANT		$ 28,163,762		$ 1,177,911
	Less:				
36	Amortizations Of CIAC (RLM-2, Col. (C), Line 5)		$ (542,445)	4.2869%	(23,254)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 1,154,656
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				1,122,442
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ 32,214
40	RUCO Adjustment (Line 39) (See RLM-7, Column (B), Line 25)				$ 32,214

References: Column (A): RLM-4, Column (E)
Column (B): Company Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	$ 4,162,136	
2	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	4,162,136	
3	Proposed Revenues	Sch. RLM-6, Col (E), Ln 4	4,919,615	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 13,243,886	
5	Average Annual Operating Revenues	Line 4 / 3	4,414,629	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 8,829,257
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 526,003	
8	10% Of CWIP	Line 7 X 10%		$ 52,600
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ 295,224	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	(291,918)	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ (3,305)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 8,878,553
	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	$ 1,864,496	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	9.8984%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.90%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 184,554
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,991
20	Company's Total Tax Liability	Line 18 + Line 19		$ 186,546
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 25		195,954
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (9,408)
23	RUCO Adjustment (See RLM-7, Column (C), Line 27)	Line 22		$ (9,408)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
DISALLOWANCE OF MISCELLANEOUS EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL
	Disallowed Miscellaneous Expenses	Co. Response To Staff D. R. CSB 1-32	
1	Bella Vista Water Company Christmas Party		$ (2,000)
2	Special Olympics Pledge		(250)
3	Muscular Distrophy Association Donation		(250)
4	RUCO Adjustment To Unnecessary/Non-Recurring Expenses	Sum Of Lines 1 Thru 17	$ (2,500)
5	RUCO Adjustment (See RLM-7, Column (D))	Line 18	$ (2,500)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To BVWC	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	24.29%	$ 47,253	14.52%	$ 6,863
2	Tax Services	518,775	25.00%	129,694	24.29%	31,497	14.52%	4,575
3	Legal	159,053	25.00%	39,763	24.29%	9,657	14.52%	1,403
4	Other Professional Services	506,082	0.00%	-	24.29%	-	14.52%	-
5	Management Fee - Total	644,943	0.00%	-	24.29%	-	14.52%	-
6	Unit Holder Communications	156,766	0.00%	-	24.29%	-	14.52%	-
7	Trustee Fees	129,000	0.00%	-	24.29%	-	14.52%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	24.29%	-	14.52%	-
9	Rent	307,337	0.00%	-	24.29%	-	14.52%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	24.29%	-	14.52%	-
11	Office Expenses	579,379	0.00%	-	24.29%	-	14.52%	-
12	Depreciation	211,653	25.00%	52,913	24.29%	12,850	14.52%	1,866
13	TOTAL	$ 4,104,971		$ 416,941		$ 101,257		$ 14,707
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 160,881
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on April 1, 2010							0.99147
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 159,508
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 14,581
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(144,927)
19	RUCO Adjustment (See RLM-7, Column (E))							(144,927)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

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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	$ 400,000	$ (200,000)	$ 200,000
2	Normalization Period - 3 Years			3
3	RUCO Adjusted Rate Case Expense For Instant Case (Line 1 / 3 Years)			$ 66,667
4	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 133,333
5	RUCO Pro Forma Rate Case Expense (Lines 3.- 4)			$ (66,667)
6	RUCO Adjustment (Line 5) (See RLM-7, Column (F))			$ (66,667)

	RUCO CALCULATED RATE CASE EXPENSES	REFERENCE	AMOUNT
	ACTUALS	Invoices Per Fennemore Craig	
7	Total Costs Through February 2010		$ 59,206
	ESTIMATES	Based On Estimate From Black Mountain Sewer Co.	
8	Remaining Costs For Company Witness Tom Borassa:		
9	Rebuttal, Surrebuttal, Rejoinder And Trial Process;		
10	Final Schedules, Assistance With Briefing, Evaluation Of ROO; Open Meeting Prep		25,000
11	Expedited Hearing Transcript		5,000
12	Fennemore Craig Estimated Remaining Costs		
13	Rebuttal, Surrebuttal, Rejoinder And Trial Process;		45,000
14	Briefing		30,000
15	Reviewing ROO; Exceptions Open Meeting Prep		10,000
16	Post Decision Compliance And Filings		15,000
17	Per Diam Expenses		10,000
18	Rounding		794
19	RUCO ESTIMATED RATE CASE EXPENSES		$ 200,000

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Schedule RLM-13
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. RLM-6, Column (C), L29 + L27	$ 181,672
	LESS:		
2	Arizona State Tax	Line 11	(5,953)
3	Interest Expense	Note (A) Line 20	(96,239)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 79,480
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 27,023
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 181,672
	LESS:		
8	Interest Expense	Note (A) Line 20	(96,239)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 85,433
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 5,953
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 27,023
13	State Income Tax Expense	Line 11	5,953
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 32,976
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		(47,787)
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 80,763
17	RUCO Adjustment (See Sch. RLM-7, Column (K), L278)	Line16	$ 80,763

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. RLM-2, Col. (E), L15)	$	7,286,645
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		1.32%
20	Interest Expense (L17 X L18)	$	96,239

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) RUCO ADJTM'T	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Long-Term Debt	$ 1,697,323	$ -	$ 1,697,323	21.08%	6.27%	1.32%
2	Common Equity	6,354,582	-	6,354,582	78.92%	9.00%	7.10%
3	Total Capitalization	$ 8,051,905	$ -	$ 8,051,905	100.00%		
4	COST OF CAPITAL						8.42%

References:
Columns (A) Thru (F): See Testimony Of RUCO Witness William Rigsby

BELLA VISTA WATER COMPANY, INC.

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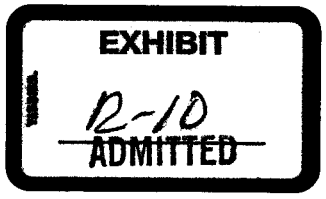

SUPPLEMENTAL DIRECT TESTIMONY AND RATE DESIGN

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 23, 2010

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INTRODUCTION

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

A. My name is Rodney L. Moore. I am a Public Utilities Analyst V with the Residential Utility Consumer Office ("RUCO"), located at 1110 West Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Have you previously filed testimony regarding this docket?

A. Yes. I filed direct testimony in this docket on April 12, 2010.

Q. What is the purpose of your supplemental direct testimony?

A. My supplemental direct testimony has three components. First, I will address Bella Vista's application on a stand-alone basis with an accompanying set of separate schedules for each of the three Companies (BVWC, NSWC and SSWC) to reflect the impact of RUCO's adjustments on the individual systems. Second, I will provide stand-alone rate designs and prove that those rate designs will produce RUCO's recommended revenues. Also an analysis of a typical residential bill for BVWC, NSWC and SSWC has been included. Finally, I will provide an alternative consolidated rate design, consolidated proof of revenue and consolidated typical bill analysis for the Commission's consideration.

To support RUCO's position in this supplemental direct testimony, Schedules numbered RLM-1 through RLM-14, RLM-RD1 and RLM-RD2

have been prepared for each Company (BVWC, NSWC and SSWC), plus a consolidated rate design numbered RLM-RD1 and RLM-RD2 is also included in this rate case proceeding.

SUMMARY OF ADJUSTMENTS

Q. Please summarize the adjustments to rate base, operating income and revenue requirement addressed in your supplemental testimony.

A. My supplemental testimony addresses RUCO adjustments previously identified in direct testimony filed on April 12, 2010 to reflect their impact on each of the three Companies (BVWC, NSWC and SSWC) individually. The issues previously discussed by RUCO on April 12, 2010 are as follows:

Rate Base

Post Test Year Gross Plant-In-Service and Accumulated Depreciation – This adjustment reflects changes in recorded plant costs from budget to the actual amounts in BVWC.

Customer Deposits – This adjustment reflects updated information to decrease meter deposits in BVWC and NSWC.

Accumulated Deferred Income Taxes – RUCO witness Timothy Coley will sponsor this adjustment for BVWC, NSWC and SSWC.

Operating Income

Test Year Depreciation Expense – This adjustment corrects a Company calculation error by including all depreciation expenses in the summation for BVWC.

Property Tax Expense - This adjustment reflects property tax expense based on RUCO's calculation of adjusted and proposed operating revenues for BVWC, NSWC and SSWC.

Miscellaneous Operating Expenses – These adjustments remove unnecessary operating expenses not required for the provisioning of water service and/or remove test year expenses deemed atypical and non-recurring in BVWC.

Central Office Cost Allocations - RUCO witness Timothy Coley will sponsor this adjustment for BVWC, NSWC and SSWC.

Rate Case Expense - This adjustment is based on RUCO's determination of the fair and reasonable cost to ratepayers for this application process for BVWC, NSWC and SSWC.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses for BVWC, NSWC and SSWC.

STAND-ALONE REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. As outlined in Schedule RLM-1, on a stand-alone basis RUCO is recommending that the Company's revenue requirement not exceed the following levels:

	COMPANY	RUCO	DIFFERENCE
BVWC	$4,484,734	$3,926,801	($557,933)
NSWC	$448,011	$359,250	($88,761)
SSWC	$753,226	$379,025	($374,201)

On a stand-alone basis, RUCO's recommended increase in Fair Value Rate Base ("FVRB") is based on the Company's Original Cost Rate Base ("OCRB") and is summarized on Schedule RLM-1:

	COMPANY	RUCO	DIFFERENCE
BVWC	$6,343,311	$5,180,398	($1,162,913)
NSWC	$742,658	$689,708	($52,950)
SSWC	$1,544,434	$1,418,329	($126,105)

On a stand-alone basis, RUCO's recommended required operating income is shown on Schedule RLM-1 as:

	COMPANY	RUCO	DIFFERENCE
BVWC	$683,175	$427,120	($256,055)
NSWC	$95,060	$54,515	($40,545)
SSWC	$197,688	$112,105	($85,583)

On a stand-alone basis, RUCO's recommended revenue requirement percentage increase versus the Company's proposal is as follows:

	COMPANY	RUCO	DIFFERENCE
BVWC	27.19 %	11.37 %	-15.82 %
NSWC	133.38 %	87.14 %	-46.24 %
SSWC	69.59 %	-14.66 %	-84.22 %

Schedule RLM-1 presents the calculation of RUCO's recommended revenue requirement.

STAND-ALONE RATE BASE

Rate Base Adjustment No. 1 – Post Test Year Gross Plant-In-Service and Accumulated Depreciation

Q. Please indicated where your adjustment to the post test year gross plant-in-service and the accumulated depreciation is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 8, line 17 and relates specifically to an adjustment to reflect actual costs incurred.

As shown on BVWC's Schedule RLM-3, column (B), and with supporting Schedule RLM-4, these adjustments decrease gross utility plant in service by $1,940 and accumulated depreciation by $3,610 for a net reduction in the adjusted test year rate base of $5,550.

Rate Base Adjustment No. 2 – Customer Deposits

Q. Please indicated where your adjustment to the customer deposits is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 9, line 10 and relates specifically to a reduction in customer deposits.

As shown on BVWC's Schedule RLM-3, column (C), this adjustment increased the adjusted test year rate base by $121,861.

Rate Base Adjustment No. 3 – Accumulated Deferred Income Taxes

Q. Please indicate where this adjustment to accumulated deferred income taxes was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley, please refer to his previously filed testimony starting on page 4, line 19 for clarification.

Q. Please explain how RUCO determined the allocation factor to appropriately determine the accumulated deferred income tax allocation to each individual Company.

A. Mr. Coley computed the allocation factor by calculating the ratio of the Company's "customer counts" for each system to the total combined customer count of the Company.

Based on Mr. Coley's testimony and as shown on BVWC's, NSWC's and SSWC's Schedule RLM-3, column (D), and with supporting Schedule RLM-5 this adjustment decreased their adjusted test year rate base by $1,279,224, $52,949 and $126,105, respectively.

STAND-ALONE OPERATING INCOMES

Operating Income Adjustment No. 1 – Test Year Depreciation Expense

Q. Please indicated where your adjustment to the test year depreciation expense is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 10, line 20 and relates specifically to a Company computation error.

As shown on BVWC's Schedule RLM-7, column (B), with supporting documentation on Schedule RLM-8, this adjustment increased the adjusted test year operating expenses by $32,214.

Operating Income Adjustment No. 2 – Property Tax Computation

Q. Please indicated where your adjustment to the property taxes is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 11, line 5 and relates specifically to RUCO's lower level of adjusted and proposed operating revenues.

As shown on BVWC's, NSWC's and SSWC's Schedule RLM-7, column (C), with supporting documentation on Schedule RLM-9 this adjustment decreased their adjusted test year operating expenses by $6,877, $1,172 and $175,308, respectively.

Operating Income Adjustment No. 3 – Miscellaneous Expense

Q. Please indicated where your adjustment to the miscellaneous expense is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 11, line 20 and relates specifically to the removal of unnecessary expenditures for charitable donations and a Company Christmas party.

As shown on BVWC's Schedule RLM-7, column (D), with supporting documentation on Schedule RLM-10, this adjustment decreased test year expenses by $2,500.

Operating Income Adjustment No. 4 – Central Office Cost Allocations

Q. Please indicate where this adjustment to the allocation of central office costs was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley, please refer to his previously filed testimony starting on page 25, line 18 for clarification.

Q. Please explain how RUCO determined the allocation factor to appropriately determine the central office cost alllocations to each individual Company.

A. Mr. Coley computed the allocation factor by calculating the ratio of the Company's "customer counts" for each system to the total combined customer count of the Company.

Based on Mr. Coley's testimony and as shown on BVWC's, NSWC's and SSWC's Schedule RLM-7, column (E), and with supporting Schedule RLM-11 this adjustment decreased their adjusted test year rate base by $127,133, $5,262 and $12,53, respectively.

Operating Income Adjustment No. 5 – Rate Case Expense

Q. Please indicated where your adjustment to rate case expenses is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 13, line 1. I decreased rate case expenses based on my analysis of the Company's actual and estimated costs associated with this proceeding.

Q. Please explain how RUCO determined the allocation factor to appropriately assess rate case expenses to each individual Company.

A. I computed the allocation factor by calculating the ratio of the Company's request rate case expenses for each system to the total aggregate amount of rate case expenses estimated by the Company.

As shown on BVWC's, NSWC's and SSWC's Schedule RLM-7, column (F) and supporting Schedule RLM-12, this adjustment decreased their adjusted test year expenses by $49,333, $8,693 and $8,640, respectively.

Operating Income Adjustment No. 6 – Income Taxes

Q. Please indicated where your adjustment to income taxes is explained.

A. My analysis is explained in my previously filed direct testimony starting on page 14, line 8 and relates specifically to RUCO's reduced revenue requirements.

As shown on BVWC's, NSWC's and SSWC's Schedule RLM-7, column (H) and supporting Schedule RLM-13, this adjustment increased their adjusted test year expenses by $67,106, $11,580 and $43,195, respectively.

STAND-ALONE COSTS OF CAPITAL

Q. Has RUCO conducted separate cost of capital analysis for BVWC, NSWC and SSWC?

A. Yes. RUCO witness William A. Rigsby has filed testimony on the cost of capital issues associated with the case. His recommended stand-alone capital structure and weighted average cost of capital is exhibited on BVWC's, NSWC's and SSWC's Schedule RLM-14.

STAND-ALONE RATE DESIGNS

Q. Please explain RUCO's stand-alone rate designs.

A. RUCO is recommending a stand-alone rate design that is generally consistent with the Company's proposed stand-alone rate design.

However, my rate design reflects RUCO's recommended revenue requirements and provides proof that the design will produce the appropriate revenue requirements.

Q. Please explain your contribution to RUCO's recommended rate designs.

A. I was responsible for producing an accurate set of bill determinants (i.e. test-year customer bill counts, gallons of water consumed). I am in agreement with the bill determinants normalized by the Company. My recommended bill determinants are an integral part of the rate designs presented on Schedules RLM-RD1.

Q. Does RUCO support the Company's request to consolidate operations and the transfer of utility assets of Bella Vista Water Company, Inc., Northern Sunrise Water Company, Inc. and Southern Sunrise Water Company, Inc. into Bella Vista Water Company, Inc.?

A. RUCO supports stand-alone rates. As explained in the direct testimony of RUCO Director Jodi Jerich, RUCO recommends rate designs on a stand-alone basis, but will not object to consolidation, if the Commission determines that such a rate design is in the public interest.

Please refer to the supplemental direct testimony filed by RUCO Director Jodi Jerich for the rationale and analysis of public policy regarding RUCO's position on rate design recommendations.

STAND-ALONE PROOF OF RECOMMENDED REVENUES

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that my recommended stand-alone rate designs will produce the recommended required revenue as illustrated, is presented also on Schedule RLM-RD1.

STAND-ALONE TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended stand-alone rate design on the typical residential customer?

A. Yes. A typical bill analysis for residential customers with various levels of usage is presented on Schedule RLM-RD2. The stand-alone rate designs will affect customers of BVWC, NSWC and SSWC differently.

Q. Please describe the financial impact of RUCO's rate design on the average BVWC residential customer.

A. RUCO's rate designs propose a basic service charge for residential customers of BVWC with a 5/8" X 3/4" meter of $16.10 (versus $18.46 proposed by the Company) and commodity charges of $1.3341 per thousand gallons for the first 4,000 gallons, $1.9445 per thousand gallons for the next 6,000 gallons and $2.2932 per thousand gallons for all usage above 10,000 gallons (versus $1.5300, $2.2300 and $2.6300, proposed respectively by the Company).

For residential customers of BVWC with a 5/8" X 3/4" meter and average consumption of 6,612 gallons, RUCO's rate design provides for a $3.04 or 15.70 percent increase, which is a decrease of $4.47 or 59.52 percent over the Company's requested $7.51 or 32.79 percent increase.

Q. Please describe the financial impact of RUCO's rate design on the average NSWC residential customer.

A. RUCO's rate designs propose a basic service charge for residential customers of NSWC with a 5/8" X 3/4" meter of $60.35 (versus $75.39 proposed by the Company) and commodity charges of $3.8902 per thousand gallons for the first 4,000 gallons, $4.6907 per thousand gallons for the next 6,000 gallons and $5.6112 per thousand gallons for all usage above 10,000 gallons (versus $4.8600, $5.8600 and $7.0100, proposed respectively by the Company).

For residential customers of NSWC with a 5/8" X 3/4" meter and average consumption of 5,755 gallons, RUCO's rate design provides for a $41.06 or 95.33 percent increase, which is a decrease of $20.98 or 33.82 percent over the Company's requested $62.04 or 144.02 percent increase.

Q. Please describe the financial impact of RUCO's rate design on the average SSWC residential customer.

A. RUCO's rate designs propose a basic service charge for residential customers of SSWC with a 5/8" X 3/4" meter of $26.96 (versus $54.37 proposed by the Company) and commodity charges of $1.7406 per thousand gallons for the first 4,000 gallons, $2.1126 per thousand gallons for the next 6,000 gallons and $2.6828 per thousand gallons for all usage

above 10,000 gallons (versus $3.5100, $4.2600 and $5.4100, proposed respectively by the Company).

For residential customers of SSWC with a 5/8" X 3/4" meter and average consumption of 5,581 gallons, RUCO's rate design provides for a $5.33 or 12.52 percent decrease, which is a decrease of $37.88 or 116.37 percent over the Company's requested $32.55 or 76.41 percent increase.

CONSOLIDATED RATE DESIGN

Q. Please explain RUCO's position on consolidated rate design.

A. RUCO will not oppose consolidated rates if the Commission finds that such rate design is in the public interest.

Therefore, RUCO is providing an alternative consolidated rate design that is generally consistent with the Company's proposed consolidated rate design, but reflects RUCO's recommended revenue requirements and provides proof that the design will produce the appropriate revenue requirements.

CONSOLIDATED PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that my recommended consolidated rate design will produce the recommended required revenue as illustrated, is presented also on Schedule RLM-RD1.

CONSOLIDATED TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's consolidated rate design on the typical residential customer?

A. Yes. A typical bill analysis for residential customers with various levels of usage is presented on Schedule RLM-RD2.

The consolidated rate design will affect customers of BVWC, NSWC and SSWC differently.

RUCO's rate designs propose a basic service charge for residential customers of BVWC with a 5/8" X 3/4" meter of $15.47 (versus $17.92 proposed by the Company) and commodity charges of $1.7059 per thousand gallons for the first 4,000 gallons, $2.5693 per thousand gallons for the next 6,000 gallons and $3.3464 per thousand gallons for all usage above 10,000 gallons (versus $1.9756, $2.9756 and $3.8756 proposed respectively by the Company).

Q. Please describe the financial impact of RUCO's rate design on the average BVWC residential customer.

A. For residential customers of BVWC with a 5/8" X 3/4" meter and average consumption of 6,612 gallons, RUCO's rate design provides for a $6.11 or 26.69 percent increase, which is a decrease of $4.59 or 20.03 percent over the Company's requested $10.70 or 46.72 percent increase.

Q. Please describe the financial impact of RUCO's rate design on the average NSWC residential customer.

A. For residential customers of NSWC with a 5/8" X 3/4" meter and average consumption of 5,755 gallons, RUCO's rate design provides for a ($16.27) or -37.77 percent decrease, which is an increase of $4.24 or 9.84 percent over the Company's requested ($12.03) or -27.93 percent decrease.

Q. Please describe the financial impact of RUCO's rate design on the average SSWC residential customer.

A. For residential customers of SSWC with a 5/8" X 3/4" meter and average consumption of 5,581 gallons, RUCO's rate design provides for a ($16.24) or -38.12 percent decrease, which is an increase of $4.17 or 9.78 percent over the Company's requested ($12.07) or -28.34 percent decrease.

Q. Does this conclude your supplemental direct testimony?

A. Yes, it does.

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TABLE OF CONTENTS TO RLM SCHEDULES

SCH. NO.	PAGE NO.	TITLE
RLM-1	1 & 2	REVENUE REQUIREMENT
RLM-2	1	RATE BASE
RLM-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
RLM-5	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
RLM-6	1	OPERATING INCOME
RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
RLM-11	1	OPERATING INCOME ADJUSTMENT NO. 4 - CENTRAL OFFICE COST ALLOCATION
RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSES
RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 6 - INCOME TAX EXPENSE
RLM-14	1	COST OF CAPITAL

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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 6,343,311	$ 5,180,398
2	Adjusted Operating Income (Loss)	$ 94,521	$ 181,044
3	Current Rate Of Return (L2 / L1)	1.49%	3.49%
4	Required Operating Income (L5 X L1)	$ 683,175	$ 427,120
5	Required Rate Of Return On Fair Value Rate Base	10.77%	8.24%
6	Operating Income Deficiency (L4 - L2)	$ 588,653	$ 246,076
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6286	1.6286
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 958,701	$ 400,768
9	Adjusted Test Year Revenue	$ 3,526,033	$ 3,526,033
10	Proposed Annual Revenue (L8 + L9)	$ 4,484,734	$ 3,926,801
11	Required Percentage Increase In Revenue (L8 / L9)	27.19%	11.37%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RLM-2, RLM-6, And RLM-14

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REVENUE REQUIREMENT - CONT'D
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. RLM-1, Col. (B), L4)	$ 427,120			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. RLM-1, Col. (B), L2)	181,044			
13	Required Increase In Operating Income (L11 - L12)		$ 246,076		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 211,730			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	57,038			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 154,692		
17	Total Required Increase In Revenue (L13 + L16)		$ 400,768		
				RUCO Recommended	
	CALCULATION OF INCOME TAX:				
18	Revenue (Sch. RLM-1, Col. (B), L10)			$ 3,926,801	
19	Operating Expense Excluding Income Tax (RLM-6, Col. (E), L28 - L27)			(3,287,951)	
20	Synchronized Interest (Col. (C), L37)			(90,311)	
21	Arizona Taxable Income (L18 + L19 + L20)			$ 548,538	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 38,222
24	Fed. Taxable Income (L21 - L23)			$ 510,316	
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%			59,608	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 173,508
31	Combined Federal And State Income Tax (L23 + L30)				$ 211,730
32	Test Year Combined Income Tax, RUCO As Adjusted (RLM-6, Col. (C), L24)				$ 57,038
33	RUCO Adjustment (L31 - L32) (See RLM-6, Col. (D), L24)				$ 154,692
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				34.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. RLM-2, Col. (H), L15)			$ 5,180,398	
36	Weighted Avg. Cost Of Debt (Sch. RLM-14, Col. (F), L1)			1.74%	
37	Synchronized Interest (L35 X L36)			$ 90,311	

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 25,625,206	$ (1,940)	$ 25,623,266
2	Accumulated Depreciation	(11,909,440)	(3,610)	(11,913,050)
3	Net Utility Plant In Service (L1 + L2)	$ 13,715,765	$ (5,550)	$ 13,710,215
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (496,445)	$ -	$ (496,445)
6	Accumulated Amortization Of CIAC	230,909	-	230,909
7	NET CIAC (L5 + L6)	$ (265,536)	$ -	$ (265,536)
8	Customer Meter Deposits	$ (556,325)	$ 134,361	$ (421,964)
9	Customer Hydrant Meter Deposits	$ -	$ (12,500)	$ (12,500)
10	Deferred Income Taxes & Credits	$ 230,850	$ (1,279,224)	$ (1,048,374)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 6,343,311	$ (1,162,913)	$ 5,180,398

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

Bella Vista Water Company (Stand-Alone)
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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) INTENT'NLY LEFT BLANK	(F) INTENT'NLY LEFT BLANK	(G) INTENT'NLY LEFT BLANK	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 25,625,206	$ (1,940)	$ -	$ -	$ -	$ -	$ -	$ 25,623,266
2	Accumulated Depreciation	(11,909,440)	(3,610)	-	-	-	-	-	(11,913,050)
3	Net Utility Plant In Service (L1 + L2)	$ 13,715,765	$ (5,550)	$ -	$ -	$ -	$ -	$ -	$ 13,710,215
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (496,445)	$ -	$ -	$ -	$ -	$ -	$ -	$ (496,445)
6	Accumulated Amortization Of CIAC	230,909	-	-	-	-	-	-	230,909
7	NET CIAC (L5 + L6)	$ (265,536)	$ -	$ -	$ -	$ -	$ -	$ -	$ (265,536)
8	Customer Meter Deposits	$ (556,325)	$ -	$ 134,361	$ -	$ -	$ -	$ -	$ (421,964)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ (12,500)	$ -	$ -	$ -	$ -	$ (12,500)
10	Deferred Income Taxes & Credits	$ 230,850	$ -	$ -	$ (1,279,224)	$ -	$ -	$ -	$ (1,048,374)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 6,343,311	$ (5,550)	$ 121,861	$ (1,279,224)	$ -	$ -	$ -	$ 5,180,398

References:

Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Testimony Of RUCO Witness Tim Coley and Schedule RLM-5)
Column (E): Intentionally Left Blank
Column (F): Intentionally Left Blank
Column (G): Intentionally Left Blank
Column (H): Sum Of Columns (A), (B), (C), (D), (E) & (F)

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Schedule RLM-4
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POST TEST YEAR PLANT SCHEDULE
YEAR ENDED JUNE 30, 2008

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) RUCO T/Y PLANT AS ADJUSTED	(B) RUCO POST TY ADJM'TS PLANT ADDITIONS	(C) RUCO POST TY ADJM'TS PLANT RETIRMENTS	(D) TOTAL PLANT VALUE	(E) ACC. DEP.	(F) NET PLANT VALUE
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise Cost	-	-	-	-	-	-
3	303	Land and Land Rights	327,399	-	-	327,399	-	327,399
4	304	Structures and Improvements	1,312,116	-	-	1,312,116	(388,090)	924,027
5	305	Collecting and Impounding Res.	-	-	-	-	-	-
6	306	Lake River and Other Intakes	-	-	-	-	-	-
7	307	Wells and Springs	1,132,179	-	-	1,132,179	(525,150)	607,029
8	308	Infiltration Galleries and Tunnels	-	-	-	-	-	-
9	309	Supply Mains	-	-	-	-	-	-
10	310	Power Generation Equipment	-	-	-	-	-	-
11	311	Electric Pumping Equipment	2,487,503	-	-	2,487,503	(2,481,910)	5,593
12	320	Water Treatment Equipment	109,639	-	-	109,639	(50,073)	59,566
13	320.1	Water Treatment Equipment	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2,343,634	-	-	2,343,634	(812,593)	1,531,041
16	330.1	Storage tanks	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	12,600,027	104,507	(8,390)	12,696,144	(4,099,875)	8,596,269
19	333	Services	1,399,781	-	-	1,399,781	(834,738)	565,043
20	334	Meters	1,491,209	-	-	1,491,209	(1,491,209)	-
21	335	Hydrants	892,445	-	-	892,445	(282,181)	610,264
22	336	Backflow Prevention Devices	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	69,551	-	-	69,551	(5,253)	64,299
24	340	Office Furniture and Fixtures	202,929	-	-	202,929	(170,545)	32,385
25	340.1	Computers and Software	161,264	-	-	161,264	(117,801)	43,463
26	341	Transportation Equipment	295,224	-	-	295,224	(291,918)	3,305
27	342	Stores Equipment	-	-	-	-	-	-
28	343	Tools and Work Equipment	124,683	-	-	124,683	(124,683)	-
29	344	Laboratory Equipment	-	-	-	-	-	-
30	345	Power Operated Equipment	31,548	-	-	31,548	(5,882)	25,666
31	346	Communications Equipment	435,668	-	-	435,668	(126,570)	309,098
32	347	Miscellaneous Equipment	110,348	-	-	110,348	(104,580)	5,768
33	348	Other Tangible Plant	-	-	-	-	-	-
34		Rounding 0	-			-	-	-
35	TOTAL WASTEWATER PLANT		$ 25,527,149	$ 104,507	$ (8,390)	$ 25,623,266	$ (11,913,050)	$ 13,710,215
36	Company As Filed					25,625,206	$ (11,909,440)	
37	Difference					(1,940)	$ (3,610)	
38	RUCO Adjustment (Line 37) (See RLM-3, Column (B))					(1,940)	$ (3,610)	

References:
Column (A): RUCO Workpapers RLM-4-A(1)
Columns (B) (C): Testimony, RLM
Column (D): Sum Of Columns (A), (B), & (C)
Column (E): Sum Of WP RLM-4-A(1), Column (B) And RLM-4, Column (C)
Column (F): Column (D) + Column (E)

Bella Vista Water Company (Stand-Alone)
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Schedule RLM-5
Page 1 of 1

ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Consolidated Allocation	Note (A)	1.5438%
5	Bella Vista Consolidated ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Consolidated Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Total Consolidated ADIT as Filed by Company	Company Schedule C-1	173,329
9	Decrease In Deferred Income Tax Assets	Line 7 - Line 8	$ (1,458,278)
10	Total Bella Vista Customer Count Factor	Per Company	0.8772
11	RUCO Adjustment (See RLM-3, Column (D), Line 10)	Line 9 X Line 10	(1,279,224)

NOTES:

12	(A)	Purchase Price of BVWC, NSWC and SSWC	Annual Report	$	15,100,000
13		Algonquin Total Assets	Annual Report	$	978,130,000
14		Ratio Of BVWC, NSWC & SSWC To Algonquin Total A	Line 12 / Line 13		1.5438%
15	(B)	Currency Conversion	moneycentral.com on 04/1/2010		0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

Bella Vista Water Company (Stand-Alone)
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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	Flat Rate Revenues	$ 3,400,892	$ -	$ 3,400,892	$ 400,768	$ 3,801,660
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	125,141	-	125,141	-	125,141
4	TOTAL OPERATING REVENUE	$ 3,526,033	$ -	$ 3,526,033	$ 400,768	$ 3,926,801
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	708	-	708
7	Purchased Power	561,094	-	561,094	-	561,094
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	4,273	-	4,273	-	4,273
10	Materials & Supplies	36,932	-	36,932	-	36,932
11	Outside Services	4,605	-	4,605	-	4,605
12	Outside Services- Legal	35,245	-	35,245	-	35,245
13	Outside Services- Other	1,258,045	(127,133)	1,130,913	-	1,130,913
14	Water Testing	18,805	-	18,805	-	18,805
15	Equipment Rental		-	-	-	-
16	Rents	60,600	-	60,600	-	60,600
17	Transportation Expenses	78,117	-	78,117	-	78,117
18	Insurance - General Liability	38,930	-	38,930	-	38,930
19	Insurance - Health and Life	7,290	-	7,290	-	7,290
20	Reg. Comm. Exp.	9,017	-	9,017	-	9,017
21	Reg. Comm. Exp. - Rate Case	83,333	(49,333)	34,000	-	34,000
22	Miscellaneous Expense	65,966	(2,500)	63,466	-	63,466
23	Bad Debt Expense	9,526	-	9,526	-	9,526
24	Depreciation Expense	1,009,435	32,214	1,041,649	-	1,041,649
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	159,659	(6,877)	152,782	-	152,782
27	Income Tax	(10,068)	67,106	57,038	154,692	211,730
28	TOTAL OPERATING EXPENSES	$ 3,431,512	$ (86,523)	$ 3,344,989	$ 154,692	$ 3,499,681
29	OPERATING INCOME (LOSS)	$ 94,521		$ 181,044		$ 427,120

References:
Column (A): Company Schedule C-1
Column (B): RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From RLM-1, Column (B), Line 8 And Income Tax From RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 CENTRAL OFFICE COST	(F) ADJ # 5 RATE CASE EXPENSES	(G) LEFT BLANK	(H) ADJ # 6 INCOME TAX	(I) RUCO AS ADJT'D
	Revenues:									
1	Flat Rate Revenues	$ 3,400,892	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,400,892
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	125,141	-	-	-	-	-	-	-	125,141
4	TOTAL OPR'G REV.	$ 3,526,033	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,526,033
	Operating Expenses:									
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	-	-	-	-	-	-	708
7	Purchased Power	561,094	-	-	-	-	-	-	-	561,094
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-
9	Chemicals	4,273	-	-	-	-	-	-	-	4,273
10	Materials & Supplies	36,932	-	-	-	-	-	-	-	36,932
11	Outside Services	4,605	-	-	-	-	-	-	-	4,605
12	Outside Services- Legal	35,245	-	-	-	-	-	-	-	35,245
13	Outside Services- Other	1,258,045	-	-	-	(127,133)	-	-	-	1,130,913
14	Water Testing	18,805	-	-	-	-	-	-	-	18,805
15	Equipment Rental	-	-	-	-	-	-	-	-	-
16	Rents	60,600	-	-	-	-	-	-	-	60,600
17	Transportation Expenses	78,117	-	-	-	-	-	-	-	78,117
18	Insurance - General Liability	38,930	-	-	-	-	-	-	-	38,930
19	Insurance - Health and Life	7,290	-	-	-	-	-	-	-	7,290
20	Reg. Comm. Exp.	9,017	-	-	-	-	-	-	-	9,017
21	Reg. Comm. Exp. - Rate Case	83,333	-	-	-	-	(49,333)	-	-	34,000
22	Miscellaneous Expense	65,966	-	-	(2,500)	-	-	-	-	63,466
23	Bad Debt Expense	9,526	-	-	-	-	-	-	-	9,526
24	Depreciation Expense	1,009,435	32,214	-	-	-	-	-	-	1,041,649
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-
26	Property Taxes	159,659	-	(6,877)	-	-	-	-	-	152,782
27	Income Tax	(10,068)	-	-	-	-	-	-	67,106	57,038
29	TOTAL OPR'G EXP.	$ 3,431,512	$ 32,214	$ (6,877)	$ (2,500)	$ (127,133)	$ (49,333)	$ -	$ 67,106	$ 3,344,989
30	OPR'G INC. (LOSS)	$ 94,521								$ 181,044

