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BEFORE THE ARIZONA CORPORATION COMMISSION

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IN THE MATTER OF THE APPLICATION OF VALENCIA WATER COMPANY – TOWN DIVISION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES FOR UTILITY SERVICE DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTY THROUGHOUT THE STATE OF ARIZONA	Docket No. W-01212A-12-0309
IN THE MATTER OF THE APPLICATION OF GLOBAL WATER – PALO VERDE UTILITIES COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES FOR UTILITY SERVICE DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTY THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. SW-20445A-12-0310
IN THE MATTER OF THE APPLICATION OF WATER UTILITY OF NORTHERN SCOTTSDALE, INC. FOR A RATE INCREASE	Docket Nos. W-03720A-12-0311
IN THE MATTER OF THE APPLICATION OF WATER UTILITY OF GREATER TONOPAH FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES FOR UTILITY SERVICE DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTY THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. W-02450A-12-0312
IN THE MATTER OF THE APPLICATION OF VALENCIA WATER COMPANY – GREATER BUCKEYE DIVISION FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES FOR UTILITY SERVICE DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTY THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. W-02451A-12-0313

IN THE MATTER OF THE APPLICATION OF GLOBAL WATER – SANTA CRUZ WATER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES FOR UTILITY SERVICE DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTY THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. W-20446A-12-0314
IN THE MATTER OF THE APPLICATION OF WILLOW VALLEY WATER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES FOR UTILITY SERVICE DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS PROPERTY THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. W-1732A-12-0315 **NOTICE OF FILING**

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Direct Testimony of Robert B. Mease and William A. Rigsby, in the above-referenced matter.

RESPECTFULLY SUBMITTED this 8th day of July, 2013.

Michelle L. Wood
Counsel

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GLOBAL UTILITIES

DOCKET NO. W-01212A-12-0309 ET AL.

DIRECT TESTIMONY

OF

ROBERT B. MEASE

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 8, 2013

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EXECUTIVE SUMMARY

On July 9, 2012, Global Water, LLC ("Global Water" or "Company") filed general rate applications for Valencia Water Company – Town Division ("VWCT"), Global Water – Palo Verde Utilities Company ("Palo Verde"), Water Utility of Northern Scottsdale ("WUNS"), Water Utility of Greater Tonopah ("WUGT"), Valencia Water Company – Greater Buckeye Division ("VWCGB"), Global Water – Santa Cruz Water Company, ("Santa Cruz"), and Willow Valley Water Company ("Willow Valley") for the establishment of just and reasonable rates using a test year ending December 31, 2011. WUGT and VWCGB are classified as Class C utilities; WUNS is classified as a Class D utility while the remaining four locations are classified as Class A utilities.

On July 12, 2012 a Motion to Consolidate was filed by the Company and on November 20, 2012, the motion was granted under Docket No. W-1212A-12-0309 ET AL.

The Company's water utilities included in the application(s) serve approximately 23,900 customers while the wastewater utility ("Palo Verde") serves approximately 15,800 customers. In addition to requesting an adjustment in rates the Company is also requesting new and revised tariffs, license fee adjustment mechanisms for CAGRD and the City of Maricopa, approving a Distribution System Improvement Charge (DSIC) for it water systems and a Collection System Improvement Charge (CSIC) for its wastewater system. Finally the Company is requesting consolidation of the rates for ("WUGT"), ("VWCT"), and ("VWCGB").

Global Water's Application requests and RUCO's proposed gross revenue increases are as follows:

	Company Requested		RUCO Proposed	
System	Increase	Percent	Increase	Percent
Palo Verde	$3,662,560	27.9%	$1,337,539	10.20%
Santa Cruz	$2,726,367	26.1%	$1,454,179	13.90%
VWCT	$823,424	16.7%	$176,472	3.58%
WUGT	$677,458	326.6%	$32,753	7.31%
Willow Valley	$507,537	72.2%	$396,281	56.40%
VWCG	$36,422	7.7%	($12,406)	-0.03%
WUNS	$2,844	1.9%	($17,196)	-11.66%

Global Water's Application requests and RUCO's proposed rate base and rate of return on the fair value rate base (FVRB) are as follows:

	OCRB / FVRB		RATE OF RETURN	
System	Company	RUCO	Company	RUCO
Palo Verde	$60,166,756	$52,813,708	8.81%	7.39%
Santa Cruz	$38,014,243	$33,994,203	8.79%	7.46%
VWCT	$2,323,476	$1,650,906	10.27%	7.91%
WUGT	$2,206,816	($1,437,481)	10.72%	8.19%
Willow Valley	$2,359,391	$2,278,955	10.60%	8.03%
VWCGB	$634,978	$634,979	11.18%	8.39%
WUNS	($181,978)	($181,978)	14.44%	8.50%

RUCO's Chief of Accounting and Rates, Mr. William A. Rigsby, will provide testimony on RUCO's recommended cost of capital and on the Company's request for a DSIC and CISC. Mr. Robert B. Mease, RUCO's Associate Chief of Accounting and Rates, will present testimony on each systems revenue requirements.

INTRODUCTION

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

A. My Name is Robert B. Mease. I am Associate Chief of Accounting and Rates 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, work experience and regulatory matters in which I have participated. In summary, I joined RUCO in October of 2011. I graduated from Morris Harvey College in Charleston, WV and attended Kanawha Valley School of Graduate Studies. I am a Certified Public Accountant and currently licensed in the State of West Virginia. My years of work experience include serving as Vice President and Controller of a public utility and energy company in Great Falls, Montana and have participated in several rate case filings on behalf of the utility. I have also provided testimony on behalf of RUCO on several rate cases before the Arizona Corporation Commission.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding Global Water's Application's for a determination of the current

fair value of its utility plant and property and will also present testimony on RUCO's proposed rate design for each utility. The test year utilized by the Company in connection with the preparation of this Application is the 12-month period that ended December 31, 2011 ("Test Year").

BACKGROUND

Q. Please describe your work effort on this project.

A. I reviewed financial data provided by the Company for each application filed and performed analytical procedures necessary to understand the Company's filing as it relates to each utility's rate base and operating income. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of this data, the review and analysis of the Company's responses to data requests, and review of prior ACC dockets related to Global Water. RUCO's participation in this proceeding is the cumulative effort of two RUCO witnesses; myself and Mr. William A. Rigsby. I was responsible for the rate base and revenue determination analysis and RUCO's Chief of Accounting and Rates, Mr. Rigsby, will present separate testimony on certain policy related issues and RUCO's cost of capital recommendation.

Q. Please identify the exhibits you are sponsoring.

A. I am sponsoring schedules numbered RBM-1 through and including RBM-19 for each of the Global Water's rate applications in this filing including

Valencia Water Company – Town Division ("VWCT"), Global Water – Palo Verde Utilities Company ("Palo Verde"), Water Utility of Northern Scottsdale ("WUNS"), Water Utility of Greater Tonopah ("WUGT"), Valencia Water Company – Greater Buckeye Division ("VWCGB"), Global Water – Santa Cruz Water Company, ("Santa Cruz"), and Willow Valley Water Company ("Willow Valley").

Q. Can you please provide a summary of the Company's filing for each of the utility systems included in this rate filing?

A. For ratemaking purposes the Company has elected not to perform a reconstruction cost new less depreciation study and is using its Original Cost Rate Base ("OCRB") as its Fair Value Rate Base ("FVRB"). The FVRB for each of the systems as filed by the Company:

	OCRB / FVRB		RATE OF RETURN	
System	Company	RUCO	Company	RUCO
Palo Verde	$60,166,756	$52,813,708	8.81%	7.39%
Santa Cruz	$38,014,243	$33,994,203	8.79%	7.46%
VWCT	$2,323,476	$1,650,906	10.27%	7.91%
WUGT	$2,206,816	($380,932)	10.72%	8.19%
Willow Valley	$2,359,391	$2,278,955	10.60%	8.06%
VWCGB	$634,978	$634,978	11.18%	8.39%
WUNS	($181,978)	($181,978)	14.44%	8.50%

The Company is also proposing an adjustment in rates that will increase operating revenues for each utility system as follows:

	Company Requested		RUCO Proposed	
System	Increase	Percent	Increase	Percent
Palo Verde	$3,662,560	27.9%	$1,337,539	10.20%
Santa Cruz	$2,726,367	26.1%	$1,454,179	13.90%
VWCT	$823,424	16.7%	$176,472	3.58%
WUGT	$677,458	326.6%	$32,753	7.31%
Willow Valley	$507,537	72.2%	$396,281	56.40%
VWCG	$36,422	7.7%	($12,406)	-0.03%
WUNS	$2,844	1.9%	($17,196)	-11.66%

RATE BASE ADJUSTMENTS - SUMMARY

Q. Is RUCO recommending any adjustments to the Company's rate base as filed in its rate application?

A. Yes. RUCO is recommending several rate base adjustments as follows:

Rate Base Adjustment No. 1 – Post Test Year Plant

RUCO is recommending excluding post-test year plant not placed in service within the first six months following the close of the Test Year. RUCO does not believe that plant placed in service after the close of the test year should be allowed except in very unusual circumstances.

RUCO is not proposing the exclusion of post-test year plant that was placed in service within the first six months after the close of the test year.

Rate Base Adjustment No. 2 – Accumulated Depreciation

RUCO is recommending adjustments to the Company's Accumulated Depreciation for several of the utilities included in this filing. The adjustments are related to RUCO's recommended exclusion of post-test year plant. In addition, RUCO has proposed several adjustments to the Company's depreciation expense calculation for several of the systems in this case, that also has a direct effect on the Accumulated Depreciation balance. Finally, RUCO is proposing adjustments to the CIAC amortization related to Infrastructure Coordination and Financing Agreements ("ICFA's") included in the rate base calculation for the Santa Cruz, Palo Verde and WUGT locations.

Rate Base Adjustment No. 3 – Infrastructure Coordination and Financing Agreements ("ICFA's")

RUCO is recommending several changes in the accounting for the Company ICFA's. RUCO is recommending adjusting the amount of ICFA funds allocated to excess capacity in the Santa Cruz and Palo Verde utility systems and the HUD reduction related to WUGT as a result of updated information obtained during our review of this rate filing.

OPERATING EXPENSE ADJUSTMENTS -- SUMMARY

Q. Can you please explain the adjustments that RUCO is recommending related to the Company's operating revenues and expenses?

A. Yes. RUCO is recommending several adjustments to the Company's test year operating expenses as follows:

Operating Income Adjustment No. 1 - Rate Case Expense

The Company is proposing rate case expense recovery of $787,174 in this rate filing while RUCO is proposing recovery of $419,000.

Operating Income Adjustment No. 2 - Purchased Power Expense

RUCO is recommending reducing the Company's post-test year increase in purchased power costs. RUCO believes that the Company is proposing increases too far removed from the current test year.

Operating Income Adjustment No. 3 - Depreciation Expense

RUCO is proposing a reduction in depreciation expense related directly to post-test year plant. RUCO also identified excessive depreciation calculations in the Santa Cruz water system. Finally, adjustments are made to the Santa Cruz, Palo Verde and WUGT systems amortization expense reflecting the accounting treatment of ICFA fees as CIAC.

Operating Income Adjustment No. 4 – Bad Debt Expense

RUCO is recommending that bad debt expense be adjusted using the same methodology as approved in Decision No. 71878. In that decision the Commission ordered that actual bad debt write-offs are recognized rather than bad debt expense.

Operating Income Adjustment No. 5 – Personnel Expense

RUCO is recommending reducing personnel expense by $381,916. The majority of the reduction relates to deferred stock compensation expense for Company officials.

Operating Income Adjustment No. 6 – Other Miscellaneous Expenses

Several categories' of expenses have been included in the Company's test year's operating expenses that should be the responsibility of shareholders and not ratepayers. Other expense items were noted that should be shared equally between both shareholders and ratepayers.

Operating Income Adjustment No. 7 – Property Taxes

RUCO is proposing adjusting property tax expense based on each location's proposed test year revenues as well as each locations required revenues in going forward to future years. Adjustments are also being made to each location's assessment valuation based on revisions identified in State of Arizona House Bill No. 2001.

Operating Income Adjustment No. 8 – Federal and State Income Tax Expense

Income Tax expenses have been adjusted based on additions to, or deletions from, each utilities taxable income. In addition, a change in State Income Tax calculation has been made based on new tax rates effective for taxable years beginning from and after December 31, 2013 through December 31, 2014.

Operating Income Adjustments Other - Fathom™

RUCO notes that the Company has sold Fathom™ in June, 2013. Although the Company asserts that the sale has no impact on Fathom™ related expenses, RUCO reserves the right to supplement testimony based on the Company's responses to further discovery.

RATE BASE ADJUSTMENT DETAILS

Q. Can you please explain those adjustments to rate base as are being proposed by RUCO?

A. See below for the following adjustments being recommended by RUCO.

Rate Base Adjustment No. 1 – Post-Test Year Plant

Q. Can you please explain the Company's proposed adjustment to rate base and their request to include post-test year plant?

A. Yes. Following is the Company's proposal for inclusion of post-test year plant and RUCO's recommendations for exclusion identified by each utility system:

POST TEST YEAR PLANT

System	Company's Proposal	RUCO'S Recommended Exclusion
Palo Verde	$818,395	$698,584
Santa Cruz	$306,892	$291,762
VWCT	$672,571	$672,570
WUGT	$106,782	$106,783
Willow Valley	$80,436	$80,436
TOTAL	$1,985,076	$1,850,135

Q. Can you please explain the adjustments and the rational for exclusion from rate base?

A. RUCO does not believe that these ordinary routine types of investments in plant assets require extraordinary post-test year treatment. RUCO also opposes these types of post-test year inclusions on the basis that it would violate the basic principles of ratemaking and would result in a mismatch with test year revenues, expenses and rate base.

Q. Has the Commission excluded post-test year plant investments in past rate cases?

A. Yes. In UNS Electric, Inc. ("UNSE") Decision No. 71914 the Commission stated:

> "Pro forma adjustments are defined in Arizona Administrative Code ("A.A.C.") R14-2-103(A)(3)(i) as adjustments to actual test year results and balances to obtain a normal or more realistic relationship between revenues, expenses and rate base."
>
> "We find that UNSE has not demonstrated that these plant investments are anything other than ordinary, routine investments in plant required to be made by a utility to maintain its service and reliability. To allow these post-test year investments into rate base would distort the level of investment needed to provide adequate and reliable service to UNSE's customers during the test year and would not reflect a "normal or more realistic relationship between revenues, expenses and rate base."

Q. Can you briefly discuss those post-test year plant additions that RUCO is proposing to be included in rate base?

A. RUCO generally will accept post-test year additions if the applicable plant assets are placed in service within a six month period following the close of the test year. The majority of the plant additions being requested by Global for inclusion as post-test year plant were completed well beyond the six month period.

Rate Base Adjustment No. 2 – Accumulated Depreciation

Q. Did the Company make adjustments to the accumulated depreciation account related to the inclusion of post-test year plant?

A. No. Depreciation expense adjustments were made to those locations requesting post-test year additions but adjustments were not made for the corresponding accumulated depreciation accounts.

Q. Can you explain the adjustments that are being proposed?

A. Adjustments are being proposed to those three location's that RUCO included ICFA funds as part of CIAC. The accumulated depreciation adjustments by location related to the ICFA funds are Santa Cruz $1,317,459, Palo Verde $1,719,662, and WUGT $1,055,498.

Q. Did you note any differences between the beginning balance of ICFA funds included as CIAC and the Commission approved amounts approved?

A. Yes. In reviewing the beginning balance as approved by the Commission in Decision No. 71878 a difference was noted. The balance as approved for the WUGT in the previous decision was $7,085,645 to be included as CIAC and the Company worksheets provided to us had an initial balance of $4,691,475. RUCO calculated its annual accumulated carryforward balance beginning with the approved balance from the last rate filing.

Q. Can you explain how the amortization expense and related accumulated depreciation was calculated?

A. First, the accumulated amortization related to ICFA funds included as CIAC and approved in Decision No. 71878 was my beginning balance as of December 31, 2008. I then reviewed the Company's updated calculation through the end of the test year, as provided during our on-site review. When making the calculations based on information provided during our review, I then adjusted the accumulated depreciation account for Santa Cruz, Palo Verde and WUGT.

Q. You have referred to both accumulated depreciation and accumulated amortization. What is the correct description in this case?