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8
Column (C): Testimony, RLM And Schedule RLM-9
Column (D): Testimony, RLM And Schedule RLM-10
Column (E): Testimony, TLC And Schedule RLM-11
Column (F): Testimony, RLM And Schedule RLM-12
Column (G): Intentionally Left Blank
Column (H): Testimony, RLM And Schedule RLM-13
Column (I): Sum Of Columns (A) Thru (H)

Bella Vista Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	-	0.00%	-
3	303	Land and Land Rights	327,399	0.00%	-
4	304	Structures and Improvements	1,312,116	3.33%	43,693
5	305	Collecting and Impounding Res.	-	2.50%	-
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	1,132,179	3.33%	37,702
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	-	2.00%	-
10	310	Power Generation Equipment	-	5.00%	-
11	311	Electric Pumping Equipment	2,487,503	12.50%	310,938
12	320	Water Treatment Equipment	109,639	3.33%	3,651
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	2,343,634	2.22%	52,029
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	12,696,144	2.00%	253,923
19	333	Services	1,399,781	3.33%	46,613
20	334	Meters	1,491,209	8.33%	124,218
21	335	Hydrants	892,445	2.00%	17,849
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	69,551	6.67%	4,639
24	340	Office Furniture and Fixtures	202,929	6.67%	13,535
25	340.1	Computers and Software	161,264	20.00%	32,253
26	341	Transportation Equipment	295,224	20.00%	59,045
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	124,683	5.00%	6,234
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	31,548	5.00%	1,577
31	346	Communications Equipment	435,668	10.00%	43,567
32	347	Miscellaneous Equipment	110,348	10.00%	11,035
33	348	Other Tangible Plant	-	10.00%	-
34		Rounding	-		-
35	TOTAL WASTEWATER PLANT		$ 25,623,266		$ 1,062,500
	Less:				
36	Amortizations Of CIAC (RLM-2, Col. (C), Line 5)		$ (496,445)	4.2001%	(20,851)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 1,041,649
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				1,009,435
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ 32,214
40	RUCO Adjustment (Line 39) (See RLM-7, Column (B), Line 25)				$ 32,214

References: Column (A): RLM-4, Column (E)
Column (B): Company Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

Bella Vista Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	$ 3,526,033	
2	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	3,526,033	
3	Proposed Revenues	Sch. RLM-6, Col (E), Ln 4	3,926,801	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 10,978,867	
5	Average Annual Operating Revenues	Line 4 / 3	3,659,622	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 7,319,245
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 379,887	
8	10% Of CWIP	Line 7 X 10%		$ 37,989
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ 295,224	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	(291,918)	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ (3,305)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 7,353,928
	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	$ 1,544,325	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	9.8053%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.81%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 151,425
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,357
20	Company's Total Tax Liability	Line 18 + Line 19		$ 152,782
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 36		159,659
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (6,877)
23	RUCO Adjustment (See RLM-7, Column (C), Line 27)	Line 22		$ (6,877)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
DISALLOWANCE OF MISCELLANEOUS EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL
	Disallowed Miscellaneous Expenses	Co. Response To Staff D. R. CSB 1-32	
1	Bella Vista Water Company Christmas Party		$ (2,000)
2	Special Olympics Pledge		(250)
3	Muscular Distrophy Association Donation		(250)
4	RUCO Adjustment To Unnecessary/Non-Recurring Expenses	Sum Of Lines 1 Thru 17	$ (2,500)
5	RUCO Adjustment (See RLM-7, Column (D))	Line 18	$ (2,500)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To BVWC	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	24.29%	$ 47,253	12.74%	$ 6,020
2	Tax Services	518,775	25.00%	129,694	24.29%	31,497	12.74%	4,013
3	Legal	159,053	25.00%	39,763	24.29%	9,657	12.74%	1,230
4	Other Professional Services	506,082	0.00%	-	24.29%	-	12.74%	-
5	Management Fee - Total	644,943	0.00%	-	24.29%	-	12.74%	-
6	Unit Holder Communications	156,766	0.00%	-	24.29%	-	12.74%	-
7	Trustee Fees	129,000	0.00%	-	24.29%	-	12.74%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	24.29%	-	12.74%	-
9	Rent	307,337	0.00%	-	24.29%	-	12.74%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	24.29%	-	12.74%	-
11	Office Expenses	579,379	0.00%	-	24.29%	-	12.74%	-
12	Depreciation	211,653	25.00%	52,913	24.29%	12,850	12.74%	1,637
13	TOTAL	$ 4,104,971		$ 416,941		$ 101,257		$ 12,901
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 141,127
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on April 1, 2010							0.99147
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 139,923
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 12,791
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(127,133)
19	RUCO Adjustment (See RLM-7, Column (E))							(127,133)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 5
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJM'T	(C) RUCO AS ADJ'D
1	Rate Case Expense Total	$ 250,000	$ (148,000)	$ 102,000
2	Normalization Period - 3 Years			3
3	RUCO Adjusted Rate Case Expense For Instant Case (Line 1 / 3 Years)			$ 34,000
4	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 83,333
5	RUCO Pro Forma Rate Case Expense (Lines 3 - 4)			$ (49,333)
6	RUCO Adjustment (Line 5) (See RLM-7, Column (F))			$ (49,333)

	RUCO CALCULATED RATE CASE EXPENSES	CONSOL'D TOTALS	BVWC ALONE	NSWC ALONE	SSWC ALONE
	ACTUALS Invoices Per Fennemore Craig	$ 59,206	$ 23,782	$ 17,633	$ 17,791
7	Total Costs Through February 2010				
	ESTIMATES Based On Estimate From Black Mountain Sewer Co.	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR
8	Remaining Costs For Company Witness Tom Borassa:	100.00%	55.56%	22.22%	22.22%
9	Rebuttal, Surrebuttal, Rejoinder And Trial Process;				
10	Final Schedules, Briefing, Evaluation Of ROO; Open Meeting Prep	$ 25,000	$ 13,889	$ 5,556	$ 5,556
			-	-	-
11	Expedited Hearing Transcript	5,000	2,778	1,111	1,111
			-	-	-
12	Fennemore Craig Estimated Remaining Costs		-	-	-
13	Rebuttal, Surrebuttal, Rejoinder And Trial Process;	45,000	25,000	10,000	10,000
14	Briefing	30,000	16,667	6,667	6,667
15	Reviewing ROO; Exceptions Open Meeting Prep	10,000	5,556	2,222	2,222
16	Post Decision Compliance And Filings	15,000	8,333	3,333	3,333
17	Per Diam Expenses	10,000	5,556	2,222	2,222
18	Rounding	794	441	176	176
19	RUCO ESTIMATED RATE CASE EXPENSES	$ 200,000	$ 102,000	$ 48,921	$ 49,079

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. RLM-6, Column (C), L29 + L27	$ 238,082
	LESS:		
2	Arizona State Tax	Line 11	(10,297)
3	Interest Expense	Note (A) Line 20	(90,311)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 137,474
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 46,741
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 238,082
	LESS:		
8	Interest Expense	Note (A) Line 20	(90,311)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 147,770
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 10,297
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 46,741
13	State Income Tax Expense	Line 11	10,297
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 57,038
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		(10,068)
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 67,106
17	RUCO Adjustment (See Sch. RLM-7, Column (K), L278)	Line16	$ 67,106

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. RLM-2, Col. (E), L15)	$	5,180,398
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		1.74%
20	Interest Expense (L17 X L18)	$	90,311

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) DOLLAR AMOUNT	(B) RUCO ADJTM'T	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Long-Term Debt	$ 1,697,323	$ -	$ 1,697,323	27.76%	6.28%	1.74%
2	Common Equity	6,354,582	-	6,354,582	72.24%	9.00%	6.50%
3	Total Capitalization	$ 8,051,905	$ -	$ 8,051,905	100.00%		
4	COST OF CAPITAL						8.24%

References:
Columns (A) Thru (F): See Testimony Of RUCO Witness William Rigsby

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RLM-14	1	COST OF CAPITAL

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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 742,658	$ 689,708
2	Adjusted Operating Income (Loss)	$ (81,316)	$ (77,769)
3	Current Rate Of Return (L2 / L1)	-10.95%	-11.28%
4	Required Operating Income (L5 X L1)	$ 95,060	$ 54,515
5	Required Rate Of Return On Fair Value Rate Base	12.80%	7.90%
6	Operating Income Deficiency (L4 - L2)	$ 176,376	$ 132,283
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.4517	1.2646
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 256,044	$ 167,284
9	Adjusted Test Year Revenue	$ 191,966	$ 191,966
10	Proposed Annual Revenue (L8 + L9)	$ 448,011	$ 359,250
11	Required Percentage Increase In Revenue (L8 / L9)	133.38%	87.14%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RLM-2, RLM-6, And RLM-14

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REVENUE REQUIREMENT - CONT'D
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)	(0.2092)			
3	Subtotal (L1 + L2)	0.7908			
4	**Revenue Conversion Factor** (L1 / L3)	**1.2646**			
	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)	15.0000%			
9	Effective Federal Income Tax Rate (L7 X L8)	13.9548%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	20.9228%			
11	Required Operating Income (Sch. RLM-1, Col. (B), L4)	$ 54,515			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. RLM-1, Col. (B), L2)	(77,769)			
13	Required Increase In Operating Income (L11 - L12)		$ 132,283		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 9,854			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	(25,146)			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ 35,000		
17	Total Required Increase In Revenue (L13 + L16)		$ 167,284		
				RUCO Recommended	
	CALCULATION OF INCOME TAX:				
18	Revenue (Sch. RLM-1, Col. (B), L10)			$ 359,250	
19	Operating Expense Excluding Income Tax (RLM-6, Col. (E), L28 - L27)			(294,881)	
20	Synchronized Interest (Col. (C), L37)			(17,270)	
21	Arizona Taxable Income (L18 + L19 + L20)			$ 47,099	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 3,282
24	Fed. Taxable Income (L21 - L23)			$ 43,817	
25	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 6,573	
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%			-	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 6,573
31	Combined Federal And State Income Tax (L23 + L30)				$ 9,854
32	Test Year Combined Income Tax, RUCO As Adjusted (RLM-6, Col. (C), L24)				$ (25,146)
33	RUCO Adjustment (L31 - L32) (See RLM-6, Col. (D), L24)				$ 35,000
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				15.00%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. RLM-2, Col. (H), L15)			$ 689,708	
36	Weighted Avg. Cost Of Debt (Sch. RLM-14, Col. (F), L1)			2.50%	
37	Synchronized Interest (L35 X L36)			$ 17,270	

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 815,886	$ -	$ 815,886
2	Accumulated Depreciation	(42,739)	-	(42,739)
3	Net Utility Plant In Service (L1 + L2)	$ 773,147	$ -	$ 773,147
4	Advances In Aid Of Const.	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (26,000)	$ -	$ (26,000)
6	Accumulated Amortization Of CIAC	63	-	63
7	NET CIAC (L5 + L6)	$ (25,937)	$ -	$ (25,937)
8	Customer Meter Deposits	$ (410)	$ -	$ (410)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (4,144)	$ (52,949)	$ (57,092)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 742,657	$ (52,949)	$ 689,708

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) INTENT'NLY LEFT BLANK	(F) INTENT'NLY LEFT BLANK	(G) INTENT'NLY LEFT BLANK	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 815,886	$ -	$ -	$ -	$ -	$ -	$ -	$ 815,886
2	Accumulated Depreciation	(42,739)	-	-	-	-	-	-	(42,739)
3	Net Utility Plant In Service (L1 + L2)	$ 773,147	$ -	$ -	$ -	$ -	$ -	$ -	$ 773,147
4	Advances In Aid Of Const.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (26,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ (26,000)
6	Accumulated Amortization Of CIAC	63	-	-	-	-	-	-	63
7	NET CIAC (L5 + L6)	$ (25,937)	$ -	$ -	$ -	$ -	$ -	$ -	$ (25,937)
8	Customer Meter Deposits	$ (410)	$ -	$ -	$ -	$ -	$ -	$ -	$ (410)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (4,144)	$ -	$ -	$ (52,949)	$ -	$ -	$ -	$ (57,092)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 742,657	$ -	$ -	$ (52,949)	$ -	$ -	$ -	$ 689,708

References:

Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Testimony Of RUCO Witness Tim Coley and Schedule RLM-5)
Column (E): Intentionally Left Blank
Column (F): Intentionally Left Blank
Column (G): Intentionally Left Blank
Column (H): Sum Of Columns (A), (B), (C), (D), (E) & (F)

Northern Sunrise Water Company (Stand-Alone)
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POST TEST YEAR PLANT SCHEDULE
YEAR ENDED JUNE 30, 2008

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) RUCO T/Y PLANT AS ADJUSTED	(B) RUCO POST TY ADJM'TS PLANT ADDITIONS	(C) RUCO POST TY ADJM'TS PLANT RETIRMENTS	(D) TOTAL PLANT VALUE	(E) ACC. DEP.	(F) NET PLANT VALUE
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise Cost	890	-	-	890	-	890
3	303	Land and Land Rights	23,926	-	-	23,926	-	23,926
4	304	Structures and Improvements	281,810	-	-	281,810	(5,969)	275,841
5	305	Collecting and Impounding Res.	51,378	-	-	51,378	(2,059)	49,319
6	306	Lake River and Other Intakes	-	-	-	-	-	-
7	307	Wells and Springs	34,064	-	-	34,064	(1,644)	32,420
8	308	Infiltration Galleries and Tunnels	-	-	-	-	-	-
9	309	Supply Mains	-	-	-	-	-	-
10	310	Power Generation Equipment	1,293	-	-	1,293	(75)	1,218
11	311	Electric Pumping Equipment	92,122	-	-	92,122	(12,342)	79,780
12	320	Water Treatment Equipment	-	-	-	-	-	-
13	320.1	Water Treatment Equipment	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	102,018	-	-	102,018	(1,762)	100,255
16	330.1	Storage tanks	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	36,763	-	-	36,763	(1,661)	35,102
19	333	Services	30,106	-	-	30,106	(930)	29,176
20	334	Meters	8,244	-	-	8,244	(462)	7,783
21	335	Hydrants	59,298	-	-	59,298	(2,037)	57,262
22	336	Backflow Prevention Devices	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	23,472	-	-	23,472	(1,799)	21,673
24	340	Office Furniture and Fixtures	-	-	-	-	-	-
25	340.1	Computers and Software	-	-	-	-	-	-
26	341	Transportation Equipment	-	-	-	-	-	-
27	342	Stores Equipment	-	-	-	-	-	-
28	343	Tools and Work Equipment	-	-	-	-	-	-
29	344	Laboratory Equipment	-	-	-	-	-	-
30	345	Power Operated Equipment	-	-	-	-	-	-
31	346	Communications Equipment	5,881	-	-	5,881	(691)	5,189
32	347	Miscellaneous Equipment	-	-	-	-	-	-
33	348	Other Tangible Plant	64,621	-	-	64,621	(11,309)	53,312
34		Rounding	-			-	-	-
		0						
35	TOTAL WASTEWATER PLANT		$ 815,886	$ -	$ -	$ 815,886	$ (42,739)	$ 773,147
36	Company As Filed					815,886	$ (42,739)	
37	Difference					-	$ -	
38	RUCO Adjustment (Line 37) (See RLM-3, Column (B))					-	$ -	

References:
Column (A): RUCO Workpapers RLM-4-A(1)
Columns (B) (C): Testimony, RLM
Column (D): Sum Of Columns (A), (B), & (C)
Column (E): Sum Of WP RLM-4-A(1), Column (B) And RLM-4, Column (C)
Column (F): Column (D) + Column (E)

Northern Sunrise Water Company (Stand-Alone)
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ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Consolidated Allocation	Note (A)	1.5438%
5	Bella Vista Consolidated ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Consolidated Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Total Consolidated ADIT as Filed by Company	Company Schedule C-1	173,329
9	Decrease In Deferred Income Tax Assets	Line 7 - Line 8	$ (1,458,278)
10	Total Northern Sunrise Customer Count Factor	Per Company	0.0363
11	RUCO Adjustment (See RLM-3, Column (D), Line 11)	Line 9 X Line 10	(52,949)

NOTES:

12	(A)	Purchase Price of NSWC	Annual Report	$ 15,100,000
13		Algonquin Total Assets	Annual Report	$ 978,130,000
14		Ratio Of NSWC To Algonquin Total Assets	Line 12 / Line 13	1.5438%
15	(B)	Currency Conversion	moneycentral.com on 04/1/2010	0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

Northern Sunrise Water Company (Stand-Alone)
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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	Flat Rate Revenues	$ 188,672	$ -	$ 188,672	$ 167,283	$ 355,956
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	3,294	-	3,294	-	3,294
4	TOTAL OPERATING REVENUE	$ 191,966	$ -	$ 191,966	$ 167,283	$ 359,250
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-
7	Purchased Power	16,012	-	16,012	-	16,012
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	178	-	178	-	178
10	Materials & Supplies	5,094	-	5,094	-	5,094
11	Outside Services	-	-	-	-	-
12	Outside Services- Legal	1,302	-	1,302	-	1,302
13	Outside Services- Other	161,902	(5,262)	156,640	-	156,640
14	Water Testing	3,787	-	3,787	-	3,787
15	Equipment Rental	140	-	140	-	140
16	Rents	-	-	-	-	-
17	Transportation Expenses	21,524	-	21,524	-	21,524
18	Insurance - General Liability	9,692	-	9,692	-	9,692
19	Insurance - Health and Life	-	-	-	-	-
20	Reg. Comm. Exp.	587	-	587	-	587
21	Reg. Comm. Exp. - Rate Case	25,000	(8,693)	16,307	-	16,307
22	Miscellaneous Expense	11,726	-	11,726	-	11,726
23	Bad Debt Expense	3,306	-	3,306	-	3,306
24	Depreciation Expense	36,631	-	36,631	-	36,631
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	13,128	(1,172)	11,956	-	11,956
27	Income Tax	(36,727)	11,580	(25,146)	35,000	9,854
28	TOTAL OPERATING EXPENSES	$ 273,282	$ (3,547)	$ 269,735	$ 35,000	$ 304,736
29	OPERATING INCOME (LOSS)	$ (81,316)		$ (77,769)		$ 54,514

References:
Column (A): Company Schedule C-1
Column (B): RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From RLM-1, Column (B), Line 8 And Income Tax From RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

Northern Sunrise Water Company (Stand-Alone)
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 CENTRAL OFFICE COST	(F) ADJ # 5 RATE CASE EXPENSES	(G) LEFT BLANK	(H) ADJ # 6 INCOME TAX	(I) RUCO AS ADJT'D
	Revenues:									
1	Flat Rate Revenues	$ 188,672	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 188,672
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	3,294	-	-	-	-	-	-	-	3,294
4	TOTAL OPR'G REV.	$ 191,966	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 191,966
	Operating Expenses:									
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-	-	-	-	-
7	Purchased Power	16,012	-	-	-	-	-	-	-	16,012
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-
9	Chemicals	178	-	-	-	-	-	-	-	178
10	Materials & Supplies	5,094	-	-	-	-	-	-	-	5,094
11	Outside Services	-	-	-	-	-	-	-	-	-
12	Outside Services- Legal	1,302	-	-	-	-	-	-	-	1,302
13	Outside Services- Other	161,902	-	-	-	(5,262)	-	-	-	156,640
14	Water Testing	3,787	-	-	-	-	-	-	-	3,787
15	Equipment Rental	140	-	-	-	-	-	-	-	140
16	Rents	-	-	-	-	-	-	-	-	-
17	Transportation Expenses	21,524	-	-	-	-	-	-	-	21,524
18	Insurance - General Liability	9,692	-	-	-	-	-	-	-	9,692
19	Insurance - Health and Life	-	-	-	-	-	-	-	-	-
20	Reg. Comm. Exp.	587	-	-	-	-	-	-	-	587
21	Reg. Comm. Exp. - Rate Case	25,000	-	-	-	-	(8,693)	-	-	16,307
22	Miscellaneous Expense	11,726	-	-	-	-	-	-	-	11,726
23	Bad Debt Expense	3,306	-	-	-	-	-	-	-	3,306
24	Depreciation Expense	36,631	-	-	-	-	-	-	-	36,631
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-
26	Property Taxes	13,128	-	(1,172)	-	-	-	-	-	11,956
27	Income Tax	(36,727)	-	-	-	-	-	-	11,580	(25,146)
29	TOTAL OPR'G EXP.	$ 273,282	$ -	$ (1,172)	$ -	$ (5,262)	$ (8,693)	$ -	$ 11,580	$ 269,735
30	OPR'G INC. (LOSS)	$ (81,316)								$ (77,769)

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8
Column (C): Testimony, RLM And Schedule RLM-9
Column (D): Testimony, RLM And Schedule RLM-10
Column (E): Testimony, TLC And Schedule RLM-11
Column (F): Testimony, RLM And Schedule RLM-12
Column (G): Intentionally Left Blank
Column (H): Testimony, RLM And Schedule RLM-13
Column (I): Sum Of Columns (A) Thru (H)

Northern Sunrise Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	890	0.00%	-
3	303	Land and Land Rights	23,926	0.00%	-
4	304	Structures and Improvements	281,810	3.33%	9,384
5	305	Collecting and Impounding Res.	51,378	2.50%	1,284
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	34,064	3.33%	1,134
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	-	2.00%	-
10	310	Power Generation Equipment	1,293	5.00%	65
11	311	Electric Pumping Equipment	92,122	12.50%	11,515
12	320	Water Treatment Equipment	-	3.33%	-
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	102,018	2.22%	2,265
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	36,763	2.00%	735
19	333	Services	30,106	3.33%	1,003
20	334	Meters	8,244	8.33%	687
21	335	Hydrants	59,298	2.00%	1,186
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	23,472	6.67%	1,566
24	340	Office Furniture and Fixtures	-	6.67%	-
25	340.1	Computers and Software	-	20.00%	-
26	341	Transportation Equipment	-	20.00%	-
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	-	5.00%	-
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	-	5.00%	-
31	346	Communications Equipment	5,881	10.00%	588
32	347	Miscellaneous Equipment	-	10.00%	-
33	348	Other Tangible Plant	64,621	10.00%	6,462
34		Rounding			
35	TOTAL WASTEWATER PLANT		$ 815,886		$ 37,874
	Less:				
36	Amortizations Of CIAC (RLM-2, Col. (C), Line 5)		$ (26,000)	4.7823%	(1,243)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 36,631
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				36,631
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ -
40	RUCO Adjustment (Line 39) (See RLM-7, Column (B), Line 25)				$ -

References: Column (A): RLM-4, Column (E)
Column (B): Company Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

Northern Sunrise Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	$ 191,966	
2	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	191,966	
3	Proposed Revenues	Sch. RLM-6, Col (E), Ln 4	359,250	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 743,183	
5	Average Annual Operating Revenues	Line 4 / 3	247,728	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 495,455
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 92,936	
8	10% Of CWIP	Line 7 X 10%		$ 9,294
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ -	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	-	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ -
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 504,749
	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	$ 105,997	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	11.1932%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	11.19%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 11,865
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 91
20	Company's Total Tax Liability	Line 18 + Line 19		$ 11,956
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 25		13,128
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (1,172)
23	RUCO Adjustment (See RLM-7, Column (C), Line 27)	Line 22		$ (1,172)

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Schedule RLM-10
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
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LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To BVWC	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	24.29%	$ 47,253	0.53%	$ 249
2	Tax Services	518,775	25.00%	129,694	24.29%	31,497	0.53%	166
3	Legal	159,053	25.00%	39,763	24.29%	9,657	0.53%	51
4	Other Professional Services	506,082	0.00%	-	24.29%	-	0.53%	-
5	Management Fee - Total	644,943	0.00%	-	24.29%	-	0.53%	-
6	Unit Holder Communications	156,766	0.00%	-	24.29%	-	0.53%	-
7	Trustee Fees	129,000	0.00%	-	24.29%	-	0.53%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	24.29%	-	0.53%	-
9	Rent	307,337	0.00%	-	24.29%	-	0.53%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	24.29%	-	0.53%	-
11	Office Expenses	579,379	0.00%	-	24.29%	-	0.53%	-
12	Depreciation	211,653	25.00%	52,913	24.29%	12,850	0.53%	68
13	TOTAL	$ 4,104,971		$ 416,941		$ 101,257		$ 534
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 5,841
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on April 1, 2010							0.99147
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 5,792
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 529
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(5,262)
19	RUCO Adjustment (See RLM-7, Column (E))							(5,262)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

Northern Sunrise Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 5
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJM'T	(C) RUCO AS ADJ'D
1	Rate Case Expense Total	$ 250,000	$ (201,079)	$ 48,921
2	Normalization Period - 3 Years			3
3	RUCO Adjusted Rate Case Expense For Instant Case (Line 1 / 3 Years)			$ 16,307
4	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 25,000
5	RUCO Pro Forma Rate Case Expense (Lines 3 - 4)			$ (8,693)
6	RUCO Adjustment (Line 5) (See RLM-7, Column (F))			$ (8,693)

	RUCO CALCULATED RATE CASE EXPENSES	CONSOL'D TOTALS	BVWC ALONE	NSWC ALONE	SSWC ALONE
	ACTUALS Invoices Per Fennemore Craig	$ 59,206	$ 23,782	$ 17,633	$ 17,791
7	Total Costs Through February 2010				
	ESTIMATES Based On Estimate From Black Mountain Sewer Co.	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR
8	Remaining Costs For Company Witness Tom Borassa:	100.00%	55.56%	22.22%	22.22%
9	Rebuttal, Surrebuttal, Rejoinder And Trial Process;				
10	Final Schedules, Briefing, Evaluation Of ROO; Open Meeting Prep	$ 25,000	$ 13,889	$ 5,556	$ 5,556
			-	-	-
11	Expedited Hearing Transcript	5,000	2,778	1,111	1,111
			-	-	-
12	Fennemore Craig Estimated Remaining Costs		-	-	-
13	Rebuttal, Surrebuttal, Rejoinder And Trial Process;	45,000	25,000	10,000	10,000
14	Briefing	30,000	16,667	6,667	6,667
15	Reviewing ROO; Exceptions Open Meeting Prep	10,000	5,556	2,222	2,222
16	Post Decision Compliance And Filings	15,000	8,333	3,333	3,333
17	Per Diam Expenses	10,000	5,556	2,222	2,222
18	Rounding	794	441	176	176
19	RUCO ESTIMATED RATE CASE EXPENSES	$ 200,000	$ 102,000	$ 48,921	$ 49,079

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. RLM-6, Column (C), L29 + L27	$ (102,915)
	LESS:		
2	Arizona State Tax	Line 11	8,374
3	Interest Expense	Note (A) Line 20	(17,270)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ (111,811)
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	15.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ (16,772)
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ (102,915)
	LESS:		
8	Interest Expense	Note (A) Line 20	(17,270)
9	State Taxable Income	Sum Of Lines 7 & 8	$ (120,185)
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ (8,374)
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ (16,772)
13	State Income Tax Expense	Line 11	(8,374)
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ (25,146)
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		(36,727)
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 11,580
17	RUCO Adjustment (See Sch. RLM-7, Column (K), L278)	Line16	$ 11,580

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. RLM-2, Col. (E), L15)	$	689,708
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		2.50%
20	Interest Expense (L17 X L18)	$	17,270

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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(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	COST OF CAPITAL			7.90%

References:
Columns (A) Thru (F): See Testimony Of RUCO Witness William Rigsby

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RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
RLM-5	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
RLM-6	1	OPERATING INCOME
RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
RLM-11	1	OPERATING INCOME ADJUSTMENT NO. 4 - CENTRAL OFFICE COST ALLOCATION
RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 5 - RATE CASE EXPENSES
RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 6 - INCOME TAX EXPENSE
RLM-14	1	COST OF CAPITAL

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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 1,544,434	$ 1,418,329
2	Adjusted Operating Income (Loss)	$ 6,042	$ 159,328
3	Current Rate Of Return (L2 / L1)	0.39%	11.23%
4	Required Operating Income (L5 X L1)	$ 197,688	$ 112,105
5	Required Rate Of Return On Fair Value Rate Base	12.80%	7.90%
6	Operating Income Deficiency (L4 - L2)	$ 191,645	$ (47,224)
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6128	1.3788
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 309,090	$ (65,111)
9	Adjusted Test Year Revenue	$ 444,136	$ 444,136
10	Proposed Annual Revenue (L8 + L9)	$ 753,226	$ 379,025
11	Required Percentage Increase In Revenue (L8 / L9)	69.59%	-14.66%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RLM-2, RLM-6, And RLM-14

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REVENUE REQUIREMENT - CONT'D
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)	(0.2747)			
3	Subtotal (L1 + L2)	0.7253			
4	**Revenue Conversion Factor** (L1 / L3)	**1.3788**			
	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)	22.0397%			
9	Effective Federal Income Tax Rate (L7 X L8)	20.5040%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	27.4720%			
11	Required Operating Income (Sch. RLM-1, Col. (B), L4)	$ 112,105			
12	Adj'd T.Y. Oper'g Inc. (Loss) (Sch. RLM-1, Col. (B), L2)	159,328			
13	Required Increase In Operating Income (L11 - L12)		$ (47,224)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 29,011			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	46,898			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		$ (17,887)		
17	Total Required Increase In Revenue (L13 + L16)		$ (65,111)		
	CALCULATION OF INCOME TAX:			RUCO Recommended	
18	Revenue (Sch. RLM-1, Col. (B), L10)			$ 379,025	
19	Operating Expense Excluding Income Tax (RLM-6, Col. (E), L28 - L27)			(237,910)	
20	Synchronized Interest (Col. (C), L37)			(35,515)	
21	Arizona Taxable Income (L18 + L19 + L20)			$ 105,600	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 7,358
24	Fed. Taxable Income (L21 - L23)			$ 98,242	
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%			7,902	
28	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%			-	
29	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%			-	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 21,652
31	Combined Federal And State Income Tax (L23 + L30)				$ 29,011
32	Test Year Combined Income Tax, RUCO As Adjusted (RLM-6, Col. (C), L24)				$ 46,898
33	RUCO Adjustment (L31 - L32) (See RLM-6, Col. (D), L24)				$ (17,887)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				22.04%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. RLM-2, Col. (H), L15)			$ 1,418,329	
36	Weighted Avg. Cost Of Debt (Sch. RLM-14, Col. (F), L1)			2.50%	
37	Synchronized Interest (L35 X L36)			$ 35,515	

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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 1,724,610	$ -	$ 1,724,610
2	Accumulated Depreciation	(105,733)	-	(105,733)
3	Net Utility Plant In Service (L1 + L2)	$ 1,618,877	$ -	$ 1,618,877
4	Advances In Aid Of Const.	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (20,000)	$ -	$ (20,000)
6	Accumulated Amortization Of CIAC	15	-	15
7	NET CIAC (L5 + L6)	$ (19,985)	$ -	$ (19,985)
8	Customer Meter Deposits	$ (2,870)	$ -	$ (2,870)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (51,588)	$ (126,105)	$ (177,693)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 1,544,434	$ (126,105)	$ 1,418,329

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

Southern Sunrise Water Company (Stand-Alone)
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SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) INTENT'NLY LEFT BLANK	(F) INTENT'NLY LEFT BLANK	(G) INTENT'NLY LEFT BLANK	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 1,724,610	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,724,610
2	Accumulated Depreciation	(105,733)	-	-	-	-	-	-	(105,733)
3	Net Utility Plant In Service (L1 + L2)	$ 1,618,877	$ -	$ -	$ -	$ -	$ -	$ -	$ 1,618,877
4	Advances In Aid Of Const.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (20,000)	$ -	$ -	$ -	$ -	$ -	$ -	$ (20,000)
6	Accumulated Amortization Of CIAC	15	-	-	-	-	-	-	15
7	NET CIAC (L5 + L6)	$ (19,985)	$ -	$ -	$ -	$ -	$ -	$ -	$ (19,985)
8	Customer Meter Deposits	$ (2,870)	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,870)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (51,588)	$ -	$ -	$ (126,105)	$ -	$ -	$ -	$ (177,693)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 1,544,434	$ -	$ -	$ (126,105)	$ -	$ -	$ -	$ 1,418,329

References:

Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Testimony Of RUCO Witness Tim Coley and Schedule RLM-5)
Column (E): Intentionally Left Blank
Column (F): Intentionally Left Blank
Column (G): Intentionally Left Blank
Column (H): Sum Of Columns (A), (B), (C), (D), (E) & (F)

Southern Sunrise Water Company (Stand-Alone)
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POST TEST YEAR PLANT SCHEDULE
YEAR ENDED JUNE 30, 2008

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) RUCO T/Y PLANT AS ADJUSTED	(B) RUCO POST TY ADJM'TS PLANT ADDITIONS	(C) RUCO POST TY ADJM'TS PLANT RETIRMENTS	(D) TOTAL PLANT VALUE	(E) ACC. DEP.	(F) NET PLANT VALUE
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise Cost	71	-	-	71	-	71
3	303	Land and Land Rights	336,686	-	-	336,686	-	336,686
4	304	Structures and Improvements	335,501	-	-	335,501	(7,855)	327,646
5	305	Collecting and Impounding Res.	-	-	-	-	-	-
6	306	Lake River and Other Intakes	-	-	-	-	-	-
7	307	Wells and Springs	133,969	-	-	133,969	(5,407)	128,562
8	308	Infiltration Galleries and Tunnels	-	-	-	-	-	-
9	309	Supply Mains	3,798	-	-	3,798	(104)	3,694
10	310	Power Generation Equipment	-	-	-	-	-	-
11	311	Electric Pumping Equipment	197,625	-	-	197,625	(33,360)	164,264
12	320	Water Treatment Equipment	-	-	-	-	-	-
13	320.1	Water Treatment Equipment	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	263,512	-	-	263,512	(8,546)	254,966
16	330.1	Storage tanks	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	85,380	-	-	85,380	(3,415)	81,965
19	333	Services	70,365	-	-	70,365	(2,248)	68,117
20	334	Meters	18,257	-	-	18,257	(1,266)	16,992
21	335	Hydrants	18,416	-	-	18,416	(379)	18,036
22	336	Backflow Prevention Devices	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	21,516	-	-	21,516	(1,701)	19,815
24	340	Office Furniture and Fixtures	-	-	-	-	-	-
25	340.1	Computers and Software	-	-	-	-	-	-
26	341	Transportation Equipment	-	-	-	-	-	-
27	342	Stores Equipment	-	-	-	-	-	-
28	343	Tools and Work Equipment	270	-	-	270	(6)	264
29	344	Laboratory Equipment	-	-	-	-	-	-
30	345	Power Operated Equipment	-	-	-	-	-	-
31	346	Communications Equipment	3,379	-	-	3,379	(253)	3,125
32	347	Miscellaneous Equipment	-	-	-	-	-	-
33	348	Other Tangible Plant	235,381	-	-	235,381	(41,192)	194,189
34		Rounding	485			485	-	485
		0						
35	TOTAL WASTEWATER PLANT		$ 1,724,610	$ -	$ -	$ 1,724,610	$ (105,733)	$ 1,618,877
36	Company As Filed					1,724,610	$ (105,733)	
37	Difference					-	$ -	
38	RUCO Adjustment (Line 37) (See RLM-3, Column (B))					-	$ -	

References:
Column (A): RUCO Workpapers RLM-4-A(1)
Columns (B) (C): Testimony, RLM
Column (D): Sum Of Columns (A), (B), & (C)
Column (E): Sum Of WP RLM-4-A(1), Column (B) And RLM-4, Column (C)
Column (F): Column (D) + Column (E)

Southern Sunrise Water Company (Stand-Alone)
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ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Consolidated Allocation	Note (A)	1.5438%
5	Bella Vista Consolidated ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Consolidated Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Total Consolidated ADIT as Filed by Company	Company Schedule C-1	173,329
9	Decrease In Deferred Income Tax Assets	Line 7 - Line 8	$ (1,458,278)
10	Total Southern Sunrise Customer Count Factor	Per Company	0.0865
11	RUCO Adjustment (See RLM-3, Column (D), Line 10)	Line 9 X Line 10	$ (126,105)

NOTES:

12	(A)	Purchase Price of BVWC, NSWC and SSWC	Annual Report	$	15,100,000
13		Algonquin Total Assets	Annual Report	$	978,130,000
14		Ratio BVWC, NSWC & SSWC To APIF Total Assets	Line 12 / Line 13		1.5438%
15	(B)	Currency Conversion	moneycentral.com on 04/1/2010		0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

Southern Sunrise Water Company (Stand-Alone)
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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	Flat Rate Revenues	$ 433,457	$ -	$ 433,457	$ (65,111)	$ 368,346
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	10,679	-	10,679	-	10,679
4	TOTAL OPERATING REVENUE	$ 444,136	$ -	$ 444,136	$ (65,111)	$ 379,025
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-
7	Purchased Power	32,354	-	32,354	-	32,354
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	1,265	-	1,265	-	1,265
10	Materials & Supplies	7,972	-	7,972	-	7,972
11	Outside Services	91	-	91	-	91
12	Outside Services- Legal	5,390	-	5,390	-	5,390
13	Outside Services- Other	179,427	(12,533)	166,895	-	166,895
14	Water Testing	5,592	-	5,592	-	5,592
15	Equipment Rental	-	-	-	-	-
16	Rents	-	-	-	-	-
17	Transportation Expenses	25,481	-	25,481	-	25,481
18	Insurance - General Liability	10,788	-	10,788	-	10,788
19	Insurance - Health and Life	-	-	-	-	-
20	Reg. Comm. Exp.	1,024	-	1,024	-	1,024
21	Reg. Comm. Exp. - Rate Case	41,667	(8,640)	33,026	-	33,026
22	Miscellaneous Expense	14,810	-	14,810	-	14,810
23	Bad Debt Expense	5,346	-	5,346	-	5,346
24	Depreciation Expense	76,419	-	76,419	-	76,419
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	26,765	(175,308)	(148,542)	-	(148,542)
27	Income Tax	3,703	43,195	46,898	(17,887)	29,011
28	TOTAL OPERATING EXPENSES	$ 438,094	$ (153,286)	$ 284,808	$ (17,887)	$ 266,921
29	OPERATING INCOME (LOSS)	$ 6,042		$ 159,328		$ 112,104

References:
Column (A): Company Schedule C-1
Column (B): RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From RLM-1, Column (B), Line 8 And Income Tax From RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

Southern Sunrise Water Company (Stand-Alone)
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SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 CENTRAL OFFICE COST	(F) ADJ # 5 RATE CASE EXPENSES	(G) LEFT BLANK	(H) ADJ # 6 INCOME TAX	(I) RUCO AS ADJT'D
	Revenues:									
1	Flat Rate Revenues	$ 433,457	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 433,457
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	10,679	-	-	-	-	-	-	-	10,679
4	TOTAL OPR'G REV.	$ 444,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 444,136
	Operating Expenses:									
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-	-	-	-	-
7	Purchased Power	32,354	-	-	-	-	-	-	-	32,354
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-
9	Chemicals	1,265	-	-	-	-	-	-	-	1,265
10	Materials & Supplies	7,972	-	-	-	-	-	-	-	7,972
11	Outside Services	91	-	-	-	-	-	-	-	91
12	Outside Services- Legal	5,390	-	-	-	-	-	-	-	5,390
13	Outside Services- Other	179,427	-	-	-	(12,533)	-	-	-	166,895
14	Water Testing	5,592	-	-	-	-	-	-	-	5,592
15	Equipment Rental	-	-	-	-	-	-	-	-	-
16	Rents	-	-	-	-	-	-	-	-	-
17	Transportation Expenses	25,481	-	-	-	-	-	-	-	25,481
18	Insurance - General Liability	10,788	-	-	-	-	-	-	-	10,788
19	Insurance - Health and Life	-	-	-	-	-	-	-	-	-
20	Reg. Comm. Exp.	1,024	-	-	-	-	-	-	-	1,024
21	Reg. Comm. Exp. - Rate Case	41,667	-	-	-	-	(8,640)	-	-	33,026
22	Miscellaneous Expense	14,810	-	-	-	-	-	-	-	14,810
23	Bad Debt Expense	5,346	-	-	-	-	-	-	-	5,346
24	Depreciation Expense	76,419	-	-	-	-	-	-	-	76,419
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-
26	Property Taxes	26,765	-	(175,308)	-	-	-	-	-	(148,542)
27	Income Tax	3,703	-	-	-	-	-	-	43,195	46,898
29	TOTAL OPR'G EXP.	$ 438,094	$ -	$ (175,308)	$ -	$ (12,533)	$ (8,640)	$ -	$ 43,195	$ 284,808
30	OPR'G INC. (LOSS)	$ 6,042								$ 159,328

References:
Column (A): Company Schedule C-1
Column (B): Testimony, RLM And Schedule RLM-8
Column (C): Testimony, RLM And Schedule RLM-9
Column (D): Testimony, RLM And Schedule RLM-10
Column (E): Testimony, TLC And Schedule RLM-11
Column (F): Testimony, RLM And Schedule RLM-12
Column (G): Intentionally Left Blank
Column (H): Testimony, RLM And Schedule RLM-13
Column (I): Sum Of Columns (A) Thru (H)

Southern Sunrise Water Company (Stand-Alone)
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Test Year Ended March 31, 2009

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	71	0.00%	-
3	303	Land and Land Rights	336,686	0.00%	-
4	304	Structures and Improvements	335,501	3.33%	11,172
5	305	Collecting and Impounding Res.	-	2.50%	-
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	133,969	3.33%	4,461
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	3,798	2.00%	76
10	310	Power Generation Equipment	-	5.00%	-
11	311	Electric Pumping Equipment	197,625	12.50%	24,703
12	320	Water Treatment Equipment	-	3.33%	-
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	263,512	2.22%	5,850
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	85,380	2.00%	1,708
19	333	Services	70,365	3.33%	2,343
20	334	Meters	18,257	8.33%	1,521
21	335	Hydrants	18,416	2.00%	368
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	21,516	6.67%	1,435
24	340	Office Furniture and Fixtures	-	6.67%	-
25	340.1	Computers and Software	-	20.00%	-
26	341	Transportation Equipment	-	20.00%	-
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	270	5.00%	13
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	-	5.00%	-
31	346	Communications Equipment	3,379	10.00%	338
32	347	Miscellaneous Equipment	-	10.00%	-
33	348	Other Tangible Plant	235,381	10.00%	23,538
34		Rounding	485		10
35	TOTAL WASTEWATER PLANT		$ 1,724,610		$ 77,537
	Less:				
36	Amortizations Of CIAC (RLM-2, Col. (C), Line 5)		$ (20,000)	5.59%	(1,117)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 76,419
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				76,419
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ -
40	RUCO Adjustment (Line 39) (See RLM-7, Column (B), Line 25)				$ -

References: Column (A): RLM-4, Column (E)
Column (B): Company Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

Southern Sunrise Water Company (Stand-Alone)
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Test Year Ended March 31, 2009

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	$ 444,136	
2	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	444,136	
3	Proposed Revenues	Sch. RLM-6, Col (E), Ln 4	379,025	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 1,267,297	
5	Average Annual Operating Revenues	Line 4 / 3	422,432	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 844,865
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 526,003	
8	10% Of CWIP	Line 7 X 10%		$ 52,600
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ -	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	-	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ -
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 897,465
	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	$ 188,468	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	9.8984%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.90%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 18,655
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,991
20	Company's Total Tax Liability	Line 18 + Line 19		$ 20,646
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 25		195,954
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (175,308)
23	RUCO Adjustment (See RLM-7, Column (C), Line 27)	Line 22		$ (175,308)

EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
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LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL

Southern Sunrise Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 4
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To BVWC	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	24.29%	$ 47,253	1.26%	$ 593
2	Tax Services	518,775	25.00%	129,694	24.29%	31,497	1.26%	396
3	Legal	159,053	25.00%	39,763	24.29%	9,657	1.26%	121
4	Other Professional Services	506,082	0.00%	-	24.29%	-	1.26%	-
5	Management Fee - Total	644,943	0.00%	-	24.29%	-	1.26%	-
6	Unit Holder Communications	156,766	0.00%	-	24.29%	-	1.26%	-
7	Trustee Fees	129,000	0.00%	-	24.29%	-	1.26%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	24.29%	-	1.26%	-
9	Rent	307,337	0.00%	-	24.29%	-	1.26%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	24.29%	-	1.26%	-
11	Office Expenses	579,379	0.00%	-	24.29%	-	1.26%	-
12	Depreciation	211,653	25.00%	52,913	24.29%	12,850	1.26%	161
13	TOTAL	$ 4,104,971		$ 416,941		$ 101,257		$ 1,272
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 13,912
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on April 1, 2010							0.99147
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 13,794
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 1,261
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(12,533)
19	RUCO Adjustment (See RLM-7, Column (E))							(12,533)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

Southern Sunrise Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 5
RATE CASE EXPENSE

LINE NO.	DESCRIPTION	(A) COMPANY ESTIMATE	(B) RUCO ADJM'T	(C) RUCO AS ADJ'D
1	Rate Case Expense Total	$ 250,000	$ (200,921)	$ 49,079
2	Normalization Period - 3 Years			3
3	RUCO Adjusted Rate Case Expense For Instant Case (Line 1 / 3 Years)			$ 16,360
4	Company Rate Case Expenses As Filed (Company Sch. C-2)			$ 25,000
5	RUCO Pro Forma Rate Case Expense (Lines 3 - 4)			$ (8,640)
6	RUCO Adjustment (Line 5) (See RLM-7, Column (F))			$ (8,640)

	RUCO CALCULATED RATE CASE EXPENSES	CONSOL'D TOTALS	BVWC ALONE	NSWC ALONE	SSWC ALONE
	ACTUALS Invoices Per Fennemore Craig	$ 59,206	$ 23,782	$ 17,633	$ 17,791
7	Total Costs Through February 2010				
	ESTIMATES Based On Estimate From Black Mountain Sewer Co.	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR	ALLOCAT'N FACTOR
8	Remaining Costs For Company Witness Tom Borassa:	100.00%	55.56%	22.22%	22.22%
9	Rebuttal, Surrebuttal, Rejoinder And Trial Process;				
10	Final Schedules, Briefing, Evaluation Of ROO; Open Meeting Prep	$ 25,000	$ 13,889	$ 5,556	$ 5,556
			-	-	-
11	Expedited Hearing Transcript	5,000	2,778	1,111	1,111
			-	-	-
12	Fennemore Craig Estimated Remaining Costs		-	-	-
13	Rebuttal, Surrebuttal, Rejoinder And Trial Process;	45,000	25,000	10,000	10,000
14	Briefing	30,000	16,667	6,667	6,667
15	Reviewing ROO; Exceptions Open Meeting Prep	10,000	5,556	2,222	2,222
16	Post Decision Compliance And Filings	15,000	8,333	3,333	3,333
17	Per Diam Expenses	10,000	5,556	2,222	2,222
18	Rounding	794	441	176	176
19	RUCO ESTIMATED RATE CASE EXPENSES	$ 200,000	$ 102,000	$ 48,921	$ 49,079

Southern Sunrise Water Company (Stand-Alone)
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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. RLM-6, Column (C), L29 + L27	$ 206,226
	LESS:		
2	Arizona State Tax	Line 11	(11,895)
3	Interest Expense	Note (A) Line 20	(35,515)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 158,816
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	22.04%
6	Federal Income Tax Expense	Line 4 X line 5	$ 35,003
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 206,226
	LESS:		
8	Interest Expense	Note (A) Line 20	(35,515)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 170,711
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 11,895
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 35,003
13	State Income Tax Expense	Line 11	11,895
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 46,898
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		3,703
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 43,195
17	RUCO Adjustment (See Sch. RLM-7, Column (K), L278)	Line16	$ 43,195

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. RLM-2, Col. (E), L15)	$	1,418,329
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		2.50%
20	Interest Expense (L17 X L18)	$	35,515

Southern Sunrise Water Company (Stand-Alone)
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COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(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	COST OF CAPITAL			7.90%

References:
Columns (A) Thru (F): See Testimony Of RUCO Witness William Rigsby

RATE DESIGN

Bella Vista Water Company (Stand-Alone)
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TABLE OF CONTENTS TO RLM RATE DESIGN SCHEDULES

SCHEDULE NO.	PAGE NO.	TITLE
RLM-RD1	1 TO 3	RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
RLM-RD2	1 TO 2	TYPICAL RESIDENTIAL BILL ANALYSIS

Bella Vista Water Company (Stand-Alone)
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Test Year Ended March 31, 2009

Schedule RLM-RD1
Pages 1 Thru 3

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	88,860	$ 16.10	$ 1,430,318	$ 1,430,318
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	287,256	$ 1.3341	$ 383,225	
3	Second Tier - Breakover @ 10,000 Gals.	182,634	$ 1.9445	$ 355,125	
4	Third Tier - Over 10,000 Gals.	117,683	$ 2.2932	$ 269,876	
8	Total Commodity Usage And Revenue	587,573			$ 1,008,226
9	3/4" Meter	396	$ 25.35	$ 10,038	$ 10,038
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	1,224	$ 1.3341	$ 1,633	
11	Second Tier - Breakover @ 10,000 Gals.	534	$ 1.9445	$ 1,039	
12	Third Tier - Over 10,000 Gals.	39	$ 2.2932	$ 90	
16	Total Commodity Usage And Revenue	1,798			$ 2,762
17	1" Meter	96	$ 32.19	$ 3,090	$ 3,090
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	764	$ 1.2643	$ 965	
19	Second Tier - Over 10,000 Gals.	965	$ 1.6567	$ 1,599	
24	Total Commodity Usage And Revenue	1,728			$ 2,564
33	2" Meter	12	$ 103.01	$ 1,236	$ 1,236
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	129	$ 1.2643	$ 162	
35	Second Tier - Over 50,000 Gals.	-	$ 1.6567	$ -	
40	Total Commodity Usage And Revenue	129			$ 162
41	Total Residential Customer Bills	89,364		$ 1,444,682	
42	Total Residential Usage	591,227		$ 1,013,715	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 2,458,396
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	4,572	$ 16.10	$ 73,592	$ 73,592
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	11,729	$ 1.2643	$ 14,829	
46	Second Tier - Over 4,000 Gals.	21,935	$ 1.6567	$ 36,339	
51	Total Commodity Usage And Revenue	33,663			$ 51,168
52	3/4" Meter	72	$ 25.35	$ 1,825	$ 1,825
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	237	$ 1.2643	$ 300	
54	Second Tier - Over 4,000 Gals.	732	$ 1.6567	$ 1,213	
59	Total Commodity Usage And Revenue	969			$ 1,513
60	1" Meter	1,668	$ 32.19	$ 53,697	$ 53,697
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	10,702	$ 1.2643	$ 13,531	
62	Second Tier - Over 10,000 Gals.	13,467	$ 1.6567	$ 22,311	
67	Total Commodity Usage And Revenue	24,170			$ 35,843
68	1.5" Meter	1,020	$ 60.37	$ 61,573	$ 61,573
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	17,687	$ 1.2643	$ 22,363	
70	Second Tier - Over 25,000 Gals.	28,480	$ 1.6567	$ 47,184	
75	Total Commodity Usage And Revenue	46,167			$ 69,546

Bella Vista Water Company (Stand-Alone)
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Schedule RLM-RD1
Pages 1 Thru 3

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	3,264	$ 103.01	$ 336,234	$ 336,234
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	101,196	$ 1.2643	$ 127,946	
78	Second Tier - Over 50,000 Gals.	178,887	$ 1.6567	$ 296,364	
83	Total Commodity Usage And Revenue	280,083			$ 424,310
	3" Meter	312	$ 128.77	$ 40,176	$ 40,176
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	20,136	$ 1.2643	$ 25,458	
	Second Tier - Over 80,000 Gals.	31,283	$ 1.6567	$ 51,827	
	Total Commodity Usage And Revenue	51,419			$ 77,285
	4" Meter	36	$ 160.96	$ 5,795	$ 5,795
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	7,922	$ 1.2643	$ 10,016	
	Second Tier - Over 350,000 Gals.	13,540	$ 1.6567	$ 22,432	
	Total Commodity Usage And Revenue	21,462			$ 32,448
84	6" Meter	12	$ 724.33	$ 8,692	$ 8,692
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	468	$ 1.2643	$ 592	
86	Second Tier - Over 450,000 Gals.	-	$ 1.6567	$ -	
91	Total Commodity Usage And Revenue	468			$ 592
92	8" Meter	12	$ 1,158.93	$ 13,907	$ 13,907
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	31	$ 1.2643	$ 39	
94	Second Tier - Over 720,000 Gals.	-	$ 1.6567	$ -	
99	Total Commodity Usage And Revenue	31			$ 39
100	Total Commercial Customer Bills	10,968		$ 595,492	
101	Total Commercial Usage	458,432		$ 692,744	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ 1,288,236
	HYDRANT CUSTOMERS				
103	3" Meter	168	$ 128.77	$ 21,633	$ 21,633
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	5,094	$ 2.2932	$ 11,682	
110	Total Commodity Usage And Revenue	5,094			$ 11,682
159	Total Hydrant Customer Bills	168			
160	Total Hydrant Usage	5,094			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ 33,315
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	1,188	$ 13.08	$ 15,538	$ 15,538
202	6" Meter	252	$ 14.49	$ 3,651	$ 3,651
210	8" Meter	12	$ 23.18	$ 278	$ 278
68	Total Fire Sprinkler Customer Bills	1,452			

Bella Vista Water Company (Stand-Alone)
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Schedule RLM-RD1
Pages 1 Thru 3

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ 19,467
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 3,799,415
	Total Company Customer Bills	101,952			
	Total Company Usage	1,054,753			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 2,458,396
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				1,288,236
192	TOTAL HYDRANT REVENUE PER BILL COUNT				33,315
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				19,467
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 3,799,415
198	Unreconciled Difference vs. Billed Revenues				2,245
200	Miscellaneous Revenues				125,141
200	**RUCO TOTAL REVENUE**				$ 3,926,801
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 3,926,801
202	Difference				$ (0)
203	Percentage Difference				0.00%

Bella Vista Water Company (Stand-Alone)
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TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A) PRESENT	(B)	(C) COMPANY PROPOSED	(D)	(E) RUCO PROPOSED	(F)
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 2,164,639	63.66%	$ 2,819,405	64.70%	$ 2,458,396	64.70%
2	OTHER	1,235,833	36.34%	1,537,943	35.30%	1,341,018	35.30%
3	TOTAL	$ 3,400,472	100.00%	$ 4,357,348	100.00%	$ 3,799,415	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 1,723,095	50.67%	$ 2,386,903	54.78%	$ 2,081,274	54.78%
5	VARIABLE REVENUE	1,677,377	49.33%	1,970,445	45.22%	1,718,141	45.22%
6	TOTAL	$ 3,400,472	100.00%	$ 4,357,348	100.00%	$ 3,799,415	100.00%

	RESIDENTIAL (5/8" X 3/4") RATE DESIGN	PRESENT BVWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
7	BASIC MONTHLY CHARGE	$ 15.00	$ 18.46	$ 16.10

	COMMODITY CHARGE PRESENT	BVWC	PROPOSED		PRESENT BVWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
8	1st Tier - Breakover	5,000	1st Tier - Breakover	4,000	$ 0.9700	$ 1.5300	$ 1.3341
9	2nd Tier - Breakove	25,000	2nd Tier - Breakover	10,000	$ 1.8900	$ 2.2300	$ 1.9445
10	3rd Tier - Over	25,000	3rd Tier - Over	10,000	$ 2.4100	$ 2.6300	$ 2.2932

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	BELLA VISTA RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 6,612	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,653	25.00%	$ 16.60	$ 18.30	$ 1.70	10.23%
2		3,306	50.00%	$ 18.21	$ 20.51	$ 2.30	12.63%
3		6,612	100.00%	$ 22.90	$ 26.51	$ 3.61	15.79%
4		9,918	150.00%	$ 29.14	$ 32.94	$ 3.79	13.02%
5		13,223	200.00%	$ 35.39	$ 39.37	$ 3.97	11.23%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 16.09	$ 17.60	$ 1.51	9.36%
7		2,250	50.00%	$ 17.18	$ 19.10	$ 1.92	11.15%
8		4,500	100.00%	$ 19.37	$ 22.40	$ 3.04	15.70%
9		6,750	150.00%	$ 21.55	$ 26.78	$ 5.23	24.28%
10		9,000	200.00%	$ 23.73	$ 31.15	$ 7.42	31.29%

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	4,116	60.34630245	$ 248,385	$ 248,385
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	11,901	$ 3.8902	$ 46,298	
3	Second Tier - Breakover @ 10,000 Gals.	7,596	$ 4.6907	$ 35,629	
4	Third Tier - Over 10,000 Gals.	4,174	$ 5.6112	$ 23,422	
8	Total Commodity Usage And Revenue	23,671			$ 105,349
9	3/4" Meter	12	$ 90.52	$ 1,086	$ 1,086
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	46	$ 3.8902	$ 177	
11	Second Tier - Breakover @ 10,000 Gals.	62	$ 4.6907	$ 288	
12	Third Tier - Over 10,000 Gals.	137	$ 5.6112	$ 769	
16	Total Commodity Usage And Revenue	244			$ 1,234
17	1" Meter	-	$ 150.87	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	-	$ 3.8902	$ -	
19	Second Tier - Over 10,000 Gals.	-	$ 4.6907	$ -	
24	Total Commodity Usage And Revenue	-			$ -
33	2" Meter	-	$ 482.77	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	-	$ 3.8902	$ -	
35	Second Tier - Over 50,000 Gals.	-	$ 4.6907	$ -	
40	Total Commodity Usage And Revenue	-			$ -
41	Total Residential Customer Bills	4,128		$ 249,472	
42	Total Residential Usage	23,915		$ 106,584	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 356,055
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	-	$ 60.35	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	-	$ 3.8902	$ -	
46	Second Tier - Over 4,000 Gals.	-	$ 4.6907	$ -	
51	Total Commodity Usage And Revenue	-			$ -
52	3/4" Meter	-	$ 90.52	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	-	$ 3.8902	$ -	
54	Second Tier - Over 4,000 Gals.	-	$ 4.6907	$ -	
59	Total Commodity Usage And Revenue	-			$ -
60	1" Meter	-	$ 150.87	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	-	$ 3.8902	$ -	
62	Second Tier - Over 10,000 Gals.	-	$ 4.6907	$ -	
67	Total Commodity Usage And Revenue	-			$ -
68	1.5" Meter	-	$ 301.73	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	-	$ 3.8902	$ -	
70	Second Tier - Over 25,000 Gals.	-	$ 4.6907	$ -	
75	Total Commodity Usage And Revenue	-			$ -

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	-	$ 482.77	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	-	$ 3.8902	$ -	
78	Second Tier - Over 50,000 Gals.	-	$ 4.6907	$ -	
83	Total Commodity Usage And Revenue	-			$ -
	3" Meter	-	$ 965.54	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	-	$ 3.8902	$ -	
	Second Tier - Over 80,000 Gals.	-	$ 4.6907	$ -	
	Total Commodity Usage And Revenue	-			$ -
	4" Meter	-	$ 1,508.66	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	-	$ 3.8902	$ -	
	Second Tier - Over 350,000 Gals.	-	$ 4.6907	$ -	
	Total Commodity Usage And Revenue	-			$ -
84	6" Meter	-	$ 3,017.32	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	-	$ 3.8902	$ -	
86	Second Tier - Over 450,000 Gals.	-	$ 4.6907	$ -	
91	Total Commodity Usage And Revenue	-			$ -
92	8" Meter	-	$ 4,827.70	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	-	$ 3.8902	$ -	
94	Second Tier - Over 720,000 Gals.	-	$ 4.6907	$ -	
99	Total Commodity Usage And Revenue	-			$ -
100	Total Commercial Customer Bills	-		$ -	
101	Total Commercial Usage	-		$ -	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ -
	HYDRANT CUSTOMERS				
103	3" Meter	-	$ -	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	-	$ -	$ -	
110	Total Commodity Usage And Revenue	-			$ -
159	Total Hydrant Customer Bills	-			
160	Total Hydrant Usage	-			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ -
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	-	$ -	$ -	$ -
202	6" Meter	-	$ -	$ -	$ -
210	8" Meter	-	$ -	$ -	$ -
68	Total Fire Sprinkler Customer Bills	-			

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ -
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 356,055
	Total Company Customer Bills	4,128			
	Total Company Usage	23,915			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 356,055
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				-
192	TOTAL HYDRANT REVENUE PER BILL COUNT				-
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				-
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 356,055
198	Unreconciled Difference vs. Billed Revenues				(99)
200	Miscellaneous Revenues				3,294
200	**RUCO TOTAL REVENUE**				$ 359,250
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 359,250
202	Difference				$ (0)
203	Percentage Difference				0.00%

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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	$ 188,390	100.00%	$ 444,816	100.00%	$ 356,055	100.00%
2	OTHER	-	0.00%	-	0.00%	-	0.00%
3	TOTAL	$ 188,390	100.00%	$ 444,816	100.00%	$ 356,055	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 129,890	68.95%	$ 311,662	70.07%	$ 249,472	70.07%
5	VARIABLE REVENUE	58,500	31.05%	133,154	29.93%	106,584	29.93%
6	TOTAL	$ 188,390	100.00%	$ 444,816	100.00%	$ 356,055	100.00%

	RESIDENTIAL (5/8" X 3/4") RATE DESIGN	PRESENT NSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
7	BASIC MONTHLY CHARGE	$ 31.00	$ 75.39	$ 60.35

	COMMODITY CHARGE PRESENT	NSWC	PROPOSED		PRESENT NSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
8	1st Tier - Breakover	5,000	1st Tier - Breakover	4,000	$ 2.0000	$ 4.8600	$ 3.8902
9	2nd Tier - Breakove	10,000	2nd Tier - Breakover	10,000	$ 2.7500	$ 5.8600	$ 4.6907
10	3rd Tier - Over	10,000	3rd Tier - Over	10,000	$ 3.9000	$ 7.0100	$ 5.6112

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	NORTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,755	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,439	25.00%	$ 33.88	$ 65.94	$ 32.07	94.65%
2		2,878	50.00%	$ 36.76	$ 71.54	$ 34.79	94.64%
3		5,755	100.00%	$ 43.08	$ 84.14	$ 41.06	95.33%
4		8,633	150.00%	$ 50.99	$ 97.64	$ 46.65	91.48%
5		11,510	200.00%	$ 74.39	$ 112.52	$ 38.14	51.26%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 33.25	$ 64.72	$ 31.47	94.66%
7		2,250	50.00%	$ 35.50	$ 69.10	$ 33.60	94.65%
8		4,500	100.00%	$ 40.00	$ 78.25	$ 38.25	95.63%
9		6,750	150.00%	$ 32.06	$ 88.81	$ 56.74	176.98%
10		9,000	200.00%	$ 52.00	$ 99.36	$ 47.36	91.08%

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	9,504	26.96235485	$ 256,250	$ 256,250
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	28,400	$ 1.7406	$ 49,435	
3	Second Tier - Breakover @ 10,000 Gals.	15,487	$ 2.1126	$ 32,718	
4	Third Tier - Over 10,000 Gals.	9,144	$ 2.6828	$ 24,532	
8	Total Commodity Usage And Revenue	53,032			$ 106,684
9	3/4" Meter	-	$ 40.45	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	-	$ 1.7406	$ -	
11	Second Tier - Breakover @ 10,000 Gals.	-	$ 2.1126	$ -	
12	Third Tier - Over 10,000 Gals.	-	$ 2.6828	$ -	
16	Total Commodity Usage And Revenue	-			$ -
17	1" Meter	-	$ 67.41	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	-	$ 1.7406	$ -	
19	Second Tier - Over 10,000 Gals.	-	$ 2.1126	$ -	
24	Total Commodity Usage And Revenue	-			$ -
33	2" Meter	-	$ 215.70	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	-	$ 1.7406	$ -	
35	Second Tier - Over 50,000 Gals.	-	$ 2.1126	$ -	
40	Total Commodity Usage And Revenue	-			$ -
41	Total Residential Customer Bills	9,504		$ 256,250	
42	Total Residential Usage	53,032		$ 106,684	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 362,934
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	-	$ 26.96	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	-	$ 1.7406	$ -	
46	Second Tier - Over 4,000 Gals.	-	$ 2.1126	$ -	
51	Total Commodity Usage And Revenue	-			$ -
52	3/4" Meter	-	$ 40.45	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	-	$ 1.7406	$ -	
54	Second Tier - Over 4,000 Gals.	-	$ 2.1126	$ -	
59	Total Commodity Usage And Revenue	-			$ -
60	1" Meter	24	$ 67.41	$ 1,618	$ 1,618
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	119	$ 1.7406	$ 207	
62	Second Tier - Over 10,000 Gals.	-	$ 2.1126	$ -	
67	Total Commodity Usage And Revenue	119			$ 207
68	1.5" Meter	-	$ 134.81	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	-	$ 1.7406	$ -	
70	Second Tier - Over 25,000 Gals.	-	$ 2.1126	$ -	
75	Total Commodity Usage And Revenue	-			$ -

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	12	$ 215.70	$ 2,588	$ 2,588
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	279	$ 1.7406	$ 485	
78	Second Tier - Over 50,000 Gals.	137	$ 2.1126	$ 289	
83	Total Commodity Usage And Revenue	415			$ 774
	3" Meter	-	$ 431.40	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	-	$ 1.7406	$ -	
	Second Tier - Over 80,000 Gals.	-	$ 2.1126	$ -	
	Total Commodity Usage And Revenue	-			$ -
	4" Meter	-	$ 674.06	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	-	$ 1.7406	$ -	
	Second Tier - Over 350,000 Gals.	-	$ 2.1126	$ -	
	Total Commodity Usage And Revenue	-			$ -
84	6" Meter	-	$ 1,348.12	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	-	$ 1.7406	$ -	
86	Second Tier - Over 450,000 Gals.	-	$ 2.1126	$ -	
91	Total Commodity Usage And Revenue	-			$ -
92	8" Meter	-	$ 2,156.99	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	-	$ 1.7406	$ -	
94	Second Tier - Over 720,000 Gals.	-	$ 2.1126	$ -	
99	Total Commodity Usage And Revenue	-			$ -
100	Total Commercial Customer Bills	36		$ 4,206	
101	Total Commercial Usage	534		$ 981	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ 5,187
	HYDRANT CUSTOMERS				
103	3" Meter	-	$ -	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	-	$ -	$ -	
110	Total Commodity Usage And Revenue	-			$ -
159	Total Hydrant Customer Bills	-			
160	Total Hydrant Usage	-			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ -
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	-	$ -	$ -	$ -
202	6" Meter	-	$ -	$ -	$ -
210	8" Meter	-	$ -	$ -	$ -
68	Total Fire Sprinkler Customer Bills	-			

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ -
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 368,122
	Total Company Customer Bills	9,540			
	Total Company Usage	53,566			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 362,934
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				5,187
192	TOTAL HYDRANT REVENUE PER BILL COUNT				-
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				-
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 368,122
198	Unreconciled Difference vs. Billed Revenues				224
200	Miscellaneous Revenues				10,679
200	**RUCO TOTAL REVENUE**				$ 379,025
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 379,025
202	Difference				$ (0)
203	Percentage Difference				0.00%

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LINE NO.	DESCRIPTION	(A) PRESENT	(B)	(C) COMPANY PROPOSED	(D)	(E) RUCO PROPOSED	(F)
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 426,488	98.49%	$ 731,862	98.59%	$ 362,934	98.59%
2	OTHER	6,543	1.51%	10,461	1.41%	5,187	1.41%
3	TOTAL	$ 433,031	100.00%	$ 742,323	100.00%	$ 368,122	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 296,965	68.58%	$ 525,214	70.75%	$ 260,456	70.75%
5	VARIABLE REVENUE	136,066	31.42%	217,109	29.25%	107,665	29.25%
6	TOTAL	$ 433,031	100.00%	$ 742,323	100.00%	$ 368,122	100.00%

	RESIDENTIAL (5/8" X 3/4") RATE DESIGN	PRESENT SSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
7	BASIC MONTHLY CHARGE	$ 31.00	$ 54.37	$ 26.96

	COMMODITY CHARGE PRESENT	SSWC	PROPOSED		PRESENT SSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
8	1st Tier - Breakover	5,000	1st Tier - Breakover	4,000	$ 2.0000	$ 3.5100	$ 1.7406
9	2nd Tier - Breakove	10,000	2nd Tier - Breakover	10,000	$ 2.7500	$ 4.2600	$ 2.1126
10	3rd Tier - Over	10,000	3rd Tier - Over	10,000	$ 3.9000	$ 5.4100	$ 2.6828

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	SOUTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,581	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,395	25.00%	$ 33.79	$ 29.39	$ (4.40)	-13.02%
2		2,791	50.00%	$ 36.58	$ 31.82	$ (4.76)	-13.02%
3		5,581	100.00%	$ 42.60	$ 37.26	$ (5.33)	-12.52%
4		8,372	150.00%	$ 50.27	$ 43.16	$ (7.11)	-14.15%
5		11,162	200.00%	$ 57.95	$ 49.05	$ (8.89)	-15.34%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 33.25	$ 28.92	$ (4.33)	-13.02%
7		2,250	50.00%	$ 35.50	$ 30.88	$ (4.62)	-13.02%
8		4,500	100.00%	$ 40.00	$ 34.98	$ (5.02)	-12.55%
9		6,750	150.00%	$ 44.50	$ 39.73	$ (4.77)	-10.71%
10		9,000	200.00%	$ 49.00	$ 44.49	$ (4.51)	-9.21%

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Bella Vista Water Company (Consolidated)
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Schedule RLM-RD1
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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	102,480	$ 15.47	$ 1,585,670	$ 1,585,670
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	327,557	$ 1.7059	$ 558,764	
3	Second Tier - Breakover @ 10,000 Gals.	205,717	$ 2.5693	$ 528,549	
4	Third Tier - Over 10,000 Gals.	131,001	$ 3.3464	$ 438,382	
8	Total Commodity Usage And Revenue	664,275			$ 1,525,695
9	3/4" Meter	408	$ 27.85	$ 11,365	$ 11,365
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	1,270	$ 1.7059	$ 2,166	
11	Second Tier - Breakover @ 10,000 Gals.	596	$ 2.5693	$ 1,530	
12	Third Tier - Over 10,000 Gals.	176	$ 3.3464	$ 590	
16	Total Commodity Usage And Revenue	2,042			$ 4,286
17	1" Meter	96	$ 36.75	$ 3,528	$ 3,528
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	764	$ 1.5245	$ 1,164	
19	Second Tier - Over 10,000 Gals.	965	$ 2.3880	$ 2,304	
24	Total Commodity Usage And Revenue	1,728			$ 3,468
33	2" Meter	12	$ 111.40	$ 1,337	$ 1,337
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	129	$ 1.5245	$ 196	
35	Second Tier - Over 50,000 Gals.	-	$ 2.3880	$ -	
40	Total Commodity Usage And Revenue	129			$ 196
41	Total Residential Customer Bills	102,996		$ 1,601,900	
42	Total Residential Usage	668,174		$ 1,533,646	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 3,135,545
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	4,572	$ 15.47	$ 70,742	$ 70,742
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	11,729	$ 1.5245	$ 17,881	
46	Second Tier - Over 4,000 Gals.	21,935	$ 2.3880	$ 52,379	
51	Total Commodity Usage And Revenue	33,663			$ 70,260
52	3/4" Meter	72	$ 27.85	$ 2,006	$ 2,006
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	237	$ 1.5245	$ 361	
54	Second Tier - Over 4,000 Gals.	732	$ 2.3880	$ 1,749	
59	Total Commodity Usage And Revenue	969			$ 2,110
60	1" Meter	1,692	$ 36.75	$ 62,178	$ 62,178
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	10,821	$ 1.5245	$ 16,498	
62	Second Tier - Over 10,000 Gals.	13,467	$ 2.3880	$ 32,159	
67	Total Commodity Usage And Revenue	24,289			$ 48,657