A. In general, amortization of CIAC is referred to as amortization expense. The Company, in its operating expense accounts, refers to the account as Depreciation Expense – CIAC Amortization.

Q. Have additional adjustments been made to Accumulated Depreciation?

A. Yes. When analyzing each locations calculation of depreciation expense for the test year, several adjustments were made to the Company's calculated depreciation and the depreciation expense as calculated by RUCO.

Rate Base Adjustment No. 3 – Accounting for Infrastructure Coordination and Financing Agreements ("ICFA's) and Discussion of Acquisition Adjustments

Q. Mr. Mease, can you describe ICFA's and how they are used?

A. Yes. I will begin with the description as provided by Company witness Mr. Trevor Hill in his testimony as included in prior Decision No. 71848.

> "An ICFA (Infrastructure Coordination and Financing Agreement), is a voluntary contract between Global Parent and a landowner. These contracts provide for Global Parent to coordinate the planning, financing and construction of off-site water, wastewater and recycled water plant. The Global Utilities will own and operate this plant when construction is complete. Under the ICFA's, Global Parent is responsible for funding both the planning and construction of water, wastewater and recycled water plant. The landowners who enter into the ICFA's agree to cooperate with Global Parent's plant planning and construction process. ICFA's formalize the cooperation between the landowner and Global, but also provide fees which allow Global Parent to impress conservation and consolidation of the carrying costs for the very expensive facilities required to implement effective water conservation and, in some cases, to fund Global Parent's acquisition of existing utilities.

Q. Are there other descriptions of ICFA's that you would like to point out that may have an impact on this rate filing?

A. Yes. I would like to quote Global Water Resources, Inc., Notes to Consolidated Financial Statements, and the description as included in the 2011 Annual Report, page 63.

> "Infrastructure coordination and financing fees – Infrastructure coordination and financing agreements ("ICFA's") are agreements with developers and homebuilders where GWRI provides services to plan, coordinate and finance the water and wastewater infrastructure that would otherwise be required to be performed or subcontracted by the developer or homebuilder."

Q. Based on the description as contained in the annual report, as well as the description provided by Mr. Hill, what is RUCO's position as to the accounting treatment related to ICFA's?

A. Basically, RUCO's believes developer-supplied ICFA funds are third party payments and constitute CIAC. Therefore, ICFA funds should be accounted for the same as all other CIAC payments received by the Company's regulated utility operations.

Q. Can you please describe RUCO's position as well as the other interveners, on the accounting treatment of ICFA's in the last rate application?

A. Yes. As stated in Decision No. 71878, page 13, "Maricopa, RUCO, and Staff contend that for ratemaking purposes, ICFA funds shall be treated as developer-supplied CIAC and imputed to the rate bases of the Utilities affected by ICFA's in these consolidated applications, as recommended by Staff."

Q. Can you please identify the ICFA funds received as of the prior rate case test year filing and how those funds were allocated based in Decision No. 71878?

A. Total ICFA funds received as of the end of the last rate case test year, December 31, 2008 are summarized as follows.

ICFA FUNDS COLLECTED THROUGH DECEMBER 31, 2008

Location	Palo Verde	Santa Cruz	WUGT	TOTAL
ICFA's	$25,441,104	$24,541,418	$9,226,100	$59,208,622
Reclass idle Capacity	(14,449,976)	(17,941,342)	-	(32,391,318)
Reclass to Hassayampa	-	-	(2,140,455)	(2,140,455)
TOTAL INC IN CIAC	$10,991,128	$6,600,076	$7,085,645	$24,676,849
Net of Amortization	$10,323,747	$6,105,227	$6,849,397	$23,278,371

Q. Has the Company received additional ICFA funds since the last rate case?

A. Since the Company's last rate case filing $6,432,558 has been received and identified to the Santa Cruz and Palo Verde utilities and $925,500 has been received and identified to the WUGT utility. In total $66,566,680 has been received by Global Water and classified as ICFA funds.

Q. Can you please explain the reclassifications related to idle capacity in Palo Verde and Santa Cruz and the reclassification to the Hassayampa ("HUD") utility as identified in the WUGT water system?

A. The funds reclassified to idle capacity for Palo Verde and Santa Cruz, relate to plant that is under construction in the southwest area of the service area. It is referred to as the SW Plant by the Company in various data responses in both the prior case, as well as this current rate proceeding. HUD happens to be a wastewater plant under construction in the WMC area and remains as plant not in use. The HUD plant is not part of this rate filing.

Q. Are the details related to the accounting for ICFA's in the last rate case and Commission's Decision No. 71878 related to final accounting for ICFA's important in this case?

A. Yes. The accounting for ICFA's and their inclusion and/or exclusion from CIAC remain as the primary focus in this current rate filing. The same issues remain and the Company has requested the Commission reverse its prior decision imputing ICFA's as CIAC. The Company is not seeking to reverse the Commission's prior decision excluding excess capacity or HUD adjustments. In summary, Global has requested the Commission exclude from rate base all ICFA funds previously imputed as CIAC but is not seeking to reverse the excess capacity and HUD adjustments previously approved in Decision No. 71878.

Q. Has Global Water requested an alternative be considered by the Commission if IFCA's are required to be included as CIAC?

A. Yes. In the event that the Commission will not provide the rate base treatment as the Company has proposed, the Company has requested an "Acquisition Adjustment" be approved which will offset the CIAC. This will be addressed later in my testimony.

Q. Did Decision No. 71878 address additional requirements related to ICFA's?

A. Yes. The decision required the following:

> IT IS FURTHER ORDERED that a generic investigation shall be commenced which looks at how best to achieve the Commission's objectives with regard to encouraging the acquisition of troubled water companies and the development of regional infrastructure where appropriate. As part of this proceeding, the workshop shall address whether ICFA's, or other mechanisms, if properly segregated and accounted for, could be utilized to finance the acquisition of troubled water companies.
>
> IT IS FURTHER ORDERED that Staff shall, within 30 days, provide notice to the parties to the Generic Docket, and to other stakeholders, of new workshops in Docket No W-0000C-06-0149, for stakeholder workshops designed to address the issues set forth in Findings of Fact No. 84 in Decision No. 71878.

Q. Were workshops held to discuss the issue of ICFA's as required in the last order?

A. Yes. Workshops were held in 2010 and 2011 and a report was published by Staff on March 12, 2012.

Q. What was Staff's recommendations and conclusions included in their report published on March 12, 2012 related to monies received pursuant to ICFA's?

A. Staff, in its recommendations stated the following: "That monies received pursuant to Infrastructure Coordination and Financing Agreements ("ICFA's") continue to be treated as Contributions in Aid of Constructions ("CIAC"). This recommendation may be modified as a result of the pending review of Global's ICFA's by an independent Certified Public Accountant firm."[1]

Q. Has the review been completed by the independent Certified Public Accounting Firm ("CPA Firm")?

A. Yes. The review was completed by Ullmann & Company, LLC, a CPA Firm, ("Ullmann") and their report was issued on November 28, 2012.

[1] See Staff report dated March 19, 2012

Q. Based on the report as published, has Staff modified their position on the accounting treatment of ICFA's?

A. No. Staff has not published a modification to their report as originally issued on March 19, 2012.

Q. Do you believe there is some misunderstanding as to the scope of the work that was performed by the CPA firm?

A. Yes. In both Mr. Hill's and Mr. Walker's testimony they refer to the work being performed by the CPA firm as an audit. The actual work performed by the CPA firm was an "Agree Upon Procedures Review."

Q. Is there a significant difference between an audit and a review of procedures?

A. Yes. As stated in the Independent Accountants' report:

> "We were not engaged to, and did not conduct an audit, the objective of which would be the expression of an opinion on the accounting records. Accordingly, we do not express such an opinion. Had we performed additional procedures, other matters might have come to our attention that would have been reported to you."

Q. Does RUCO believe that clarification of the work performed by the CPA Firm related to their review is necessary is this case?

A. Yes. RUCO believes that this clarification is necessary. The work performed in an audit is more detailed and the auditors would express an opinion on the reliability of the information contained in the report. The

scope of an agreed upon procedures review is less detailed and as stated in the Accountants' Report "an opinion cannot be provided."

Q. Why does RUCO believe this clarification is necessary?

A. RUCO believes this clarification is necessary as several readers of the report believe that an audit was performed as evidenced by their testimony. Those individuals who believe that an audit was performed may be putting more reliance on the contents of the auditors' report than is intended.

Q. Has RUCO reviewed the report issued by CPA Firm?

A. Yes. RUCO has obtained a copy of the report.

Q. Does RUCO believe that the review performed by the CPA Firm supports the position that the Company has taken in its accounting treatment related to ICFA's?

A. While the engagement performed by Ullmann was very informative and complete RUCO does not believe that the report and the Agreed Upon Procedures Review that was performed provides additional support for changing the accounting treatment related to ICFA funds. In other words, RUCO believes that ICFA revenue be imputed as CIAC and recorded as a reduction in rate base as was approved in the last rate case.

Q. What about the ICFA funds that the Commission excluded from rate base (idle capacity and HUD) in Decision No 71878.

A. No change is being proposed to the treatment of ICFA's related to the plant identified as "idle capacity" (Santa Cruz, Palo Verde) or the value of HUD excluded from (WUGT).

Q. Can you please explain the adjustment's that are being proposed by RUCO related to ICFA's and their accounting treatment?

A. Yes. RUCO is making the following recommendations for updating Test Year results as identified in the following table:

RUCO'S Proposed Adjustments

Santa Cruz	Through Dec. 2009	Dec. 2009 Dec. 2011	Thru 2011 TOTAL
Allocated to CIAC	$6,600,076	$787,522	$7,387,598
Accumulated Amortization	494,849	822,610	1,317,459
Unamortized CIAC	$6,105,227	N/A	$6,070,139

Palo Verde	Through Dec. 2009	Dec. 2009 Dec. 2011	TOTAL
Allocated to CIAC	$10,991,125	$1,575,044	$12,566,169
Accumulated Amortization	667,381	1,052,281	1,719,622
Unamortized CIAC	$11,658,506	N/A	$10,846,507

Tonopah	Through Dec. 2009	Dec. 2009 Dec. 2011	TOTAL

Allocated to CIAC	$7,085,645	$437,714	$7,523,359
Accumulated Amortization	236,248	819,250	1,055,498
Unamortized CIAC	$6,776,279	N/A	$6,467,861

RUCO is recommending increasing CIAC, less Accumulated Amortization by $6,070,139 in the Santa Cruz utility, $10,846,507 in the Palo Verde utility and the WUGT utility by $6,467,861.

Acquisition Adjustments

Q. Has the Company asked for an acquisition adjustment in this rate case filing in place of ICFS's?

A. In Mr. Walker's testimony he states "In the 2009 rate case we argued that ICFA funds should be used to cover the carrying costs of regional infrastructure and the acquisition premium associated with the purchase of troubled systems. However, the acquisition premiums alone are sufficient to justify a near complete reversal of the CIAC imputations made in the last rate case."[2]

[2] Mr. Walkers testimony pages 1 and 2

Q. Which option is the Company pursuing in this rate case, allowing the ICFA's as a non-CIAC contribution or computing as acquisition adjustment on system purchases?

A. Mr. Walker in his testimony states that "Global believes the first option, no net change to rate base, is the best option for dealing with use of ICFA funds to buy a utility. But if that option is rejected, Global requests that the Commission authorize an acquisition adjustment to recognize the significant public policy and customer benefits of the acquisition." [3]

Q. Have you done any research of how other State Utility Commissions are treating acquisition premiums?

A. Yes. I have done some review on how other Commissions are looking at this issue. I have attached a summary,[4] as prepared by the National Association of Water Companies, identifying some basic details on the subject, how Commission's in other States see acquisition adjustments and what criteria is considered by the respective Commission's. In summary, some states allow adjustments; some will not allow adjustments in any case, however, most Commission's review acquisition adjustments on a case by case basis.

[3] Mr. Walkers testimony page 7
[4] See Exhibit A

Q. Is there a commonality among the states that you would like to highlight?

A. Yes. In those states that will approve an acquisition adjustment certain conditions must exist. For example: (1) The Commission has identified a water or wastewater system as being "distressed or troubled" and is seeking a buyer to purchase that system, (2) If the acquiring utility can demonstrate that the acquisition will provide clear, tangible benefits to the ratepayers in an amount that is at least equal to the acquisition adjustment, (3) If it can be demonstrated that the ratepayers have not previously paid for the systems assets through previously imposed rates, (4) That the purchase was "Prudent" and the buyer exercised good judgment and common sense, (5) The amount of the acquisition premium is reasonable, (6) The transaction must be an "arm's length" transaction.

Q. Does RUCO believe these condition(s) must exist prior to their recommending an acquisition adjustment?

A. Yes. RUCO believes that one or all of these conditions, depending on the situation, should exist prior to the Commission approving an acquisition adjustment. I believe that the lacking of any of the conditions could negate the approval of an adjustment.

Q. Can you please discuss the details of the company's purchase of the West Maricopa Combine Inc. ("WMC")?

A. WMC was acquired on July 11, 2006, through a stock acquisition for a purchase price of $60,000,000. Through arbitration the price was negotiated downward and the final negotiated price was $54,369,889. The final agreed upon purchase price included a $45,300,326 acquisition price, $8,699,674 imputed interest and $369,889 in stated interest. The WMC consists of VWCT, WUNS, WUGT, VWCGB and Willow Valley.

Q. Does RUCO believe that the acquisition of the WMC warrants an acquisition premium?

A. No, an acquisition premium should not be approved for the purchase of the WMC for the following reasons:

1. There was no indication in documentation provided that any of the five systems included in the WMC were identified as "troubled Systems." During the due diligence phase prior to purchase the Company's Vice President of Operations issued a letter identifying several deficiencies in the operational aspects of each system. However, in his final conclusions he states:

> "The initial due diligence period has identified many issues that are germane to the on-going operations of the WMC utilities. While these are cause for concern going forward, and will certainly require careful consideration by Global management and staff, they do not in and of themselves constitute any fatal flaw for the acquisition. The WMC acquisition

> represents a strategic deployment of the Global methodologies to the west valley – an area where the growth is just beginning. It is recommended that the acquisition continue to be pursued."

2. When reviewing the financial statements of the WMC for the year ending December 31, 2005, the last year-end prior to Global's acquisition, the Company had a positive cash flow, had made significant investments in plant during the year, had positive income and overall appeared to be financially stable. There was no indication from the financial statements that the WMC was in financial difficulties of any kind.

3. Global calculated the purchase price based on expected growth in the West Valley. More specifically, in their due diligence documentation the Company was expecting the WMC to increase in customers from 5,021 at the end of year 2005 to 23,300 by the end of year 2011 and assumed the risk that the growth would occur. The actual number of customers at the end of year 2011 was 5,343. The Company anticipated growth that just didn't materialize and now the Company seeks to pass that risk on to ratepayers. RUCO does not believe it should be the responsibility of the ratepayer to pay for the Company's overly optimistic growth expectations.

4. The total book value of the plant at the date of purchase was $12,771,723 and the book value minus AIAC was ($5,005,082).[5] As identified in the audited financial statements for the year ending December 31, 2006, the net assets acquired were $49,476,000 and included $45,809,111 identified as Goodwill.[6] Based on the financial data as presented you would have to question whether the purchase of the WMC was a prudent investment and was the purchase price reasonable.

Q. Does RUCO believe that the acquisition of the Sonoran system warrants an acquisition premium?

A. Conditions existed at the time of purchasing the Sonoran system that the Company agrues that an acquisition premium could be allowed. For example, according to testimony provided by Mr. Ron Fleming, Global Water's General Manager, Arizona, when asked what happened when Sonoran and the 387 Districts were not able to provide service, he stated,

> "At the time, Global's utilities (Santa Cruz and Palo Verde) were the closest utilities and were in a position to assist, in numerous locations we actually had parallel infrastructure in the same area. The City of Maricopa, ADEQ and ADWR ask Santa Cruz and Palo Verde to take over service on an emergency basis."[7]

[5] Ullman Report dated November 28, 2012.
[6] Audited Financial Statements prepared by Deloitte & Touche LLP, Page No. 13
[7] Mr. Ron Flemings testimony pages 2 and 3

Q. Can you please discuss the details of the company's purchase of the Sonoran and the 387 Districts?

A. The Company completed the purchase of the assets of Sonoran on June 15, 2005 with an effective purchase date of March 31, 2005. The Sonoran system was a private system and not regulated by the Commission. Santa Cruz and Palo Verde filed an application to extend their CC&N application to cover the former 387 areas. The initial application requesting the extension was filed on June 30, 2005, and the CC&N was ultimately granted on September 30, 2008 in Decision No. 70533. The purchase price of the Sonoran system was $18,550,000 and the book value of the plant assets at time of acquisition was $1,085,451. The book value minus AIAC was $213,594.[8]

Q. Does RUCO believe that an acquisition adjustment is warranted in the purchase of the Sonoran system?

A. No. RUCO does not believe an adjustment is warranted. Based on the financial data as presented the purchase price paid for the Sonoran system was excessive and it is not a reasonable request to ask the ratepayers to pay for Company mistakes.

[8]Ullmann Report dated November 28, 2012

Q. Would RUCO be open to consider an acquisition adjustment under certain circumstances?

A. Yes. As RUCO has testified earlier acquisition adjustment should be evaluated on a case by case basis. If the circumstances warrant that the Commission may determine that an acquisition premium is appropriate.

OPERATING INCOME ADJUSTMENTS

Q. Is RUCO recommending changes to the Company's proposed Test Year operating revenues and expenses for the utilities included in this rate filing?

A. Yes. The Company proposed numerous adjustments to its historical test year operating income. RUCO analyzed the Company's adjustments and proposed several changes. In addition, RUCO is recommending additional adjustments based on data requests provided by Global Water. RUCO's adjustments to operating income are explained as follows

Operating Income Adjustment No. 1 – Rate Case Expense

Q. Please explain your adjustment to Rate Case Expense.

A. The Company has proposed recovery of $787,174 for rate case expenses for outside services and requests to amortize this expense over a three year period. RUCO believes the Company's proposed rate case expense is excessive, and should be reduced significantly, when compared with rate case expense in prior rate case submissions that have been

approved by the Commission. RUCO proposes a rate case expense recovery of $419,000 and continue to be amortized over a three year period as is consistent with the Company's filing.

Q. Can you please identify the rate case expense being requested by the Company and RUCO's recommendation by utility system?

A. Yes. The following table identifies rate case expense by system. The expense is allocated to each system in proportion to its revenue.

Location	Company Proposed	RUCO Proposed	Proposed Adjustment
Palo Verde	$313,756	$167,068	$146,688
Santa Cruz	$317,403	$156,729	$160,674
VWCT	$105,894	$72,327	$33,567
WUGT	$6,420	$3,144	$3,276
Willow Valley	$29,769	$10,500	$19,269
VWCGB	$12,426	$7,020	$5,406
WUNS	$1,506	$2,212	($706)
TOTAL	$787,174	$419,000	$368,174

Q. How did RUCO determine its recommended level of rate case expense?

A. The Commission approved $400,000 in rate case expense recovery in Decision No. 71878, the Company's last rate case filing. The major issues identified in the current filing are basically the same and the additional

recovery is not justified. RUCO's recommended rate case expense recovery was calculated by increasing the last approved amount of $400,000 and applying the accumulated inflation factor of 4.75%, as reported by the Consumer Price Index.

Q. Are there other reasons that rate case expense should be reduced?

A. The Company began accruing expenses related to rate case expense for approximately two years prior to the rate case filing. Approximately 53 percent of the expense that the Company is seeking recovery relate to activities that could be considered outside services unrelated to rate case activities. By excluding these expenses from the total expense the Company is requesting, approximately $419,000 remains as identified direct rate case expense.

Operating Income Adjustment No. 2 – Purchased Power

Q. Can you please identify those systems that RUCO is proposing an adjustment to purchased power expense?

A. RUCO is proposing a reduction in test year purchased power expense as follows:

PURCHASED POWER PROPOSED REDUCTIONS

VWCT	$62,786	VWCGB	$2,881
WUGT	$2,562	Willow Valley	$1,582

Q. What is RUCO's rational for reducing purchased power costs for these locations?

A. The Company is proposing to include the total of three years increases in test year adjustments for each location. While RUCO believes that increase's for known and measurable changes are acceptable projecting forward for a three year period is inappropriate.

Operating Income Adjustment No. 3 – Depreciation/Amortization Expense

Q. Can you please explain the adjustments that RUCO is recommending to the Company's filing as it relates to depreciation and amortization expense?

A. Yes. RUCO is proposing adjustments to depreciation/amortization expense related to changes in the Company's depreciation calculation for several of the utilities as well as amortizat ion expense related to the inclusion of ICFA's fees as CIAC for the Santa Cruz, Palo Verde and WUGT.

Q. How did you calculate the amortization that is being included in test year depreciation expense related to the ICFA fees that you included as CIAC?

A. RUCO reviewed the amortization expense schedules for the Palo Verde and Santa Cruz utilities as provided to us during our on-site review. The carried forward balances were correct from Decision No. 71878 and was

our beginning point. The calculations related to test year amortization for these two locations appeared to be correct and we then included the calculated expense for both systems as our test year adjustment.

Operating Income Adjustment No. 4 – Bad Debt Expense

Q. Can you please identify the adjustments that RUCO is proposing for the Company's bad debt expense accounts?

A. RUCO is proposing reductions to the utility systems as follows:

BAD DEBT EXPENSE

Palo Verde	$11,624	Willow Valley	3,821
Santa Cruz	$19,433	VWCGB	6,490
VWCT	$6,426	WUNS	2,281
WUGT	$1,018		

Q. Why is RUCO proposing this adjustment?

A. The Company calculates bad debt expense as a percentage of revenues and is included in test year operating expenses. In Decision No. 71878 the Commission ruled that **actual** bad debt write-offs were to be recognized as bad debt expense as opposed to the estimated expense calculation.[9]

[9] Decision No. 71878 page 34

Operating Income Adjustment No. 5 – Personnel Expense

Q. Has RUCO recommended adjusting operating expense accounts related to personnel expenses?

A. RUCO is recommending adjustments related to the following operating expense accounts.

PERSONNEL EXPENSES TO BE ADJUSTED

Location	Company Proposed	RUCO Adjustment	RUCO Proposed
Overtime Hours	$95,796	$47,898	$47,898
Bonuses Operation	$1,160	$580	$580
Deferred Compensation	$293,306	$293,306	$0
Employee Moving	$80,264	$40,132	$40,132
TOTAL	$470,526	$381,916	$88,610

Q Can you please identify your proposed adjustment by utility?

A. The adjustment of $381,916 by utility system is as follows:

ADJUSTMENT BY SYSTEM

Palo Verde	$152,280	Willow Valley	$9,571
Santa Cruz	$142,858	VWCGB	$6,397
VWCT	$65,926	WUNS	$2,018
WUGT	$2,865		

Q. Can you explain the adjustments proposed for personnel expense?

A. The majority of the reduction relates to deferred stock compensation expense for Company officials. RUCO does not believe that "Bonuses" for Company officials should be paid for by ratepayers. The remaining expenses, overtime hours, bonuses, and moving expense also relate to expenses that are typically excluded from test year since quite often they vary in value from year to year and in many cases are not recurring type expenses. RUCO has allowed fifty percent of these expenses and excluded the remaining fifty percent.

Operating Income Adjustment No. 6 – Miscellaneous Operating Expense

Q. Can you please identify the miscellaneous expenses that RUCO is recommending be adjusted?

A. Yes. RUCO is recommending that the following expenses classified as miscellaneous, totaling $462,793 be deducted from test year expenses.

MISCELLANEOUS EXPENSES TO BE ADJUSTED

Expense Account	Company Proposed	Expense Acount	Company Proposed
Investor Relations	$57,595	Travel & Entertainment	$74,400
Charitable Contributions	$6,268	Meals	$42,101
Dues and Subscriptions	$43,011	Business Development	$26,161
Promotions $ Advertising	$28,763	Sales Tax Late Fee	$1,636
Employee Relations	$32,955	Professional Fees Other	$94,713
Board Compensation	$26,396	Other Compensation	$28,794

Q. Can you please further identify the adjustments by utility system?

A. Yes. The adjustments are as follows:

ADJUSTMENTS BY SYSTEM

Palo Verde	$164,977	Willow Valley	$26,087
Santa Cruz	$194,371	VWCGB	$6,831
VWCT	$64,729	WUNS	$1,858
WUGT	$3,940		

Q. Why does RUCO believe that these miscellaneous expenses should be excluded from the Company's rate filing?

A. RUCO believes that these expenses are more appropriately the types of expenses that should be paid for by the shareholders. More specifically, expenses such as Board Compensation, Investor Relations, Travel and Entertainment, Meals, Business Development, and Sales Tax Late Fees provide no benefit to the ratepayer. Expenses such as Publications and dues are being allocated evenly at 50 percent to the shareholder and ratepayer.

Operating Income Adjustment No. 7 – Property Tax Expense

Q. Did RUCO review the Company's property tax calculations for each of the utilities included in this filing?

A. Yes. RUCO reviewed he calculation and made several adjustment.

Q. Can you please elaborate on your review and identify any adjustments made?

A. Property tax adjustments were made on each of the utilities included in this filing based on adjusted test year revenues and recommended revenues in going forward. We also made an adjustment on each location based on State of Arizona House Bill 2011. As identified in this House Bill section 42-15001

> "The assessed valuation of class one property is the following percentage of its full cash value as

applicable, No. 9 "NINETEEN PER CENT BEGINNING FROM AND AFTER DECEMBER 31, 2013 THROUGH DECEMBER 31, 2014."

RUCO is recommending the following adjustments, by utility, based on the revised assessed valuations as identified in this Bill.

Q. Can you please identify the property tax expense adjustments that RUCO is recommending in this filing?

A. Yes. Following are the adjustments as being proposed?

PROPERTY TAX EXPENSE

Location	Company Proposed	RUCO Proposed	RUCO Adjustment
Palo Verde	$1,064,073	$962,732	($101,341)
Santa Cruz	897,129	811,688	(85,441)
VWCT	273,680	246,830	(26,850)
WUGT	11,254	10,183	(1,071)
Willow Valley	33,931	30,700	(3,231)
VWCGB	11,663	10,552	(1,111)
WUNS	3,104	7,301	4,197
TOTAL	$2,294,834	$2,079,986	($214,848)

Operating Income Adjustment No. 8 – Income Tax Expense

Q. Has RUCO made an adjustment to Income Tax Expense as filed by the Company?

A. Yes. RUCO has adjusted income tax expense based upon the methodology that is used in all rate applications reviewed by RUCO.

Q. Can you explain the method utilized in calculating income tax expense both for the test year adjustment as well as the method used in calculating the tax effects of proposed revenue adjustments?

A. When calculating Federal income tax expense for rate making purposes RUCO begins with operating income before taxes and from that amount will deduct Arizona income taxes due and interest synchronization. (Interest synchronization is calculated as follows: Adjusted ACC Jurisdictional Rate Base X Weighted Cost of Debt) The two results, Arizona income taxes and interest synchronization, are multiplied by the statutory Federal Income Tax Rate. In this case RUCO has used 34 percent as the statutory Federal Income Tax Rate.

Q. Has RUCO made any adjustments related to statutory income tax rates?

A. Yes. A change in State Income Tax calculation has been made based on new tax rates effective for taxable years beginning from and after

December 31, 2013 through December 31, 2014. The State Income Tax rate has been reduced from 6.969% to 6.5%.

Q. Can you please identify the income tax expense adjustments that RUCO is recommending in this filing?

A. Yes. Following are the adjustments as being proposed?

INCOME TAX EXPENSE

Location	Company Proposed	RUCO Proposed	RUCO Adjustment
Palo Verde	$682,693	$844,141	$161,448
Santa Cruz	98,898	277,849	178,950
VWCT	(249,144)	(2,468)	246,676
WUGT	(197,785)	(310,193)	66,548
Willow Valley	(106,730)	(36,509)	70,221
VWCGB	5,781	18,333	12,552
WUNS	13,391	7,302	(6,089)
TOTAL	$247,104	$798,455	$730,306

Q. Does this conclude your testimony?

A. Yes.

ROBERT B. MEASE, CPA
Education and Professional Qualifications

EDUCATION

Bachelors Degree Business Administration / Accounting - Morris Harvey College.

Attended West Virginia School of Graduate Studies and studied Accounting and Public Administration

Attended numerous courses and seminars for Continuing Professional Educational purposes.

WORK EXPERIENCE

Controller
Knives of Alaska, Inc., Diamond Blade, LLC., and Alaska Expedition Company.

Financial Manager / CFO
All Saints Camp & Conference Center

Energy West, Inc.
Vice President, Controller

- Led team that succeeded in obtaining a $1.5 million annual utility rate increase
- Coached accountants for proper communication techniques with Public Service Commission, supervised 9 professional accountants
- Developed financial models used to negotiate an $18 million credit line
- Responsible for monthly, quarterly and annual financial statements for internal and external purposes, SEC filings on a quarterly and annual basis, quarterly presentations to Board of Directors and shareholders during annual meetings, coordinated annual audit
- Communication with senior management team, supervised accounting staff and resolved all accounting issues, reviewed expenditures related to capital projects
- Monitored natural gas prices and worked with senior buyers to ensure optimal price obtained

Junkermier, Clark, Campanella, Stevens
Consulting Staff

- Established a consulting practice that generated approximately $160k the first year of existence
- Prepared business plan and projections for inclusion in clients financing documents
- Prepared written reports related to consulting engagements performed
- Developed models used in financing documents and made available for other personnel to use
- Performed Profit Enhancement engagements
- Participated during audit of large manufacturing client for two reporting years

Prior to 1999, held various positions: TMC Sales, Inc. as **Vice President / Controller**, with American Agri-Technology Corporation as **Vice President / CFO** and with Union Carbide Corporation as **Accounting Manager. (Union Carbide was a multi-national Fortune 500 Company that was purchased by Dow Chemical)**

PROFESSIONAL AFFILIATIONS
Member - Institute of Management Accountants
Member - American Institute of CPA's
Past Member –WV Society of CPA's and Montana Society of CPA's

RESUME OF RATE CASE AND REGULATORY PARTICIPATION WITH RUCO

Utility Company	Docket No.
Arizona Water Company (Eastern Group)	W-01445A-11-0310
Pima Utility Company	W-02199A-11-0329 et al.
Tucson Electric Power Company	E-01933A-12-0291
Arizona Water Company	W-01445A-12-0348
UNS Electric	E-04204A-12-0504

EXHIBIT 1

STATE	ACQUISITION ADJUSTMENT
Alabama	The Commission regulates the rates of eight small water companies. There is no specific statutory authority dealing with water company acquisition adjustments. However, in ***Re Mobile Gas Service Corporation,* 2003 WL 23101066 (Ala. P.S.C. Oct. 9, 2003)**, the Commission relied on prior precedent to find that a positive acquisition adjustment would be allowed in rate base where the following principal criteria are satisfied: (1) the purchase price was the result of arm's length negotiations; (2) the acquisition would produce operational efficiencies; and (3) the acquisition would promote the integration of facilities.
Alaska	***In the Matter of Alaska Power Co. Application*, No. U-01-98, Order No. 1 (R.C.A. Feb. 25, 2002)**("The Commissio has interpreted this statute [AS 42.05.441(b)] to permit recovery of an acquisition adjustment if the utility demonstrate that the acquisition will provide clear, tangible benefits to ratepayers in an amount at least equal to the acquisition adjustment. However, the Commission has interpreted this rule narrowly and has refused to permit acquisition adjustments in many cases.").
Arizona	***In the Matter of the Joint Application of Citizens Utilities Company, et. al*, Decision No. 63584 (A.C.C. Apr. 24, 2001)** ("Arizona-American is cautioned that the Commission will require Arizona-American to demonstrate that clear quantifiable and substantial net benefits to ratepayers have resulted from the acquisition of Citizens' systems that would not have been realized had the transaction not occurred before the Commission will consider recovery of any acquisition adjustment in a future rate proceeding.").
Arkansas	**Ark. Code Ann. § 23-4-111 (2008)**(Commission will use net book value unless adjustment warranted after consideration of factors such as the reasonableness of original cost and whether customers will receive known and measurable benefits at least equal to the incremental amount sought to be recovered.).