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
68	1.5" Meter	1,020	$ 61.89	$ 63,130	$ 63,130
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	17,687	$ 1.5245	$ 26,965	
70	Second Tier - Over 25,000 Gals.	28,480	$ 2.3880	$ 68,010	
75	Total Commodity Usage And Revenue	46,167			$ 94,975
76	2" Meter	3,276	$ 111.40	$ 364,953	$ 364,953
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	101,475	$ 1.5245	$ 154,701	
78	Second Tier - Over 50,000 Gals.	179,023	$ 2.3880	$ 427,504	
83	Total Commodity Usage And Revenue	280,498			$ 582,205
	3" Meter	312	$ 123.78	$ 38,621	$ 38,621
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	20,136	$ 1.5245	$ 30,697	
	Second Tier - Over 80,000 Gals.	31,283	$ 2.3880	$ 74,703	
	Total Commodity Usage And Revenue	51,419			$ 105,400
	4" Meter	36	$ 154.73	$ 5,570	$ 5,570
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	7,922	$ 1.5245	$ 12,078	
	Second Tier - Over 350,000 Gals.	13,540	$ 2.3880	$ 32,333	
	Total Commodity Usage And Revenue	21,462			$ 44,411
84	6" Meter	12	$ 851.01	$ 10,212	$ 10,212
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	468	$ 1.5245	$ 713	
86	Second Tier - Over 450,000 Gals.	-	$ 2.3880	$ -	
91	Total Commodity Usage And Revenue	468			$ 713
92	8" Meter	12	$ 1,361.62	$ 16,339	$ 16,339
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	31	$ 1.5245	$ 47	
94	Second Tier - Over 720,000 Gals.	-	$ 2.3880	$ -	
99	Total Commodity Usage And Revenue	31			$ 47
100	Total Commercial Customer Bills	11,004		$ 633,751	
101	Total Commercial Usage	458,966		$ 948,778	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ 1,582,529
	HYDRANT CUSTOMERS				
103	3" Meter	168	$ 123.78	$ 20,796	$ 20,796
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	5,094	$ 3.3464	$ 17,046	
110	Total Commodity Usage And Revenue	5,094			$ 17,046
159	Total Hydrant Customer Bills	168			
160	Total Hydrant Usage	5,094			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ 37,842

Bella Vista Water Company (Consolidated)
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Schedule RLM-RD1
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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	1,188	15.00	$ 17,820	$ 17,820
202	6" Meter	252	17.02	$ 4,289	$ 4,289
210	8" Meter	12	27.23	$ 327	$ 327
68	Total Fire Sprinkler Customer Bills	1,452			
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ 22,436
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 4,778,352
	Total Company Customer Bills	115,620			
	Total Company Usage	1,132,234			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 3,135,545
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				1,582,529
192	TOTAL HYDRANT REVENUE PER BILL COUNT				37,842
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				22,436
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 4,778,352
198	Unreconciled Difference vs. Billed Revenues				2,148
200	Miscellaneous Revenues				139,114
200	**RUCO TOTAL REVENUE**				$ 4,919,614
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 4,919,615
202	Difference				$ (0)
203	Percentage Difference				0.00%

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A) PRESENT	(B)	(C) COMPANY PROPOSED	(D)	(E) RUCO PROPOSED	(F)
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 2,771,302	69.02%	$ 3,631,427	65.73%	$ 3,135,545	65.62%
2	OTHER	1,243,988	30.98%	1,893,459	34.27%	1,642,807	34.38%
3	TOTAL	$ 4,015,290	100.00%	$ 5,524,886	100.00%	$ 4,778,352	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 2,158,470	53.76%	$ 2,634,057	47.68%	$ 2,278,882	47.69%
5	VARIABLE REVENUE	1,856,821	46.24%	2,890,829	52.32%	2,499,470	52.31%
6	TOTAL	$ 4,015,290	100.00%	$ 5,524,886	100.00%	$ 4,778,352	100.00%

RESIDENTIAL (5/8" X 3/4") RATE DESIGN

		PRESENT BVWC	PRESENT NS & SS	COMPANY PROPOSED CONSOL'D	RUCO PROPOSED CONSOL'D
7	BASIC MONTHLY CHARGE	$ 15.00	$ 31.00	$ 17.92	$ 15.47

COMMODITY CHARGE

	PRESENT	BVWC	NS & SS	PROPOSED	CONSOL'D	PRESENT BVWC	PRESENT NS & SS	COMPANY PROPOSED CONSOL'D	RUCO PROPOSED CONSOL'D
8	1st Tier - Breakover	5,000	5,000	1st Tier - Breakover	4,000	$ 0.9700	$ 2.0000	$ 1.9756	$ 1.7059
9	2nd Tier - Breakove	25,000	10,000	2nd Tier - Breakover	10,000	$ 1.8900	$ 2.7500	$ 2.9756	$ 2.5693
10	3rd Tier - Over	25,000	10,000	3rd Tier - Over	10,000	$ 2.4100	$ 3.9000	$ 3.8756	$ 3.3464

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	BELLA VISTA RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 6,612	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,653	25.00%	$ 16.60	$ 18.29	$ 1.69	10.17%
2		3,306	50.00%	$ 18.21	$ 21.11	$ 2.91	15.96%
3		6,612	100.00%	$ 22.90	$ 29.01	$ 6.11	26.69%
4		9,918	150.00%	$ 29.14	$ 37.50	$ 8.36	28.67%
5		13,223	200.00%	$ 35.39	$ 45.99	$ 10.60	29.96%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 16.09	$ 17.39	$ 1.30	8.08%
7		2,250	50.00%	$ 17.18	$ 19.31	$ 2.13	12.39%
8		4,500	100.00%	$ 19.37	$ 23.58	$ 4.22	21.77%
9		6,750	150.00%	$ 21.55	$ 29.36	$ 7.81	36.27%
10		9,000	200.00%	$ 23.73	$ 35.14	$ 11.41	48.09%

TYPICAL RESIDENTIAL BILL ANALYSIS

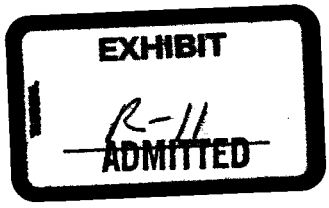
LINE NO.	NORTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,755	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,439	25.00%	$ 33.88	$ 17.93	$ (15.95)	-47.08%
2		2,878	50.00%	$ 17.79	$ 20.38	$ 2.59	14.56%
3		5,755	100.00%	$ 43.08	$ 26.81	$ (16.27)	-37.77%
4		8,633	150.00%	$ 50.99	$ 34.20	$ (16.79)	-32.93%
5		11,511	200.00%	$ 74.39	$ 42.77	$ (31.62)	-42.51%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 33.25	$ 17.39	$ (15.86)	-47.69%
7		2,250	50.00%	$ 35.50	$ 19.31	$ (16.19)	-45.60%
8		4,500	100.00%	$ 40.00	$ 23.58	$ (16.42)	-41.05%
9		6,750	150.00%	$ 32.06	$ 29.36	$ (2.70)	-8.42%
10		9,000	200.00%	$ 52.00	$ 35.14	$ (16.86)	-32.42%

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	SOUTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,581	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,395	25.00%	$ 33.79	$ 17.85	$ (15.94)	-47.17%
2		2,791	50.00%	$ 17.71	$ 20.23	$ 2.53	14.27%
3		5,581	100.00%	$ 42.60	$ 26.36	$ (16.24)	-38.12%
4		8,372	150.00%	$ 50.27	$ 33.53	$ (16.74)	-33.31%
5		11,162	200.00%	$ 73.03	$ 41.60	$ (31.43)	-43.04%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 3,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		875	25.00%	$ 32.75	$ 16.97	$ (15.78)	-48.20%
7		1,750	50.00%	$ 34.50	$ 18.46	$ (16.04)	-46.50%
8		3,500	100.00%	$ 38.00	$ 21.44	$ (16.56)	-43.57%
9		5,250	150.00%	$ 27.94	$ 24.43	$ (3.51)	-12.56%
10		7,000	200.00%	$ 46.50	$ 27.41	$ (19.09)	-41.05%

BELLA VISTA WATER COMPANY, INC.

DOCKET NO. W-02465A-09-0411 ET AL.



SURREBUTTAL TESTIMONY

OF

RODNEY L. MOORE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 18, 2010

SURREBUTTAL

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INTRODUCTION

Q. Please state your name for the record.

A. My name is Rodney Lane Moore.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on June 12, 2010 and supplemental direct testimony with my rate design testimony on June 23, 2010.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address Company's rebuttal comments pertaining to adjustments I sponsored in my direct testimony. I will also provide revised rate design testimony.

SUMMARY OF ADJUSTMENTS

Q. After analyzing the Company's rebuttal testimony, did RUCO find positions of agreement?

A. Yes. RUCO is now in substantial agreement with several of the Company's rebuttal adjustments identified by BVWC as:

Rate Base

1. Post Test Year Plant and Accumulated Depreciation (RUCO Direct Adjustment No. 1);
2. Customers' Deposits (RUCO Surrebuttal Adjustment No. 2);

3. Allowance for Funds Used During Construction (RUCO Surrebuttal Adjustment No. 4);
4. Retired Plant (RUCO Surrebuttal Adjustment No. 5); and
5. Acquisition Costs Associated With Purchase of the Former McLain Systems (RUCO Surrebuttal Adjustment No. 6).

Operating Income

1. Test Year Depreciation (RUCO Surrebuttal Adjustment No. 1);
2. Property Tax - Method of Computation (RUCO Surrebuttal Adjustment No. 2);
3. Miscellaneous Expenses (RUCO Surrebuttal Adjustment No. 3);
4. Water Testing Expense (RUCO Surrebuttal Adjustment No. 4); and
5. Transportation Expense (RUCO Surrebuttal Adjustments No. 5).

Q. What areas will you address in your surrebuttal testimony?

A. My surrebuttal testimony will address the following RUCO proposed adjustments:

Rate Base

Customers' Deposits - This is a revision to my direct testimony adjustment, which reflects a misunderstanding of information provided by the Company in its data response. RUCO is now in substantial agreement with the Company.

Accumulated Deferred Income Taxes – RUCO witness Timothy Coley will sponsor this adjustment.

Plant Retirements and Accumulated Depreciation – This is a revision to my direct testimony adjustment, which reflects updated information

provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Allowance for Funds Used During Construction ("AFUDC") - This is an additional adjustment, which reflects updated information provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Acquisition Costs Associated With Purchase of the Former McLain Systems – This is an additional adjustment, which reflects updated information provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Hook-Up Fee Tariff - RUCO witness Timothy Coley will sponsor this adjustment.

Operating Income

Test Year Depreciation Expense – This is a revision to my direct testimony adjustment, which reflects updated information provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Property Tax Expense - This adjustment reflects property tax expense based on RUCO's calculation of adjusted and proposed operating revenues.

Miscellaneous Expenses – This is a revision to my direct testimony adjustment, which reflects updated information provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Water Testing Expenses – This is an additional adjustment, which reflects updated information provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Transportation Expenses – This is an additional adjustment, which reflects updated information provided in the Company's rebuttal testimony. RUCO is now in substantial agreement with the Company.

Central Office Cost Allocations - RUCO witness Timothy Coley will sponsor this adjustment.

Rate Case Expense - RUCO will provide a final recommended level of rate case expense when it files final schedules after the evidentiary hearing on the instant case is concluded.

Income Tax Expense – This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

To support the adjustments in my surrebuttal testimony, I prepared sixteen separate Surrebuttal Schedules for each Company (BVWC, NSWC and SSWC), which are filed concurrently in my surrebuttal testimony.

RATE BASE

Rate Base Adjustment No. 2 – Customers' Deposits

Q. Please explain the basis for your adjustment to customers' deposits.

A. RUCO and the Company are now in substantial agreement with the level of customers' deposits as adjusted in my surrebuttal schedules.

Originally, in my direct testimony, I interpreted the Company's response to RUCO's data request 2.01 incorrectly. I failed to aggregate the individual amounts into my adjustment. Consequently, after analyzing the Company's rebuttal workpapers, RUCO will restore the customers' deposits to its original level as filed.

Therefore, as shown on Schedule SURR RLM-3, column C, I revised my direct testimony to reflect the correct level of customers' deposits, by removing my adjustment. The appropriate level of customers' deposits is BVWC's at $556,325, NSWC's at $410 and SSWC's at $2,870.

Rate Base Adjustment No. 3 – Accumulated Deferred Income Taxes

Q. Please explain how this adjustment to accumulated deferred income taxes was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley; please refer to his testimony for clarification.

Based on Mr. Coley's testimony and as shown on Schedule SURR RLM-3, column D, and with supporting Schedules SURR RLM-5A and SURR RLM-5B this adjustment decreases BVWC's rate base by $2,703,488, NSWC's rate base by $57,525 and SSWC's rate base by $84,614.

Rate Base Adjustment No. 4 – Plant Retirements and Accumulated Depreciation (BVWC Only)

Q. Please explain the basis for your adjustment for retired plant and the accumulated depreciation.

A. RUCO and the Company are now in substantial agreement with the level of gross plant-in-service and accumulated depreciation as adjusted in my surrebuttal schedules.

In its rebuttal testimony, the Company acknowledged it did not retire assets when replacements were placed in service in BVWC. Therefore, after analyzing the Company's rebuttal workpapers RUCO will remove $1,333,328 of retired plant from gross plant in service and simultaneously $1,333,328 was removed from accumulated depreciation to recognize the plant was fully depreciated; thus recording a zero effect on the rate base.

However, as shown on BVWC's Schedule SURR RLM-3, column E, the actual entry under accumulated depreciation is $1,509,449 a difference of $176,221. This anomaly was a reconciling computation in the Company's

accumulated depreciation schedules that required an additional adjustment to recognize a difference between the accrued booked accumulated depreciation balance and the computed level of accumulated depreciation since the previous rate case test year.

Therefore, as shown BVWC's Schedule SURR RLM-3, column E, RUCO and the Company recommend an aggregate increase to BVWC's rate base of $176,221.

Rate Base Adjustment No. 5 – Allowance for Funds Used During Construction ("AFUDC")

Q. Please explain the basis for your adjustment for AFUDC.

A. RUCO and the Company are now in substantial agreement with the level of AFUDC as adjusted in my surrebuttal schedules.

In its rebuttal testimony and workpapers, the Company provided a revised computation of AFUDC based on a methodology established by NARUC. Consequently, after analyzing the Company's rebuttal documentation, RUCO will remove $80,055 of AFUDC.

Therefore, as shown on Schedule SURR RLM-3, I revised my direct testimony to reflect the correct level of AFUDC, with an adjustment to decrease BVWC's rate base by $40,887, NSWC's rate base by $13,740 and SSWC's rate base by $25,428.

Rate Base Adjustment No. 6 – Acquisition Costs Associated with Purchase of the Former McLain Systems (NSWC and SSWC Only)

Q. Please explain the basis for your adjustment for acquisition costs.

A. RUCO and the Company are now in substantial agreement with the level of acquisition costs as adjusted in my surrebuttal schedules.

In its rebuttal testimony and workpapers, the Company provided the actual amount of acquisition costs. Consequently, after analyzing the Company's rebuttal documentation, RUCO will set the acquisition costs at $155,378 by removing $144,623 from account 348 (Other Tangible Plant).

Therefore, as shown on Schedule SURR RLM-3 (NSWC and SSWC only), I revised my direct testimony to reflect the correct level of the acquisition costs, with an adjustment to decrease NSWC's rate base by $15,636 and SSWC's rate base by $128,987.

Rate Base Adjustment No. 7 – Hook-Up Fee Tariff

Q. Please explain how this adjustment to the hook-up fee tariff was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley; please refer to his testimony for clarification.

OPERATING INCOME

Operating Income Adjustment No. 1 – Test Year Depreciation Expense

Q. Please explain your adjustment to the test year depreciation expense.

A. RUCO and the Company are now in substantial agreement with the level of test year depreciation expense. This adjustment of reflects RUCO's end of test year gross plant-in-service. The adjustment is driven by the revisions to plant retirements as explained previously in my testimony.

As shown on Schedule SURR RLM-7, column B and supporting Schedule SURR RLM-8, this adjustment decreases adjusted test-year operating expenses of BVWC by $58,288, NSWC by $2,225 and SSWC by $13,933.

Operating Income Adjustment No. 2 – Property Tax Computation

Q. Did RUCO and the Company use the same methodology to calculate property tax expenses?

A. Yes. This adjustment varies from the Company's recommendation only to reflect RUCO's lower proposed annual revenue.

As shown on Schedule SURR RLM-7, column C and supporting Schedule SURR RLM-9, this adjustment decreases adjusted test-year operating expenses of BVWC by $10,267, NSWC by $1,266 and SSWC by $4,177 on a stand-alone basis.

Q. Does consolidation affect the total Company level of property tax expense?

A. Yes, because there is a difference between the individual tax rates of each separate Company and the composite tax rate used for the consolidation model, the stand-alone property tax expense level is aggregately $1,456 higher than the consolidated property tax expense.

Operating Income Adjustment No. 3 – Miscellaneous Expense

Q. Please explain your adjustment to the test year miscellaneous expenses.

A RUCO and the Company are now in substantial agreement with the level of test year miscellaneous expense. This adjustment removes an additional $4,064 for an aggregate total of $9,064 of unnecessary costs for meals, entertainment and contributions identified by the Company in its rebuttal testimony.

As shown on Schedule RLM-7, column D and supporting Schedule SURR RLM-10, this adjustment decreases test year expenses of BVWC by $7,681, NSWC by $610 and SSWC by $773.

Operating Income Adjustment No. 4 – Water Testing Expense

Q. Please explain your adjustment to the test year water testing expenses.

A In its rebuttal testimony and workpapers, the Company acknowledged an oversight when originally computing the test year water testing expenses. The Company failed to recognize the projected three-year average water testing expense. The costs vary significantly over the three-year cycle because of different annual number of Compliance Sampling requirements. Consequently, after analyzing the Company's rebuttal documentation, RUCO will set the water testing expense at $66,652, which is an increase $38,457.

Therefore, as shown on Schedule RLM-7, column E, this adjustment increases test year expenses of BVWC by $39,722 and NSWC by $570, but decreases SSWC by $1,825.

Operating Income Adjustment No. 5 – Transportation Expense

Q. Please explain your adjustment to the test year transportation expenses.

A In its rebuttal testimony and workpapers, the Company acknowledged a courtesy adjustment to reflect the removal transportation costs associated with private corporate air travel through an entity called Airlink. Consequently, after analyzing the Company's rebuttal documentation, RUCO will remove transportation expenses of $8,703.

Therefore, as shown on Schedule RLM-7, column F, this adjustment decreased test year expenses of BVWC by $7,023, NSWC by $647 and SSWC by $1,033.

Operating Income Adjustment No. 6A, 6B and 6C – Central Office Cost Allocations

Q. Please explain how this adjustment to the allocation of central office costs was analyzed by RUCO.

A. This adjustment is sponsored by RUCO witness Timothy Coley; please refer to his testimony for clarification.

Based on Mr. Coley's testimony and as shown on Schedule SURR RLM-7, columns G, H and I and supporting Schedules SURR RLM-11A, SURR RLM-11B and SURR RLM-11C, this adjustment aggregately decreases adjusted test year rate base of BVWC by $133,749, NSWC by $5,536 and SSWC by $13,185.

RUCO Operating Income Adjustment No. 7 – Rate Case Expense

Q. Please explain RUCO's adjustment to rate case expenses.

A. RUCO proposes a fair and reasonable level of rate case expenses based on a Company provided estimate. This estimate was originally offered by the Company to determine the present and future rate case expenditures to be incurred in the recent Black Mountain Sewer Company ("BMSC")

rate case proceedings. Moreover, I presented the Company with the BMSC estimate and requested an updated version to reflect suitable adjustments for any variations in the instant case. The Company refused to update the BMSC estimate.

RUCO finds no compelling reason to adjust its recommended level of rate case expense at this time and believes its estimate remains fair and reasonable at $200,000 (normalized over three years) for an annual expense $66,666 and subsequently allocated to each Company.

However, RUCO will continue to analyze any documentation made available and will provide a final recommended level of rate case expense when it files final schedules after the evidentiary hearing on the instant case is concluded.

As shown on Schedule SURR RLM-7 column J, this adjustment decreases adjusted test-year operating expenses of BVWC by $49,333, NSWC by $8,693 and SSWC by $8,640.

RUCO Operating Income Adjustment No. 8 – Income Taxes

Q. Please explain RUCO's adjustment to the income tax expenses.

A. This adjustment reflects income tax expenses calculated on RUCO's recommended revenues and expenses.

As shown on Schedule SURR RLM-7 column K and supporting Schedule SURR RLM-13, this adjustment increases adjusted test-year operating expenses of BVWC by $104,773, NSWC by $12,419 and SSWC by $1,725 on a stand-alone basis.

Q. Does consolidation affect the total Company level of income tax expense?

A. Yes, because there is a difference between the individual income tax rates of each separate Company and the composite tax rate used for the consolidation model, the stand-alone income tax expense level is aggregately $65,604 lower than the consolidated income tax expense.

COST OF CAPITAL

Q. Is RUCO proposing any surrebuttal adjustments to the Company proposed cost of capital?

A. No. This adjustment is fully explained in the testimony of RUCO witness William A. Rigsby.

RATE DESIGN AND PROOF OF RECOMMENDED REVENUE

Q. Have you revised your Schedule presenting your recommended rate designs?

A. Yes, as shown on Schedule SURR RLM-RD1, I am recommending a rate design that is consistent with RUCO's recommended revenue allocations and requirement as revised in my surrebuttal testimony. I have also

modified the rate design to reflect the Company's revisions to its basic rate design to remove "cross-over points" where customers on small meters with high levels of usage pay more than larger metered customers.

STAND-ALONE RATE DESIGNS

Q. Please explain RUCO's stand-alone rate designs.

A. RUCO is recommending a stand-alone rate design that is generally consistent with the Company's proposed stand-alone rate design. However, my rate design reflects RUCO's recommended revenue requirements and provides proof that the design will produce the appropriate revenue requirements.

STAND-ALONE PROOF OF RECOMMENDED REVENUES

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that my recommended stand-alone rate designs will produce the recommended required revenue as illustrated, is presented also on Schedule SURR RLM-RD1.

STAND-ALONE TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's recommended stand-alone rate design on the typical residential customer?

A. Yes. A typical bill analysis for residential customers with various levels of usage is presented on Schedule SURR RLM-RD2. The stand-alone rate designs will affect customers of BVWC, NSWC and SSWC differently.

Q. Please describe the financial impact of RUCO's rate design on the average BVWC residential customer.

A. RUCO's rate designs propose a basic service charge for residential customers of BVWC with a 5/8" X 3/4" meter of $15.08 (versus $18.46 proposed by the Company) and commodity charges of $1.2495 per thousand gallons for the first 4,000 gallons, $1.8211 per thousand gallons for the next 6,000 gallons and $2.1478 per thousand gallons for all usage above 10,000 gallons (versus $1.5300, $2.2300 and $2.6300, proposed respectively by the Company).

Residential customers of BVWC with a 5/8" X 3/4" meter and average consumption of 6,612 gallons will see a monthly bill of $24.83. RUCO's rate design provides for a $1.93 or 8.44 percent increase over the present monthly bill of $22.90 (at the same level of consumption). This is a

decrease of $5.58 or 74.30 percent over the Company's requested increase of $7.51 or 32.79 percent.

Q. Please describe the financial impact of RUCO's rate design on the average NSWC residential customer.

A. RUCO's rate designs propose a basic service charge for residential customers of NSWC with a 5/8" X 3/4" meter of $59.33 (versus $75.39 proposed by the Company) and commodity charges of $3.8247 per thousand gallons for the first 4,000 gallons, $4.6117 per thousand gallons for the next 6,000 gallons and $5.5168 per thousand gallons for all usage above 10,000 gallons (versus $4.8600, $5.8600 and $7.0100, proposed respectively by the Company).

Residential customers of NSWC with a 5/8" X 3/4" meter and average consumption of 5,755 gallons will see a monthly bill of $82.72. RUCO's rate design provides for a $39.65 or 92.04 percent increase over the current monthly bill of $43.08 (at the same level of consumption). This is a decrease of $22.39 or 36.09 percent over the Company's requested $62.04 or 144.02 percent increase.

Q. Please describe the financial impact of RUCO's rate design on the average SSWC residential customer.

A. RUCO's rate designs propose a basic service charge for residential customers of SSWC with a 5/8" X 3/4" meter of $37.32 (versus $54.37 proposed by the Company) and commodity charges of $2.4095 per thousand gallons for the first 4,000 gallons, $2.9243 per thousand gallons for the next 6,000 gallons and $3.7138 per thousand gallons for all usage above 10,000 gallons (versus $3.5100, $4.2600 and $5.4100, proposed respectively by the Company).

Residential customers of SSWC with a 5/8" X 3/4" meter and average consumption of 5,581 gallons will see a monthly bill of $51.58. RUCO's rate design provides for an $8.99 or 21.10 percent increase over the current monthly charge of $42.60 (at the same level of consumption). This is a decrease of $23.56 or 72.38 percent over the Company's requested $32.55 or 76.41 percent increase.

CONSOLIDATED RATE DESIGN

Q. Please explain RUCO's position on consolidated rate design.

A. RUCO will not oppose consolidated rates if the Commission finds that such rate design is in the public interest.

Therefore, RUCO is providing an alternative consolidated rate design that is generally consistent with the Company's proposed consolidated rate design, but reflects RUCO's recommended revenue requirements and provides proof that the design will produce the appropriate revenue requirements.

CONSOLIDATED PROOF OF RECOMMENDED REVENUE

Q. Have you prepared a Schedule presenting proof of your recommended revenue?

A. Yes, I have. Proof that my recommended consolidated rate design will produce the recommended required revenue as illustrated, is presented also on Schedule SURR RLM-RD1.

CONSOLIDATED TYPICAL BILL ANALYSIS

Q. Have you prepared a Schedule representing the financial impact of RUCO's consolidated rate design on the typical residential customer?

A. Yes. A typical bill analysis for residential customers with various levels of usage is presented on Schedule SURR RLM-RD2.

The consolidated rate design will affect customers of BVWC, NSWC and SSWC differently.

RUCO's consolidated rate design proposes a basic service charge for residential customers of BVWC with a 5/8" X 3/4" meter of $14.69 (versus $17.92 proposed by the Company) and commodity charges of $1.6193 per thousand gallons for the first 4,000 gallons, $2.4389 per thousand gallons for the next 6,000 gallons and $3.1766 per thousand gallons for all usage above 10,000 gallons (versus $1.9756, $2.9756 and $3.8756 proposed respectively by the Company).

Q. Please describe the financial impact of RUCO's rate design on the average BVWC residential customer.

A. Residential customers of BVWC with a 5/8" X 3/4" meter and average consumption of 6,612 gallons will see a monthly bill of $27.53. RUCO's rate design provides for a $4.64 or 20.26 percent increase over the present monthly bill of $22.90 (at the same level of consumption). This is a decrease of $6.06 or 56.64 percent over the Company's requested $10.70 or 46.72 percent increase.

Q. Please describe the financial impact of RUCO's rate design on the average NSWC residential customer.

A. Residential customers of NSWC with a 5/8" X 3/4" meter and average consumption of 5,755 gallons will see a monthly bill of $25.45. RUCO's rate design provides for a $17.63 or 40.93 percent decrease over the present monthly bill of $43.08 (at the same level of consumption). This is

an increase of $5.60 or 46.55 percent over the Company's requested $12.03 or 27.93 percent decrease.

Q. Please describe the financial impact of RUCO's rate design on the average SSWC residential customer.

A. Residential customers of SSWC with a 5/8" X 3/4" meter and average consumption of 5,581 gallons will see a monthly bill of $25.02. RUCO's rate design provides for a $17.58 or 41.26 percent decrease over the present monthly bill of $42.60 (at the same level of consumption). This is an increase of $5.51 or 45.65 percent over the Company's requested $12.07 or 28.34 percent decrease.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

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SURREBUTTAL
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SURR RLM-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
DIRECT TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
SURR RLM-5A & 5B	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
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SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 5 - AFUDC
SURR RLM-6	1	OPERATING INCOME
SURR RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
SURR RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
SURR RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
SURR RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 6,343,311	$ 3,769,607
2	Adjusted Operating Income (Loss)	$ 94,521	$ 216,368
3	Current Rate Of Return (L2 / L1)	1.49%	5.74%
4	Required Operating Income (L5 X L1)	$ 683,175	$ 310,801
5	Required Rate Of Return On Fair Value Rate Base	10.77%	8.24%
6	Operating Income Deficiency (L4 - L2)	$ 588,653	$ 94,433
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6286	1.6286
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 958,701	$ 153,798
9	Adjusted Test Year Revenue	$ 3,526,033	$ 3,526,033
10	Proposed Annual Revenue (L8 + L9)	$ 4,484,734	$ 3,679,831
11	Required Percentage Increase In Revenue (L8 / L9)	27.19%	4.36%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule SURR RLM-2, SURR RLM-6, And RLM-14

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Schedule SURR RLM-2
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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 25,625,206	$ (1,376,055)	$ 24,249,151
2	Accumulated Depreciation	(11,909,440)	1,505,839	(10,403,601)
3	Net Utility Plant In Service (L1 + L2)	$ 13,715,765	$ 129,784	$ 13,845,549
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (496,445)	$ -	$ (496,445)
6	Accumulated Amortization Of CIAC	230,909	-	230,909
7	NET CIAC (L5 + L6)	$ (265,536)	$ -	$ (265,536)
8	Customer Meter Deposits	$ (556,325)	$ -	$ (556,325)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ 230,850	$ (2,703,488)	$ (2,472,638)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 6,343,311	$ (2,573,704)	$ 3,769,607

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): SURR RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) ADJ # 4 PLANT RETIREMENTS	(F) ADJ # 5 AFUDC	(G) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 25,625,206	$ (1,940)	$ -	$ -	$ (1,333,228)	$ (40,887)	$ 24,249,151
2	Accumulated Depreciation	(11,909,440)	(3,610)	-	-	1,509,449	-	(10,403,601)
3	Net Utility Plant In Service (L1 + L2)	$ 13,715,765	$ (5,550)	$ -	$ -	$ 176,221	$ (40,887)	$ 13,845,549
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ -	$ -	$ -	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (496,445)	$ -	$ -	$ -	$ -	$ -	$ (496,445)
6	Accumulated Amortization Of CIAC	230,909	-	-	-	-	-	230,909
7	NET CIAC (L5 + L6)	$ (265,536)	$ -	$ -	$ -	$ -	$ -	$ (265,536)
8	Customer Meter Deposits	$ (556,325)	$ -	-	$ -	$ -	$ -	$ (556,325)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ 230,850	$ -	$ -	$ (2,703,488)	$ -	$ -	$ (2,472,638)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 6,343,311	$ (5,550)	$ -	$ (2,703,488)	$ 176,221	$ (40,887)	$ 3,769,607

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Surrebuttal Testimony Of RUCO Witness Tim Coley and Schedule SURR RLM-5A & 5B)
Column (E): Adjustment No. 4 - RUCO Adjustment For Retired Plant (See Surrebuttal Testimony, RLM)
Column (F): Adjustment No. 5 - RUCO Adjustment To AFUDC (See Surrebuttal Testimony, RLM)
Column (G): Sum Of Columns (A), (B), (C), (D), (E) & (F)

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Schedule RLM-5(A)
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Original Cost Rate Base Proforma Adjustments
ADIT Calculation Based on RUCO's Surrebuttal Schedules

Line No.											
1	Deferred Income Tax as of March 31, 2009										
2											
3				Probability	Deductible TD						
4		Adjusted		of Realization	(Taxable TD)	[5]	Future Tax Asset		Future Tax Liability	
5		Book Value[1]	Tax Value	of Future Tax Benefit	Expected to be Realized	Tax Rate	Current	Non Current	Current	Non Current
6	Plant-in-Service	$ 24,249,151 [1]								
7	Accum. Deprec.	(10,403,601) [1]								
8	CIAC (Net)	(265,536) [1]								
9	Fixed Assets	$ 13,580,013	$ 6,730,491 [2]	100.0%	$ (6,849,522)	38.60%		-		(2,643,839)
10	AIAC		6,136,045 [3]	7.2% [4]	$ 443,538	38.60%		$ 171,201		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	38.60%		$ -		
12							$ -	$ 171,201	$ -	$ (2,643,839)
13										
14	RUCO Net Asset (Liability)						$ (2,472,638)			
15										
16	Company ADIT Asset (Liability) for BVWC Stand Alone Adjusted Test Year						$ 230,850			
17										
18	RUCO BVWC (Stand Alone) Adjustment to ADIT						$ (2,703,488)			
19										
20										
21										
22	**1 Adjusted per RUCO Surrebuttal Schedule RLM-2, page 1**									
23										
24	**2 Tax Basis per Company as of March 31, 2009**									
25										
26	**3 AIAC (including impact of change in probability of realization)**									
27	AIAC per B-2						$ 6,781,443			
28	Less: Pre-1996 AIAC included for book and tax purposes						(645,398)			
29	Net AIAC before unrealized portion							$ 6,136,045		
30										
31	**4 Effective AIAC Refund Rate Over a 30 Year AIAC/Refund Study (See Coley Work Papers)**									
32										
33	**5 Effective tax rates Per RLM-1, page 2**									
34										
35										
36										
37										
38										

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Schedule SURR RLM-5B
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SURREBUTTAL
ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Consolidated Allocation	Note (A)	1.5438%
5	Bella Vista Consolidated ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Consolidated Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Total Consolidated ADIT as Filed by Company	Company Schedule C-1	173,329
9	Decrease In Deferred Income Tax Assets	Line 7 - Line 8	$ (1,458,278)
10	Total Bella Vista Customer Count Factor	Per Company	0.8772
11	RUCO Adjustment (See RLM-3, Column (D), Line 10)	Line 9 X Line 10	(1,279,224)

NOTES:

12	(A)	Purchase Price of BVWC, NSWC and SSWC	Annual Report	$	15,100,000
13		Algonquin Total Assets	Annual Report	$	978,130,000
14		Ratio Of BVWC, NSWC & SSWC To Algonquin Total A	Line 12 / Line 13		1.5438%
15	(B)	Currency Conversion	moneycentral.com on 04/1/2010		0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

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Schedule SURR RLM-6
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SURREBUTTAL
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	Flat Rate Revenues	$ 3,400,892	$ -	$ 3,400,892	$ 153,798	$ 3,554,690
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	125,141	-	125,141	-	125,141
4	TOTAL OPERATING REVENUE	$ 3,526,033	$ -	$ 3,526,033	$ 153,798	$ 3,679,831
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	708	-	708
7	Purchased Power	561,094	-	561,094	-	561,094
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	4,273	-	4,273	-	4,273
10	Materials & Supplies	36,932	-	36,932	-	36,932
11	Outside Services	4,605	-	4,605	-	4,605
12	Outside Services- Legal	35,245	-	35,245	-	35,245
13	Outside Services- Other	1,258,045	(133,749)	1,124,297	-	1,124,297
14	Water Testing	18,805	39,722	58,527	-	58,527
15	Equipment Rental		-	-	-	-
16	Rents	60,600	-	60,600	-	60,600
17	Transportation Expenses	78,117	(7,023)	71,094	-	71,094
18	Insurance - General Liability	38,930	-	38,930	-	38,930
19	Insurance - Health and Life	7,290	-	7,290	-	7,290
20	Reg. Comm. Exp.	9,017	-	9,017	-	9,017
21	Reg. Comm. Exp. - Rate Case	83,333	(49,333)	34,000	-	34,000
22	Miscellaneous Expense	65,966	(7,681)	58,285	-	58,285
23	Bad Debt Expense	9,526	-	9,526	-	9,526
24	Depreciation Expense	1,009,435	(58,288)	951,146	-	951,146
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	159,659	(10,267)	149,392	-	149,392
27	Income Tax	(10,068)	104,773	94,705	59,364	154,069
28	TOTAL OPERATING EXPENSES	$ 3,431,512	$ (121,847)	$ 3,309,665	$ 59,364	$ 3,369,029
29	OPERATING INCOME (LOSS)	$ 94,521		$ 216,368		$ 310,801