California	**Cal. Pub. Util. Code § 2720 (2008)**(Commission will use fair market value to establish the rate base value of a distribution system of a public water system acquired by a water corporation. If fair market value exceeds reproduction cost, difference may be included in rate base if commission determines additional amount is fair and reasonable.). ***Application of Citizens Utilities Co. of California (U-87-W), a California Corp., and California-American Water Company, a California Corp.,* Decision 01-09-057 (Cal. P.U.C. Sept. 20, 2001)** (approving alternative sharing program, compliant with § 2720, whereby realized synergies go first to acquiring company to amortize acquisition premium, and second to customers and company in a 90%/10% split).
Colorado	No general policy has been established for dealing with water company acquisition adjustments. Commission staff was unable to recall any requests for acquisition adjustments by water companies. In other sectors, acquisition adjustments are considered on a case-by-case basis.
Connecticut	**Conn. Gen. Stat. § 16-262o, § 16-262s (2008)** (all reasonable costs of the acquisition of troubled or economically nor viable water systems may be recovered in rates).
Delaware	***Re Tidewater Water Supply Co., Inc.,* 2000 WL 33121630 (Del. P.S.C. Nov. 21, 2000)** (Commission has an "established practice of not allowing rate base recognition of premiums over net book value paid by an acquirer of a utility," barring exceptional circumstances).
District of Columbia	***PRIVATE WATER SYSTEMS NOT REGULATED***
Florida	**Fla. Admin. Code 25-30.0371 (2008)** (positive acquisition adjustment not allowed in rate base absent extraordinary circumstances; negative acquisition adjustments recognized under certain circumstances).
Georgia	***PRIVATE WATER SYSTEMS NOT REGULATED***

Hawaii	The Commission has consistently disallowed the recovery of any acquisition adjustments from customers, but evaluates requests on a case-by-case basis. ***In the Matter of the Application of Citizens Communications Company, Kauai Electric Div. and Kauai Island Utility Co-op*, Docket No. 02-0060, Order No. 19658 (Haw. P.U.C. Sept. 17, 2002)** (approving stipulation which included the following condition: "Applicants acknowledge the commission's policy to not allow recovery from utility customers of goodwill or acquisition premium amounts arising from utility merger and acquisition transactions. In accordance with this policy, [acquiring company] will not seek rate recovery of any goodwill amortization, acquisition premium costs or goodwill impairment changes . . . in future rate proceedings.").
Idaho	***Re United Water Idaho Inc.*, 187 P.U.R.4th 312 (1998)** (approving an acquisition adjustment to the rate base "based on its findings that the acquisition benefits customers as well as its conclusion that the purchase price was fair and reasonable and arrived at through arms-length negotiation.").
	***Re Resort Water Co., Inc.*, 2005 WL 673648 (Idaho P.U.C. Mar. 15, 2005)** ("It has been a consistent policy of the Commission that rate base not include the purchase price of a water system unless it could be reasonably shown that the customers have not previously paid for the water system assets . . . the amount to be included in rate base as an acquisition adjustment must be determined on a case-by-case basis").
Illinois	***Re Consumers Illinois Water Co.*, 2003 WL 21108549 (Ill. C.C. Mar. 18, 2003)** (traditional practice of Commission is to require that acquisition adjustment be recorded below the line; however, under unique circumstances, ICC will include it in rate base).

Indiana	***City of Ft. Wayne v. Util. Center, Inc., d/b/a/ Aquasource*, 840 N.E.2d 836 (Ind. Ct. App. 2006)** (affirming Commission finding that, based on new owner's efforts to remedy problems at troubled utility and arms-length transaction, a return on the acquisition adjustment should be allowed). ***Re Indiana-American Water Co., Inc.* 238 P.U.R. 4th 428 (2004)** ("[G]ranting a return on an acquisition adjustment but no return of an acquisition adjustment is consistent with past practice of this Commission." The acquisition was found to have "resulted in cost savings in excess of the cost of capital investment needed to make those savings possible. . .".). ***Re Lincoln Util., Inc.,* 2006 WL 452338 (Ind. U.R.C. Jan. 25, 2006)** (order authorizing water company to earn a return on acquisition adjustment). ***Re Indiana-American Water Co., Inc.* 2002 WL 32091039 (Ind. U.R.C. Nov. 6, 2002)** ("It is the established policy of this Commission to allow an acquisition adjustment in rates in only two events, namely: 1. As a result of the acquisition, are there significant and demonstrable benefits flowing to the ratepayers, e.g. better service and/or lower rates? 2. Does the acquisition result in correction or salvage of an entity identified by this Commission as a 'troubled' utility?").
Iowa	***Office of Consumer Advocate v. Iowa Util. Bd.*, 454 N.W.2d 883, 113 P.U.R.4th 479 (Iowa 1990)** ("According to prior board precedent, the acquisition amount may be included in the rate base if actual benefits to customers are established by the utility.").
Kansas	The State Corporation Commission regulates a few very small water companies. There is no specific authority dealin with water company acquisition adjustments. However, in the gas and electric sectors, the Commission limits recover of an acquisition premium to an amount that reflects the realistic level of savings that the Commission believes can be achieved by the merged company. ***See In the Matter of the Application of Kansas City Power & Light Co. for approval of its acquisition of all classes of the capital stock of Kansas Gas and Electric*, Docket Nos. 172, 745-U; 174, 155-D (Kan. S.C.C. Nov. 14, 1991).**
Kentucky	***Re Kentucky-American Water Co.,* 2005 WL 578209 (Ky. P.S.C. Feb. 28, 2005)** ("[T]he net original cost of plant devoted to utility use is the fair value for rate-making purposes, unless the utility can prove, with conclusive evidence, that the overall operations and financial condition of the utility have benefited from acquisitions at prices in excess of net book value. Any utility seeking recovery of an acquisition adjustment must justify its purchase decision based on economic and quality of service criteria.")(internal quotations omitted).

Louisiana	No information available.
Maine	As a general matter, acquisition adjustments are not allowed, but requests will be evaluated on a case-by-case basis. Commission staff was unable to recall any requests for acquisition adjustments by water companies in the past decade ***Re Terms and Conditions of Edmund J. Quirion*, 1995 WL 785875 (Me. P.U.C. Nov. 14, 1995)** ("We note that this Commission's general policy has been to use the original cost minus depreciation as the proper method of determining the value of utility property. However, there may be circumstances under which acquisition cost might be considered.").
Maryland	As a general matter, if sufficient customer benefits are shown the Commission may allow an acquisition adjustment and amortize it over several years. Commission staff noted requests for acquisition adjustments by water companies are rare. ***Re Greenridge Utilities, Inc.*, 1997 WL 998596 (Md. P.S.C. June 4, 1997)** ("The decision to allow inclusion of the acquisition adjustment in the Company's rate base is predicated upon consideration of whether such inclusion provide a benefit to the ratepayers.").
Massachusetts	***Guidelines and Standards for Acquisitions and Mergers*, D.P.U. 93-167-A at 6-7, 18-19 (1994)** (Companies may use savings that result from mergers and acquisitions to offset acquisition premiums and related transaction costs, based on a balancing of the benefits arising from the merger with the costs associated with the merger). Commission staff noted that a showing of savings must be made at the time of the acquisition, and not be based on generalized statements about potential merger benefits. While the policy has been focused on gas and electric company merger and acquisition activity, the precedents in ***Guidelines and Standards for Acquisitions and Mergers*** could potentially be applied to water companies.
Michigan	***PRIVATE WATER SYSTEMS NOT REGULATED***
Minnesota	***PRIVATE WATER SYSTEMS NOT REGULATED***
Mississippi	***State of Miss. v. Miss. Pub. Serv. Comm'n*, 435 So.2d 608 (Miss. 1983)** ("...public utilities' amortization of acquisition adjustment is a proper component of cost of service and should be included as a proper operating expense

	when proven by the utility to be beneficial.").
Missouri	**Mo. Rev. Stat. § 393.146(11) (2008)** "If the commission orders the acquisition of a small water or sewer corporation, the commission shall authorize the acquiring capable public utility to utilize the commission's small company rate case procedure for establishing the rates to be applicable to the system being acquired. Such rates may be designed to recover the costs of operating the acquired system and to recover one hundred percent of the revenues necessary to provide a net after-tax return on the ratemaking rate base value of the small water or sewer corporation's facilities acquired by the capable public utility, and the ratemaking rate base value of any improvements made to the facilities by the acquiring capable public utility subsequent to the acquisition, at a rate of return equivalent to one hundred basis points above the rate of return authorized for the acquiring capable public utility in its last general rate proceeding. ***Re Alliance Gas Energy Corp.*, 2008 WL 320768 (Mo. P.S.C. Feb. 5, 2008)** (observing that "there are strong precedents against allowing acquisition premiums to be reflected in rates when the assets are purchased at more than book value. For example, the Commission has stated that it will not require a company to write down its rate base when the assets are sold at less than book value."). ***Re UtiliCorp United Inc.*, 2004 WL 431561 (Mo. P.S.C. Feb. 26, 2004)** ("Missouri has traditionally applied the net original cost standard when considering the ratemaking treatment of acquisition adjustments. That means that the purchasing utility has not been allowed to recover an acquisition premium from its ratepayers. But it also means that ratepayers do not receive lower rates through a decreased rate base when the utility receives a negative acquisition adjustment.").

Montana	**Mont. Code Ann. § 69-3-109. Ascertaining property values.** "The commission may, in its discretion, investigate and ascertain the value of the property of each public utility actually used and useful for the convenience of the public. The commission is not bound to accept or use any particula value in determining rates. However, if any value is used, the value may not exceed the original cost of the property, except that the commission may include all or some of an acquisition adjustment for certain property purchased by a public utility in the purchasing utility's rate base if the transfer of the property to the purchasing utility is in the public interest." ***Re NorthWestern Corp.*, 259 P.U.R.4th 493 (2007)** ("It is a long held regulatory principle of this Commission that th value of plant in rate base is determined by original cost less depreciation. Original cost of utility property is determined when the asset is first dedicated to public service. The action of selling a utility, absent any compelling reason, is not sufficient to allow an adjustment in rate base to reflect acquisition costs.").
Nebraska	No general policy has been established for dealing with water company acquisition adjustments. Commission staff was unable to recall any requests for acquisition adjustments by water companies. In other areas, the Commission sometimes allows acquisition adjustments.
Nevada	The Commission includes the original cost of the acquired system in rate base and does not recognize acquisition adjustments.
New Hampshire	***Re Lakes Region Water Co., Inc.*, 2004 WL 3457746 (N.H. P.U.C. Sept. 23, 2004)** (after noting commission's longstanding practice of not allowing recovery in excess of original cost, PUC ordered water company to book purchase price in excess of net book value as an acquisition adjustment so that it was not reflected in future customer rates).
New Jersey	No general policy has been established for dealing with water company acquisition adjustments but the Commission rarely grants acquisition adjustments and will require that a benefit to existing customers be shown by the requesting utility. ***Re Consumers New Jersey Water Company*, 1995 WL 592835 (N.J.B.P.U. Sept. 20, 1995)**(adopting stipulation where given the "special and unique" circumstance of proven benefits of the acquisition to customers, company woul be allowed an acquisition adjustment in next rate base by amortizing adjustment over a period of years and including the unamortized portion into rate base).

New Mexico	***In the Matter of the Petition By New Mexico-American Water Company, Inc. to Change Its Service Rates,*** **Case Nc 2202 (N.M. P.S.C. Dec. 28, 1988)** (order approving stipulation that excluded the acquisition adjustment from the rate base and its amortization from the cost of service - acquired assets would be treated as if transferred at original cost.). Commission staff noted that general policy is to not allow an acquisition adjustment unless net benefit to customers is proven.
New York	***Proceeding on Motion of the Commission to Establish a Policy to Provide Incentives for the Acquisition and Merger of Small Water Utilities,*** **Case No. 93-W-0962 (N.Y. P.S.C. Aug. 8, 1994)** (established guidelines for acquisition of small water companies whereby, if certain customer benefits are shown, Commission may provide incentives such as inclusion of acquisition adjustment in rate base (if purchase price greater than acquired company rate base) or inclusion of acquired company rate base (if purchased for less than rate base)). ***Joint Petition of United Waterworks Inc. and South County Services Co., Inc. for Permission for United Waterworks to Acquire the Stock of South County Water Corp.,*** **Case No. 02-W-0949 (N.Y. P.S.C. May 21, 2004)** (citing to policy on acquisition of small water utilities, allowed acquiring company to include book value of stocks in rates instead of lower purchase price). ***Joint Petition of Aqua New York, Inc., f/k/a Kingsvale Water Co., Inc., and New York Water Service Corp.,*** **Case No. 06-W-0700 (N.Y. P.S.C. Dec. 20, 2006)** (the full amount of purchase premium treated as goodwill (not recoverable in rates) where acquisition was not of a small water utility).
North Carolina	***In the Matter of Petition of Utilities, Inc.,*** **147 N.C. App. 182, 555 S.E.2d 333 (2001)** (affirming Commission approach whereby it would refrain from allowing rate base treatment of an acquisition adjustment unless the purchasing utility established by the greater weight of the evidence that the purchase price was prudent and that both the existing customers of the acquiring utility and the customers of the acquired utility would be better off (or at least no worse off) with the proposed transfer, taking into consideration rate base treatment of any acquisition adjustment).
North Dakota	***PRIVATE WATER SYSTEMS NOT REGULATED***
Ohio	The Commission includes the original cost of the acquired system in rate base and does not allow acquisition adjustments. ***Re Dayton Power and Light Co.,*** **21 P.U.R.4th 376 (Oh. P.U.C. 1977)** (proposed acquisition adjustmer should "clearly" be excluded from rate base given state's use of original cost.).

Oklahoma	Acquisition adjustments are not allowed in rate base absent extraordinary circumstances, although requests are evaluated on a case-by-case basis. Commission staff did not recall any recent requests for acquisition adjustments by water companies.
Oregon	**Or. Admin. R. 860-036-0716 (2008)** (water utility may petition Commission for approval of acquisition adjustment ii rates where benefits of acquisition outweigh the increase to customers' rates resulting from acquisition).
Pennsylvania	**66 Pa. C.S.A. § 1327 (2008)** (positive acquisition adjustments allowed under identified circumstances where small, troubled or non-viable water systems are acquired and improved; negative acquisition adjustments must be amortized to utility operating income unless, in the Commission's discretion, the public interest would not be served by doing so).
Rhode Island	Acquisition adjustments are generally not allowed, although they are evaluated on a case-by-case basis. Cost savings or other extraordinary circumstances may justify an acquisition adjustment. Commission staff did not to recall any requests for acquisition adjustments by water companies in the past decade. ***In re: Petition of Valley Gas Co., Bristoi and Warren Gas Co. and Southern Union Company for Approval of Mergers*, Docket Nos. D-00-02, D-00-03 (R.I. P.U.C. July 24, 2000)** (order approving a settlement agreement which contained the following term : "The Settling Parties agree that the Companies will not seek direct or indirect recovery of any acquisition premium in rates either through an amortization or rate base adjustment in future rate cases . . .".).
South Carolina	***Re Georgia Water & Well Serv., Inc.*, 233 P.U.R.4th 482 (2004)** ("If a regulatory agency determines that the cost wa reasonable and beneficial to the customers, an above-the-line expense could be allowed as an Amortization of Utility Acquisition Adjustments." However, "[t]he prevailing rule relating to the acquisition of utility plant previously used ii a regulated business is that the plant must continue to be recorded at the depreciated original cost to the first owner devoting the property to public service.").
South Dakota	***PRIVATE WATER SYSTEMS NOT REGULATED***
Tennessee	The Authority does not have a general policy on acquisition adjustments. Generally speaking, the purchase of utility plant previously used in providing utility service is recorded on the acquiring company's books at original cost, net of accumulated depreciation. Exceptions would be considered only if the price above the seller's original cost was clearl in the public interest and would be addressed on a case-by-case basis.

Texas	**30 Tex. Admin Code § 291.31(d) (2008)**(positive acquisition adjustment allowed under identified circumstances).
Utah	Commission Staff stated that, in general, when the acquired asset is already a utility asset, the book value goes into rat base. When the acquired asset was not previously a utility asset, the purchase price goes in to the rate base. ***Re Utah Power and Light Co.*, 53 P.U.R.4th 461 (Ut. P.S.C. May 23, 1983)** ("The commission agrees that in the context of acquiring assets already dedicated to the providing of public service the general rule for determining the value of such acquired property for rate-making purposes is depreciated book value . . .The commission also recognizes, however, that there may be exceptions to this general rule should sufficient benefits accrue to the acquiring public utility and its ratepayers to justify deviations from net book value treatment. It should be emphasized that this exception would be a unusual circumstance and would be evaluated on a case-by-case basis.").
Vermont	Board includes acquisition adjustments below the line; never included in rates. Board staff was unable to recall any recent requests for acquisition adjustments by water companies. ***Joint Petition of Young's Cable TV Corp. and Okemo Vue, Inc.*, 1986 WL 361091 (Vt. P.S.B. May 26, 1986)** ("the Board policy on rate-base acquisition adjustments is that permitted earnings on rate-base investment are limited to the depreciated cost of utility property when first placed into service, and that an upward rate base adjustment will not be permitted when ownership of the assets is directly or indirectly at a price in excess of their depreciated original cost.")
Virginia	***Re Virginia Natural Gas, Inc.*, 250 P.U.R.4th 421 (2006)** ("An acquisition adjustment is allowed only in extraordinary circumstances and may be authorized if the applicant utility satisfies certain criteria ...(i) the purchase price was determined in an arms-length bargaining and (ii) the purchase was an investment made prudently for the benefit of the customers and the utility.").
Washington	***Washington Util. and Transp. Comm'n v. PacifiCorp*, 2006 WL 1517095 (Wash U.T.C. Apr. 17, 2006)** ("When a utility purchases a plant, it may seek an acquisition premium adjustment to reflect that the price paid for the plant may be higher than its book value. However, the cost of the premium is not included in rate base unless the Commission allows such treatment after finding the underlying plant purchase was prudent."). ***In the Matter of the Application of Herman Suess Applicant, For the Sale and Transfer of Assets to Pattison Water Co.*, 2005 WL 2660173 (Wash. U.T.C. June 15, 2005)** (Staff advised applicant that "absent a showing of commensurate benefits, acquisition adjustments are not included in rate base for inclusion in rates.").

West Virginia	No general policy has been established for dealing with water company acquisition adjustments. Acquisition adjustments are often not allowed. ***Re West Virginia-American Water Co.,* 231 P.U.R.4th 423 (W. Va. P.S.C. Jan. 2, 2004)** (ordered negative acquisition adjustment to rate base). ***West Virginia-American Water Co. and East Bank Water Dep't.*, Case No. 00-1719-W-PC (W. Va. P.S.C. Feb. 6, 2001)** (ordered acquiring company to record the book cost of assets, and "[a]ny amount paid in excess of the net book value of the acquired assets, as adjusted, should be recorded in [the acquisition adjustment account] and be amortized over 20 years. Any amount of asset book value in excess of the amount paid will be considered as a contribution. Lastly, any necessary rate recognition relating to this acquisition will be given the appropriate treatment in the [next rate case].").
Wisconsin	***Joint Application for Approvals Related to Wisconsin Power and Light Company's Sale of its Beloit Area Water Utility Assets to the City of Beloit*, 2003 WL 22220326 (Wis. P.U.C. Sept. 19, 2003)**(after finding sufficient benefits to customers, allowed city to recover in customer rates a straight-line amortization of acquisition adjustment over 25 years and a return on the unamortized balance). ***Preliminary Agreement of the Village of Footville, Rock County, as an Electric Public Utility, to Sell Its Electric Public Utility Plant to Wisconsin Power and Light Company*, Dockets 2040-EA-100, 6680-EB-103 (Wis. P.U.C. Feb. 24, 1989)**(As a general matter, a utility must provide some substantial physical or electrical benefit to the purchaser's system in order to be exempted from the ordinary rule that utility customers pay no more than net book value. Redistribution of costs or spreading costs over more customers is not a system benefit in and of itself.).
Wyoming	No general policy has been established for dealing with water company acquisition adjustments. Commission staff was unable to recall any requests for acquisition adjustments by water companies. Requests would be reviewed on a case-by-case basis.

Global Utilities
Docket No. W-01212A-12-309 et al
Test Year Ended December 31, 2011
12-0310

Palo Verde Utilities Company

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RBM-4	1	RATE BASE ADJUSTMENT NO. 3 - INFRASTRUCTURE COORDINATION AND FINANCING AGREEMENTS
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RBM-17	1	OPERATING INCOMEADJUSTMENT NO. 8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ 60,166,756	$ 52,813,708
2			
3	Adjusted Operating Income (Loss)	$ 3,066,067	$ 3,098,107
4			
5	Current Rate Of Return (L3 / L1)	5.10%	5.87%
6			
7	Required Operating Income (L9 X L1)	$ 5,300,691	$ 3,904,484
8			
9	Required Rate Of Return On Fair Value Rate Base	8.81%	7.39%
10			
11	Operating Income Deficiency (L7 - L3)	$ 2,234,624	$ 806,378
12			
13	Gross Revenue Conversion Factor (RBM-1, Pg 2)	1.6390	1.6587
14			
15	Increase In Gross Revenue Requirement (L11 X L13)	$ 3,662,560	$ 1,337,539
16			
17	Adjusted Test Year Revenue	$ 13,107,528	$ 13,107,528
18			
19	Proposed Annual Revenue (L15 + L17)	$ 16,770,088	$ 14,445,067
20			
21	Required Percentage Increase In Revenue (L15 / L17)	27.94%	10.20%
22			
23	Rate Of Return On Common Equity	11.44%	8.50%

References:

Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A]	[B]	[C]
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor	0.0000%		
3	Revenues (L1 - L2)	100.0000%		
4	Combined Federal and State Income Tax and Property Tax Rate (L23)	39.7118%		
5	Subtotal (L3 - L4)	60.2882%		
6	**Revenue Conversion Factor (L1 / L5)**	1.658700		
	Calculation of Uncollecttible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (L17)	38.2900%		
9	One Minus Combined Income Tax Rate (L7 - L8)	61.7100%		
10	Uncollectible Rate	0.00000		
11	Uncollectible Factor (L9 * L10)	0.0000%		
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.5000%		
14	Federal Taxable Income (L12 - L13)	93.5000%		
15	Applicable Federal Income Tax Rate (Col [C] L53)	34.0000%		
16	Effective Federal Income Tax Rate (L14 x L15)	31.7900%		
17	Combined Federal and State Income Tax Rate (L13 + L16)		38.2900%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (Col. [B], L17)	38.2900%		
20	One Minus Combined Income Tax Rate (L18-L19)	61.7100%		
21	Property Tax Factor (Sch. RBM-16, Col. [B], L24)	2.3041%		
22	Effective Property Tax Factor (L20 x L21)		1.4218%	
23	Combined Federal and State Income Tax and Property Tax Rate (Col. (B), L17 + L22)			39.7118%
24	Required Operating Income (Sch. RBM-1, Col. (B) L7)	$ 3,904,484		
25	Adjusted Test Year Operating Income (Loss) (Sch. RBM-1, Col (B) L3)	3,098,107		
26	Required Increase in Operating Income (L24 - L25)		$ 806,378	
27	Income Taxes on Recommended Revenue (Col. [C], L52)	$ 1,344,484		
28	Income Taxes on Test Year Revenue (Col. (A), L52)	844,141		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		500,344	
30	Recommended Revenue Requirement (Sch. RBM-1, Col. (B), L19	$ 14,445,067		
31	Uncollectible Rate (L10)	0.00000		
32	Uncollectible Expense on Recommended Revenue (L30 x L31)	$ -		
33	Adjusted Test Year Uncollectible Expense(Sch. RBM-8, Col. (K), L31)	$ -		
34	Required Increase in Revenue to Provide for Uncollectible Exp. (L32 - L33)		-	
35	Property Tax with Recommended Revenue (Sch. RBM -8, Col. (K), L36)	$ 993,550		
36	Property Tax on Test Year Revenue (Sch. RBM-8, Col. (Q), L32)	962,732		
37	Increase in Property Tax Due to Increase in Revenue (L35 - 36)		30,818	
38	Total Required Increase in Revenue (Col. [B], L26 + L29 + L34 + L37)		$ 1,337,539	

	Calculation of Income Tax:	Test Year		RUCO Recommended
39	Revenue (Sch.RBM-7 Col [C] L4 and Col (D) L4	$ 13,107,528	$ 1,337,539	$ 14,445,067
40	Operating Expenses Excluding Income Taxes	$ 9,165,281		$ 9,196,099
41	Synchronized Interest (Col. [C], L57)	$ 1,737,649		$ 1,737,649
42	Arizona Taxable Income (L39 - L40 - L41)	$ 2,204,598		$ 3,511,319
43	Arizona State Income Tax Rate	6.5000%		6.5000%
44	Arizona Income Tax (L42 x L43)	$ 143,299		$ 228,236
45	Federal Taxable Income (L42 - L44)	$ 2,061,299		$ 3,283,084
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ 7,500		$ 7,500
47	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ 6,250		$ 6,250
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ 8,500		$ 8,500
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ 91,650		$ 91,650
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ 586,942		$ 1,002,348
51	Total Federal Income Tax	$ 700,842		$ 1,116,248
52	Combined Federal and State Income Tax (L44 + L51)	$ 844,141		$ 1,344,484
53	Applicable Federal Income Tax Rate [Col. [C], L46 - Col. [A], L46] / [Col. [C], L40 - Col. [A], L40]			34.0000%
54	Synchronized Interest Calculation			
55	Rate Base			$ 52,813,708
56	Weighted Average Cost of Debt			3.29%
57	Synchronized Interest			$ 1,737,649

SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO 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	$ 109,787,648	$ (698,584)	$ 109,089,064
		-		
2	Accumulated Depreciation	(19,012,634)	-	(19,012,634)
3	Net Utility Plant In Service (L1 + L2)	$ 90,775,014	$ (698,584)	$ 90,076,430
4	Advances In Aid Of Const.	$ (27,839,315)	$ -	$ (27,839,315)
		-		
5	Contribution In Aid Of Const.	$ (30,362)	$ (12,566,169)	$ (12,596,531)
6	Accumulated Amortization Of CIAC	-	1,719,622	1,719,622
7	NET CIAC (L5 + L6)	$ (30,362)	$ (10,846,547)	$ (10,876,909)
8	Customer Meter Deposits	$ (669,926)	$ -	$ (669,926)
9	Deferred Income Taxes & Credits	$ (2,068,654)	$ 4,192,082	$ 2,123,428
10	Unamortized Finance Charges	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 60,166,757	$ (7,353,049)	$ 52,813,708

References:
Column (A) Company Schedule B-1
Column (B) RBM-3 page 1

References:
Column (A): Company Schedule B-1
Column (B): RBM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

RUCO POST TEST YEAR PLANT ADJUSTMENTS

	(A)	(B)	(C)	(D)	(E)		(F)
	Company's Initial Filing			Co. Follow Up Response			
	Date Const Began	Date Const est to be Completed	Included in Rate Base Initial Est	Date Const Actually Completed	Final Costs/ as of March 31, 2013		RUCO Adjustment
Global Water - Santa Cruz							
Edison Rd Waterline Ext	Aug 2012	Aug 2012	$ 300,742	Dec 2012	$ 240,224		$ (300,742)
RED WDC Chl Sys Replacement	Jan 2012	Jan 2012	6,149	April 2012	15,129		8,980
TOTALS			$ 306,891		$ 255,353		$ (291,762)
Willow Valley Water Company							
WVR SCADA - WVWC	Oct 2012	Oct 2012	$ 80,436	Not Started	-		$ (80,436)
TOTALS			$ 80,436		-		$ (80,436)
Water Utility of Greater Tonopah							
West Phoenix 6 Elec Upgrades	Nov 2012	Dec 2012	$ 3,076	Dec 2012	$ 3,501		$ (3,076)
West Phoenix 6 Fluoride	Nov 2012	Dec 2012	8,625	Jan 2013	18,693		(8,625)
WPE 6 Tank and Well Replacmt	May 2012	June 2012	95,082	Dec 2012	128,934		(95,082)
TOTALS			$ 106,783		$ 151,128		$ (106,783)
Valencia Water Company							
Bales Fill Line	July 2012	July 2012	$ 78,750	In Progress	$ 12,027		$ (78,750)
Buena Vista Fill Line	July 2012	July 2012	203,702	In Progress	20,004		(203,702)
Pima Road Waterline	April 2012	April 2012	182,563	Sept 2012	195,474		(182,563)
WVR SCADA Command Sta Imp	July 2012	July 2012	136,029	Jan 2013	21,962		(136,029)
SVWDC Optimization	June 2012	June 2012	71,526	Feb 2013	48,565		(71,526)
TOTALS			$ 672,570		$ 298,032		$ (672,570)
Global Water - Palo Verde Utilities							
Campus I WRF Ph 3 Exp	Nov 2008	June 2012	$ 119,810	Dec 2011	$ 119,810		$ -
PVUC In Pipe Odor Control	Mar 2012	June 2012	52,022	Nov 2012	57,397	Note (1)	(52,022)
PVUC Lagoon Clean Closure	April 2012	July 2012	406,949	Dec 2012	543,461	Note (1)	(406,949)
PVUC PEQB	April 2012	July 2012	12,564	Dec 2012	48,475	Note (1)	(12,564)
SRW MH Rehab and LS Imp Ph I	Dec 2010	Feb 2012	6,408	Dec 2012	3,295	Note (1)	(6,408)
PVUC WRF Headworks Rehab	Sept 2012	Sept 2012	69,132	Dec 2012	84,155	Note (1)	(69,132)
Sewer Manhole Rehab	Oct 2012	Oct 2012	66,509	Dec 2012	68,199	Note (1)	(66,509)
Edison Rd Sewer Ln Ext	Aug 2012	Aug 2012	85,000	Dec 2012	110,734	Note (1)	(85,000)
			$ 818,394		$ 1,035,526		$ (698,584)

References:
Columns (A), (B), (C) - Fleming Testimony pages 21 and 22. Company included in rate base.
Columns (D), (E) - Company Response to RUCO Data Request No. 2.01
NOTE (1): See Column (F) The costs for projects not completed and placed in service by June 30, 2012, were adjusted and excluded from rate base by RUCO

RUCO POST TEST YEAR PLANT DEPRECIATION & A/D ADJUSTMENTS

	(A) Company Initial Filing Included in Rate Base Initial Est	(B) Date Const Actually Completed	(C) Company Final Costs/ as of March 31, 2013	(D) RUCO Adjustment PTY Plant	(E) Company Calculated Depreciation	(F) RUCO Calculated Depreciation	(G) RUCO Adjustment Depre & A/D
Global Water - Santa Cruz							
Edison Rd Waterline Ext	$ 300,742	Dec 2012	$ 240,224	$ (300,742)			
RED WDC Chl Sys Replacement	6,149	April 2012	15,129	8,980			
TOTALS	$ 306,891		$ 255,353	$ (291,762)	$ 15,345	$ 757	$ (14,588)
Willow Valley Water Company							
WVR SCADA - WVWC	$ 80,436	Not Started	-	$ (80,436)			
TOTALS	$ 80,436		-	$ (80,436)	$ 4,022	$ -	$ (4,022)
Water Utility of Greater Tonopah							
West Phoenix 6 Elec Upgrades	$ 3,076	Dec 2012	$ 3,501	$ (3,076)			
West Phoenix 6 Fluoride	8,625	Jan 2013	18,693	(8,625)			
WPE 6 Tank and Well Replacmt	95,082	Dec 2012	128,934	(95,082)			
TOTALS	$ 106,783		$ 151,128	$ (106,783)	$ 5,339	$ -	$ (5,339)
Valencia Water Company							
Bales Fill Line	$ 78,750	In Progress	$ 12,027	$ (78,750)			
Buena Vista Fill Line	203,702	In Progress	20,004	(203,702)			
Pima Road Waterline	182,563	Sept 2012	195,474	(182,563)			
WVR SCADA Command Sta Imp	136,029	Jan 2013	21,962	(136,029)			
SVWDC Optimization	71,526	Feb 2013	48,565	(71,526)			
TOTALS	$ 672,570		$ 298,032	$ (672,570)	$ 33,629	$ -	$ (33,629)
Global Water - Palo Verde Utilities							
Campus I WRF Ph 3 Exp	$ 119,810	Dec 2011	$ 119,810	$ -			
PVUC In Pipe Odor Control	52,022	Nov 2012	57,397	(52,022)			Note (1)
PVUC Lagoon Clean Closure	406,949	Dec 2012	543,461	(406,949)			
PVUC PEQB	12,564	Dec 2012	48,475	(12,564)			
SRW MH Rehab and LS Imp Ph I	6,408	Dec 2012	3,295	(6,408)			
PVUC WRF Headworks Rehab	69,132	Dec 2012	84,155	(69,132)			
Sewer Manhole Rehab	66,509	Dec 2012	68,199	(66,509)			
Edison Rd Sewer Ln Ext	85,000	Dec 2012	110,734	(85,000)			
	$ 818,394		$ 1,035,526	$ (698,584)	$ 40,920	$ 5,991	$ (34,929)