References:
Column (A): Company Schedule C-1
Column (B): SURR RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From SURR RLM-1, Column (B), Line 8 And Income Tax From SURR RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 WATER TEST EXPENSES	(F) ADJ # 5 TRANSPORT EXPENSES	(G) ADJ # 6A CENTRAL OFFICE COST	(H) ADJ # 6B CENTRAL OFFICE COST	(I) ADJ # 6C CENTRAL OFFICE COST	(J) ADJ # 7 RATE CASE EXPENSES	(K) ADJ # 8 INCOME TAX	(L) RUCO AS ADJT'D
	Revenues:												
1	Flat Rate Revenues	$ 3,400,892	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,400,892
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	125,141	-	-	-	-	-	-	-	-	-	-	125,141
4	TOTAL OPR'G REV.	$ 3,526,033	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,526,033
	Operating Expenses:												
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	-	-	-	-	-	-	-	-	-	708
7	Purchased Power	561,094	-	-	-	-	-	-	-	-	-	-	561,094
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-	-	-	-
9	Chemicals	4,273	-	-	-	-	-	-	-	-	-	-	4,273
10	Materials & Supplies	36,932	-	-	-	-	-	-	-	-	-	-	36,932
11	Outside Services	4,605	-	-	-	-	-	-	-	-	-	-	4,605
12	Outside Services- Legal	35,245	-	-	-	-	-	-	-	-	-	-	35,245
13	Outside Services- Other	1,258,045	-	-	-	-	-	(122,927)	(959)	(9,863)	-	-	1,124,297
14	Water Testing	18,805	-	-	-	39,722	-	-	-	-	-	-	58,527
15	Equipment Rental	-	-	-	-	-	-	-	-	-	-	-	-
16	Rents	60,600	-	-	-	-	-	-	-	-	-	-	60,600
17	Transportation Expenses	78,117	-	-	-	-	(7,023)	-	-	-	-	-	71,094
18	Insurance - General Liability	38,930	-	-	-	-	-	-	-	-	-	-	38,930
19	Insurance - Health and Life	7,290	-	-	-	-	-	-	-	-	-	-	7,290
20	Reg. Comm. Exp.	9,017	-	-	-	-	-	-	-	-	-	-	9,017
21	Reg. Comm. Exp. - Rate Case	83,333	-	-	-	-	-	-	-	-	(49,333)	-	34,000
22	Miscellaneous Expense	65,966	-	-	(7,681)	-	-	-	-	-	-	-	58,285
23	Bad Debt Expense	9,526	-	-	-	-	-	-	-	-	-	-	9,526
24	Depreciation Expense	1,009,435	(58,288)	-	-	-	-	-	-	-	-	-	951,146
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
26	Property Taxes	159,659	-	(10,267)	-	-	-	-	-	-	-	-	149,392
27	Income Tax	(10,068)	-	-	-	-	-	-	-	-	-	104,773	94,705
29	TOTAL OPR'G EXP.	$ 3,431,512	$ (58,288)	$ (10,267)	$ (7,681)	$ 39,722	$ (7,023)	$ (122,927)	$ (959)	$ (9,863)	$ (49,333)	$ 104,773	$ 3,309,665
30	OPR'G INC. (LOSS)	$ 94,521											$ 216,368

References:
Column (A): Company Schedule C-1
Column (B): Surrebuttal Testimony, RLM And Schedule SURR RLM-8
Column (C): Surrebuttal Testimony, RLM And Schedule SURR RLM-9
Column (D): Surrebuttal Testimony, RLM And Schedule SURR RLM-10
Column (E): Surrebuttal Testimony, RLM
Column (F): Surrebuttal Testimony, RLM
Column (G): Surrebuttal Testimony, TLC And Schedule SURR RLM-11A
Column (H): Surrebuttal Testimony, TLC And Schedule SURR RLM-11B
Column (I): Surrebuttal Testimony, TLC And Schedule SURR RLM-11C
Column (J): Surrebuttal Testimony, RLM And Schedule SURR RLM-12
Column (K): Surrebuttal Testimony, RLM And Schedule SURR RLM-13
Column (L): Sum Of Columns (A) Thru (K)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	-	0.00%	-
3	303	Land and Land Rights	327,399	0.00%	-
4	304	Structures and Improvements	1,307,936	3.33%	43,554
5	305	Collecting and Impounding Res.	-	2.50%	-
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	1,127,614	3.33%	37,550
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	-	2.00%	-
10	310	Power Generation Equipment	-	5.00%	-
11	311	Electric Pumping Equipment	2,044,322	12.50%	255,540
12	320	Water Treatment Equipment	83,385	3.33%	2,777
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	2,280,128	2.22%	50,619
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	12,109,036	2.00%	242,181
19	333	Services	1,382,479	3.33%	46,037
20	334	Meters	1,358,176	8.33%	113,136
21	335	Hydrants	884,182	2.00%	17,684
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	69,551	6.67%	4,639
24	340	Office Furniture and Fixtures	177,672	6.67%	11,851
25	340.1	Computers and Software	160,920	20.00%	32,184
26	341	Transportation Equipment	268,464	20.00%	53,693
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	122,443	5.00%	6,122
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	31,548	5.00%	1,577
31	346	Communications Equipment	411,484	10.00%	41,148
32	347	Miscellaneous Equipment	107,306	10.00%	10,731
33	348	Other Tangible Plant	-	10.00%	-
34		Rounding	-		-
35	TOTAL WASTEWATER PLANT		$ 24,254,044		$ 971,022
	Less:				
36	Amortizations Of CIAC (SURR RLM-2, Col. (C), Line 5)		$ (496,445)	4.0035%	(19,875)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 951,146
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				1,009,435
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ (58,288)
40	RUCO Adjustment (Line 39) (See SURR RLM-7, Column (B), Line 25)				$ (58,288)

References:
Columns (A) & (B): Company Rebuttal Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. SURR RLM-6, Col (C), Ln 4	$ 3,526,033	
2	Adjusted Revenues In Year Ended December 2007	Sch. SURR RLM-6, Col (C), Ln 4	3,526,033	
3	Proposed Revenues	Sch. SURR RLM-6, Col (E), Ln 4	3,679,831	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 10,731,897	
5	Average Annual Operating Revenues	Line 4 / 3	3,577,299	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 7,154,598
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 379,887	
8	10% Of CWIP	Line 7 X 10%		$ 37,989
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ 295,224	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	(291,918)	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ (3,305)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 7,189,281
	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	$ 1,509,749	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	9.8053%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.81%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 148,035
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,357
20	Company's Total Tax Liability	Line 18 + Line 19		$ 149,392
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 26		159,659
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (10,267)
23	RUCO Adjustment (See SURR RLM-7, Column (C), Line 27)	Line 22		$ (10,267)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
DISALLOWANCE OF MISCELLANEOUS EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL
	Disallowed Miscellaneous Expenses	Co. Response To Staff D. R. CSB 1-32	
1	Bella Vista Water Company Christmas Party		$ (2,000)
2	Special Olympics Pledge		(250)
3	Muscular Distrophy Association Donation		(250)
4	Additional Disallowance By Company		(5,181)
5	RUCO Adjustment To Unnecessary/Non-Recurring Expenses	Sum Of Lines 1 Thru 17	$ (7,681)
6	RUCO Adjustment (See SURR RLM-7, Column (D))	Line 18	$ (7,681)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6(A)
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To BVWC	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	25.35%	$ 49,328	12.74%	$ 6,285
2	Tax Services	518,775	25.00%	129,694	25.35%	32,880	12.74%	4,189
3	Legal	159,053	25.00%	39,763	25.35%	10,081	12.74%	1,284
4	Other Professional Services	506,082	0.00%	-	25.35%	-	12.74%	-
5	Management Fee - Total	644,943	0.00%	-	25.35%	-	12.74%	-
6	Unit Holder Communications	156,766	0.00%	-	25.35%	-	12.74%	-
7	Trustee Fees	129,000	0.00%	-	25.35%	-	12.74%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	25.35%	-	12.74%	-
9	Rent	307,337	0.00%	-	25.35%	-	12.74%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	25.35%	-	12.74%	-
11	Office Expenses	579,379	0.00%	-	25.35%	-	12.74%	-
12	Depreciation	211,653	25.00%	52,913	25.35%	13,415	12.74%	1,709
13	TOTAL	$ 4,104,971		$ 416,941		$ 105,703		$ 13,467
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 141,127
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on June 9, 2010							0.96293
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 135,896
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 12,968
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(122,927)
19	RUCO Adjustment (See RLM-7, Column (E))							(122,927)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

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Schedule SURR RLM-11(B)

OPERATING INCOME ADJUSTMENT #6(B)
APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Adjusted Costs	RUCO Other Disallowed Costs	RUCO Allowable Costs	RUCO 2009 Allocation Factor	RUCO Allowed Allocated Costs	Allocation % To BV	RUCO Amount Allocated To BV
1	Rent	273,965	(273,965)	-	25.35%	-	14.52%	-
2	Audit	680,812	(510,609)	170,203	25.35%	43,150	14.52%	6,267.11
3	Tax Services	469,804	(352,353)	117,451	25.35%	29,776	14.52%	4,324.71
4	Legal - General	138,531	(103,898)	34,633	25.35%	8,780	14.52%	1,275.22
5	Other Professional Services	452,202	(452,202)	-	25.35%	-	14.52%	-
6	Management Fee	563,803	(563,803)	-	25.35%	-	14.52%	-
7	Unit Holder Communications	145,658	(145,658)	-	25.35%	-	14.52%	-
8	Trustee Fees	127,116	(127,116)	-	25.35%	-	14.52%	-
9	Office Costs	425,755	(425,755)	-	25.35%	-	14.52%	-
10	Licenses/Fees and Permits	14,565	(14,565)	-	25.35%	-	14.52%	-
11	Escrow and Transfer Fees	85,354	(85,354)	-	25.35%	-	14.52%	-
12	Depreciation Expense	189,797	(142,348)	47,449	25.35%	12,029	14.52%	1,747.15
	Total	3,567,363	(3,197,626)	369,736		93,736		13,614
	RUCO Direct Testimony Amount of APT Costs Allowed							14,707
	RUCO Surrebuttal Testimony Company Adjusted APT Costs Allowed							(1,093)
	Bella Vista Customer Count Allocation Factor							87.72%
	RUCO's Adjustment per Company's Rebuttal Adjustment							(959)

OPERATING INCOME ADJUSTMENT #6(C)
RUCO's APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Test-Year Booked APT Amount
1	Company's Total APT Test-Year Book Costs per RUCO Informal 2nd Set of Data Requests #5.(	$ 156,149
2	Company's Total APT Test-Year End Costs per RUCO Formal Data Request #3.01	144,906
3	APT Costs Overstated in the Company's Direct Rate Application	$ (11,243)
4	Bella Vista (Stand Alone) Customer Count Allocation Factor	87.72%
5	RUCO's Adjustment to Bella Vista (Stand Alone) APT Costs for Outside Services - Other Accou	$ (9,863)

Notes:

Line 1 - Company's Response to RUCO 2nd Set of Data Request #5.01 reconciles to the Company's Rate Application Test-Year Book Outside Services - Other Account in the Amount of $156,149.21

Line 2 - Company Response to RUCO Formal Data Request 3.01 for APT Costs in the Amount of $144,906

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. SURR RLM-6, Column (C), L29 + L27	$ 311,073
	LESS:		
2	Arizona State Tax	Line 11	(17,096)
3	Interest Expense	Note (A) Line 20	(65,717)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 228,260
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 77,608
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 311,073
	LESS:		
8	Interest Expense	Note (A) Line 20	(65,717)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 245,356
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 17,096
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 77,608
13	State Income Tax Expense	Line 11	17,096
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 94,705
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		(10,068)
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 104,773
17	RUCO Adjustment (See Sch. SURR RLM-7, Column (K), L278)	Line16	$ 104,773

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. SURR RLM-2, Col. (E), L15)	$	3,769,607
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		1.74%
20	Interest Expense (L17 X L18)	$	65,717

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	88,860	$ 15.08	$ 1,339,597	$ 1,339,597
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	287,256	$ 1.2495	$ 358,918	
3	Second Tier - Breakover @ 10,000 Gals.	182,634	$ 1.8211	$ 332,600	
4	Third Tier - Over 10,000 Gals.	117,683	$ 2.1478	$ 252,758	
8	Total Commodity Usage And Revenue	587,573			$ 944,277
9	3/4" Meter	396	$ 22.61	$ 8,955	$ 8,955
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	1,224	$ 1.2495	$ 1,530	
11	Second Tier - Breakover @ 10,000 Gals.	534	$ 1.8211	$ 973	
12	Third Tier - Over 10,000 Gals.	39	$ 2.1478	$ 84	
16	Total Commodity Usage And Revenue	1,798			$ 2,587
17	1" Meter	96	$ 33.92	$ 3,256	$ 3,256
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	764	$ 1.1841	$ 904	
19	Second Tier - Over 10,000 Gals.	965	$ 1.5516	$ 1,497	
24	Total Commodity Usage And Revenue	1,728			$ 2,401
33	2" Meter	12	$ 84.42	$ 1,013	$ 1,013
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	129	$ 1.1841	$ 152	
35	Second Tier - Over 50,000 Gals.	-	$ 1.5516	$ -	
40	Total Commodity Usage And Revenue	129			$ 152
41	Total Residential Customer Bills	89,364		$ 1,352,821	
42	Total Residential Usage	591,227		$ 949,417	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 2,302,238
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	4,572	$ 15.08	$ 68,925	$ 68,925
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	11,729	$ 1.1841	$ 13,889	
46	Second Tier - Over 4,000 Gals.	21,935	$ 1.5516	$ 34,034	
51	Total Commodity Usage And Revenue	33,663			$ 47,923
52	3/4" Meter	72	$ 22.61	$ 1,628	$ 1,628
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	237	$ 1.1841	$ 281	
54	Second Tier - Over 4,000 Gals.	732	$ 1.5516	$ 1,137	
59	Total Commodity Usage And Revenue	969			$ 1,417
60	1" Meter	1,668	$ 30.15	$ 50,291	$ 50,291
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	10,702	$ 1.1841	$ 12,673	
62	Second Tier - Over 10,000 Gals.	13,467	$ 1.5516	$ 20,896	
67	Total Commodity Usage And Revenue	24,170			$ 33,569
68	1.5" Meter	1,020	$ 67.84	$ 69,196	$ 69,196
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	17,687	$ 1.1841	$ 20,944	
70	Second Tier - Over 25,000 Gals.	28,480	$ 1.5516	$ 44,191	
75	Total Commodity Usage And Revenue	46,167			$ 65,135

Bella Vista Water Company (Stand-Alone)
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Schedule SURR RLM-RD1
Pages 1 Thru 3

SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	3,264	$ 84.42	$ 275,553	$ 275,553
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	101,196	$ 1.1841	$ 119,831	
78	Second Tier - Over 50,000 Gals.	178,887	$ 1.5516	$ 277,567	
83	Total Commodity Usage And Revenue	280,083			$ 397,398
	3" Meter	312	$ 168.84	$ 52,679	$ 52,679
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	20,136	$ 1.1841	$ 23,843	
	Second Tier - Over 80,000 Gals.	31,283	$ 1.5516	$ 48,540	
	Total Commodity Usage And Revenue	51,419			$ 72,383
	4" Meter	36	$ 282.66	$ 10,176	$ 10,176
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	7,922	$ 1.1841	$ 9,381	
	Second Tier - Over 350,000 Gals.	13,540	$ 1.5516	$ 21,009	
	Total Commodity Usage And Revenue	21,462			$ 30,390
84	6" Meter	12	$ 753.77	$ 9,045	$ 9,045
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	468	$ 1.1841	$ 554	
86	Second Tier - Over 450,000 Gals.	-	$ 1.5516	$ -	
91	Total Commodity Usage And Revenue	468			$ 554
92	8" Meter	12	$ 1,206.03	$ 14,472	$ 14,472
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	31	$ 1.1841	$ 36	
94	Second Tier - Over 720,000 Gals.	-	$ 1.5516	$ -	
99	Total Commodity Usage And Revenue	31			$ 36
100	Total Commercial Customer Bills	10,968		$ 551,966	
101	Total Commercial Usage	458,432		$ 648,806	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ 1,200,772
	HYDRANT CUSTOMERS				
103	3" Meter	168	$ 120.60	$ 20,261	$ 20,261
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	5,094	$ 2.1478	$ 10,941	
110	Total Commodity Usage And Revenue	5,094			$ 10,941
159	Total Hydrant Customer Bills	168			
160	Total Hydrant Usage	5,094			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ 31,202
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	1,188	$ 12.25	$ 14,553	$ 14,553
202	6" Meter	252	$ 13.57	$ 3,419	$ 3,419
210	8" Meter	12	$ 21.71	$ 261	$ 261
68	Total Fire Sprinkler Customer Bills	1,452			

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ 18,232
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 3,552,444
	Total Company Customer Bills	101,952			
	Total Company Usage	1,054,753			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 2,302,238
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				1,200,772
192	TOTAL HYDRANT REVENUE PER BILL COUNT				31,202
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				18,232
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 3,552,444
198	Unreconciled Difference vs. Billed Revenues				2,245
200	Miscellaneous Revenues				125,141
200	**RUCO TOTAL REVENUE**				$ 3,679,831
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 3,679,831
202	Difference				$ (0)
203	Percentage Difference				0.00%

Bella Vista Water Company (Stand-Alone)
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SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A) PRESENT	(B)	(C) COMPANY PROPOSED	(D)	(E) RUCO PROPOSED	(F)
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 2,164,639	63.66%	$ 2,819,405	64.70%	$ 2,302,238	64.81%
2	OTHER	1,235,833	36.34%	1,537,943	35.30%	1,250,206	35.19%
3	TOTAL	$ 3,400,472	100.00%	$ 4,357,348	100.00%	$ 3,552,444	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 1,723,095	50.67%	$ 2,386,903	54.78%	$ 1,943,281	54.70%
5	VARIABLE REVENUE	1,677,377	49.33%	1,970,445	45.22%	1,609,164	45.30%
6	TOTAL	$ 3,400,472	100.00%	$ 4,357,348	100.00%	$ 3,552,444	100.00%

RESIDENTIAL (5/8" X 3/4") RATE DESIGN

		PRESENT BVWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
7	BASIC MONTHLY CHARGE	$ 15.00	$ 18.46	$ 15.08

	COMMODITY CHARGE PRESENT	BVWC	PROPOSED		PRESENT BVWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
8	1st Tier - Breakover	5,000	1st Tier - Breakover	4,000	$ 0.9700	$ 1.5300	$ 1.2495
9	2nd Tier - Breakove	25,000	2nd Tier - Breakover	10,000	$ 1.8900	$ 2.2300	$ 1.8211
10	3rd Tier - Over	25,000	3rd Tier - Over	10,000	$ 2.4100	$ 2.6300	$ 2.1478

SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	BELLA VISTA RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 6,612	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,653	25.00%	$ 16.60	$ 17.14	$ 0.54	3.24%
2		3,306	50.00%	$ 18.21	$ 19.21	$ 1.00	5.49%
3		6,612	100.00%	$ 22.90	$ 24.83	$ 1.93	8.44%
4		9,918	150.00%	$ 29.14	$ 30.85	$ 1.71	5.85%
5		13,223	200.00%	$ 35.39	$ 36.87	$ 1.48	4.18%

	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 16.09	$ 16.48	$ 0.39	2.42%
7		2,250	50.00%	$ 17.18	$ 17.89	$ 0.70	4.10%
8		4,500	100.00%	$ 19.37	$ 20.98	$ 1.62	8.36%
9		6,750	150.00%	$ 21.55	$ 25.08	$ 3.53	16.40%
10		9,000	200.00%	$ 23.73	$ 29.18	$ 5.45	22.96%

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SURREBUTTAL
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SURR RLM-2	1	RATE BASE
SURR RLM-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
DIRECT TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
SURR RLM-5A & 5B	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 5 - AFUDC
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 6 - ACQUISITION COSTS FROM PURCHASE OF MCCLAIN SYSTEMS
SURR RLM-6	1	OPERATING INCOME
SURR RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
SURR RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
SURR RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
SURR RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
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SURR TESTIMONY		OPERATING INCOME ADJUSTMENT NO. 5 - TRANSPORTATION EXPENSE
SURR RLM-11A	1	OPERATING INCOME ADJUSTMENT NO. 6A - CENTRAL OFFICE COST ALLOCATION
SURR RLM-11B	1	OPERATING INCOME ADJUSTMENT NO. 6B - CENTRAL OFFICE COST ALLOCATION
SURR RLM-11C	1	OPERATING INCOME ADJUSTMENT NO. 6C - CENTRAL OFFICE COST ALLOCATION
RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 7 - RATE CASE EXPENSE
SURR RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 8 - INCOME TAX EXPENSE
SURR RLM-RD1	1 TO 3	RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
SURR RLM-RD2	1 TO 2	TYPICAL RESIDENTIAL BILL ANALYSIS

Northern Sunrise Water Company (Stand-Alone)
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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 742,658	$ 660,635
2	Adjusted Operating Income (Loss)	$ (81,316)	$ (75,328)
3	Current Rate Of Return (L2 / L1)	-10.95%	-11.40%
4	Required Operating Income (L5 X L1)	$ 95,060	$ 52,217
5	Required Rate Of Return On Fair Value Rate Base	12.80%	7.90%
6	Operating Income Deficiency (L4 - L2)	$ 176,376	$ 127,544
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.4517	1.2646
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 256,044	$ 161,291
9	Adjusted Test Year Revenue	$ 191,966	$ 191,966
10	Proposed Annual Revenue (L8 + L9)	$ 448,011	$ 353,258
11	Required Percentage Increase In Revenue (L8 / L9)	133.38%	84.02%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule SURR RLM-2, SURR RLM-6, And RLM-14

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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 815,886	$ (29,376)	$ 786,510
2	Accumulated Depreciation	(42,739)	4,879	(37,860)
3	Net Utility Plant In Service (L1 + L2)	$ 773,147	$ (24,497)	$ 748,650
4	Advances In Aid Of Const.	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (26,000)	$ -	$ (26,000)
6	Accumulated Amortization Of CIAC	63	-	63
7	NET CIAC (L5 + L6)	$ (25,937)	$ -	$ (25,937)
8	Customer Meter Deposits	$ (410)	$ -	$ (410)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (4,144)	$ (57,525)	$ (61,668)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 742,657	$ (82,022)	$ 660,635

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): SURR RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) ADJ # 5 AFUDC	(F) ADJ # 6 McCLAIN ACQ. COSTS	(G) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 815,886	$ -	$ -	$ -	$ (13,740)	$ (15,636)	$ 786,510
2	Accumulated Depreciation	(42,739)	4,879	-	-	-	-	(37,860)
3	Net Utility Plant In Service (L1 + L2)	$ 773,147	$ 4,879	$ -	$ -	$ (13,740)	$ (15,636)	$ 748,650
4	Advances In Aid Of Const.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (26,000)	$ -	$ -	$ -	$ -	$ -	$ (26,000)
6	Accumulated Amortization Of CIAC	63	-	-	-	-	-	63
7	NET CIAC (L5 + L6)	$ (25,937)	$ -	$ -	$ -	$ -	$ -	$ (25,937)
8	Customer Meter Deposits	$ (410)	$ -	$ -	$ -	$ -	$ -	$ (410)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (4,144)	$ -	$ -	$ (57,525)	$ -	$ -	$ (61,668)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 742,657	$ 4,879	$ -	$ (57,525)	$ (13,740)	$ (15,636)	$ 660,635

References:
- Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
- Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
- Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
- Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Testimony Of RUCO Witness Tim Coley and Schedule SURR RLM-5A & 5B)
- Column (E): Adjustment No. 5 - RUCO Adjustment To AFUDC (See Surrebuttal Testimony, RLM)
- Column (F): Adjustment No. 6 - RUCO Adjustment To Acquisition Costs (See Surrebuttal Testimony, RLM)
- Column (G): Sum Of Columns (A), (B), (C), (D), (E) & (F)

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Original Cost Rate Base Proforma Adjustments
ADIT Calculation Based on RUCO's Surrebuttal Schedules

Deferred Income Tax as of March 31, 2009

Line No.		Adjusted Book Value[1]	Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate[4]	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
6	Plant-in-Service	$ 786,510 [1]								
7	Accum. Deprec.	(37,860) [1]								
8	CIAC (Net)	(25,937) [1]								
9	Fixed Assets	$ 722,713	$ 492,090 [2]	100.0%	$ (230,623)	26.74%		-		(61,669)
10	AIAC		- [3]	0.0%	$ -	26.74%		$ -		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	26.74%		$ -		
12							$ -	$ -	$ -	$ (61,669)
13										
14	RUCO Net Asset (Liability)						$ (61,669)			
15										
16	Company ADIT Asset (Liability) for NSWC Stand Alone Adjusted Test Year						$ (4,144)			
17										
18	RUCO NSWC (Stand Alone) Adjustment to ADIT						$ (57,525)			

1 Adjusted per RUCO Surrebuttal Schedule RLM-2, page 1

2 Tax Basis per Company as of March 31, 2009

3 AIAC (including impact of change in probability of realization)

4 Effective tax rates Per RUCO's Surrebuttal Schedule RLM-1, page 2

Northern Sunrise Water Company (Stand-Alone)
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SURREBUTTAL
ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Consolidated Allocation	Note (A)	1.5438%
5	Bella Vista Consolidated ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Consolidated Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Total Consolidated ADIT as Filed by Company	Company Schedule C-1	173,329
9	Decrease In Deferred Income Tax Assets	Line 7 - Line 8	$ (1,458,278)
10	Total Northern Sunrise Customer Count Factor	Per Company	0.0363
11	RUCO Adjustment (See SURR RLM-3, Column (D), Line 11)	Line 9 X Line 10	(52,949)

NOTES:

12	(A)	Purchase Price of NSWC	Annual Report	$ 15,100,000
13		Algonquin Total Assets	Annual Report	$ 978,130,000
14		Ratio Of NSWC To Algonquin Total Assets	Line 12 / Line 13	1.5438%
15	(B)	Currency Conversion	moneycentral.com on 04/1/2010	0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

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Schedule SURR RLM-6
Page 1 of 1

SURREBUTTAL
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	Flat Rate Revenues	$ 188,672	$ -	$ 188,672	$ 161,291	$ 349,964
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	3,294	-	3,294	-	3,294
4	TOTAL OPERATING REVENUE	$ 191,966	$ -	$ 191,966	$ 161,291	$ 353,258
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-
7	Purchased Power	16,012	-	16,012	-	16,012
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	178	-	178	-	178
10	Materials & Supplies	5,094	-	5,094	-	5,094
11	Outside Services	-	-	-	-	-
12	Outside Services- Legal	1,302	-	1,302	-	1,302
13	Outside Services- Other	161,902	(5,536)	156,366	-	156,366
14	Water Testing	3,787	570	4,357	-	4,357
15	Equipment Rental	140	-	140	-	140
16	Rents	-	-	-	-	-
17	Transportation Expenses	21,524	(647)	20,877	-	20,877
18	Insurance - General Liability	9,692	-	9,692	-	9,692
19	Insurance - Health and Life	-	-	-	-	-
20	Reg. Comm. Exp.	587	-	587	-	587
21	Reg. Comm. Exp. - Rate Case	25,000	(8,693)	16,307	-	16,307
22	Miscellaneous Expense	11,726	(610)	11,116	-	11,116
23	Bad Debt Expense	3,306	-	3,306	-	3,306
24	Depreciation Expense	36,631	(2,225)	34,406	-	34,406
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	13,128	(1,266)	11,862	-	11,862
27	Income Tax	(36,727)	12,419	(24,308)	33,747	9,439
28	TOTAL OPERATING EXPENSES	$ 273,282	$ (5,988)	$ 267,294	$ 33,747	$ 301,041
29	OPERATING INCOME (LOSS)	$ (81,316)		$ (75,328)		$ 52,217

References:

Column (A): Company Schedule C-1
Column (B): SURR RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From SURR RLM-1, Column (B), Line 8 And Income Tax From SURR RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 WATER TEST EXPENSES	(F) ADJ # 5 TRANSPORT EXPENSES	(G) ADJ # 6A CENTRAL OFFICE COST	(H) ADJ # 6B CENTRAL OFFICE COST	(I) ADJ # 6C CENTRAL OFFICE COST	(J) ADJ # 7 RATE CASE EXPENSES	(K) ADJ # 8 INCOME TAX	(L) RUCO AS ADJT'D
	Revenues:												
1	Flat Rate Revenues	$ 188,672	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 188,672
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	3,294	-	-	-	-	-	-	-	-	-	-	3,294
4	TOTAL OPR'G REV.	$ 191,966	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 191,966
	Operating Expenses:												
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-	-	-	-	-	-	-	-
7	Purchased Power	16,012	-	-	-	-	-	-	-	-	-	-	16,012
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-	-	-	-
9	Chemicals	178	-	-	-	-	-	-	-	-	-	-	178
10	Materials & Supplies	5,094	-	-	-	-	-	-	-	-	-	-	5,094
11	Outside Services	-	-	-	-	-	-	-	-	-	-	-	-
12	Outside Services- Legal	1,302	-	-	-	-	-	-	-	-	-	-	1,302
13	Outside Services- Other	161,902	-	-	-	-	-	(5,088)	(40)	(408)	-	-	156,366
14	Water Testing	3,787	-	-	-	570	-	-	-	-	-	-	4,357
15	Equipment Rental	140	-	-	-	-	-	-	-	-	-	-	140
16	Rents	-	-	-	-	-	-	-	-	-	-	-	-
17	Transportation Expenses	21,524	-	-	-	-	(647)	-	-	-	-	-	20,877
18	Insurance - General Liability	9,692	-	-	-	-	-	-	-	-	-	-	9,692
19	Insurance - Health and Life	-	-	-	-	-	-	-	-	-	-	-	-
20	Reg. Comm. Exp.	587	-	-	-	-	-	-	-	-	-	-	587
21	Reg. Comm. Exp. - Rate Case	25,000	-	-	-	-	-	-	-	-	(8,693)	-	16,307
22	Miscellaneous Expense	11,726	-	-	(610)	-	-	-	-	-	-	-	11,116
23	Bad Debt Expense	3,306	-	-	-	-	-	-	-	-	-	-	3,306
24	Depreciation Expense	36,631	(2,225)	-	-	-	-	-	-	-	-	-	34,406
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
26	Property Taxes	13,128	-	(1,266)	-	-	-	-	-	-	-	-	11,862
27	Income Tax	(36,727)	-	-	-	-	-	-	-	-	-	12,419	(24,308)
29	TOTAL OPR'G EXP	$ 273,282	$ (2,225)	$ (1,266)	$ (610)	$ 570	$ (647)	$ (5,088)	$ (40)	$ (408)	$ (8,693)	$ 12,419	$ 267,294
30	OPR'G INC. (LOSS)	$ (81,316)											$ (75,328)

References:
Column (A): Company Schedule C-1
Column (B): Surrebuttal Testimony, RLM And Schedule SURR RLM-8
Column (C): Surrebuttal Testimony, RLM And Schedule SURR RLM-9
Column (D): Surrebuttal Testimony, RLM And Schedule SURR RLM-10
Column (E): Surrebuttal Testimony, RLM
Column (F): Surrebuttal Testimony, RLM
Column (G): Surrebuttal Testimony, TLC And Schedule SURR RLM-11A
Column (H): Surrebuttal Testimony, TLC And Schedule SURR RLM-11B
Column (I): Surrebuttal Testimony, TLC And Schedule SURR RLM-11C
Column (J): Surrebuttal Testimony, RLM And Schedule SURR RLM-12
Column (K): Surrebuttal Testimony, RLM And Schedule SURR RLM-13
Column (L): Sum Of Columns (A) Thru (K)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	890	0.00%	-
3	303	Land and Land Rights	23,926	0.00%	-
4	304	Structures and Improvements	280,668	3.33%	9,346
5	305	Collecting and Impounding Res.	51,378	2.50%	1,284
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	34,064	3.33%	1,134
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	-	2.00%	-
10	310	Power Generation Equipment	1,293	5.00%	65
11	311	Electric Pumping Equipment	91,019	12.50%	11,377
12	320	Water Treatment Equipment	-	3.33%	-
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	95,668	2.22%	2,124
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	36,763	2.00%	735
19	333	Services	29,756	3.33%	991
20	334	Meters	3,449	8.33%	287
21	335	Hydrants	59,298	2.00%	1,186
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	23,472	6.67%	1,566
24	340	Office Furniture and Fixtures	-	6.67%	-
25	340.1	Computers and Software	-	20.00%	-
26	341	Transportation Equipment	-	20.00%	-
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	-	5.00%	-
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	-	5.00%	-
31	346	Communications Equipment	5,881	10.00%	588
32	347	Miscellaneous Equipment	-	10.00%	-
33	348	Other Tangible Plant	48,984	10.00%	4,898
34		Rounding			
35	TOTAL WASTEWATER PLANT		$ 786,509		$ 35,582
	Less:				
36	Amortizations Of CIAC (SURR RLM-2, Col. (C), Line 5)		$ (26,000)	4.5241%	(1,176)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 34,406
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				36,631
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ (2,225)
40	RUCO Adjustment (Line 39) (See SURR RLM-7, Column (B), Line 25)				$ (2,225)

References:
Columns (A) & (B): Company Rebuttal Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	$ 191,966	
2	Adjusted Revenues In Year Ended December 2007	Sch. RLM-6, Col (C), Ln 4	191,966	
3	Proposed Revenues	Sch. RLM-6, Col (E), Ln 4	353,258	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 737,191	
5	Average Annual Operating Revenues	Line 4 / 3	245,730	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 491,460
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 92,936	
8	10% Of CWIP	Line 7 X 10%		$ 9,294
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ -	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	-	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ -
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 500,754
	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	$ 105,158	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	11.1932%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	11.19%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 11,771
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 91
20	Company's Total Tax Liability	Line 18 + Line 19		$ 11,862
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 26		13,128
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (1,266)
23	RUCO Adjustment (See SURR RLM-7, Column (C), Line 27)	Line 22		$ (1,266)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
DISALLOWANCE OF MISCELLANEOUS EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL
	Disallowed Miscellaneous Expenses	Co. Response To Staff D. R. CSB 1-32	
1	Bella Vista Water Company Christmas Party		$ -
2	Special Olympics Pledge		-
3	Muscular Distrophy Association Donation		-
4	Additional Disallowance By Company		(610)
5	RUCO Adjustment To Unnecessary/Non-Recurring Expenses	Sum Of Lines 1 Thru 17	$ (610)
6	RUCO Adjustment (See SURR RLM-7, Column (D))	Line 18	$ (610)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6(A)
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To NSR	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	25.35%	$ 49,328	0.53%	$ 260
2	Tax Services	518,775	25.00%	129,694	25.35%	32,880	0.53%	173
3	Legal	159,053	25.00%	39,763	25.35%	10,081	0.53%	53
4	Other Professional Services	506,082	0.00%	-	25.35%	-	0.53%	-
5	Management Fee - Total	644,943	0.00%	-	25.35%	-	0.53%	-
6	Unit Holder Communications	156,766	0.00%	-	25.35%	-	0.53%	-
7	Trustee Fees	129,000	0.00%	-	25.35%	-	0.53%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	25.35%	-	0.53%	-
9	Rent	307,337	0.00%	-	25.35%	-	0.53%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	25.35%	-	0.53%	-
11	Office Expenses	579,379	0.00%	-	25.35%	-	0.53%	-
12	Depreciation	211,653	25.00%	52,913	25.35%	13,415	0.53%	71
13	TOTAL	$ 4,104,971		$ 416,941		$ 105,703		$ 557
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 5,841
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on June 9, 2010							0.96293
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 5,625
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 537
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(5,088)
19	RUCO Adjustment (See RLM-7, Column (E))							(5,088)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