References:
Columns (A), (B), (C), (D) - See Sch RBM-2
Columns (E) - Company Schedules and testimony of Mr. Brett Higgabotham

NOTE (1): RUCO Depreciation and A/D adjustment calculated as follows:

Column (E) / Column (A)	40,920		
	818,394	5.00%	Depreciation allowance as calculated by Company
Column (A) less Column (D)	$ 818,394		
	$ 698,584		
		$ 119,810	Test Year Plant as proposed by RUCO
Depreciation expense proposed by RUCO		$ 5,991	
Depreciation expense proposed by Company		$ 40,920	
RUCO proposed depreciation and A/D adjustment related to Post Test Year Plant		$ (34,929)	

POST TEST YEAR ADJUSTMENT NO. 3
INFRASTRUCTURE COORDINATION AND CONSTRUCTION AGREEMENTS

Line No.		SANTA CRUZ (A) Total Fees Collected	SANTA CRUZ (B) Allocated to Excess Cap.	SANTA CRUZ (C) Allocated to CIAC	PALO VERDE (A) Total Fees Collected	PALO VERDE (B) Allocated to Excess Cap.	PALO VERDE (C) Allocated to CIAC	TONOPAH (A) Total Fees Collected	TONOPAH (B) Allocated to Hassayampa	TONOPAH (C) Allocated to CIAC
1										
2	ICFA Fees Collected									
3										
4	Included in last rate filing	$ 24,541,553	$ 17,941,477	$ 6,600,076	$ 25,440,969	$ 14,449,844	$ 10,991,125	$ 9,226,100	$ 2,140,455	$ 7,085,645
5										
6	Fees Collected Since Last Rate Case	3,158,403	2,370,881	787,522	3,274,155	1,699,111	1,575,044	569,940	132,226	437,714
7										
8	Total ICFA Fees Collected	$ 27,699,956	$ 20,312,358	$ 7,387,598	$ 28,715,124	$ 16,148,955	$ 12,566,169	$ 9,796,040	$ 2,272,681	$ 7,523,359
9										
10	Calculation of ICFA Amortization									
11										
12	Amortization Expense Last Rate Filing	$ -	$ -	$ 494,849	$ -	$ -	$ 667,381	$ -	$ -	$ 236,248
13										
14	Amortization from 2008 thru 2011	-	-	822,610	-	-	$ 1,052,281	$ -	$ -	$ 819,250
15										
16	Total ICFA Accu. Amortization Expense thru Test Year			$ 1,317,459			$ 1,719,622			$ 1,719,622
17										
18										
19	**Amortization Expense for Test Year 2011**									
20										
21	First Quarter	$ 6,600,076	$ 66,951		First Quarter	$ 10,991,128	$ 88,221	First Quarter	$ 7,523,359	$ 54,921
22	Second Quarter	6,600,076	66,888		Second Quarter	11,057,409	85,406	Second Quarter	7,523,359	148,210
23	Third Quarter	6,633,216	66,607		Third Quarter	11,057,409	91,757	Third Quarter	7,523,359	130,154
24	Fourth Quarter	7,387,598	70,968		Fourth Quarter	12,566,172	94,794	Fourth Quarter	7,523,359	134,668
25										
26	Total Amortization Expense		$ 271,414		Total Amortization Expense		$ 360,178	Total Amortization Expense		$ 467,953

Reference:
Balances from last rate filing - See Decision No. 71878
Details of information obtained since last rate filing - On Site Review
Current Amortization from on site review

SCHEDULE OF AGREEMENTS, INCLUDING ICFS's

Line No.		(A) 2004	(B) 2005	(C) 2006	(D) 2007	(E) 2008	(F) 2009	(G) 2010	(H) 2011	(I) TOTAL
1	**Santa Cruz and Palo Verde Utilities**									
2										
3	Santa Cruz and Palo Verde original CC&N	$ 4,757,941	$ 10,068,311	$ 8,164,494	$ 767,844	$ 87,750	$ 2,722,149	$ 175,515	$ 99,421	$ 26,843,425
4										
5	Santa Cruz and Palo Verde Eastern Exp	165,625	6,127,681	-	2,982,915	1,319,600	-	-	-	10,595,821
6										
7	Santa Cruz and Palo Verde Southwest Exp	-	280,017	4,763,450	-	612,500	-	98,225	150,000	5,904,192
8										
9	Santa Cruz and Palo Verde 387 District	-	3,792,300	3,874,408	-	-	602,300	-	-	8,269,008
10										
11	Santa Cruz and Palo Verde Southeast Exp	-	-	262,800	-	-	-	-	-	262,800
12										
13	Santa Cruz and Palo Verde N/NW2nd SW Exp	-	-	22,925	23,300	26,250	321,803	-	2,263,145	2,657,423
14										
15	Santa Cruz and Palo Verde Future Southeast	-	-	-	882,411	1,000,000	-	-	-	1,882,411
16										
17	TOTAL Santa Cruz / Palo Verde	$ 4,923,566	$ 20,268,309	$ 17,088,077	$ 4,656,470	$ 3,046,100	$ 3,646,252	$ 273,740	$ 2,512,566	$ 56,415,080
18										
19										
20										

Line No.	**ALLOCATION - SANTA CRUZ / PALO VERDE**	**THRU YR 2008**	**2009 to 2011**	**TOTALS**	
21					
22					
23	Allocated to Palo Verde	$ 25,440,969	3,274,155	$ 28,715,124	
24	Allocated to Santa Cruz	$ 24,541,553	$ 3,158,403	$ 27,699,956	
25	**Total ICFS's Funds Collected**	$ 49,982,522	$ 6,432,558	$ 56,415,080	See Columns (A) thru (I) L17
26					
27					
28	**FURTHER ALLCOATION BASED ON CIAC / EXCESS CAPACITY - SANTA CRUZ**				
29					
30					
31	Funds Excluded from CIAC / Excess Capacity	$ 17,941,477	$ -	$ 17,941,477	
32					
33	Funds Included in CIAC	$ 6,600,076	$ 3,158,403	$ 9,758,479	
34					
35	Total ICFA funds from last rate case	$ 24,541,553	$ 3,158,403	$ 27,699,956	
36					
37					
38					
39	**FURTHER ALLCOATION BASED ON CIAC / EXCESS CAPACITY - PALO VERDE**				
40					
41					
42	Funds Excluded from CIAC / Excess Capacity	$ 14,449,844	$ -	$ 14,449,844	
43					
44	Funds Included in CIAC	$ 10,991,125	$ 3,274,155	$ 14,265,280	
45					
46	Total ICFA funds from last rate case	$ 25,440,969	$ 3,274,155	$ 28,715,124	

PLANT SCHEDULES
YEAR ENDED DECEMBER 31, 2011

Line No.	Acct No	Account Description	(A) Plant Balance 12/31/2010	(B) Additions	(C) Other Costs	(D) Disposals	(E) RUCO Balance 12/31/2011
1	353	353 Land and Land Rights	186,342	-	-	-	$ 186,342
2	354	354 Structures and Improvements	22,855,163	61,771	-	-	22,916,934
3	355	355 Power Generation Equipment	356,501	4,595	-	-	361,096
4	360	360 Collection Sewers - Force	3,857,656	7,659	-	-	3,865,315
5	361	361 Collection Sewers - Gravity	47,558,359	226,926	-	-	47,785,285
6	363	363 Services to Customers	5,244,342	-	-	-	5,244,342
7	364	364 Flow Measuring Devices	23,636	-	-	-	23,636
8	370	370 Receiving Wells	1,921,877	-	-	-	1,921,877
9	371	371 Pumping Equipment	3,958,196	80,815	-		4,039,011
10	374	374 Reuse Distribution Reservoirs	11,043	22,978	-	-	34,021
11	375	375 Reuse Transmission and Distribution System	11,074,139	15,318	-	-	11,089,457
12	380	380 Treatment and Disposal Equipment	5,846,144	129,431	-	-	5,975,575
13	381	381 Plant Sewers	78,384	-	-	-	78,384
14	382	382 Outfall Sewer Lines	353,645	-	-		353,645
15	389	389 Other Plant and Miscellaneous Equipment	2,264,309	31,256	-	-	2,295,565
16	390	390 Office Furniture and Equipment	402,021	1,153	-	-	403,174
17	391	391 Transportation Equipment	170,644	2,878	-	-	173,522
18	393	393 Tools, Shop and Garage Equipment	106,797	7,453	-	-	114,250
19	394	394 Laboratory Equipment	24,614	327	-	-	24,941
20	395	395 Power Operated Equipment	10,320	30,828	-	-	41,148
21	396	396 Communication Equipment	39,288	36,950	-	-	76,238
22	397	397 Miscellaneous Equipment	362,822	6,501	-	-	369,323
23	398	398 Other Tangible Plant	1,592,799	3,372	-	-	1,596,171
24							
25		Total Plant in Service	$ 108,299,042	$ 670,211	$ -	$ -	$ 108,969,253
26							

References:
Company Schedules and RUCO Data Request 1.14

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	108,969,253	$ 818,395	$ -	$ -	$ 109,787,648
2	Accumulated Depreciation	(19,012,634)	-	-	-	(19,012,634)
3	Net Utility Plant In Service (L1 + L2)	$ 89,956,619	$ 818,395	$ -	$ -	$ 90,775,014
4	Advances In Aid Of Const.	$ (27,839,315)	$ -	$ -	$ -	$ (27,839,315)
5	Contribution In Aid Of Const.	$ (27,616,063)	$ -	$ 16,739,152	$ 10,846,549	$ (30,362)
6	Accumulated Amortization Of CIAC	-	-	-	-	-
7	NET CIAC (L5 + L6)	$ (27,616,063)	$ -	$ 16,739,152	$ 10,846,549	$ (30,362)
8	Customer Meter Deposits	$ (669,926)	$ -	$ -	$ -	$ (669,926)
9	Deferred Income Taxes & Credits	$ 8,593,041	$ -	$ (6,469,574)	$ (4,192,121)	$ (2,068,654)
10	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 42,424,356	$ 818,395	$ 10,269,578	$ 6,654,428	$ 60,166,757

References:
Column (A): Company Schedule B-1
Column (B); Company Schedule B-2-1
Column (E); Columns (A) through (D)

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year' Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
		Revenues:					
1	521	Metered Water Revenues	$ 12,423,785	$ -	$ 12,423,785	$ 1,337,539	$ 13,761,324
2	536	Unmetered Water Revenues	345,001	-	345,001		345,001
3	541	Other Water Revenues	338,742	-	338,742		338,742
4		TOTAL OPERATING REVENUE	$ 13,107,528	$ -	$ 13,107,528	$ 1,337,539	$ 14,445,067
		Operating Expenses:					
5	701	Salaries And Wages - Employees	$ 1,472,381	(152,280)	$ 1,320,101	$ -	$ 1,320,101
6	710	Purchased Water	-	-	-	-	-
7	715	Purchased Power	530,509	-	530,509	-	530,509
8	718	Chemicals	408,431	-	408,431	-	408,431
9	720	Materials And Supplies	114,852	-	114,852	-	114,852
10	721	Office Supplies and Expense	120,122	-	120,122	-	120,122
11	731	Contractural Services - Professional	901,541	-	901,541	-	901,541
12	735	Contractural Services - Testing	40,577	-	40,577	-	40,577
13	736	Contractural Services - Other	197,061	-	197,061	-	197,061
14	740	Rents	119,990	-	119,990	-	119,990
15	742	Rental of Equipment	-	-	-	-	-
16	750	Transportation Expense	76,568	-	76,568	-	76,568
17	755	Insurance Expense	102,147	-	102,147	-	102,147
18	759	Insurance Expense - Other	-	-	-	-	-
19	765	Regulatory Expense	112,973	(48,896)	64,077	-	64,077
20	767	Rate Case Expense	-	-	-	-	-
21	770	Bad Debt Expense	82,936	(11,624)	71,312	-	71,312
22	775	Miscellaneous Expense	485,687	(164,977)	320,710	-	320,710
23	403	Depreciation Expense	3,479,794	(33,629)	3,446,165	-	3,446,165
24	403	Depreciation Exp - CIAC Amort	(1,292)	360,178	358,886	-	358,886
25	408	Taxes Other than Income	9,500	-	9,500	-	9,500
26	408.1	Property Taxes	1,064,073	(101,341)	962,732	30,818	993,550
27	409	Income Taxes	682,693	161,448	844,141	500,344	1,344,484
28			-				
29		TOTAL OPERATING EXPENSES	$ 10,000,543	$ 8,878	$ 10,009,421	$ 531,162	$ 10,540,583
30		OPERATING INCOME (LOSS)	$ 3,106,985		$ 3,098,107		$ 3,904,484

References:

Column (A): Company Schedule C-1
Column (B): RLM-7, Columns (B) Thru (I)
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)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Left Blank	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 10 Property Taxes	(I) Adj. No 13 Income Taxes	(J) Total Pro Forma Adjustments	(K) Test Year Adjusted Results
	Revenues:											
1	521 Metered Water Revenues	$ 12,423,785	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 12,423,785
2	536 Other Water Revenues	345,001	-	-	-	-	-	-	-	-	-	345,001
3	541 Unmetered Water Revenues	338,742	-	-	-	-	-	-	-	-	-	338,742
4	TOTAL OPR'G REV.	$ 13,107,528	$ -	$ -	$ -	$ -	$ -		$ -		$ -	$ 13,107,528
5	Operating Expenses:											
6	701 Salaries And Wages - Employees	$ 1,472,381					$ (152,280)				$ (152,280)	$ 1,320,101
7	710 Purchased Water	-									-	-
8	715 Purchased Power	530,509									-	530,509
9	718 Chemicals	408,431									-	408,431
10	720 Materials And Supplies	114,852									-	114,852
11	721 Office Supplies and Expense	120,122									-	120,122
12	731 Contractural Services - Professional	901,541									-	901,541
13	735 Contractural Services - Testing	40,577									-	40,577
14	736 Contractural Services - Other	197,061									-	197,061
15	740 Rents	119,990									-	119,990
16	742 Rental of Equipment	-									-	-
17	750 Transportation Expense	76,568									-	76,568
18	755 Insurance Expense	102,147									-	102,147
19	759 Insurance Expense - Other	-									-	-
20	765 Regulatory Expense	112,973	(48,896)								(48,896)	64,077
21	767 Rate Case Expense	-									-	-
22	770 Bad Debt Expense	82,936				(11,624)					(11,624)	71,312
23	775 Miscellaneous Expense	485,687						(164,977)			(164,977)	320,710
24	403 Depreciation Expense	3,479,794			(33,629)						(33,629)	3,446,165
25	403 Depreciation Exp - CIAC Amort	(1,292)			360,178						360,178	358,886
26	408 Taxes Other than Income	9,500									-	9,500
27	408.1 Property Taxes	1,064,073							(101,341)		(101,341)	962,732
28	409 Income Taxes	682,693								161,448	161,448	844,141
29		-									-	-
30		-									-	-
31		-									-	-
32		-									-	-
33		-									-	-
34	Total Operating Expneses	$ 10,000,543	$ (48,896)	$ -	$ 326,549	$ (11,624)	$ (152,280)	$ (164,977)	$ (101,341)	$ 161,448	$ 8,878	$ 10,009,421
35		-										
36	Operating Income (Loss)	$ 3,106,985	$ 48,896	$ -	$ (326,549)	$ 11,624	$ 152,280	$ 164,977	$ 101,341	$ (161,448)	$ (8,878)	$ 3,098,107

References:
Column (A) See Company Schedule C-1; RBM-9
Columns (B) through (K) See RBM-10 through RBM-18

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH COMPANY ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Rate Case Expense	(D) Adj. No 3 Low Income Relief	(E) Adj. No 4 Annualized Revenue	(F) Adj. No 5 Accrued Revenue	(G) Adj. No 6 BLANK	(H) Adj. No 7 Remove CIAC ICFA Depre	(I) Adj. No 8 BLANK	(J) Adj. No 9 Depre Test Yr Plant	(K) Adj. No 10 Phase In of Rates	(L) Adj. No 11 Bad Debts	(M) Adj. No 12 Property Tax	(N) Adj. No 13 License Fee	(O) Adj No. 14 Income Taxes	(P) Adj. No 20 Self Billing Adj	(O) Company Adjustments Test Year	(P) Company As Adjusted Test Year
	Revenues:																		
1	521 Metered Water Revenues	$ 10,763,095	$ -	$ -	$ -	$ 139,660	$ (564,294)	$ -	$ -	$ -		$ 2,080,277				$ -	$ 5,047	$ 1,660,690	$ 12,423,785
2	536 Other Water Revenues	345,001	-	-	-	-	-	-	-	-								-	345,001
3	541 Unmetered Water Revenues	303,836	-	-	-	33,333	1,573	-	-	-								34,906	338,742
4	TOTAL OPR'G REV.	$ 11,411,932	$ -	$ -	$ -	$ 172,993	$ (562,721)		$ -			$ 2,080,277					$ 5,047	$ 1,660,690	$ 13,107,528
5	Operating Expenses:																		
6	701 Salaries And Wages - Employees	$ 1,472,381	$ -		$ -		$ -		$ -									-	$ 1,472,381
7	710 Purchased Water	-	-		-		-		-									-	-
8	715 Purchased Power	523,952	-		-	6,557	-	-	-									6,557	530,509
9	718 Chemicals	403,612	-		-	4,819	-		-									4,819	408,431
10	720 Materials And Supplies	114,852	-		-		-		-									-	114,852
11	721 Office Supplies and Expense	120,122	-		-		-		-									-	120,122
12	731 Contractural Services - Professional	901,541																-	901,541
13	735 Contractural Services - Testing	40,577																-	40,577
14	736 Contractural Services - Other	197,061	-		-		-		-									-	197,061
15	740 Rents	119,990	-		-		-		-									-	119,990
16	742 Rental of Equipment	-	-		-		-		-									-	-
17	750 Transportation Expense	76,568	-		-		-		-									-	76,568
18	755 Insurance Expense	102,147	-		-		-		-									-	102,147
19	759 Insurance Expense - Other	-	-		-		-		-									-	-
20	765 Regulatory Expense	61,721	(53,333)	104,585														51,252	112,973
21	767 Rate Case Expense	-			-		-		-									-	-
22	770 Bad Debt Expense	72,207	-		-		-		-				10,729					10,729	82,936
23	775 Miscellaneous Expense	459,105	-		(8,407)		-		-						34,989			26,582	485,687
24	403 Depreciation Expense	3,479,794	-		-		-		-		-				-			-	3,479,794
25	403 Depreciation Exp - CIAC Amort	(368,101)	-		-		-		366,809									366,809	(1,292)
26	408 Taxes Other than Income	9,500	-		-		-		-									-	9,500
27	408 Property Taxes	520,532	-		-		-		-					543,541				543,541	1,064,073
28	409 Income Taxes	1,190,746	-		-		-		-							(508,053)		(508,053)	682,693
29		-	-		-		-		-									-	-
30		-	-		-		-		-									-	-
31		-	-		-		-		-									-	-
32		-	-		-		-		-									-	-
33																		-	-
34	Total Operating Expneses	$ 9,498,307	$ (53,333)	$ 104,585	$ (8,407)	$ 11,376	$ -	$ -	$ 366,809	$ -	$ -	$ -	$ 10,729	$ 543,541	$ 34,989	$ (508,053)	$ -	$ 502,236	$ 10,000,543
35																			
36	Operating Income (Loss)	$ 1,913,625	$ 53,333	$ (104,585)	$ 8,407	$ 161,617	$ (562,721)	$ -	$ (366,809)	$ -	$ -	$ 2,080,277	$ (10,729)	$ (543,541)	$ (34,989)	$ 508,053	$ 5,047	$ 1,158,454	$ 3,106,985

References:
Column (A): Company Schedule C-1
Column (B) through (N): Company Schedules C-2 pg. 1 through pg. 16
Column (O): Sum of Columns (B) through (N)
Column (P): Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor (L34)			39.87%
4				
5	Palo Verde Utilities Company			$ 167,067
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 55,689
10				
11	Company Amortized Rate Case Expense for Palo Verde as Filed (Sch. C-2.2)			$ 104,585
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (48,896)
14				
15	RUCO Adjustment			$ (48,896)
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
18	Decision No. 71878, dated September 15, 2010, approved amount			
19	$400,000 forGlobal Water.		$ 400,000	
20				
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) Ln 27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
29					
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

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OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Plant Balance 12/31/2010	(B) Additions	(C) Other Costs	(D) Disposals	(E) RUCO Balance 12/31/2011
1	353	353 Land and Land Rights	-	-	-	-	$ -
2	354	354 Structures and Improvements	22,855,163	61,771	-	-	761,180
3	355	355 Power Generation Equipment	356,501	4,595	-	-	8,918
4	360	360 Collection Sewers - Force	3,857,656	7,659	-	-	96,451
5	361	361 Collection Sewers - Gravity	47,558,359	226,926	-	-	1,584,071
6	363	363 Services to Customers	5,244,342	-	-	-	349,798
7	364	364 Flow Measuring Devices	23,636	-	-	-	473
8	370	370 Receiving Wells	1,921,877	-	-	-	96,094
9	371	371 Pumping Equipment	3,958,196	80,815	-		495,280
10	374	374 Reuse Distribution Reservoirs	11,043	22,978	-	-	406
11	375	375 Reuse Transmission and Distribution System	11,074,139	15,318	-	-	245,863
12	380	380 Treatment and Disposal Equipment	5,846,144	129,431	-	-	117,052
13	381	381 Plant Sewers	78,384	-	-	-	2,610
14	382	382 Outfall Sewer Lines	353,645	-	-		29,459
15	389	389 Other Plant and Miscellaneous Equipment	2,264,309	31,256	-	-	45,317
16	390	390 Office Furniture and Equipment	402,021	1,153	-	-	26,819
17	391	391 Transportation Equipment	170,644	2,878	-	-	11,392
18	393	393 Tools, Shop and Garage Equipment	106,797	7,453	-	-	7,148
19	394	394 Laboratory Equipment	24,614	327	-	-	8,209
20	395	395 Power Operated Equipment	10,320	30,828	-	-	2,372
21	396	396 Communication Equipment	39,288	36,950	-	-	1,645
22	397	397 Miscellaneous Equipment	362,822	6,501	-	-	18,157
23	398	398 Other Tangible Plant	1,592,799	3,372	-	-	159,297
24							
		Total Plant in Service	$ 108,112,700	$ 670,211	$ -	$ -	$ 4,068,011

RUCO calculated depreciation on an account by account basis assuming that there are no fully depreciated assets. The Company calculates depreciation expense on each individual asset and when the asset if fully depreciated than depreciation expense is no longer calculates. RUCO ACCEPTS THE COMPANY DEPRECIATION FOR TEST YEAR.

References:
Company Schedules B-1 and RUCO Data Request 1.14

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense	Acct. No.	(A) COMPANY SLECTED EXPENSES	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	-
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (24)			39.873%	
12					
13	Palo Verde Utilities Co.			$ (152,280)	
14					
15	Personnel Expense as Filed			$ 1,320,101	
16					
17	RUCO Pro Forma Expense (B15 + B13)			$ 1,167,820	
18					
19	RUCO Adjustment (B17-B15)			$ (152,280)	
20					
21	Allocation Factor Based on Test Year Revenue		Operating Revenue	Percent of Total	Adjustment by System
22	Palo Verde Utilities Co.		11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company		10,705,825	37.406%	(142,858)
24	Valencia Town Water Company		4,940,530	17.262%	(65,926)
25	Willow Valley Water Company		717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah		214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility		479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale		151,196	0.528%	(2,018)
29	Total Revenue Percentages		28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08
Column (C) -- Company Schedules C-2

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	Allocation: (D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94025	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970.41)	(11,480.96)	(152.11)	(216.03)	(482.33)	(10,770.58)	(721.57)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	# $ (194,371)	# $ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water L	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Percei	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (B-J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 13,107,528	$ 13,107,528
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 26,215,056	$ 26,215,056
4a	Adjusted Test Year Revenues	13,107,528	
4b	Recommended Revenue, Per Schedule		14,445,067
5	Subtotal (L3 + L4a)	$ 39,322,584	$ 40,660,123
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 13,107,528	$ 13,553,374
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 26,215,056	$ 27,106,749
10	Plus: 10% of CWIP Per Company Schedule E	1,648,165	1,648,165
11	Less: Net Book Value of Licensed Vehicles	7,190	7,190
12	Full Cash Value (Line 9 + L10 - L11)	$ 27,856,031	$ 28,747,724
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 5,292,646	$ 5,462,067
15	Composite Property Tax Rate (Per RUCO Effective Property Tax Calculation Analysis W/P)	18.1900%	18.1900%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 962,732	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedule)	1,064,073	
18	RUCO Test Year Adjustment (L16-L17)	$ (101,341)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 993,550
20	RUCO Test Year Adjusted Property Tax Expense (L16)		962,732
21	Increase/(Decrease) to Property Tax Expense		$ 30,818
22	Increase/(Decrease) to Property Tax Expense		$ 30,818
23	Increase in Revenue Requirement		1,337,539
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		2.30407%

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No.	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Expense As Filed by Company - RBM-7 Col (A) Ln 27	$	682,693
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO RBM-7 Col (C) Ln 27		844,141
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	161,448
7			

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 62,047,253	$ -	$ 62,047,253	51.73%	6.36%	3.29%
3	Common Equity	$ 57,892,796	$ -	$ 57,892,796	48.27%	8.50%	4.10%
4	TOTAL CAPITAL	$ 119,940,049	$ -	$ 119,940,049	100.00%		
5	COST OF CAPITAL						7.39%

References:
Columns (A) Thru (F): Testimony, WAR

Global Utilities
Docket No. W-01212A-12-309 et al
Test Year Ended December 31, 2011

Palo Verde Utilities Company
Schedule RBM-5
Page 1

COMPANY PLANT BALANCES SINCE LAST RATE CASE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Total Plant Value 2008	(B) Additions	(C) Other Costs	(D) Disposals	(E) Balance 2009	(F) Additions 2010	(G) Other Costs 2010	(H) Disposals	(I) Balance 2010	(J) Additions 2011	(K) Other Costs 2011	(L) Disposals	(M) v Balance 2011
1	303	Land and Land Rights	$ 44,856	$ 334	$ -	$ -	$ 45,190	$ 319	$ -	$ -	$ 45,508	$ 17,338	$ -	$ -	$ 62,847
2	304	Structures and Improvements	9,447,338	(10,660)	125,487	-	9,562,165	2,200	-	-	9,564,365	1,739	-	-	9,566,105
3	305	Collecting and impounding Reservoirs	-				-		-		-				-
4	306	Lake, River and Other Intakes	1,855	-	-	-	1,855	-	-	-	1,855	-	-	-	1,855
5	307	Wells and Springs	3,694,926	(3)	-	(8,173)	3,686,749	21,511	-	-	3,708,260	751,217	-	-	4,459,478
6	308	Infiltration Galleries	-				-		-		-				-
7	309	Supply Mains	2,086,246	-	-	-	2,086,246	97,997	-	-	2,184,243	156,531	-	-	2,340,773
7	310	Power Generation Equipment	323,093	1,059	-	-	324,152	-	-	-	324,152	803	-	-	324,955
8	311	Pumping Equipment	6,353,511	259,155	(31,723)	-	6,580,943	65,227	-	-	6,646,169	136,373	-	-	6,782,543
8	320	Water Treatment Equipment	12,554	-	-	-	12,554	-	-	-	12,554	14,541	-	-	27,095
9	330	Distribution Reservoirs and Standpipes	1,367,063	6,528	-	-	1,373,591	-	-	-	1,373,591	4,683	-	-	1,378,274
10	331	Transmission and Distribution Mains	44,478,940	112,186	(25,450)	(289,411)	44,276,266	94,071	-	-	44,370,337	28,246	-	-	44,398,583
11	333	Services	4,598,396	46,741	-	-	4,645,137	-	-	-	4,645,137	303	-	-	4,645,440
12	334	Meters and Meter Installations	3,553,579	143,507	-	(2,546)	3,694,539	64,457	-	(21,310)	3,737,686	60,669	-	(5,500)	3,792,855
13	335	Hydrants	4,305,040	25,725	-	(14,770)	4,315,994	-	-	-	4,315,994	-	-	(11,500)	4,304,494
14	336	Backflow Prevention Devices	26,572	-	-	-	26,572	-	-	(14,910)	11,662	3,482	-	-	15,144
15	339	Other Plant and Miscellaneous Equipment	122,823	-	-	-	122,823	27,512	-	-	150,335	1,488	-	(64)	151,759
16	340	Office Furniture And Equipment	1,033,413	-	-	-	1,033,413	3,954	-	-	1,037,367	-	-	-	1,037,367
17	340.1	Computers and Software	43,296	50,116	-	-	93,412	2,879	-	-	96,292	(3,096)	-	-	93,195
18	341	Transportation Equipment	596,576	-	-	(20,483)	576,093	-	-	-	576,093	9,102	-	-	585,195
19	342	Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
20	343	Tools, Shop And Garage Equip	65,276	5,107	-	-	70,383	-	-	-	70,383	1,742	-	-	72,125
21	344	Laboratory Equipment	107,172	-	-	(4,109)	103,063	-	-	-	103,063	-	-	-	103,063
22	345	Power Operated Equipment	60,372	-	-	-	60,372	-	-	-	60,372	-	-	-	60,372
23	346	Communication Equipment	565,936	42,452	-	-	608,388	7,716	-	-	616,104	13,609	-	-	629,714
24	347	Miscellaneous Equipment	80,859	2,913	-	-	83,772	-	-	(835)	82,937	2,290	-	-	85,226
25	348	Other Tangible Equipment	4,783,710	343,336	-	-	5,127,046	14627.38	-	-	5,141,673	-	-	-	5,141,673
26		Offic (Incorrect Account No)	-			(1,545)	(1,545)				(1,545)				(1,545)
27												11,131			11,131
28															
29															
30		TOTAL PLANT IN SERVICE	$ 87,753,402	$ 1,028,495	$ 68,314	$ (341,038)	$ 88,509,173	$ 402,470	$ -	$ (37,056)	$ 88,874,587	$ 1,212,191	$ -	$ (17,064)	$ 90,069,714

References:
Column (A) agrees with Decision No. 71878
Column (B) through (M) RUCO Data Request 1.14

TABLE OF CONTENTS TO RBM SCHEDULES

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RBM-1	1 of 2	REVENUE REQUIREMENT
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RBM-3	1 of 2	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT WITH RUCO ADJUSTMENTS
RBM-3	2 of 2	RATE BASE ADJUSTMENT NO. 2 - POST TEST YEAR PLANT DEPRECIATION & ACCUMULATE DEPRECIATION
RBM-4	1	RATE BASE ADJUSTMENT NO. 3 - INFRASTRUCTURE COORDINATION AND FINANCING AGREEMENTS
RBM-5	1	COMPANY PLANT BALANCES SINCE LAST RATE CASE
RBM-6	1	SUMMARY ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS
RBM-7	1	SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS
RBM-8	1	DETAIL OF OPERATING INCOME WITH RUCO ADJUSTMENTS
RBM-9	1	DETAIL OF OPERATING INCOME WITH COMPANY ADJUSTMENTS
RBM-10	1	OPERATING INCOME ADJUSTMENT NO. 1 - RATE CASE EXPENSE
RBM-11	1	INTENTIONALLY LEFT BLANK
RBM-12	1	OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE
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RBM-17	1	OPERATING INCOMEADJUSTMENT NO. 8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ 38,014,243	$ 33,994,203
2			
3	Adjusted Operating Income (Loss)	$ 1,675,030	$ 1,666,872
4			
5	Current Rate Of Return (L3 / L1)	4.41%	4.90%
6			
7	Required Operating Income (L9 X L1)	$ 3,341,452	$ 2,537,188
8			
9	Required Rate Of Return On Fair Value Rate Base	8.79%	7.46%
10			
11	Operating Income Deficiency (L7 - L3)	$ 1,666,422	$ 870,315
12			
13	Gross Revenue Conversion Factor (RBM-1, Pg 2)	1.6371	1.6709
14			
15	Increase In Gross Revenue Requirement (L11 X L13)	$ 2,728,053	$ 1,454,179
16			
17	Adjusted Test Year Revenue	$ 10,463,460	$ 10,463,460
18			
19	Proposed Annual Revenue (L15 + L17)	$ 13,191,513	$ 11,917,639
20			
21	Required Percentage Increase In Revenue (L15 / L17)	26.07%	13.90%
22			
23	Rate Of Return On Common Equity	11.44%	8.50%