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OPERATING INCOME ADJUSTMENT #6(B)
APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Adjusted Costs	RUCO Other Disallowed Costs	RUCO Allowable Costs	RUCO 2009 Allocation Factor	RUCO Allowed Allocated Costs	Allocation % To BVWC	RUCO Amount Allocated To NSR
1	Rent	273,965	(273,965)	-	25.35%	-	14.52%	-
2	Audit	680,812	(510,609)	170,203	25.35%	43,150	14.52%	6,267.11
3	Tax Services	469,804	(352,353)	117,451	25.35%	29,776	14.52%	4,324.71
4	Legal - General	138,531	(103,898)	34,633	25.35%	8,780	14.52%	1,275.22
5	Other Professional Services	452,202	(452,202)	-	25.35%	-	14.52%	-
6	Management Fee	563,803	(563,803)	-	25.35%	-	14.52%	-
7	Unit Holder Communications	145,658	(145,658)	-	25.35%	-	14.52%	-
8	Trustee Fees	127,116	(127,116)	-	25.35%	-	14.52%	-
9	Office Costs	425,755	(425,755)	-	25.35%	-	14.52%	-
10	Licenses/Fees and Permits	14,565	(14,565)	-	25.35%	-	14.52%	-
11	Escrow and Transfer Fees	85,354	(85,354)	-	25.35%	-	14.52%	-
12	Depreciation Expense	189,797	(142,348)	47,449	25.35%	12,029	14.52%	1,747.15
	Total	3,567,363	(3,197,626)	369,736		93,736		13,614
	RUCO Direct Testimony Amount of APT Costs Allowed							14,707
	RUCO Surrebuttal Testimony Company Adjusted APT Costs Allowed							(1,093)
	Northern Sunrise Customer Count Allocation Factor							3.63%
	RUCO's Adjustment per Company's Rebuttal Adjustment							(40)

OPERATING INCOME ADJUSTMENT #6(C)
RUCO's APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Test-Year Booked APT Amount
1	Company's Total APT Test-Year Book Costs per RUCO Informal 2nd Set of Data Requests #5.01	$ 156,149
2	Company's Total APT Test-Year End Costs per RUCO Formal Data Request #3.01	144,906
3	APT Costs Overstated in the Company's Direct Rate Application	$ (11,243)
4	Northern Sunrise (Stand Alone) Customer Count Allocation Factor	3.63%
5	RUCO's Adjustment to Northern Sunrise (Stand Alone) APT Costs	$ (408)

Notes:

Line 1 - Company's Response to RUCO 2nd Set of Data Request #5.01 reconciles to the Company's Rate Application Test-Year Book Outside Services - Other Account in the Amount of $156,149.21

Line 2 - Company Response to RUCO Formal Data Request 3.01 for APT Costs in the Amount of $144,906

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. SURR RLM-6, Column (C), L29 + L27	$ (99,636)
	LESS:		
2	Arizona State Tax	Line 11	8,095
3	Interest Expense	Note (A) Line 20	(16,542)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ (108,083)
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	15.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ (16,212)
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ (99,636)
	LESS:		
8	Interest Expense	Note (A) Line 20	(16,542)
9	State Taxable Income	Sum Of Lines 7 & 8	$ (116,178)
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ (8,095)
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ (16,212)
13	State Income Tax Expense	Line 11	(8,095)
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ (24,308)
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		(36,727)
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 12,419
17	RUCO Adjustment (See Sch. SURR RLM-7, Column (J), L27)	Line16	$ 12,419

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. SURR RLM-2, Col. (E), L15)	$	660,635
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		2.50%
20	Interest Expense (L17 X L18)	$	16,542

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS		(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS					
1	5/8" X 3/4" Meter	4,116		59.33072376	$ 244,205	$ 244,205
	Commodity Usage (In Thousands Of Gallons)					
2	First Tier -Breakover @ 4,000 Gals.	11,901	$	3.8247	$ 45,519	
3	Second Tier - Breakover @ 10,000 Gals.	7,596	$	4.6117	$ 35,030	
4	Third Tier - Over 10,000 Gals.	4,174	$	5.5168	$ 23,028	
8	Total Commodity Usage And Revenue	23,671				$ 103,576
9	3/4" Meter	12	$	89.00	$ 1,068	$ 1,068
	Commodity Usage (In Thousands Of Gallons)					
10	First Tier -Breakover @ 4,000 Gals.	46	$	3.8247	$ 174	
11	Second Tier - Breakover @ 10,000 Gals.	62	$	4.6117	$ 284	
12	Third Tier - Over 10,000 Gals.	137	$	5.5168	$ 756	
16	Total Commodity Usage And Revenue	244				$ 1,213
17	1" Meter	-	$	133.49	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)					
18	First Tier -Breakover @ 10,000 Gals.	-	$	3.8247	$ -	
19	Second Tier - Over 10,000 Gals.	-	$	4.6117	$ -	
24	Total Commodity Usage And Revenue	-				$ -
33	2" Meter	-	$	332.25	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)					
34	First Tier -Breakover @ 50,000 Gals.	-	$	3.8247	$ -	
35	Second Tier - Over 50,000 Gals.	-	$	4.6117	$ -	
40	Total Commodity Usage And Revenue	-				$ -
41	Total Residential Customer Bills	4,128			$ 245,273	
42	Total Residential Usage	23,915			$ 104,790	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE					$ 350,063
	COMMERCIAL CUSTOMERS					
44	5/8" X 3/4" Meter	-	$	59.33	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)					
45	First Tier -Breakover @ 4,000 Gals.	-	$	3.8247	$ -	
46	Second Tier - Over 4,000 Gals.	-	$	4.6117	$ -	
51	Total Commodity Usage And Revenue	-				$ -
52	3/4" Meter	-	$	89.00	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)					
53	First Tier -Breakover @ 4,000 Gals.	-	$	3.8247	$ -	
54	Second Tier - Over 4,000 Gals.	-	$	4.6117	$ -	
59	Total Commodity Usage And Revenue	-				$ -
60	1" Meter	-	$	133.49	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)					
61	First Tier -Breakover @ 10,000 Gals.	-	$	3.8247	$ -	
62	Second Tier - Over 10,000 Gals.	-	$	4.6117	$ -	
67	Total Commodity Usage And Revenue	-				$ -
68	1.5" Meter	-	$	266.99	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)					
69	First Tier -Breakover @ 25,000 Gals.	-	$	3.8247	$ -	
70	Second Tier - Over 25,000 Gals.	-	$	4.6117	$ -	
75	Total Commodity Usage And Revenue	-				$ -

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	-	$ 332.25	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	-	$ 3.8247	$ -	
78	Second Tier - Over 50,000 Gals.	-	$ 4.6117	$ -	
83	Total Commodity Usage And Revenue	-			$ -
	3" Meter	-	$ 664.50	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	-	$ 3.8247	$ -	
	Second Tier - Over 80,000 Gals.	-	$ 4.6117	$ -	
	Total Commodity Usage And Revenue	-			$ -
	4" Meter	-	$ 1,112.45	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	-	$ 3.8247	$ -	
	Second Tier - Over 350,000 Gals.	-	$ 4.6117	$ -	
	Total Commodity Usage And Revenue	-			$ -
84	6" Meter	-	$ 2,966.54	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	-	$ 3.8247	$ -	
86	Second Tier - Over 450,000 Gals.	-	$ 4.6117	$ -	
91	Total Commodity Usage And Revenue	-			$ -
92	8" Meter	-	$ 4,746.46	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	-	$ 3.8247	$ -	
94	Second Tier - Over 720,000 Gals.	-	$ 4.6117	$ -	
99	Total Commodity Usage And Revenue	-			$ -
100	Total Commercial Customer Bills	-		$ -	
101	Total Commercial Usage	-		$ -	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ -
	HYDRANT CUSTOMERS				
103	3" Meter	-	$ -	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	-	$ -	$ -	
110	Total Commodity Usage And Revenue	-			$ -
159	Total Hydrant Customer Bills	-			
160	Total Hydrant Usage	-			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ -
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	-	$ -	$ -	$ -
202	6" Meter	-	$ -	$ -	$ -
210	8" Meter	-	$ -	$ -	$ -
68	Total Fire Sprinkler Customer Bills	-			

Northern Sunrise Water Company (Stand-Alone)
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Schedule SURR RLM-RD1
Pages 1 Thru 3

SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ -
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 350,063
	Total Company Customer Bills	4,128			
	Total Company Usage	23,915			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 350,063
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				-
192	TOTAL HYDRANT REVENUE PER BILL COUNT				-
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				-
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 350,063
198	Unreconciled Difference vs. Billed Revenues				(99)
200	Miscellaneous Revenues				3,294
200	**RUCO TOTAL REVENUE**				$ 353,258
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 353,258
202	Difference				$ 0
203	Percentage Difference				0.00%

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SURREBUTTAL

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	$ 188,390	100.00%	$ 444,816	100.00%	$ 350,063	100.00%
2	OTHER	-	0.00%	-	0.00%	-	0.00%
3	TOTAL	$ 188,390	100.00%	$ 444,816	100.00%	$ 350,063	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 129,890	68.95%	$ 311,662	70.07%	$ 245,273	70.07%
5	VARIABLE REVENUE	58,500	31.05%	133,154	29.93%	104,790	29.93%
6	TOTAL	$ 188,390	100.00%	$ 444,816	100.00%	$ 350,063	100.00%

	RESIDENTIAL (5/8" X 3/4") RATE DESIGN	PRESENT NSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
7	BASIC MONTHLY CHARGE	$ 31.00	$ 75.39	$ 59.33

	COMMODITY CHARGE PRESENT	NSWC	PROPOSED		PRESENT NSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
8	1st Tier - Breakover	5,000	1st Tier - Breakover	4,000	$ 2.0000	$ 4.8600	$ 3.8247
9	2nd Tier - Breakove	10,000	2nd Tier - Breakover	10,000	$ 2.7500	$ 5.8600	$ 4.6117
10	3rd Tier - Over	10,000	3rd Tier - Over	10,000	$ 3.9000	$ 7.0100	$ 5.5168

SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	NORTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,755	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,439	25.00%	$ 33.88	$ 64.83	$ 30.96	91.38%
2		2,878	50.00%	$ 36.76	$ 70.34	$ 33.58	91.37%
3		5,755	100.00%	$ 43.08	$ 82.72	$ 39.65	92.04%
4		8,633	150.00%	$ 50.99	$ 95.99	$ 45.00	88.26%
5		11,510	200.00%	$ 74.39	$ 110.63	$ 36.24	48.72%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 33.25	$ 63.63	$ 30.38	91.38%
7		2,250	50.00%	$ 35.50	$ 67.94	$ 32.44	91.37%
8		4,500	100.00%	$ 40.00	$ 76.94	$ 36.94	92.34%
9		6,750	150.00%	$ 32.06	$ 87.31	$ 55.25	172.32%
10		9,000	200.00%	$ 52.00	$ 97.69	$ 45.69	87.86%

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SURREBUTTAL
TABLE OF CONTENTS TO RLM SCHEDULES

SCH. NO.	PAGE NO.	TITLE
SURR RLM-1	1	REVENUE REQUIREMENT
SURR RLM-2	1	RATE BASE
SURR RLM-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
DIRECT TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
SURR RLM-5A & 5B	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 5 - AFUDC
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 6 - ACQUISITION COSTS FROM PURCHASE OF MCCLAIN SYSTEMS
SURR RLM-6	1	OPERATING INCOME
SURR RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
SURR RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
SURR RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
SURR RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
SURR TESTIMONY		OPERATING INCOME ADJUSTMENT NO. 4 - WATER TESTING EXPENSE
SURR TESTIMONY		OPERATING INCOME ADJUSTMENT NO. 5 - TRANSPORTATION EXPENSE
SURR RLM-11A	1	OPERATING INCOME ADJUSTMENT NO. 6A - CENTRAL OFFICE COST ALLOCATION
SURR RLM-11B	1	OPERATING INCOME ADJUSTMENT NO. 6B - CENTRAL OFFICE COST ALLOCATION
SURR RLM-11C	1	OPERATING INCOME ADJUSTMENT NO. 6C - CENTRAL OFFICE COST ALLOCATION
RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 7 - RATE CASE EXPENSE
SURR RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 8 - INCOME TAX EXPENSE
SURR RLM-RD1	1 TO 3	RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
SURR RLM-RD2	1 TO 2	TYPICAL RESIDENTIAL BILL ANALYSIS

Southern Sunrise Water Company (Stand-Alone)
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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 1,544,434	$ 1,305,405
2	Adjusted Operating Income (Loss)	$ 6,042	$ 47,884
3	Current Rate Of Return (L2 / L1)	0.39%	3.67%
4	Required Operating Income (L5 X L1)	$ 197,688	$ 103,179
5	Required Rate Of Return On Fair Value Rate Base	12.80%	7.90%
6	Operating Income Deficiency (L4 - L2)	$ 191,645	$ 55,295
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6128	1.3572
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 309,090	$ 75,045
9	Adjusted Test Year Revenue	$ 444,136	$ 444,136
10	Proposed Annual Revenue (L8 + L9)	$ 753,226	$ 519,181
11	Required Percentage Increase In Revenue (L8 / L9)	69.59%	16.90%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RLM-2, RLM-6, And RLM-14

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Schedule SURR RLM-2
Page 1 of 1

SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 1,724,610	$ (154,415)	$ 1,570,195
2	Accumulated Depreciation	(105,733)	-	(105,733)
3	Net Utility Plant In Service (L1 + L2)	$ 1,618,877	$ (154,415)	$ 1,464,462
4	Advances In Aid Of Const.	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (20,000)	$ -	$ (20,000)
6	Accumulated Amortization Of CIAC	15	-	15
7	NET CIAC (L5 + L6)	$ (19,985)	$ -	$ (19,985)
8	Customer Meter Deposits	$ (2,870)	$ -	$ (2,870)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (51,588)	$ (84,614)	$ (136,202)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 1,544,434	$ (239,029)	$ 1,305,405

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

Southern Sunrise Water Company (Stand-Alone)
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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) ADJ # 5 AFUDC	(F) ADJ # 6 McCLAIN ACQ. COSTS	(G) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 1,724,610	$ -	$ -	$ -	$ (25,428)	$ (128,987)	$ 1,570,195
2	Accumulated Depreciation	(105,733)	-	-	-	-	-	(105,733)
3	Net Utility Plant In Service (L1 + L2)	$ 1,618,877	$ -	$ -	$ -	$ (25,428)	$ (128,987)	$ 1,464,462
4	Advances In Aid Of Const.	$ -	$ -	$ -	$ -	$ -	$ -	$ -
5	Contribution In Aid Of Const.	$ (20,000)	$ -	$ -	$ -	$ -	$ -	$ (20,000)
6	Accumulated Amortization Of CIAC	15	-	-	-	-	-	15
7	NET CIAC (L5 + L6)	$ (19,985)	$ -	$ -	$ -	$ -	$ -	$ (19,985)
8	Customer Meter Deposits	$ (2,870)	$ -	$ -	$ -	$ -	$ -	$ (2,870)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ (51,588)	$ -	$ -	$ (84,614)	$ -	$ -	$ (136,202)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 1,544,434	$ -	$ -	$ (84,614)	$ (25,428)	$ (128,987)	$ 1,305,405

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Testimony Of RUCO Witness Tim Coley and Schedule SURR RLM-5)
Column (E): Adjustment No. 5 - RUCO Adjustment To AFUDC (See Surrebuttal Testimony, RLM)
Column (F): Adjustment No. 6 - RUCO Adjustment To Acquisition Costs (See Surrebuttal Testimony, RLM)
Column (G): Sum Of Columns (A), (B), (C), (D), (E) & (F)

Southern Sunrise Water Company (Stand-Alone)
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Original Cost Rate Base Proforma Adjustments
ADIT Calculation Based on RUCO's Surrebuttal Schedules

Line No.	Deferred Income Tax as of March 31, 2009	Adjusted Book Value[1]		Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate[5]	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
1											
2											
3											
4											
5											
6	Plant-in-Service	$ 1,570,195	1								
7	Accum. Deprec.	(105,733)	1								
8	CIAC (Net)	(19,985)	1								
9	Fixed Assets	$ 1,444,477		$ 1,065,085	2						
10	AIAC			-	3	100.0%					
11	Tax Benefits from O.L. Carry Forward.					0.0%	4 $	(379,392)	35.90%		
12						100.0%	$	-	35.90%		
13							$	-	35.90%		
14	Net Asset (Liability)								$ -		
15									$ -		
16	ADIT Asset (Liability) per Adjusted Test Year							$ -	$ -		(136,202)
17	RUCO Adjustment to ADIT							$ -	$ -	$ -	$ (136,202)
18								$ (136,202)			
19								$ (51,588)			
20								$ (84,614)			
21											
22	1 Adjusted per RUCO Surrebuttal Schedule RLM-2, page 1										
23											
24	2 Tax Basis as of March 31, 2009										
25											
26	3 AIAC (including impact of change in probability of realization)										
27											
28	4 Effective AIAC Refund Rate Over a 30 Year AIAC/Refund Study (See Coley Work Papers)										
29											
30	5 Effective tax rates Per RUCO's Surrebuttal Schedule RLM-1, page 2										
31											
32											
33											
34											
35											
36											
37											
38											
39											
40											

Southern Sunrise Water Company (Stand-Alone)
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Schedule SURR RLM-5(B)
Page 1 of 1

SURREBUTTAL
ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Consolidated Allocation	Note (A)	1.5438%
5	Bella Vista Consolidated ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Consolidated Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Total Consolidated ADIT as Filed by Company	Company Schedule C-1	173,329
9	Decrease In Deferred Income Tax Assets	Line 7 - Line 8	$ (1,458,278)
10	Total Southern Sunrise Customer Count Factor	Per Company	0.0865
11	RUCO Adjustment (See SURR RLM-3, Column (D), Lin	Line 9 X Line 10	$ (126,105)

NOTES:

12	(A)	Purchase Price of BVWC, NSWC and SSWC	Annual Report	$	15,100,000
13		Algonquin Total Assets	Annual Report	$	978,130,000
14		Ratio BVWC, NSWC & SSWC To APIF Total Assets	Line 12 / Line 13		1.5438%
15	(B)	Currency Conversion	moneycentral.com on 04/1/2010		0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

Southern Sunrise Water Company (Stand-Alone)
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SURREBUTTAL
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	Flat Rate Revenues	$ 433,457	$ -	$ 433,457	$ 75,045	$ 508,502
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	10,679	-	10,679	-	10,679
4	TOTAL OPERATING REVENUE	$ 444,136	$ -	$ 444,136	$ 75,045	$ 519,181
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-
7	Purchased Power	32,354	-	32,354	-	32,354
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	1,265	-	1,265	-	1,265
10	Materials & Supplies	7,972	-	7,972	-	7,972
11	Outside Services	91	-	91	-	91
12	Outside Services- Legal	5,390	-	5,390	-	5,390
13	Outside Services- Other	179,427	(13,185)	166,242	-	166,242
14	Water Testing	5,592	(1,825)	3,767	-	3,767
15	Equipment Rental	-	-	-	-	-
16	Rents	-	-	-	-	-
17	Transportation Expenses	25,481	(1,033)	24,448	-	24,448
18	Insurance - General Liability	10,788	-	10,788	-	10,788
19	Insurance - Health and Life	-	-	-	-	-
20	Reg. Comm. Exp.	1,024	-	1,024	-	1,024
21	Reg. Comm. Exp. - Rate Case	41,667	(8,640)	33,026	-	33,026
22	Miscellaneous Expense	14,810	(773)	14,037	-	14,037
23	Bad Debt Expense	5,346	-	5,346	-	5,346
24	Depreciation Expense	76,419	(13,933)	62,486	-	62,486
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	26,765	(4,177)	22,589	-	22,589
27	Income Tax	3,703	1,725	5,428	19,749	25,177
28	TOTAL OPERATING EXPENSES	$ 438,094	$ (41,842)	$ 396,252	$ 19,749	$ 416,002
29	OPERATING INCOME (LOSS)	$ 6,042		$ 47,884		$ 103,179

References:
Column (A): Company Schedule C-1
Column (B): SURR RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From SURR RLM-1, Column (B), Line 8 And Income Tax From SURR RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 WATER TEST EXPENSES	(F) ADJ # 5 TRANSPORT EXPENSES	(G) ADJ # 6A CENTRAL OFFICE COST	(H) ADJ # 6B CENTRAL OFFICE COST	(I) ADJ # 6C CENTRAL OFFICE COST	(J) ADJ # 7 RATE CASE EXPENSES	(K) ADJ # 8 INCOME TAX	(L) RUCO AS ADJT'D
	Revenues:												
1	Flat Rate Revenues	$ 433,457	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 433,457
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	10,679	-	-	-	-	-	-	-	-	-	-	10,679
4	TOTAL OPR'G REV	$ 444,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 444,136
	Operating Expenses:												
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	-	-	-	-	-	-	-	-	-	-	-	-
7	Purchased Power	32,354	-	-	-	-	-	-	-	-	-	-	32,354
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-	-	-	-
9	Chemicals	1,265	-	-	-	-	-	-	-	-	-	-	1,265
10	Materials & Supplies	7,972	-	-	-	-	-	-	-	-	-	-	7,972
11	Outside Services	91	-	-	-	-	-	-	-	-	-	-	91
12	Outside Services- Legal	5,390	-	-	-	-	-	-	-	-	-	-	5,390
13	Outside Services- Other	179,427	-	-	-	-	-	(12,118)	(95)	(972)	-	-	166,242
14	Water Testing	5,592	-	-	-	(1,825)	-	-	-	-	-	-	3,767
15	Equipment Rental	-	-	-	-	-	-	-	-	-	-	-	-
16	Rents	-	-	-	-	-	-	-	-	-	-	-	-
17	Transportation Expenses	25,481	-	-	-	-	(1,033)	-	-	-	-	-	24,448
18	Insurance - General Liability	10,788	-	-	-	-	-	-	-	-	-	-	10,788
19	Insurance - Health and Life	-	-	-	-	-	-	-	-	-	-	-	-
20	Reg. Comm. Exp.	1,024	-	-	-	-	-	-	-	-	-	-	1,024
21	Reg. Comm. Exp. - Rate Case	41,667	-	-	-	-	-	-	-	-	(8,640)	-	33,026
22	Miscellaneous Expense	14,810	-	-	(773)	-	-	-	-	-	-	-	14,037
23	Bad Debt Expense	5,346	-	-	-	-	-	-	-	-	-	-	5,346
24	Depreciation Expense	76,419	(13,933)	-	-	-	-	-	-	-	-	-	62,486
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
26	Property Taxes	26,765	-	(4,177)	-	-	-	-	-	-	-	-	22,589
27	Income Tax	3,703	-	-	-	-	-	-	-	-	-	1,725	5,428
29	TOTAL OPR'G EXP.	$ 438,094	$ (13,933)	$ (4,177)	$ (773)	$ (1,825)	$ (1,033)	$ (12,118)	$ (95)	$ (972)	$ (8,640)	$ 1,725	$ 396,252
30	OPR'G INC. (LOSS)	$ 6,042											$ 47,884

References:
Column (A): Company Schedule C-1
Column (B): Surrebuttal Testimony, RLM And Schedule SURR RLM-8
Column (C): Surrebuttal Testimony, RLM And Schedule SURR RLM-9
Column (D): Surrebuttal Testimony, RLM And Schedule SURR RLM-10
Column (E): Surrebuttal Testimony, RLM
Column (F): Surrebuttal Testimony, RLM
Column (G): Surrebuttal Testimony, TLC And Schedule SURR RLM-11A
Column (H): Surrebuttal Testimony, TLC And Schedule SURR RLM-11B
Column (I): Surrebuttal Testimony, TLC And Schedule SURR RLM-11C
Column (J): Surrebuttal Testimony, RLM And Schedule SURR RLM-12
Column (K): Surrebuttal Testimony, RLM And Schedule SURR RLM-13
Column (L): Sum Of Columns (A) Thru (K)

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Schedule SURR RLM-8

SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	71	0.00%	-
3	303	Land and Land Rights	336,686	0.00%	-
4	304	Structures and Improvements	326,168	3.33%	10,861
5	305	Collecting and Impounding Res.	-	2.50%	-
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	132,029	3.33%	4,397
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	3,256	2.00%	65
10	310	Power Generation Equipment	-	5.00%	-
11	311	Electric Pumping Equipment	192,066	12.50%	24,008
12	320	Water Treatment Equipment	-	3.33%	-
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	261,921	2.22%	5,815
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	81,090	2.00%	1,622
19	333	Services	70,227	3.33%	2,339
20	334	Meters	16,708	8.33%	1,392
21	335	Hydrants	18,416	2.00%	368
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	21,516	6.67%	1,435
24	340	Office Furniture and Fixtures	-	6.67%	-
25	340.1	Computers and Software	-	20.00%	-
26	341	Transportation Equipment	-	20.00%	-
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	270	5.00%	13
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	-	5.00%	-
31	346	Communications Equipment	3,379	10.00%	338
32	347	Miscellaneous Equipment	-	10.00%	-
33	348	Other Tangible Plant	106,394	10.00%	10,639
34		Rounding	485		-
35	TOTAL WASTEWATER PLANT		$ 1,570,681		$ 63,292
	Less:				
36	Amortizations Of CIAC (SURR RLM-2, Col. (C), Line 5)		$ (20,000)	4.03%	(806)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 62,486
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				76,419
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ (13,933)
40	RUCO Adjustment (Line 39) (See SURR RLM-7, Column (B), Line 25)				$ (13,933)

References:
Columns (A) & (B): Company Rebuttal Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. SURR RLM-6, Col (C), Ln 4	$ 444,136	
2	Adjusted Revenues In Year Ended December 2007	Sch. SURR RLM-6, Col (C), Ln 4	444,136	
3	Proposed Revenues	Sch. SURR RLM-6, Col (E), Ln 4	519,181	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 1,407,453	
5	Average Annual Operating Revenues	Line 4 / 3	469,151	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 938,302
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 526,003	
8	10% Of CWIP	Line 7 X 10%		$ 52,600
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ -	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	-	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ -
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 990,903
	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	$ 208,090	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	9.8984%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.90%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 20,597
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,991
20	Company's Total Tax Liability	Line 18 + Line 19		$ 22,589
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 25		26,765
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (4,177)
23	RUCO Adjustment (See SURR RLM-7, Column (C), Line 27)	Line 22		$ (4,177)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
DISALLOWANCE OF MISCELLANEOUS EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL
	Disallowed Miscellaneous Expenses	Co. Response To Staff D. R. CSB 1-32	
1	Bella Vista Water Company Christmas Party		$ -
2	Special Olympics Pledge		-
3	Muscular Distrophy Association Donation		-
4	Additional Disallowance By Company		(773)
5	RUCO Adjustment To Unnecessary/Non-Recurring Expenses	Sum Of Lines 1 Thru 17	$ (773)
6	RUCO Adjustment (See SURR RLM-7, Column (D))	Line 18	$ (773)

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EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6(A)
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To SSR	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	25.35%	$ 49,328	1.26%	$ 620
2	Tax Services	518,775	25.00%	129,694	25.35%	32,880	1.26%	413
3	Legal	159,053	25.00%	39,763	25.35%	10,081	1.26%	127
4	Other Professional Services	506,082	0.00%	-	25.35%	-	1.26%	-
5	Management Fee - Total	644,943	0.00%	-	25.35%	-	1.26%	-
6	Unit Holder Communications	156,766	0.00%	-	25.35%	-	1.26%	-
7	Trustee Fees	129,000	0.00%	-	25.35%	-	1.26%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	25.35%	-	1.26%	-
9	Rent	307,337	0.00%	-	25.35%	-	1.26%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	25.35%	-	1.26%	-
11	Office Expenses	579,379	0.00%	-	25.35%	-	1.26%	-
12	Depreciation	211,653	25.00%	52,913	25.35%	13,415	1.26%	168
13	TOTAL	$ 4,104,971		$ 416,941		$ 105,703		$ 1,328
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 13,912
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on June 9, 2010							0.96293
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 13,397
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 1,278
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(12,118)
19	RUCO Adjustment (See RLM-7, Column (E))							(12,118)

References:
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

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OPERATING INCOME ADJUSTMENT #6(B) - APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Adjusted Costs	RUCO Other Disallowed Costs	RUCO Allowable Costs	RUCO 2009 Allocation Factor	RUCO Allowed Allocated Costs	Allocation % To BVWC	RUCO Amount Allocated To SSR
1	Rent	273,965	(273,965)	-	25.35%	-	14.52%	-
2	Audit	680,812	(510,609)	170,203	25.35%	43,150	14.52%	6,265.39
3	Tax Services	469,804	(352,353)	117,451	25.35%	29,776	14.52%	4,323.52
4	Legal - General	138,531	(103,898)	34,633	25.35%	8,780	14.52%	1,274.88
5	Other Professional Services	452,202	(452,202)	-	25.35%	-	14.52%	-
6	Management Fee	563,803	(563,803)	-	25.35%	-	14.52%	-
7	Unit Holder Communications	145,658	(145,658)	-	25.35%	-	14.52%	-
8	Trustee Fees	127,116	(127,116)	-	25.35%	-	14.52%	-
9	Office Costs	425,755	(425,755)	-	25.35%	-	14.52%	-
10	Licenses/Fees and Permits	14,565	(14,565)	-	25.35%	-	14.52%	-
11	Escrow and Transfer Fees	85,354	(85,354)	-	25.35%	-	14.52%	-
12	Depreciation Expense	189,797	(142,348)	47,449	25.35%	12,029	14.52%	1,746.67
	Total	3,567,363	(3,197,626)	369,736		93,736		13,610
	RUCO Direct Testimony Amount of APT Costs Allowed							14,707
	RUCO Surrebuttal Testimony Company Adjusted APT Costs Allowed							(1,097)
	Southern Sunrise Customer Count Allocation Factor							8.65%
	RUCO's Adjustment per Company's Rebuttal Adjustment							(95)

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OPERATING INCOME ADJUSTMENT #6(C) - RUCO's APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Adjusted Costs	RUCO Other Disallowed Costs	RUCO Allowable Costs	RUCO 2009 Allocation Factor	RUCO Allowed Allocated Costs	Allocation % To BVWC	Company Test-Year Booked APT Amount
1	Company's Total APT Test-Year Book Costs per RUCO Informal 2nd Set of Data Requests #5.01							$ 156,149
2	Company's Total APT Test-Year End Costs per RUCO Formal Data Request #3.01							144,906
3	APT Costs Overstated in the Company's Direct Rate Application							$ (11,243)
4	Southern Sunrise (Stand Alone) Customer Count Allocation Factor							8.65%
5	RUCO's Adjustment to Southern Sunrise (Stand Alone) APT Costs							$ (972)

Notes:

Line 1 - Company's Response to RUCO 2nd Set of Data Request #5.01 reconciles to the Company's Rate Application Test-Year Book Outside Services - Other Account in the Amount of $156,149.21

Line 2 - Company Response to RUCO Formal Data Request 3.01 for APT Costs in the Amount of $144,906

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 8
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. RLM-6, Column (C), L29 + L27	$ 53,312
	LESS:		
2	Arizona State Tax	Line 11	(1,437)
3	Interest Expense	Note (A) Line 20	(32,687)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 19,187
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	20.80%
6	Federal Income Tax Expense	Line 4 X line 5	$ 3,991
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 53,312
	LESS:		
8	Interest Expense	Note (A) Line 20	(32,687)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 20,624
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 1,437
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 3,991
13	State Income Tax Expense	Line 11	1,437
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 5,428
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		3,703
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 1,725
17	RUCO Adjustment (See Sch. SURR RLM-7, Column (K), L278)	Line16	$ 1,725

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. SURR RLM-2, Col. (E), L15)	$ 1,305,405
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)	2.50%
20	Interest Expense (L17 X L18)	$ 32,687

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	9,504	37.32293894	$ 354,717	$ 354,717
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	28,400	$ 2.4095	$ 68,430	
3	Second Tier - Breakover @ 10,000 Gals.	15,487	$ 2.9243	$ 45,290	
4	Third Tier - Over 10,000 Gals.	9,144	$ 3.7138	$ 33,958	
8	Total Commodity Usage And Revenue	53,032			$ 147,678
9	3/4" Meter	-	$ 55.98	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	-	$ 2.4095	$ -	
11	Second Tier - Breakover @ 10,000 Gals.	-	$ 2.9243	$ -	
12	Third Tier - Over 10,000 Gals.	-	$ 3.7138	$ -	
16	Total Commodity Usage And Revenue	-			$ -
17	1" Meter	-	$ 83.98	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	-	$ 2.4095	$ -	
19	Second Tier - Over 10,000 Gals.	-	$ 2.9243	$ -	
24	Total Commodity Usage And Revenue	-			$ -
33	2" Meter	-	$ 209.01	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	-	$ 2.4095	$ -	
35	Second Tier - Over 50,000 Gals.	-	$ 2.9243	$ -	
40	Total Commodity Usage And Revenue	-			$ -
41	Total Residential Customer Bills	9,504		$ 354,717	
42	Total Residential Usage	53,032		$ 147,678	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 502,396
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	-	$ 37.32	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	-	$ 2.4095	$ -	
46	Second Tier - Over 4,000 Gals.	-	$ 2.9243	$ -	
51	Total Commodity Usage And Revenue	-			$ -
52	3/4" Meter	-	$ 55.98	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	-	$ 2.4095	$ -	
54	Second Tier - Over 4,000 Gals.	-	$ 2.9243	$ -	
59	Total Commodity Usage And Revenue	-			$ -
60	1" Meter	24	$ 83.98	$ 2,015	$ 2,015
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	119	$ 2.4095	$ 287	
62	Second Tier - Over 10,000 Gals.	-	$ 2.9243	$ -	
67	Total Commodity Usage And Revenue	119			$ 287
68	1.5" Meter	-	$ 167.95	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	-	$ 2.4095	$ -	
70	Second Tier - Over 25,000 Gals.	-	$ 2.9243	$ -	
75	Total Commodity Usage And Revenue	-			$ -

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	12	$ 209.01	$ 2,508	$ 2,508
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	279	$ 2.4095	$ 671	
78	Second Tier - Over 50,000 Gals.	137	$ 2.9243	$ 401	
83	Total Commodity Usage And Revenue	415			$ 1,072
	3" Meter	-	$ 418.02	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	-	$ 2.4095	$ -	
	Second Tier - Over 80,000 Gals.	-	$ 2.9243	$ -	
	Total Commodity Usage And Revenue	-			$ -
	4" Meter	-	$ 699.81	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	-	$ 2.4095	$ -	
	Second Tier - Over 350,000 Gals.	-	$ 2.9243	$ -	
	Total Commodity Usage And Revenue	-			$ -
84	6" Meter	-	$ 1,866.15	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	-	$ 2.4095	$ -	
86	Second Tier - Over 450,000 Gals.	-	$ 2.9243	$ -	
91	Total Commodity Usage And Revenue	-			$ -
92	8" Meter	-	$ 2,985.84	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	-	$ 2.4095	$ -	
94	Second Tier - Over 720,000 Gals.	-	$ 2.9243	$ -	
99	Total Commodity Usage And Revenue	-			$ -
100	Total Commercial Customer Bills	36		$ 4,524	
101	Total Commercial Usage	534		$ 1,358	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ 5,882
	HYDRANT CUSTOMERS				
103	3" Meter	-	$ -	$ -	$ -
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	-	$ -	$ -	
110	Total Commodity Usage And Revenue	-			$ -
159	Total Hydrant Customer Bills	-			
160	Total Hydrant Usage	-			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ -
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	-	$ -	$ -	$ -
202	6" Meter	-	$ -	$ -	$ -
210	8" Meter	-	$ -	$ -	$ -
68	Total Fire Sprinkler Customer Bills	-			

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ -
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 508,278
	Total Company Customer Bills	9,540			
	Total Company Usage	53,566			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 502,396
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				5,882
192	TOTAL HYDRANT REVENUE PER BILL COUNT				-
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				-
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 508,278
198	Unreconciled Difference vs. Billed Revenues				224
200	Miscellaneous Revenues				10,679
200	**RUCO TOTAL REVENUE**				$ 519,181
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 519,181
202	Difference				$ (0)
203	Percentage Difference				0.00%

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SURREBUTTAL

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	$ 426,488	98.49%	$ 731,862	98.59%	$ 502,396	98.84%
2	OTHER	6,543	1.51%	10,461	1.41%	5,882	1.16%
3	TOTAL	$ 433,031	100.00%	$ 742,323	100.00%	$ 508,278	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 296,965	68.58%	$ 525,214	70.75%	$ 359,241	70.68%
5	VARIABLE REVENUE	136,066	31.42%	217,109	29.25%	149,037	29.32%
6	TOTAL	$ 433,031	100.00%	$ 742,323	100.00%	$ 508,278	100.00%

RESIDENTIAL (5/8" X 3/4") RATE DESIGN

		PRESENT SSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
7	BASIC MONTHLY CHARGE	$ 31.00	$ 54.37	$ 37.32

	COMMODITY CHARGE PRESENT	SSWC	PROPOSED		PRESENT SSWC	COMPANY PROPOSED STAND-ALONE	RUCO PROPOSED STAND-ALONE
8	1st Tier - Breakover	5,000	1st Tier - Breakover	4,000	$ 2.0000	$ 3.5100	$ 2.4095
9	2nd Tier - Breakove	10,000	2nd Tier - Breakover	10,000	$ 2.7500	$ 4.2600	$ 2.9243
10	3rd Tier - Over	10,000	3rd Tier - Over	10,000	$ 3.9000	$ 5.4100	$ 3.7138

SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	SOUTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,581	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,395	25.00%	$ 33.79	$ 40.68	$ 6.89	20.40%
2		2,791	50.00%	$ 36.58	$ 44.05	$ 7.47	20.41%
3		5,581	100.00%	$ 42.60	$ 51.58	$ 8.99	21.10%
4		8,372	150.00%	$ 50.27	$ 59.74	$ 9.47	18.84%
5		11,162	200.00%	$ 57.95	$ 67.90	$ 9.96	17.19%

	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 33.25	$ 40.03	$ 6.78	20.40%
7		2,250	50.00%	$ 35.50	$ 42.74	$ 7.24	20.41%
8		4,500	100.00%	$ 40.00	$ 48.42	$ 8.42	21.06%
9		6,750	150.00%	$ 44.50	$ 55.00	$ 10.50	23.60%
10		9,000	200.00%	$ 49.00	$ 61.58	$ 12.58	25.68%

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SURREBUTTAL
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SCH. NO.	PAGE NO.	TITLE
SURR RLM-1	1	REVENUE REQUIREMENT
SURR RLM-2	1	RATE BASE
SURR RLM-3	1	SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS
RLM-4	1	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT AND ACCUMULATED DEPRECIATION
DIRECT TESTIMONY		RATE BASE ADJUSTMENT NO. 2 - CUSTOMER DEPOSITS
SURR RLM-5A & 5B	1	RATE BASE ADJUSTMENT NO. 3 - ACCUMULATED DEFERRED INCOME TAXES
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 4 - PLANT RETIREMENT AND ACCUMULATED DEPRECIATION
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 5 - AFUDC
SURR TESTIMONY		RATE BASE ADJUSTMENT NO. 6 - ACQUISITION COSTS FROM PURCHASE OF MCCLAIN SYSTEMS
SURR RLM-6	1	OPERATING INCOME
SURR RLM-7	1	SUMMARY OF OPERATING INCOME ADJUSTMENTS
SURR RLM-8	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
SURR RLM-9	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX COMPUTATION
SURR RLM-10	1	OPERATING INCOME ADJUSTMENT NO. 3 - MISCELLANEOUS EXPENSES
SURR TESTIMONY		OPERATING INCOME ADJUSTMENT NO. 4 - WATER TESTING EXPENSE
SURR TESTIMONY		OPERATING INCOME ADJUSTMENT NO. 5 - TRANSPORTATION EXPENSE
SURR RLM-11A	1	OPERATING INCOME ADJUSTMENT NO. 6A - CENTRAL OFFICE COST ALLOCATION
SURR RLM-11B	1	OPERATING INCOME ADJUSTMENT NO. 6E - CENTRAL OFFICE COST ALLOCATION
SURR RLM-11C	1	OPERATING INCOME ADJUSTMENT NO. 6C - CENTRAL OFFICE COST ALLOCATION
RLM-12	1	OPERATING INCOME ADJUSTMENT NO. 7 - RATE CASE EXPENSE
SURR RLM-13	1	OPERATING INCOME ADJUSTMENT NO. 8 - INCOME TAX EXPENSE
SURR RLM-RD1	1 TO 3	RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
SURR RLM-RD2	1 TO 4	TYPICAL RESIDENTIAL BILL ANALYSIS

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Schedule SURR RLM-1
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SURREBUTTAL
REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 8,628,612	$ 5,695,062
2	Adjusted Operating Income (Loss)	$ 38,170	$ 198,934
3	Current Rate Of Return (L2 / L1)	0.44%	3.49%
4	Required Operating Income (L5 X L1)	$ 965,542	$ 479,728
5	Required Rate Of Return On Fair Value Rate Base	11.19%	8.42%
6	Operating Income Deficiency (L4 - L2)	$ 927,371	$ 280,794
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6286	1.6286
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 1,510,349	$ 457,311
9	Adjusted Test Year Revenue	$ 4,162,136	$ 4,162,136
10	Proposed Annual Revenue (L8 + L9)	$ 5,672,485	$ 4,619,447
11	Required Percentage Increase In Revenue (L8 / L9)	36.29%	10.99%
12	Rate Of Return On Common Equity	12.50%	9.00%

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule SURR RLM-2, SURR RLM-6, And RLM-14

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Schedule SURR RLM-2
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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 28,165,701	$ (1,559,846)	$ 26,605,855
2	Accumulated Depreciation	(12,057,912)	1,505,839	(10,552,073)
3	Net Utility Plant In Service (L1 + L2)	$ 16,107,789	$ (54,007)	$ 16,053,782
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (542,445)	$ -	$ (542,445)
6	Accumulated Amortization Of CIAC	230,987	-	230,987
7	NET CIAC (L5 + L6)	$ (311,458)	$ -	$ (311,458)
8	Customer Meter Deposits	$ (559,605)	$ -	$ (559,605)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ 173,329	$ (2,879,543)	$ (2,706,214)
11	Unamortized Finance Charges	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 8,628,612	$ (2,933,550)	$ 5,695,062

References:
Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): SURR RLM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

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SURREBUTTAL
SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 POST TY PLT & ACC DEP	(C) ADJ # 2 CUSTOMER DEPOSITS	(D) ADJ # 3 DEFERRED INCOME TAX	(E) ADJ # 4 PLANT RETIREMENTS	(F) ADJ # 5 AFUDC	(G) ADJ # 6 McCLAIN ACQ. COSTS	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 28,165,701	$ (1,940)	$ -	$ -	$ (1,333,228)	$ (80,055)	$ (144,623)	$ 26,605,855
2	Accumulated Depreciation	(12,057,912)	(3,610)	-	-	1,509,449	-	-	(10,552,073)
3	Net Utility Plant In Service (L1 + L2)	$ 16,107,789	$ (5,550)	$ -	$ -	$ 176,221	$ (80,055)	$ (144,623)	$ 16,053,782
4	Advances In Aid Of Const.	$ (6,781,443)	$ -	$ -	$ -	$ -	$ -	$ -	$ (6,781,443)
5	Contribution In Aid Of Const.	$ (542,445)	$ -	$ -	$ -	$ -	$ -	$ -	$ (542,445)
6	Accumulated Amortization Of CIAC	230,987	-	-	-	-	-	-	230,987
7	NET CIAC (L5 + L6)	$ (311,458)	$ -	$ -	$ -	$ -	$ -	$ -	$ (311,458)
8	Customer Meter Deposits	$ (559,605)	$ -	$ -	$ -	$ -	$ -	$ -	$ (559,605)
9	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	Deferred Income Taxes & Credits	$ 173,329	$ -	$ -	$ (2,879,543)	$ -	$ -	$ -	$ (2,706,214)
11	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 8,628,612	$ (5,550)	$ -	$ (2,879,543)	$ 176,221	$ (80,055)	$ (144,623)	$ 5,695,062

References:

Column (A): Company Schedule B-2, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Post Test-Year GPIS And Acc. Dep. (See Testimony and Schedule RLM-4)
Column (C): Adjustment No. 2 - RUCO Adjustment To Customer Deposits (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment To Deferred Income Taxes (See Surrebuttal Testimony Of RUCO Witness Tim Coley and Schedule SURR RLM-5A & 5B)
Column (E): Adjustment No. 4 - RUCO Adjustment For Retired Plant (See Surrebuttal Testimony, RLM)
Column (F): Adjustment No. 5 - RUCO Adjustment To AFUDC (See Surrebuttal Testimony, RLM)
Column (G): Adjustment No. 6 - RUCO Adjustment To Acquisition Costs (See Surrebuttal Testimony, RLM)
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F) & (G)

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Schedule SURR RLM-5(A)
Page 1 of 1

Original Cost Rate Base Proforma Adjustments
ADIT Calculation Based on RUCO's Surrebuttal Schedules

Line No.		Adjusted Book Value[1]	Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate[5]	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
1	Deferred Income Tax as of March 31, 2009									
6	Plant-in-Service	$ 26,605,855 [1]								
7	Accum. Deprec.	(10,552,073) [1]								
8	CIAC (Net)	(311,458) [1]								
9	Fixed Assets	$ 15,742,324	$ 8,287,666 [2]	100.0%	$ (7,454,658)	38.60%		-		(2,877,415)
10	AIAC		6,136,045 [3]	7.2% [4]	$ 443,538	38.60%		$ 171,201		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	38.60%		$ -		
12							$ -	$ 171,201	$ -	$ (2,877,415)
13										
14	Net Asset (Liability)						$ (2,706,214)			
15										
16	DIT Asset (Liability) per Adjusted Test Year						$ 173,329			
17										
18	Adjustment to DIT						$ (2,879,543)			
19										
20	**1 Adjusted per RUCO Surrebuttal Schedule RLM-2, page 1**									
21										
22	**2 Tax Basis as of March 31, 2009**									
23										
24	Unadjusted Cost Basis per 2008 Tax Return (Fiscal Year Ended 12/31/2008)							$ 18,314,641		
25	Adjustments:									
26	Land not on tax return depreciation report							656,307		
27	Tax accumulated depreciation through 12/31/2008							(9,166,130)		
28	Tax depreciation from 1/1/2009 to 3/31/2009 for assets added before 12/31/2008.							(254,979)		
29	Bonus Depreciation/Section 179 deductions through 12/31/2008							(1,490,506)		
30	Assets added after 12/31/2008 (net of affiliate profit, AIAC, CIAC)							947,275		
31	Tax depreciation for assets added after 12/31/2008 thru 3/31/2009 (Estimated 25 yr S.L. half-year convention)							(4,736)		
32	Bonus depreciation for assets added after 12/31/2008 thru 3/31/2009 (Estimated)							(118,409)		
33	B-2 Adjustments to plant-in-service (PTY Plant of $110,057 and plant retirement of $12,000)							101,011		
34	Tax accumulated depreciation from B-2 adjustments to plant-in-service							(3,496)		
35	Affiliate profit removed through 2008							(229,194)		
36	Tax accumulated depreciation related to affilitate profit through 2008							17,533		
37	Proposed retirements per B-2							(1,333,228)		
38	Estimated tax depreciation on B- 2 proposed retirements							1,162,419		
39	Proposed B-2 adjustments (AFUDC)							(80,055)		
40	Estimated Tax depreciation on B- 2 proposed adjustments (AFUDC)							4,214		
41	Proposed B-2 adjustments (McClain acquistion costs)							(144,623)		
42	Estimated Tax depreciation on B- 2 proposed adjustments (McClain acqusition costs)							9,943		
43	Timing difference through 2008							(100,321)		
44	Net tax value as of March 31, 2009									
45	Net tax value as of March 31, 2009							$ 8,287,666		
46										
47	**3 AIAC (including impact of change in probability of realization)**									
48	AIAC per B-2						$ 6,781,443			
49	Less: Pre-1996 AIAC included for book and tax purposes						(645,398)			
50	Net AIAC before unrealized portion							$ 6,136,045		

4 Effective AIAC Refund Rate Over a 30 Year AIAC/Refund Study (See Coley Work Papers)

5 Effective tax rates Per RLM-1, page 2

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Schedule SURR RLM-5(B)
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SURREBUTTAL
ACCUMULATED DEFERRED INCOME TAXES

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	Deferred Income Taxes:		
1	Algonquin Accumulated Deferred Income Tax Assets	2008 Algonquin Annual Report	$ 23,032,000
2	Algonquin Accumulated Deferred Income Tax Liabilities	2008 Algonquin Annual Report	(106,983,000)
3	Net Accumulated Deferred Income Tax Assets (Liabilities)	Line 1 + Line 2	$ (83,951,000)
4	Bella Vista Allocation	Note (A)	1.5438%
5	Bella Vista ADIT Liabilities Allocation	Line 3 X Line 4	$ (1,296,004)
6	Convert to US Dollars	Note (B)	0.9915
7	Bella Vista Allocated ADIT Liabilites Balance	Line 5 X Line 6	$ (1,284,949)
8	Test Year Deferred Income Taxes & Credits As Filed	Company Schedule C-1	173,329
9	Decrease In Deferred Income Taxes & Credits	Line 7 - Line 8	$ (1,458,278)
10	RUCO Adjustment (See SURR RLM-3, Column (D), Lir	Line 9	$ (1,458,278)

	NOTES:				
11	(A)	Purchase Price of BVWC, NSWC and SSWC	Annual Report	$	15,100,000
12		Algonquin Total Assets	Annual Report	$	978,130,000
13		Ratio Of BVWC, NSWC & SSWC To Algonquin Total /	Line 11 / Line 12		1.5438%
14	(B)	Currency Conversion	moneycentral.com on 04/1/2010		0.9915

SUPPORTING SCHEDULES
2008 Algonquin Power Income Fund Annual Report

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Schedule SURR RLM-6
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SURREBUTTAL
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	Flat Rate Revenues	$ 4,023,022	$ -	$ 4,023,022	$ 457,311	$ 4,480,333
2	Misc. Service Revenues	-	-	-	-	-
3	Other WW Revenues	139,114	-	139,114	-	139,114
4	TOTAL OPERATING REVENUE	$ 4,162,136	$ -	$ 4,162,136	$ 457,311	$ 4,619,447
	Operating Expenses:					
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	708	-	708
7	Purchased Power	609,481	-	609,481	-	609,481
8	Fuel for Power Production	-	-	-	-	-
9	Chemicals	5,709	-	5,709	-	5,709
10	Materials & Supplies	49,998	-	49,998	-	49,998
11	Outside Services	4,696	-	4,696	-	4,696
12	Outside Services- Legal	41,937	-	41,937	-	41,937
13	Outside Services- Other	1,599,375	(152,470)	1,446,905	-	1,446,905
14	Water Testing	28,184	38,467	66,651	-	66,651
15	Equipment Rental	6,205	-	6,205	-	6,205
16	Rents	60,600	-	60,600	-	60,600
17	Transportation Expenses	125,122	(8,703)	116,419	-	116,419
18	Insurance - General Liability	59,410	-	59,410	-	59,410
19	Insurance - Health and Life	7,290	-	7,290	-	7,290
20	Reg. Comm. Exp.	10,628	-	10,628	-	10,628
21	Reg. Comm. Exp. - Rate Case	133,333	(66,667)	66,667	-	66,667
22	Miscellaneous Expense	92,502	(9,064)	83,438	-	83,438
23	Bad Debt Expense	18,178	-	18,178	-	18,178
24	Depreciation Expense	1,122,442	(74,318)	1,048,124	-	1,048,124
25	Taxes Other Than Income	-	-	-	-	-
26	Property Taxes	195,954	(13,568)	182,386	-	182,386
27	Income Tax	(47,787)	125,559	77,772	176,517	254,289
28	TOTAL OPERATING EXPENSES	$ 4,123,965	$ (160,763)	$ 3,963,202	$ 176,517	$ 4,139,719
29	OPERATING INCOME (LOSS)	$ 38,170		$ 198,934		$ 479,728

References:
Column (A): Company Schedule C-1
Column (B): SURR RLM-7, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From SURR RLM-1, Column (B), Line 8 And Income Tax From SURR RLM-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

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SURREBUTTAL
SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 MISC. EXPENSES	(E) ADJ # 4 WATER TEST EXPENSES	(F) ADJ # 5 TRANSPORT EXPENSES	(G) ADJ # 6A CENTRAL OFFICE COST	(H) ADJ # 6B CENTRAL OFFICE COST	(I) ADJ # 6C CENTRAL OFFICE COST	(J) ADJ # 7 RATE CASE EXPENSES	(K) ADJ # 8 INCOME TAX	(L) RUCO AS ADJ'D
	Revenues:												
1	Flat Rate Revenues	$ 4,023,022	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,023,022
2	Misc. Service Revenues	-	-	-	-	-	-	-	-	-	-	-	-
3	Other WW Revenues	139,114	-	-	-	-	-	-	-	-	-	-	139,114
4	TOTAL OPR'G REV	$ 4,162,136	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 4,162,136
	Operating Expenses:												
5	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	Purchased Water	708	-	-	-	-	-	-	-	-	-	-	708
7	Purchased Power	609,481	-	-	-	-	-	-	-	-	-	-	609,481
8	Fuel for Power Production	-	-	-	-	-	-	-	-	-	-	-	-
9	Chemicals	5,709	-	-	-	-	-	-	-	-	-	-	5,709
10	Materials & Supplies	49,998	-	-	-	-	-	-	-	-	-	-	49,998
11	Outside Services	4,696	-	-	-	-	-	-	-	-	-	-	4,696
12	Outside Services- Legal	41,937	-	-	-	-	-	-	-	-	-	-	41,937
13	Outside Services- Other	1,599,375	-	-	-	-	-	(140,134)	(1,093)	(11,243)	-	-	1,446,905
14	Water Testing	28,184	-	-	-	38,467	-	-	-	-	-	-	66,651
15	Equipment Rental	6,205	-	-	-	-	-	-	-	-	-	-	6,205
16	Rents	60,600	-	-	-	-	-	-	-	-	-	-	60,600
17	Transportation Expenses	125,122	-	-	-	-	(8,703)	-	-	-	-	-	116,419
18	Insurance - General Liability	59,410	-	-	-	-	-	-	-	-	-	-	59,410
19	Insurance - Health and Life	7,290	-	-	-	-	-	-	-	-	-	-	7,290
20	Reg. Comm. Exp.	10,628	-	-	-	-	-	-	-	-	-	-	10,628
21	Reg. Comm. Exp. - Rate Case	133,333	-	-	-	-	-	-	-	-	(66,667)	-	66,667
22	Miscellaneous Expense	92,502	-	-	(9,064)	-	-	-	-	-	-	-	83,438
23	Bad Debt Expense	18,178	-	-	-	-	-	-	-	-	-	-	18,178
24	Depreciation Expense	1,122,442	(74,318)	-	-	-	-	-	-	-	-	-	1,048,124
25	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
26	Property Taxes	195,954	-	(13,568)	-	-	-	-	-	-	-	-	182,386
27	Income Tax	(47,787)	-	-	-	-	-	-	-	-	-	125,559	77,772
29	TOTAL OPR'G EXP.	$ 4,123,965	$ (74,318)	$ (13,568)	$ (9,064)	$ 38,467	$ (8,703)	$ (140,134)	$ (1,093)	$ (11,243)	$ (66,667)	$ 125,559	$ 3,963,202
30	OPR'G INC. (LOSS)	$ 38,170											$ 198,934

References:
Column (A): Company Schedule C-1
Column (B): Surrebuttal Testimony, RLM And Schedule SURR RLM-8
Column (C): Surrebuttal Testimony, RLM And Schedule SURR RLM-9
Column (D): Surrebuttal Testimony, RLM And Schedule SURR RLM-10
Column (E): Surrebuttal Testimony, RLM
Column (F): Surrebuttal Testimony, RLM
Column (G): Surrebuttal Testimony, TLC And Schedule SURR RLM-11A
Column (H): Surrebuttal Testimony, TLC And Schedule SURR RLM-11B
Column (I): Surrebuttal Testimony, TLC And Schedule SURR RLM-11C
Column (J): Surrebuttal Testimony, RLM And Schedule SURR RLM-12
Column (K): Surrebuttal Testimony, RLM And Schedule SURR RLM-13
Column (L): Sum Of Columns (A) Thru (K)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ -	0.00%	$ -
2	302	Franchise Cost	961	0.00%	-
3	303	Land and Land Rights	688,011	0.00%	-
4	304	Structures and Improvements	1,914,771	3.33%	63,762
5	305	Collecting and Impounding Res.	46,813	2.50%	1,170
6	306	Lake River and Other Intakes	-	2.50%	-
7	307	Wells and Springs	1,298,272	3.33%	43,232
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	3,256	2.00%	65
10	310	Power Generation Equipment	1,293	5.00%	65
11	311	Electric Pumping Equipment	2,327,407	12.50%	290,926
12	320	Water Treatment Equipment	83,385	3.33%	2,777
13	320.1	Water Treatment Equipment	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	2,637,716	2.22%	58,557
16	330.1	Storage tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	12,226,889	2.00%	244,538
19	333	Services	1,482,462	3.33%	49,366
20	334	Meters	1,378,333	8.33%	114,815
21	335	Hydrants	961,896	2.00%	19,238
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	114,539	6.67%	7,640
24	340	Office Furniture and Fixtures	177,672	6.67%	11,851
25	340.1	Computers and Software	160,920	20.00%	32,184
26	341	Transportation Equipment	268,464	20.00%	53,693
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	122,712	5.00%	6,136
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	31,548	5.00%	1,577
31	346	Communications Equipment	420,744	10.00%	42,074
32	347	Miscellaneous Equipment	107,306	10.00%	10,731
33	348	Other Tangible Plant	155,378	10.00%	15,538
34		Rounding	485		-
35	TOTAL WASTEWATER PLANT		$ 26,611,234		$ 1,069,934
36	Less: Amortizations Of CIAC (RLM-2, Col. (C), Line 5)		$ (542,445)	4.0207%	(21,810)
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 1,048,124
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				1,122,442
39	Increase In Depreciation Expense (Line 37 - Line 37)				$ (74,318)
40	RUCO Adjustment (Line 39) (See SURR RLM-7, Column (B), Line 25)				$ (74,318)

References:
Columns (A) & (B): Company Rebuttal Schedule "C-2p1Depr"
Column (C): Column (A) X Column (B)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2007	Sch. SURR RLM-6, Col (C), Ln 4	$ 4,162,136	
2	Adjusted Revenues In Year Ended December 2007	Sch. SURR RLM-6, Col (C), Ln 4	4,162,136	
3	Proposed Revenues	Sch. SURR RLM-6, Col (E), Ln 4	4,619,447	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 12,943,718	
5	Average Annual Operating Revenues	Line 4 / 3	4,314,573	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 8,629,145
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ 526,003	
8	10% Of CWIP	Line 7 X 10%		$ 52,600
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	RLM-4, Col. (E), Ln 26	$ 295,224	
10	Acc. Dep. Of Transportation Equipment	RLM-4, Col. (F), Ln 26	(291,918)	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ (3,305)
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 8,678,441
	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	$ 1,822,473	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	9.8984%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	9.90%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 180,395
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,991
20	Company's Total Tax Liability	Line 18 + Line 19		$ 182,386
21	Test Year Adjusted Property Tax Expense As Filing	Co. Sch. C-1, Line 25		195,954
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (13,568)
23	RUCO Adjustment (See SURR RLM-7, Column (C), Line 27)	Line 22		$ (13,568)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 3
DISALLOWANCE OF MISCELLANEOUS EXPENSES

LINE NO.	DESCRIPTION	REFERENCE	(A) TOTAL
	Disallowed Miscellaneous Expenses	Co. Response To Staff D. R. CSB 1-32	
1	Bella Vista Water Company Christmas Party		$ (2,000)
2	Special Olympics Pledge		(250)
3	Muscular Distrophy Association Donation		(250)
4	Additional Disallowance By Company		(6,564)
5	RUCO Adjustment To Unnecessary/Non-Recurring Expenses	Sum Of Lines 1 Thru 17	$ (9,064)
6	RUCO Adjustment (See SURR RLM-7, Column (D))	Line 18	$ (9,064)

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6A
CENTRAL OFFICE COST ALLOCATIONS

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL COSTS (CAN $)	(B) RUCO ALLOWED % OF COSTS	(C) RUCO ALLOWABLE COSTS	(D) RUCO UTILITIES % ALLOCATION	(E) RUCO ALLOCATED COSTS	(F) ALLOCATION % To BVWC	(G) RUCO ALLOCATED BVWC COSTS
1	Audit	$ 778,285	25.00%	$ 194,571	25.35%	$ 49,328	14.52%	$ 7,164
2	Tax Services	518,775	25.00%	129,694	25.35%	32,880	14.52%	4,776
3	Legal	159,053	25.00%	39,763	25.35%	10,081	14.52%	1,464
4	Other Professional Services	506,082	0.00%	-	25.35%	-	14.52%	-
5	Management Fee - Total	644,943	0.00%	-	25.35%	-	14.52%	-
6	Unit Holder Communications	156,766	0.00%	-	25.35%	-	14.52%	-
7	Trustee Fees	129,000	0.00%	-	25.35%	-	14.52%	-
8	Escrow & Transfer Agent Fees	96,138	0.00%	-	25.35%	-	14.52%	-
9	Rent	307,337	0.00%	-	25.35%	-	14.52%	-
10	Licenses/Fees & Permits	17,561	0.00%	-	25.35%	-	14.52%	-
11	Office Expenses	579,379	0.00%	-	25.35%	-	14.52%	-
12	Depreciation	211,653	25.00%	52,913	25.35%	13,415	14.52%	1,948
13	TOTAL	$ 4,104,971		$ 416,941		$ 105,703		$ 15,352
14	Company's APT Cost Allocation for Bella Vista in Canadian Dollars (Per RUCO DR 3.01)							$ 160,881
15	Conversion Factor to Convert Canadian Dollars to US Dollars per http://moneycentral.msn.com on June 9, 2010							0.96293
16	Company's APT Cost Allocation for Bella Vista in US Dollars							$ 154,917
17	RUCO's Allowed APT Cost Allocations in US Dollars							$ 14,783
18	RUCO's APT Cost Allocation Adjustment for Bella Vista in US Dollars							(140,134)
19	RUCO Adjustment (See SURR RLM-7, Column (E))							(140,134)

References.
Columns (A) (D) (F): Company Response To RUCO Data Requestion 3.01
Column (B): Testimony, RUCO Witness Tim Coley
Column (C): Sum Of Columns (A) & (B)
Column (E): Column (C) X Column (D)
Column (G): Column (E) X Column (F)

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OPERATING INCOME ADJUSTMENT #6(B)
APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Adjusted Costs	RUCO Other Disallowed Costs	RUCO Allowable Costs	RUCO 2009 Allocation Factor	RUCO Allowed Allocated Costs	Allocation % To BVWC	RUCO Amount Allocated To BVWC
1	Rent	273,965	(273,965)	-	25.35%	-	14.52%	-
2	Audit	680,812	(510,609)	170,203	25.35%	43,150	14.52%	6,267.11
3	Tax Services	469,804	(352,353)	117,451	25.35%	29,776	14.52%	4,324.71
4	Legal - General	138,531	(103,898)	34,633	25.35%	8,780	14.52%	1,275.22
5	Other Professional Services	452,202	(452,202)	-	25.35%	-	14.52%	-
6	Management Fee	563,803	(563,803)	-	25.35%	-	14.52%	-
7	Unit Holder Communications	145,658	(145,658)	-	25.35%	-	14.52%	-
8	Trustee Fees	127,116	(127,116)	-	25.35%	-	14.52%	-
9	Office Costs	425,755	(425,755)	-	25.35%	-	14.52%	-
10	Licenses/Fees and Permits	14,565	(14,565)	-	25.35%	-	14.52%	-
11	Escrow and Transfer Fees	85,354	(85,354)	-	25.35%	-	14.52%	-
12	Depreciation Expense	189,797	(142,348)	47,449	25.35%	12,029	14.52%	1,747.15
	Total	3,567,363	(3,197,626)	369,736		93,736		13,614
	RUCO Direct Testimony Amount of APT Costs Allowed							14,707
	RUCO's Adjustment per Company's Rebuttal Adjustment							(1,093)

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OPERATING INCOME ADJUSTMENT #6(C)
RUCO's APT CORPORATE COST ALLOCATIONS ADJUSTMENT

Line No.	Description	Company Test-Year Booked APT Amount
1	Company's Total APT Test-Year Book Costs per RUCO Informal 2nd Set of Data Requests #5.0	$ 156,149
2	Company's Total APT Test-Year End Costs per RUCO Formal Data Request #3.01	144,906
3	APT Costs Overstated in the Company's Direct Rate Application	$ (11,243)
4	RUCO's Adjustment to Bella Vista (Consolidated) APT Costs	$ (11,243)

Notes:

Line 1 - Company's Response to RUCO 2nd Set of Data Request #5.01 reconciles to the Company's Rate Application Test-Year Book Outside Services - Other Account in the Amount of $156,149.21

Line 2 - Company Response to RUCO Formal Data Request 3.01 for APT Costs in the Amount of $144,906

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SURREBUTTAL
EXPLANATION OF OPERATING INCOME ADJUSTMENT NO. 6
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. RLM-6, Column (C), L29 + L27	$ 276,706
	LESS:		
2	Arizona State Tax	Line 11	(14,040)
3	Interest Expense	Note (A) Line 20	(75,218)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 187,448
5	Federal Tax Rate	Sch. RLM-1, Pg 2, Col. (D), L34	34.00%
6	Federal Income Tax Expense	Line 4 X line 5	$ 63,732
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 276,706
	LESS:		
8	Interest Expense	Note (A) Line 20	(75,218)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 201,488
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 14,040
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 63,732
13	State Income Tax Expense	Line 11	14,040
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 77,772
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		(47,787)
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 125,559
17	RUCO Adjustment (See Sch. SURR RLM-7, Column (K), L278)	Line16	$ 125,559

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. SURR RLM-2, Col. (E), L15)	$	5,695,062
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		1.32%
20	Interest Expense (L17 X L18)	$	75,218

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	RESIDENTIAL CUSTOMERS				
1	5/8" X 3/4" Meter	102,480	$ 14.69	$ 1,505,196	$ 1,505,196
	Commodity Usage (In Thousands Of Gallons)				
2	First Tier -Breakover @ 4,000 Gals.	327,557	$ 1.6193	$ 530,406	
3	Second Tier - Breakover @ 10,000 Gals.	205,717	$ 2.4389	$ 501,724	
4	Third Tier - Over 10,000 Gals.	131,001	$ 3.1766	$ 416,134	
8	Total Commodity Usage And Revenue	664,275			$ 1,448,264
9	3/4" Meter	408	$ 22.03	$ 8,989	$ 8,989
	Commodity Usage (In Thousands Of Gallons)				
10	First Tier -Breakover @ 4,000 Gals.	1,270	$ 1.6193	$ 2,056	
11	Second Tier - Breakover @ 10,000 Gals.	596	$ 2.4389	$ 1,453	
12	Third Tier - Over 10,000 Gals.	176	$ 3.1766	$ 560	
16	Total Commodity Usage And Revenue	2,042			$ 4,069
17	1" Meter	96	$ 33.05	$ 3,173	$ 3,173
	Commodity Usage (In Thousands Of Gallons)				
18	First Tier -Breakover @ 10,000 Gals.	764	$ 1.4472	$ 1,105	
19	Second Tier - Over 10,000 Gals.	965	$ 2.2668	$ 2,187	
24	Total Commodity Usage And Revenue	1,728			$ 3,292
33	2" Meter	12	$ 82.25	$ 987	$ 987
	Commodity Usage (In Thousands Of Gallons)				
34	First Tier -Breakover @ 50,000 Gals.	129	$ 1.4472	$ 186	
35	Second Tier - Over 50,000 Gals.	-	$ 2.2668	$ -	
40	Total Commodity Usage And Revenue	129			$ 186
41	Total Residential Customer Bills	102,996		$ 1,518,344	
42	Total Residential Usage	668,174		$ 1,455,811	
43	TOTAL RESIDENTIAL CUSTOMERS REVENUE				$ 2,974,156
	COMMERCIAL CUSTOMERS				
44	5/8" X 3/4" Meter	4,572	$ 14.69	$ 67,152	$ 67,152
	Commodity Usage (In Thousands Of Gallons)				
45	First Tier -Breakover @ 4,000 Gals.	11,729	$ 1.4472	$ 16,973	
46	Second Tier - Over 4,000 Gals.	21,935	$ 2.2668	$ 49,721	
51	Total Commodity Usage And Revenue	33,663			$ 66,694
52	3/4" Meter	72	$ 22.03	$ 1,586	$ 1,586
	Commodity Usage (In Thousands Of Gallons)				
53	First Tier -Breakover @ 4,000 Gals.	237	$ 1.4472	$ 343	
54	Second Tier - Over 4,000 Gals.	732	$ 2.2668	$ 1,660	
59	Total Commodity Usage And Revenue	969			$ 2,003
60	1" Meter	1,692	$ 33.05	$ 55,916	$ 55,916
	Commodity Usage (In Thousands Of Gallons)				
61	First Tier -Breakover @ 10,000 Gals.	10,821	$ 1.4472	$ 15,660	
62	Second Tier - Over 10,000 Gals.	13,467	$ 2.2668	$ 30,527	
67	Total Commodity Usage And Revenue	24,289			$ 46,188
68	1.5" Meter	1,020	$ 66.09	$ 67,417	$ 67,417
	Commodity Usage (In Thousands Of Gallons)				
69	First Tier -Breakover @ 25,000 Gals.	17,687	$ 1.4472	$ 25,596	
70	Second Tier - Over 25,000 Gals.	28,480	$ 2.2668	$ 64,558	
75	Total Commodity Usage And Revenue	46,167			$ 90,155

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RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
76	2" Meter	3,276	$ 82.25	$ 269,455	$ 269,455
	Commodity Usage (In Thousands Of Gallons)				
77	First Tier -Breakover @ 50,000 Gals.	101,475	$ 1.4472	$ 146,850	
78	Second Tier - Over 50,000 Gals.	179,023	$ 2.2668	$ 405,807	
83	Total Commodity Usage And Revenue	280,498			$ 552,657
	3" Meter	312	$ 164.50	$ 51,325	$ 51,325
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 80,000 Gals.	20,136	$ 1.4472	$ 29,139	
	Second Tier - Over 80,000 Gals.	31,283	$ 2.2668	$ 70,912	
	Total Commodity Usage And Revenue	51,419			$ 100,051
	4" Meter	36	$ 275.39	$ 9,914	$ 9,914
	Commodity Usage (In Thousands Of Gallons)				
	First Tier -Breakover @ 350,000 Gals.	7,922	$ 1.4472	$ 11,465	
	Second Tier - Over 350,000 Gals.	13,540	$ 2.2668	$ 30,692	
	Total Commodity Usage And Revenue	21,462			$ 42,157
84	6" Meter	12	$ 734.39	$ 8,813	$ 8,813
	Commodity Usage (In Thousands Of Gallons)				
85	First Tier -Breakover @ 450,000 Gals.	468	$ 1.4472	$ 677	
86	Second Tier - Over 450,000 Gals.	-	$ 2.2668	$ -	
91	Total Commodity Usage And Revenue	468			$ 677
92	8" Meter	12	$ 1,175.02	$ 14,100	$ 14,100
	Commodity Usage (In Thousands Of Gallons)				
93	First Tier -Breakover @ 720,000 Gals.	31	$ 1.4472	$ 44	
94	Second Tier - Over 720,000 Gals.	-	$ 2.2668	$ -	
99	Total Commodity Usage And Revenue	31			$ 44
100	Total Commercial Customer Bills	11,004		$ 545,678	
101	Total Commercial Usage	458,966		$ 900,626	
102	TOTAL COMMERCIAL CUSTOMERS REVENUE				$ 1,446,304
	HYDRANT CUSTOMERS				
103	3" Meter	168	$ 117.50	$ 19,740	$ 19,740
	Commodity Usage (In Thousands Of Gallons)				
104	All Usage	5,094	$ 3.1766	$ 16,181	
110	Total Commodity Usage And Revenue	5,094			$ 16,181
159	Total Hydrant Customer Bills	168			
160	Total Hydrant Usage	5,094			
161	TOTAL HYDRANT CUSTOMERS REVENUE				$ 35,922

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SURREBUTTAL
RATE DESIGN AND PROOF OF RECOMMENDED REVENUE
PROPOSED REVENUE

LINE NO.	DESCRIPTION	(A) TEST YEAR ADJUSTED DETERMINANTS	(B) PROPOSED CHARGES & USAGE FEES	(C) PROPOSED REVENUES	(D) TOTAL REVENUES
	FIRE SPRINKLER CUSTOMERS				
194	4" Meter	1,188	15.00	$ 17,820	$ 17,820
202	6" Meter	252	14.69	$ 3,701	$ 3,701
210	8" Meter	12	23.50	$ 282	$ 282
68	Total Fire Sprinkler Customer Bills	1,452			
70	TOTAL FIRE SPRINKLER CUSTOMERS REVENUE				$ 21,803
189	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 4,478,184
	Total Company Customer Bills	115,620			
	Total Company Usage	1,132,234			
190	TOTAL RESIDENTIAL REVENUE PER BILL COUNT				$ 2,974,156
191	TOTAL COMMERCIAL REVENUE PER BILL COUNT				1,446,304
192	TOTAL HYDRANT REVENUE PER BILL COUNT				35,922
194	TOTAL FIRE SPRINKLER REVENUE PER BILL COUNT				21,803
197	**RUCO TOTAL PROPOSED REVENUE PER BILL COUNT**				$ 4,478,184
198	Unreconciled Difference vs. Billed Revenues				2,148
200	Miscellaneous Revenues				139,114
200	**RUCO TOTAL REVENUE**				$ 4,619,446
201	**PROPOSED REVENUE PER RUCO SCHEDULE RLM-1**				$ 4,619,447
202	Difference				$ (0)
203	Percentage Difference				0.00%

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SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	DESCRIPTION	(A) PRESENT	(B)	(C) COMPANY PROPOSED	(D)	(E) RUCO PROPOSED	(F)
	REVENUE ALLOCATION						
1	RESIDENTIAL	$ 2,771,302	69.02%	$ 3,631,427	65.73%	$ 2,974,156	66.41%
2	OTHER	1,243,988	30.98%	1,893,459	34.27%	1,504,029	33.59%
3	TOTAL	$ 4,015,290	100.00%	$ 5,524,886	100.00%	$ 4,478,184	100.00%
	ALLOCATION RATIOS						
4	FIX REVENUE	$ 2,158,470	53.76%	$ 2,634,057	47.68%	$ 2,105,565	47.02%
5	VARIABLE REVENUE	1,856,821	46.24%	2,890,829	52.32%	2,372,619	52.98%
6	TOTAL	$ 4,015,290	100.00%	$ 5,524,886	100.00%	$ 4,478,184	100.00%

RESIDENTIAL (5/8" X 3/4") RATE DESIGN

		PRESENT BVWC	PRESENT NS & SS	COMPANY PROPOSED CONSOL'D	RUCO PROPOSED CONSOL'D
7	BASIC MONTHLY CHARGE	$ 15.00	$ 31.00	$ 17.92	$ 14.69

COMMODITY CHARGE

	PRESENT	BVWC	NS & SS	PROPOSED	CONSOL'D	PRESENT BVWC	PRESENT NS & SS	COMPANY PROPOSED CONSOL'D	RUCO PROPOSED CONSOL'D
8	1st Tier - Breakover	5,000	5,000	1st Tier - Breakover	4,000	$ 0.9700	$ 2.0000	$ 1.9756	$ 1.6193
9	2nd Tier - Breakove	25,000	10,000	2nd Tier - Breakover	10,000	$ 1.8900	$ 2.7500	$ 2.9756	$ 2.4389
10	3rd Tier - Over	25,000	10,000	3rd Tier - Over	10,000	$ 2.4100	$ 3.9000	$ 3.8756	$ 3.1766

SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	BELLA VISTA RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 6,612	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,653	25.00%	$ 16.60	$ 17.36	$ 0.76	4.58%
2		3,306	50.00%	$ 18.21	$ 20.04	$ 1.83	10.07%
3		6,612	100.00%	$ 22.90	$ 27.53	$ 4.64	20.26%
4		9,918	150.00%	$ 29.14	$ 35.60	$ 6.45	22.14%
5		13,223	200.00%	$ 35.39	$ 43.66	$ 8.27	23.36%

	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 16.09	$ 16.51	$ 0.42	2.60%
7		2,250	50.00%	$ 17.18	$ 18.33	$ 1.15	6.68%
8		4,500	100.00%	$ 19.37	$ 22.38	$ 3.02	15.59%
9		6,750	150.00%	$ 21.55	$ 27.87	$ 6.32	29.35%
10		9,000	200.00%	$ 23.73	$ 33.36	$ 9.63	40.58%

SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	NORTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,755	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,439	25.00%	$ 33.88	$ 17.02	$ (16.86)	-49.77%
2		2,878	50.00%	$ 17.79	$ 19.35	$ 1.56	8.75%
3		5,755	100.00%	$ 43.08	$ 25.45	$ (17.63)	-40.93%
4		8,633	150.00%	$ 50.99	$ 32.46	$ (18.53)	-36.33%
5		11,511	200.00%	$ 74.39	$ 40.60	$ (33.79)	-45.43%

	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 4,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		1,125	25.00%	$ 33.25	$ 16.51	$ (16.74)	-50.35%
7		2,250	50.00%	$ 35.50	$ 18.33	$ (17.17)	-48.36%
8		4,500	100.00%	$ 40.00	$ 22.38	$ (17.62)	-44.04%
9		6,750	150.00%	$ 32.06	$ 27.87	$ (4.19)	-13.07%
10		9,000	200.00%	$ 52.00	$ 33.36	$ (18.64)	-35.85%

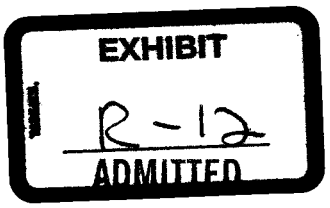
SURREBUTTAL

TYPICAL RESIDENTIAL BILL ANALYSIS

LINE NO.	SOUTHERN SUNRISE RESIDENTIAL (5/8" X 3/4") METER	(A) VARIABLE MONTHLY USAGE	(B) PERCENT AVERAGE USAGE OF 5,581	(C) PRESENT TOTAL MONTHLY COST	(D) RUCO MONTHLY COST	(E) RUCO MONTHLY INCREASE	(F) % MONTHLY INCREASE
	AVERAGE RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL						
1		1,395	25.00%	$ 33.79	$ 16.95	$ (16.84)	-49.85%
2		2,791	50.00%	$ 17.71	$ 19.21	$ 1.50	8.47%
3		5,581	100.00%	$ 42.60	$ 25.02	$ (17.58)	-41.26%
4		8,372	150.00%	$ 50.27	$ 31.83	$ (18.45)	-36.69%
5		11,162	200.00%	$ 73.03	$ 39.49	$ (33.54)	-45.93%
	MEDIAN RESIDENTIAL BILL COMPARISONS COST OF WATER SERVICE AT DIFFERENT LEVELS OF USAGE WITH PERCENTAGE INCREASE IN BILL	VARIABLE MONTHLY USAGE	PERCENT MEDIAN USAGE OF 3,500	PRESENT TOTAL MONTHLY COST	RUCO MONTHLY COST	RUCO MONTHLY INCREASE	% MONTHLY INCREASE
6		875	25.00%	$ 32.75	$ 16.10	$ (16.65)	-50.83%
7		1,750	50.00%	$ 34.50	$ 17.52	$ (16.98)	-49.21%
8		3,500	100.00%	$ 38.00	$ 20.36	$ (17.64)	-46.43%
9		5,250	150.00%	$ 27.94	$ 23.19	$ (4.75)	-17.00%
10		7,000	200.00%	$ 46.50	$ 26.02	$ (20.48)	-44.04%

BELLA VISTA WATER COMPANY, INC.

DOCKET NO. W-02465A-09-0411 ET AL.



DIRECT TESTIMONY

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 12, 2010

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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 restricted to two issues, which are Bella Vista Water Company's as consolidated ("BVWC" or "Company") requested levels of accumulated deferred income taxes and central office cost allocations.

Q. What other RUCO witnesses will be filing direct testimony in this proceeding?

A. RUCO Director Jodi Jerich will sponsor direct testimony on RUCO's rate design policy positions. RUCO witness, Mr. Rodney L. Moore, will addresses all of the remaining rate base and operating income

adjustments. Mr. Moore will also sponsor RUCO's direct testimony on rate design. RUCO witness, Mr. William A. Rigsby, sponsors RUCO's recommended overall cost of capital in his testimony. The test year utilized by the Company in connection with the preparation of this application is the 12-month period that ended March 31, 2009.

Q. Are you providing testimony for each of the three Liberty Water systems on a stand alone basis?

A. No. In this round of testimony I am providing testimony on a consolidated basis. As explained in the direct testimony of RUCO Director Jodi Jerich, RUCO will present schedules on a stand alone basis when RUCO's direct testimony on rate design is filed on April 23, 2010. At that time I will provide my recommendations for BVWC, NSWC and SSWC on a stand alone basis.

BACKGROUND

Q. Please describe your work effort on this project.

A. I recently provided revenue requirement testimonies and schedules in Rio Rico Utilities, Inc. ("RRUI") in Docket No. WS-02676A-09-0257, which is owned by the same parent Company, Algonquin Power Trust Fund ("APTF" or "Fund"), that owns BVWC in this case. RUCO employed the same methodologies in the instant case that was utilized in the RRUI case. The methodologies will be fully explained here in my testimony for

both of my adjustments to ADIT and the central office cost allocations accordingly.

Q. Please identify the Schedules and Exhibits you are sponsoring.

A. I am sponsoring Schedules for BVWC that are numbered RLM-5, which relates to ADIT, and RLM-11, which relates to the central office cost allocations, and RUCO Exhibits 1 through 4.

SUMMARY OF ADJUSTMENTS

Q. Please summarize your two adjustments to the rate base and operating income contained in your testimony.

A. My testimony addresses the following two issues as follows:

Rate Base

RUCO Rate Base Adjustment #3 – Accumulated Deferred Income Taxes

This adjustment allocates the parent Company's, APTF, 2008 accumulated deferred income tax ("ADIT") balances based on BVWC's total purchase price to APTF's 2008 total assets. RUCO's ADIT adjustment reduces BVWC's ADIT asset balance by $1,458,278. The Company had requested an ADIT asset, which increases rate base. However, RUCO's allocation of the parent Company's ADIT liability balance recognizes an ADIT liability balance of $1,284,949, which is a reduction to rate base.

Operating Income

RUCO Operating Income Adjustment #4 – Central Office Cost Allocations

This adjustment removes some central office cost allocations that RUCO finds unnecessary and excessive for the provisioning of water service. There were a number of invoices that either should not have been charged to ratepayers or should have been directly charged to the affiliate causing the costs. RUCO's adjustment reduces the Outside Services – Other account by $144,927.

REQUIRED REVENUE

Q. Please summarize the results of RUCO's analysis of the Company's filing and state RUCO's recommended revenue requirement.

A. RUCO's witness, Mr. Moore, addresses RUCO's recommended overall revenue requirement for BVWC in his testimony.

RATE BASE ADJUSTMENT

RUCO Rate Base Adjustment #3 – Accumulated Deferred Income Tax

Q. Did the Company make a pro-forma adjustment in its rate application to the test-year end ADIT balance that further increases BVWC's rate base?

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 an ADIT Liability ("ADTL") or ADIT Asset ("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") for 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 Table 1 on the following 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 could conceivably and logically have a deferred tax liability or a reduction to rate base on its books indefinitely?

A. Yes. 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 BVWC has continually added plant since its last rate case Decision No. 65350. Therefore, accelerated tax depreciation will be greater than straight-line book depreciation, which in itself would result in lower operating and hence, less income tax payable to the IRS versus income tax expense embedded in ratepayers' water rates. That scenario creates a deferred tax liability, which is a reduction to rate base. Therefore, BVWC should be reflecting a deferred tax liability rather than an asset that increases rate base.

Q. Did RUCO review the parent Company's, APTF, balance sheet provided in its 2008 Annual Report to assess the amount of ADIT reported there?

A. Yes. APTF reported a net ADIT Liability in the amount of $83,951,000, as shown in RUCO Exhibit 1. When that amount is allocated down from APTF to its affiliates in some logical, rationale, and/or systematic[5] manner as RUCO did, that would amount to a reduction in rate base rather than an addition to rate base as the Company's rate application reports.

...

[4] Source: http:www.utdallas.edu, Accounting Text, Chapter 16, Accounting for Income Taxes, page 3 of 20.
[5] As prescribed in Statement of Financial Standards No. 109, Section 40, page 19.

Q. Did BVWC report any ADIT's in the Company's Annual Reports that it files with the Commission annually?

A. RUCO reviewed the Company's last three-years (2006-2008) of Annual Reports that were filed with the Commission and no ADIT's were reported for those years (See RUCO Exhibit 2).

Q. Did Commission Decision No. 65350, docketed on November 1, 2002, in BVWC's last rate case authorize any ADIT balance in that case?

A. Yes.

Q. What did Commission Decision No. 65350 authorize for BVWC regarding the Company's ADIT balance in that case?

A. Commission Decision No. 65350 adopted an Original Cost Rate Base ("OCRB") of $7,482,520 that included an Accumulated Deferred Tax Liability ("ADTL") balance, which is a reduction to rate base, for the ADIT in the amount of $235,258.

Q. What exactly is an Accumulated Deferred Tax Liability ("ADTL"), which is a reduction to rate base?

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]

[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. 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 reduces rate base.

Q. Do you have another source that supports RUCO's position regarding the ADIT issue?

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...

[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.

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 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** [emphasis added] 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** [emphasis added] 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** [emphasis added] 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. 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. 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 some portion of investments in fixed assets. The first is the Internal Revenue Code ("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 methods 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.

Assume, 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 50 percent Special Depreciation Allowance or Bonus Depreciation as some people refer to it. The company can take the 50 percent special deduction allowance to recover half 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 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 50 percent 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.

...

[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.

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 not 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 newly added asset. 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 50 percent 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 on the company's books. The company can now figure its regular annual MACRS depreciation for tax purposes and its straight-line book depreciation 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 MACRS tax depreciation on its adjusted $1,250,000 tax basis on the new plant

additions or $93,750 ($1,250,000 X (15% / 2)). 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)). The reason why the straight-line book depreciation expense of $125,000 is greater than accelerated tax depreciation expense amount of $93,750 is because the company's book basis in the newly added plant is $2,500,000 whereas the tax basis of the new plant was now only $1,250,000 due to the special 50 percent depreciation election.

For tax purposes, the company is allowed to deduct the additional special depreciation allowance of $1,250,000 plus the regular annual MACRS depreciation expense calculation of $93,750 for a total depreciation deduction of $1,343,750 ($1,250,000 + $93,750) in the first year that the plant is placed in service. 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 operating income in that year is $1,218,750 ($1,343,750 - $125,000) less for tax purposes than book purposes because of the greater tax depreciation deduction generated by claiming the special 50 percent deduction allowance. Assuming a 38.6 percent[9] federal and state income tax rate, this scenario alone would create an income tax savings of

[9] This is the effective federal and state income tax rate (38.6%) for Bella Vista Water Company in the instant case.

$470,438 for the company compared to its recorded book / ratemaking income tax expense amount. The $470,438 tax savings represents a deferred tax liability, which is a reduction to rate base.

The deferred tax calculation for the hypothetical DIT scenario is summarized and 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 and its first year HY convention for MACRS depreciation deduction 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. For BVWC as consolidated, please explain the Company's Schedule B-2, page 5, line 9, fixed assets component of its deferred income tax calculation.

A. That line of schedule shows the Company's adjusted book basis in its fixed assets to be $15,565,344. It also shows BVWC's adjusted tax basis in its fixed assets to be $9,232,954. Thus, the Company's tax basis in its fixed assets component is $6,332,390 less than its book basis. That's a

sensible and logical result because the accelerated tax depreciation decreases the tax basis faster than the slower straight-line book depreciation method, which has been thoroughly illustrated in the previous several pages of my testimony. When the fixed assets' tax basis is less than the book basis, as in BVWC's case, this creates a deferred income tax liability that is a reduction to rate base. Isolating the fixed assets component of the Company's deferred income tax calculation, the calculation of the DIT takes the difference between the book basis of $15,565,344 and the tax basis of $9,232,954, which is $6,332,390, and multiplies the difference by the effective tax rate of 38.6 percent. By multiplying $6,332,390 by 38.6 percent, the product equals the deferred income tax liability of $2,444,232.[10] As RUCO has demonstrated through sources and illustrations throughout this testimony, that is what creates the **bulk** of a utilities ADIT.

Q. Does RUCO agree with the Company's fixed asset component of its ADIT calculation that results in a non-current future tax liability?

A. RUCO generally agrees with the Company's methodology in determining the fixed assets component of its ADIT balance. However, RUCO made two plant adjustments that would result in a small difference in the fixed assets component of the Company ADIT calculation.

[10] There is an approximate $71 rounding issue.

...

Q. What two adjustments did RUCO make that would make a small difference in the Company's fixed assets component of its ADIT calculation?

A. RUCO reduced the Gross Utility Plant in Service ("GUPIS") by $1,940 and increased Accumulated Depreciation by $3,610. Those adjustments are fully explained in RUCO witness, Mr. Moore's, testimony.

Q. What impact would Mr. Moore's adjustments have on the Company's fixed assets component of BVWC's ADIT calculation?

A. The impact of Mr. Moore's two adjustment referenced above would reduce the fixed assets component, which is an ADIT liability, by $2,142 from $2,444,232 to $2,442,090.

Q. What other reason(s) does RUCO provide in opposing the Company's ADTA balance?

A. Most importantly, beyond the issues of what RUCO has already discussed in its testimony, RUCO takes issue with the Company's attempt to create an ADTA, which increases rate base, solely by using non-investor supplied Advances in Aid of Construction ("AIAC") funds. AIAC funds are interest free funds to which the Company has no right to earn a return on in rate base. Rightfully, AIAC is recorded as a reduction to rate base on the Company's Schedule B-1. Appropriate ratemaking already allows the

Company a return of AIAC through depreciation expense and should be denied the ability to also earn a return on such non-investor supplied funds until the AIAC is refunded. Any future income taxes associated with the AIAC are already reflected in the rates through the depreciation expense of AIAC for ratemaking purposes.

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 BVWC.

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 BVWC 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...

Since the parent company, APTF, elected to file a consolidated tax return showing an ADIT liability, then SFAS No. 109 requires apportionment of the liability among the affiliates and precludes the listing of an ADIT asset for BVWC. The excerpt of SFAS No. 109 is provided in this testimony as RUCO Exhibit 3.

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 the consolidated BVWC's total asset cost ($15.1 million) divided by Algonquin Power Trust Fund's total assets ($978.1 million) to arrive at BVWC's asset ratio, as reported in 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, which meets the criteria established therein. These deferred income tax liabilities are attributable

to all APTF's affiliates. The ratepayers of BVWC are entitled to those tax benefits that it contributed towards.

...

Q. What is RUCO's recommendation for BVWC's ADIT balance?

A. RUCO recommends adjusting the Company's ADIT Asset balance by $1,458,278 for an ADIT Liability balance of $1,284,949 for BVWC. This adjustment reflects SFAS No. 109 criteria of allocating the tax benefits that the ratepayers are entitled, which reduces rate base accordingly. This adjustment is on Schedule RLM-2 with the supporting detail on Schedules RLM-3 and RLM-5.

OPERATING INCOME ADJUSTMENT

RUCO Operating Income Adjustment #4 – Central Office Cost Allocations

Q. Did RUCO make an adjustment to the Company's Central Office Cost Allocations?

A. Yes.

Q. What is RUCO's rationale for making the adjustment to the Central Office Cost Allocations?

A. First, RUCO believes that most of the expenses being allocated to the Arizona Utility Infrastructure regulated affiliates, including BVWC, are unnecessary and not directly attributable in the provisioning of water

service. 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 BVWC 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 APTF. Finally, RUCO has concerns with the allocation and documentation methods between an unregulated affiliate, APT, and regulated affiliates such as BVWC. The NARUC Guidelines for Cost Allocations and Affiliate Transactions, attached as RUCO Exhibit 4, 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 are classified as indirect costs and fully allocated to each of the Fund's affiliates.

Q. Please describe the Fund'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 in Canadian dollars is $4,104,971 for the test-year. 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 converts the Canadian dollars to US dollars for a total cost of $3,697,367 and multiplies it by the 26.98 percent allocation factor that it claims the seventeen utility companies are attributable to arrive at $997,702 US dollars, which RUCO also disagrees. Finally, the $997,702 of US dollars is allocated to each of the seventeen utility companies based on each utility's customer count. BVWC's consolidated customer count represents approximately 14.52 percent of the total 64,094 customers in the seventeen utility companies. The Company ultimately allocates 14.52 percent of the $997,702 to BVWC, which is $144,906.

Q. If RUCO does not agree with the Company's first allocation factor of 26.98 percent, what does RUCO recommend that allocation factor be?

A. RUCO does not agree with the Company's proposed allocation methodology but has no remedial solution for a better overall allocation methodology. RUCO utilizes the Company's proposed methodology in making our recommended adjustment. The Company computes the first allocation factor of 26.98 percent by dividing the 17 utilities by the 63 total affiliates, (17 / 63), that it claims to own. RUCO disagrees with the variable of 63 total affiliates 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 $997,702 US dollars 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. In addition, RUCO's calculation does not convert the Canadian dollars to US dollars until the end of the calculation in order to capture the most recent known and measurable conversion rate.

Q. What is RUCO's position regarding the Company's allocated APT costs of $997,702 US dollars 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 $997,702 US dollars is attributable to BVWC. RUCO cannot directly trace any of those costs to BVWC. The invoices essentially contain no detail. Other costs are directly attributable to the Fund's other affiliates, i.e. implementation of Sanger electrical location and annual memberships for the Canadian Wind Energy Association etc. I also saw an invoice for a man's Fossil watch. At the very most, only a fraction of the costs would

appear to be of some benefit to BVWC's water utility ratepayers in Arizona.

...

Q. What APT expenses does RUCO believe could be attributable to BVWC?

A. RUCO's analysis and review determined that the audit, tax services, legal – general, and depreciation expenses could possibly benefit the ratepayers of BVWC to some minor extent.

Q. What amount of those expenses does RUCO believe could possibly benefit BVWC in the provisioning 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 other operating affiliates and shareholders.

Q. Does RUCO agree with the Company's methodology in allocating the APT costs to BVWC by customer count?

A. RUCO is in general agreement to allocate RUCO's recommended level of APT expenses to BVWC 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. RUCO's main concern with the APT cost allocations is not so much the Company's

allocation methodology but rather the expenses are inappropriate and unnecessary to the provision of water utility service and are in large part unsupported by detailed invoices.

Q. Does RUCO believe BVWC 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 the stand alone companies which are included in BVWC as consolidated 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 other Arizona utility companies to companies structured with shared service models such as BVWC.

Q. What adjustment did RUCO make to Outside Services – Other account in direct testimony to remove the majority of the APT related costs?

A. RUCO's adjustment removes $144,927 from the Outside Services – Other account of BVWC. This adjustment is shown on Schedules RLM-6 and RLM-7 with the details appearing in RLM-11.

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

Residential Utility Consumer Office For Years 2000 To Present (cont'd)

Arizona Water Company - Docket No. W-01445A-08-0440

Far West Water & Sewer Company - WS-03478A-08-0608

Rio Rico Utilities, Inc. - WS-02676A-08-09-0257

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 by 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

B

W-02465A
Bella Vista Water Company, Inc.
12725 W. Indian School Rd Suite D 101
Avondale, AZ 85323

ANNUAL REPORT

FOR YEAR ENDING

12	31	2006

FOR COMMISSION USE

ANN 04	06

PROCESSED BY:
4-18-07

SCANNED

COMPANY NAME
BELLA VISTA WATER CO., INC.

BALANCE SHEET

Acct. No.	ASSETS	BALANCE AT BEGINNING OF YEAR	BALANCE AT END OF YEAR
	CURRENT AND ACCRUED ASSETS		
131	Cash	$ 72,882	$ 99,034
134	Working Funds		
135	Temporary Cash Investments		
141	Customer Accounts Receivable	259,421	274,222
146	Notes/Receivables from Associated Companies		
151	Plant Material and Supplies	24,451	
162	Prepayments	108,356	37,042
174	Miscellaneous Current and Accrued Assets		
	TOTAL CURRENT AND ACCRUED ASSETS	**$ 465,110**	**$ 410,297**
	FIXED ASSETS		
101	Utility Plant in Service	$ 20,200,182	$ 21,971,846
103	Property Held for Future Use		
105	Construction Work in Progress	177,580	351,197
108	Accumulated Depreciation - Utility Plant	9,804,105	9,960,835
121	Non-Utility Property		
122	Accumulated Depreciation - Non Utility		
	TOTAL FIXED ASSETS	$ 10,573,657	$ 12,362,208
	TOTAL ASSETS	**$ 11,038,768**	**$ 12,772,506**

NOTE: The Assets on this page should be equal to Total Liabilities and Capital on the following page.

COMPANY NAME
BELLA VISTA WATER CO., INC.

BALANCE SHEET (CONTINUED)

Acct. No.	LIABILITIES	BALANCE AT BEGINNING OF YEAR	BALANCE AT END OF YEAR
	CURRENT LIABILITES		
231	Accounts Payable	$ 15,145	$ 32,839
232	Notes Payable (Current Portion)	110,732	98,645
234	Notes/Accounts Payable to Associated Companies	(350,901)	11,810
235	Customer Deposits	159,563	174,510
236	Accrued Taxes	734,851	384,956
237	Accrued Interest	20,779	18,481
241	Miscellaneous Current and Accrued Liabilities	37,929	45,248
	TOTAL CURRENT LIABILITIES	$ 728,097	$ 766,487
	LONG-TERM DEBT (Over 12 Months)		
224	Long-Term Notes and Bonds	$ 1,994,025	$ 1,987,678
	DEFERRED CREDITS		
251	Unamortized Premium on Debt		
252	Advances in Aid of Construction	4,664,209	6,140,034
255	Accumulated Deferred Investment Tax Credits	222,755	15,775
271	Contributions in Aid of Construction	489,515	503,145
272	Less: Amortization of Contributions	191,471	213,015
281	Accumulated Deferred Income Tax		
	TOTAL DEFERRED CREDITS	$ 5,185,008	$ 6,445,939
	TOTAL LIABILITIES	$ 7,907,130	$ 9,200,104
	CAPITAL ACCOUNTS		
201	Common Stock Issued	$ 1,520,080	$ 1,520,080
211	Paid in Capital in Excess of Par Value	377,948	377,948
215	Retained Earnings	1,233,610	1,674,374
218	Proprietary Capital (Sole Props and Partnerships)		
	TOTAL CAPITAL	$ 3,131,638	$ 3,572,402
	TOTAL LIABILITIES AND CAPITAL	**$ 11,038,767**	**$ 12,772,506**

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION

ANNUAL REPORT MAILING LABEL – MAKE CHANGES AS NECESSARY

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W-02465A
Bella Vista Water Company, Inc.
12725 W. Indian School Rd Suite D 101
Avondale, AZ 85392

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AZ CORPORATION COMMISSION
DIRECTOR OF UTILITIES

ANNUAL REPORT

FOR YEAR ENDING

12	31	2007

FOR COMMISSION USE

ANN 06	07

PROCESSED BY:
4-16-08

SCANNED

COMPANY NAME
BELLA VISTA WATER CO., INC.

BALANCE SHEET

Acct. No.	ASSETS	BALANCE AT BEGINNING OF YEAR	BALANCE AT END OF YEAR
	CURRENT AND ACCRUED ASSETS		
131	Cash	$ 99,034	$ 82,476
134	Working Funds		
135	Temporary Cash Investments		
141	Customer Accounts Receivable	274,222	300,263
146	Notes/Receivables from Associated Companies		
151	Plant Material and Supplies		
162	Prepayments	37,042	27,772
174	Miscellaneous Current and Accrued Assets		
	TOTAL CURRENT AND ACCRUED ASSETS	**$ 410,297**	**$ 410,511**
	FIXED ASSETS		
101	Utility Plant in Service	$ 21,971,846	$ 22,467,362
103	Property Held for Future Use		
105	Construction Work in Progress	351,197	439,637
108	Accumulated Depreciation - Utility Plant	9,960,835	10,686,406
121	Non-Utility Property		
122	Accumulated Depreciation - Non Utility		
	TOTAL FIXED ASSETS	$ 12,362,208	$ 12,220,594
	TOTAL ASSETS	**$ 12,772,505**	**$ 12,631,104**

NOTE: The Assets on this page should be equal to Total Liabilities and Capital on the following page.

COMPANY NAME
BELLA VISTA WATER CO., INC.

BALANCE SHEET (CONTINUED)

Acct. No.	LIABILITIES	BALANCE AT BEGINNING OF YEAR	BALANCE AT END OF YEAR
	CURRENT LIABILITES		
231	Accounts Payable	$ 32,839	$ 12,702
232	Notes Payable (Current Portion)	98,645	104,163
234	Notes/Accounts Payable to Associated Companies	11,810	(304,624)
235	Customer Deposits	174,510	176,735
236	Accrued Taxes	384,956	464,374
237	Accrued Interest	18,481	14,551
241	Miscellaneous Current and Accrued Liabilities	45,248	191,807
	TOTAL CURRENT LIABILITIES	$ 766,487	$ 659,707
	LONG-TERM DEBT (Over 12 Months)		
224	Long-Term Notes and Bonds	$ 1,987,678	$ 1,982,159
	DEFERRED CREDITS		
251	Unamortized Premium on Debt		
252	Advances in Aid of Construction	6,140,034	6,180,906
255	Accumulated Deferred Investment Tax Credits	15,775	122,872
271	Contributions in Aid of Construction	503,145	503,945
272	Less: Amortization of Contributions	213,015	233,688
281	Accumulated Deferred Income Tax		
	TOTAL DEFERRED CREDITS	$ 6,445,939	$ 6,574,035
	TOTAL LIABILITIES	$ 9,200,104	$ 9,215,902
	CAPITAL ACCOUNTS		
201	Common Stock Issued	$ 1,520,080	$ 1,520,080
211	Paid in Capital in Excess of Par Value	377,948	377,948
215	Retained Earnings	1,674,373	1,517,175
218	Proprietary Capital (Sole Props and Partnerships)		
	TOTAL CAPITAL	$ 3,572,401	$ 3,415,203
	TOTAL LIABILITIES AND CAPITAL	**$ 12,772,505**	**$ 12,631,104**

ARIZONA CORPORATION COMMISSION
UTILITIES DIVISION

ANNUAL REPORT MAILING LABEL – MAKE CHANGES AS NECESSARY

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Director Utilities

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Bella Vista Water Company, Inc.
12725 W. Indian School Rd Suite D 101
Avondale, AZ 85392

ANNUAL REPORT

FOR YEAR ENDING

12	31	2008

FOR COMMISSION USE

ANN 06	07

PROCESSED BY:
4-17-09

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COMPANY NAME
BELLA VISTA WATER CO., INC.

BALANCE SHEET

Acct. No.	ASSETS	BALANCE AT BEGINNING OF YEAR	BALANCE AT END OF YEAR
	CURRENT AND ACCRUED ASSETS		
131	Cash	$ 82,476	$ 77,418
134	Working Funds		
135	Temporary Cash Investments		
141	Customer Accounts Receivable	300,263	312,928
146	Notes/Receivables from Associated Companies		
151	Plant Material and Supplies		
162	Prepayments	27,772	28,613
174	Miscellaneous Current and Accrued Assets		
	TOTAL CURRENT AND ACCRUED ASSETS	**$ 410,511**	**$ 418,959**
	FIXED ASSETS		
101	Utility Plant in Service	$ 22,467,362	$ 24,603,532
103	Property Held for Future Use		
105	Construction Work in Progress	439,637	601,131
108	Accumulated Depreciation - Utility Plant	10,686,406	11,237,911
121	Non-Utility Property		
122	Accumulated Depreciation - Non Utility		
	TOTAL FIXED ASSETS	$ 12,220,594	$ 13,966,752
	TOTAL ASSETS	**$ 12,631,104**	**$ 14,385,711**

NOTE: The Assets on this page should be equal to Total Liabilities and Capital on the following page.

COMPANY NAME
BELLA VISTA WATER CO., INC.

BALANCE SHEET (CONTINUED)

Acct. No.	LIABILITIES	BALANCE AT BEGINNING OF YEAR	BALANCE AT END OF YEAR
	CURRENT LIABILITES		
231	Accounts Payable	$ 12,702	$ 30,416
232	Notes Payable (Current Portion)	104,163	111,632
234	Notes/Accounts Payable to Associated Companies	(304,624)	301,032
235	Customer Deposits	176,735	183,579
236	Accrued Taxes	464,374	460,116
237	Accrued Interest	14,551	18,923
241	Miscellaneous Current and Accrued Liabilities	191,807	46,000
	TOTAL CURRENT LIABILITIES	$ 659,707	$ 1,151,699
	LONG-TERM DEBT (Over 12 Months)		
224	Long-Term Notes and Bonds	$ 1,982,159	$ 1,424,266
	DEFERRED CREDITS		
251	Unamortized Premium on Debt		
252	Advances in Aid of Construction	6,180,906	7,199,993
255	Accumulated Deferred Investment Tax Credits	122,872	101,160
271	Contributions in Aid of Construction	503,945	503,945
272	Less: Amortization of Contributions	233,688	254,360
281	Accumulated Deferred Income Tax		
	TOTAL DEFERRED CREDITS	$ 6,574,035	$ 7,550,738
	TOTAL LIABILITIES	$ 9,215,902	$ 10,126,703
	CAPITAL ACCOUNTS		
201	Common Stock Issued	$ 1,520,080	$ 1,520,080
211	Paid in Capital in Excess of Par Value	377,948	377,948
215	Retained Earnings	1,517,175	2,360,981
218	Proprietary Capital (Sole Props and Partnerships)		
	TOTAL CAPITAL	$ 3,415,203	$ 4,259,009
	TOTAL LIABILITIES AND CAPITAL	**$ 12,631,104**	**$ 14,385,711**

EXHIBIT 3

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 4

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.