References:

Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A]	[B]	[C]
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor	0.4326%		
3	Revenues (L1 - L2)	99.5674%		
4	Combined Federal and State Income Tax and Property Tax Rate (L23)	39.7181%		
5	Subtotal (L3 - L4)	59.8493%		
6	**Revenue Conversion Factor (L1 / L5)**	1.670864		
	Calculation of Uncollecttible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (L17)	38.2900%		
9	One Minus Combined Income Tax Rate (L7 - L8)	61.7100%		
10	Uncollectible Rate	0.00701		
11	Uncollectible Factor (L9 * L10)	0.4326%		
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.5000%		
14	Federal Taxable Income (L12 - L13)	93.5000%		
15	Applicable Federal Income Tax Rate (Col [C] L53)	34.0000%		
16	Effective Federal Income Tax Rate (L14 x L15)	31.7900%		
17	Combined Federal and State Income Tax Rate (L13 + L16)		38.2900%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (Col. [B], L17)	38.2900%		
20	One Minus Combined Income Tax Rate (L18-L19)	61.7100%		
21	Property Tax Factor (Sch. RBM-16, Col. [B], L24)	2.3142%		
22	Effective Property Tax Factor (L20 x L21)		1.4281%	
23	Combined Federal and State Income Tax and Property Tax Rate (Col. (B), L17 + L22)			39.7181%
24	Required Operating Income (Sch. RBM-1, Col. (B) L7)	$ 2,537,188		
25	Adjusted Test Year Operating Income (Loss) (Sch. RBM-1, Col (B) L3)	1,666,872		
26	Required Increase in Operating Income (L24 - L25)		$ 870,315	
27	Income Taxes on Recommended Revenue (Col. [C], L52)	$ 817,864		
28	Income Taxes on Test Year Revenue (Col. (A), L52)	277,848		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		540,016	
30	*Recommended Revenue Requirement (Sch. RBM-1, Col. (B), L30*	$ 11,917,639		
31	Uncollectible Rate (L10)	0.00701		
32	Uncollectible Expense on Recommended Revenue (L30 x L31)	$ 83,553		
33	Adjusted Test Year Uncollectible Expense(Sch. RBM-8, Col. (K), L19)	$ 73,358		
34	Required Increase in Revenue to Provide for Uncollectible Exp. (L32 - L33)		10,195	
35	Property Tax with Recommended Revenue (Sch. RBM -8, Col. (K), L24)	$ 845,341		
36	Property Tax on Test Year Revenue (Sch. RBM-16)	811,688		
37	Increase in Property Tax Due to Increase in Revenue (L35 - 36)		33,653	
38	Total Required Increase in Revenue (Col. [B], L26 + L29 + L34 + L37)		$ 1,454,179	

	Calculation of Income Tax:	Test Year		RUCO Recommended
39	Revenue (Sch.RBM-7 Col [C] L4 and Col (D) L4	$ 10,463,460	$ 1,454,179	$ 11,917,639
40	Operating Expenses Excluding Income Taxes	$ 8,518,740		$ 8,562,587
41	Synchronized Interest (Col. [C], L57)	$ 1,219,079		$ 1,219,079
42	Arizona Taxable Income (L39 - L40 - L41)	$ 725,642		$ 2,135,973
43	Arizona State Income Tax Rate	6.5000%		6.5000%
44	Arizona Income Tax (L42 x L43)	$ 47,167		$ 138,838
45	Federal Taxable Income (L42 - L44)	$ 678,475		$ 1,997,135
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ 7,500		$ 7,500
47	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ 6,250		$ 6,250
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ 8,500		$ 8,500
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ 91,650		$ 91,650
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ 116,781		$ 565,126
51	Total Federal Income Tax	$ 230,681		$ 679,026
52	Combined Federal and State Income Tax (L44 + L51)	$ 277,848		$ 817,864
53	Applicable Federal Income Tax Rate [Col. [C], L46 - Col. [A], L46] / [Col. [C], L40 - Col. [A], L40]			34.0000%

54	Synchronized Interest Calculation	
55	Rate Base	$ 33,994,203
56	Weighted Average Cost of Debt	3.59%
57	Synchronized Interest	$ 1,219,079

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SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO ADJUSTMENTS

Line No.	Description	(A) Company As Filed OCRB/FVRB	(B) Adj No. 1 Post Test Year Plant	(C) Adj No. 2 CIAC Related to ICFA's	(D) Adj No. 3 Non CIAC Related to ICFA's	(E) RUCO As Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	$ 90,376,391	$ (291,762)			$ 90,084,629
2		-				
3	Accumulated Depreciation	(19,047,719)	-			(19,047,719)
4	Net Utility Plant In Service (L1 + L3)	$ 71,328,672	$ (291,762)			$ 71,036,910
5						
6	Advances In Aid Of Const.	$ (33,414,961)				$ (33,414,961)
7		-				
8	Contribution In Aid Of Const.	$ (77,293)		$ (7,387,598)		$ (7,464,891)
9	Accumulated Amortization Of CIAC	-		1,317,459		$ 1,317,459
10	NET CIAC (L8 + L9)	$ (77,293)	$ -	$ (6,070,139)		$ (6,147,432)
11						
12	Customer Meter Deposits	$ (1,193,499)	$ -			$ (1,193,499)
13						
14	Deferred Income Taxes & Credits	$ 1,371,325	$ -	$ 2,341,860		$ 3,713,185
15						
16	Unamortized Finance Charges	$ -	$ -			$ -
17						
18	Deferred Regulatory Assets	$ -	$ -			$ -
19						
20	Allowance For Working Capital	$ -	$ -			$ -
21						
22						
23	TOTAL RATE BASE (Sum L's 4,6,10-20)	$ 38,014,244	$ (291,762)	$ (3,728,279)		$ 33,994,203

References:
Column (A) Company Schedule B-1
Column (B) RBM-3 page 1

RATE BASE ADJUSTMENT NO. 1
RUCO POST TEST YEAR PLANT ADJUSTMENTS

	(A)	(B)	(C)	(D)	(E)		(F)
	Company's Initial Filing			Co. Follow Up Response			RUCO Adjustment
	Date Const Began	Date Const est to be Completed	Included in Rate Base Initial Est	Date Const Actually Completed	Final Costs/ as of March 31, 2013		
Global Water - Santa Cruz							
Edison Rd Waterline Ext	Aug 2012	Aug 2012	$ 300,742	Dec 2012	$ 240,224		$ (300,742)
RED WDC Chl Sys Replacement	Jan 2012	Jan 2012	6,149	April 2012	15,129		8,980
TOTALS			$ 306,891		$ 255,353		$ (291,762)
Willow Valley Water Company							
WVR SCADA - WVWC	Oct 2012	Oct 2012	$ 80,436	Not Started	-		$ (80,436)
TOTALS			$ 80,436		-		$ (80,436)
Water Utility of Greater Tonopah							
West Phoenix 6 Elec Upgrades	Nov 2012	Dec 2012	$ 3,076	Dec 2012	$ 3,501		$ (3,076)
West Phoenix 6 Fluoride	Nov 2012	Dec 2012	8,625	Jan 2013	18,693		(8,625)
WPE 6 Tank and Well Replacmt	May 2012	June 2012	95,082	Dec 2012	128,934		(95,082)
TOTALS			$ 106,783		$ 151,128		$ (106,783)
Valencia Water Company							
Bales Fill Line	July 2012	July 2012	$ 78,750	In Progress	$ 12,027		$ (78,750)
Buena Vista Fill Line	July 2012	July 2012	203,702	In Progress	20,004		(203,702)
Pima Road Waterline	April 2012	April 2012	182,563	Sept 2012	195,474		(182,563)
WVR SCADA Command Sta Imp	July 2012	July 2012	136,029	Jan 2013	21,962		(136,029)
SVWDC Optimization	June 2012	June 2012	71,526	Feb 2013	48,565		(71,526)
TOTALS			$ 672,570		$ 298,032		$ (672,570)
Global Water - Palo Verde Utilities							
Campus I WRF Ph 3 Exp	Nov 2008	June 2012	$ 119,810	Dec 2011	$ 119,810		$ -
PVUC In Pipe Odor Control	Mar 2012	June 2012	52,022	Nov 2012	57,397	Note (1)	(52,022)
PVUC Lagoon Clean Closure	April 2012	July 2012	406,949	Dec 2012	543,461	Note (1)	(406,949)
PVUC PEQB	April 2012	July 2012	12,564	Dec 2012	48,475	Note (1)	(12,564)
SRW MH Rehab and LS Imp Ph I	Dec 2010	Feb 2012	6,408	Dec 2012	3,295	Note (1)	(6,408)
PVUC WRF Headworks Rehab	Sept 2012	Sept 2012	69,132	Dec 2012	84,155	Note (1)	(69,132)
Sewer Manhole Rehab	Oct 2012	Oct 2012	66,509	Dec 2012	68,199	Note (1)	(66,509)
Edison Rd Sewer Ln Ext	Aug 2012	Aug 2012	85,000	Dec 2012	110,734	Note (1)	(85,000)
			$ 818,394		$ 1,035,526		$ (698,584)

References:
Columns (A), (B), (C) - Fleming Testimony pages 21 and 22. Company included in rate base.
Columns (D), (E) - Company Response to RUCO Data Request No. 2.01
NOTE (1): See Column (F) The costs for projects not completed and placed in service by June 30, 2012, were adjusted and excluded from rate base by RUCO

RATE BASE ADJUSTMENT NO. 2
RUCO POST TEST YEAR PLANT DEPRECIATION & A/D ADJUSTMENTS

		(A) Company Initial Filing Included in Rate Base Initial Est	(B) Date Const Actually Completed	(C) Company Final Costs/ as of March 31, 2013	(D) RUCO Adjustment PTY Plant	(E) Company Calculated Depreciation	(F) RUCO Calculated Depreciation	(G) RUCO Adjustment Depre & A/D
1	**Global Water - Santa Cruz**							
2	Edison Rd Waterline Ext	$ 300,742	Dec 2012	$ 240,224	$ (300,742)			
3	RED WDC Chl Sys Replacement	6,149	April 2012	15,129	8,980			
4	TOTALS	$ 306,891		$ 255,353	$ (291,762)	$ 15,345	$ 757	$ (14,588)
5								
6	**Willow Valley Water Company**							
7	WVR SCADA - WVWC	$ 80,436	Not Started	-	$ (80,436)			
8	TOTALS	$ 80,436		-	$ (80,436)	$ 4,022	$ -	$ (4,022)
9								
10	**Water Utility of Greater Tonopah**							
11	West Phoenix 6 Elec Upgrades	$ 3,076	Dec 2012	$ 3,501	$ (3,076)			
12	West Phoenix 6 Fluoride	8,625	Jan 2013	18,693	(8,625)			
13	WPE 6 Tank and Well Replacmt	95,082	Dec 2012	128,934	(95,082)			
14	TOTALS	$ 106,783		$ 151,128	$ (106,783)	$ 5,339	$ -	$ (5,339)
15								
16	**Valencia Water Company**							
17	Bales Fill Line	$ 78,750	In Progress	$ 12,027	$ (78,750)			
18	Buena Vista Fill Line	203,702	In Progress	20,004	(203,702)			
19	Pima Road Waterline	182,563	Sept 2012	195,474	(182,563)			
20	WVR SCADA Command Sta Imp	136,029	Jan 2013	21,962	(136,029)			
21	SVWDC Optimization	71,526	Feb 2013	48,565	(71,526)			
22	TOTALS	$ 672,570		$ 298,032	$ (672,570)	$ 33,629	$ -	$ (33,629)
23								
24	**Global Water - Palo Verde Utilities**							
25	Campus I WRF Ph 3 Exp	$ 119,810	Dec 2011	$ 119,810	$ -			
26	PVUC In Pipe Odor Control	52,022	Nov 2012	57,397	(52,022)			Note (1)
27	PVUC Lagoon Clean Closure	406,949	Dec 2012	543,461	(406,949)			
28	PVUC PEQB	12,564	Dec 2012	48,475	(12,564)			
29	SRW MH Rehab and LS Imp Ph I	6,408	Dec 2012	3,295	(6,408)			
30	PVUC WRF Headworks Rehab	69,132	Dec 2012	84,155	(69,132)			
31	Sewer Manhole Rehab	66,509	Dec 2012	68,199	(66,509)			
32	Edison Rd Sewer Ln Ext	85,000	Dec 2012	110,734	(85,000)			
33		$ 818,394		$ 1,035,526	$ (698,584)	$ 40,920	$ 5,991	$ (34,929)
34								

35 References:
36 Columns (A), (B), (C), (D) - See Sch RBM-2
37 Columns (E) - Company Schedules and testimony of Mr. Brett Higgabotham

38 NOTE (1): RUCO Depreciation and A/D adjustment calculated as follows:

39	Column (E) / Column (A)	15,345	
40		306,891	5.00% Depreciation allowance as calculated by Company
41			
42	Column (A) less Column (D)	$ 306,891	
43		$ 291,762	
44			$ 15,129 Test Year Plant as proposed by RUCO
45			
46	Depreciation expense proposed by RUCO		$ 757
47	Depreciation expense proposed by Company		$ 15,345
48	RUCO proposed depreciation and A/D adjustment		
49	related to Post Test Year Plant		$ (14,588)

POST TEST YEAR ADJUSTMENT NO. 3
INFRASTRUCTURE COORDINATION AND CONSTRUCTION AGREEMENTS

Line No.		SANTA CRUZ (A) Total Fees Collected	SANTA CRUZ (B) Allocated to Excess Cap.	SANTA CRUZ (C) Allocated to CIAC	PALO VERDE (A) Total Fees Collected	PALO VERDE (B) Allocated to Excess Cap.	PALO VERDE (C) Allocated to CIAC	TONOPAH (A) Total Fees Collected	TONOPAH (B) Allocated to Hassayampa	TONOPAH (C) Allocated to CIAC
1										
2	ICFA Fees Collected									
3										
4	Included in last rate filing	$ 24,541,553	$ 17,941,477	$ 6,600,076	$ 25,440,969	$ 14,449,844	$ 10,991,125	$ 9,226,100	$ 2,140,455	$ 7,085,645
5										
6	Fees Collected Since Last Rate Case	3,158,403	2,370,881	787,522	3,274,155	1,699,111	1,575,044	569,940	132,226	437,714
7										
8	Total ICFA Fees Collected	$ 27,699,956	$ 20,312,358	$ 7,387,598	$ 28,715,124	$ 16,148,955	$ 12,566,169	$ 9,796,040	$ 2,272,681	$ 7,523,359
9										
10	Calculation of ICFA Amortization									
11										
12	Amortization Expense Last Rate Filing	$ -	$ -	$ 494,849	$ -	$ -	$ 667,381	$ -	$ -	$ 236,248
13										
14	Amortization from 2008 thru 2011	-	-	822,610	-	-	$ 1,052,281	$ -	$ -	$ 819,250
15										
16	Total ICFA Accu. Amortization Expense thru Test Year			$ 1,317,459			$ 1,719,622			$ 1,719,622
17										
18										
19	**Amortization Expense for Test Year 2011**									
20										
21	First Quarter	$ 6,600,076	$ 66,951		First Quarter	$ 10,991,128	$ 88,221	First Quarter	$ 7,523,359	$ 54,921
22	Second Quarter	6,600,076	66,888		Second Quarter	11,057,409	85,406	Second Quarter	7,523,359	148,210
23	Third Quarter	6,633,216	66,607		Third Quarter	11,057,409	91,757	Third Quarter	7,523,359	130,154
24	Fourth Quarter	7,387,598	70,968		Fourth Quarter	12,566,172	94,794	Fourth Quarter	7,523,359	134,668
25										
26	Total Amortization Expense		$ 271,414		Total Amortization Expense		$ 360,178	Total Amortization Expense		$ 467,953

Reference:
Balances from last rate filing - See Decision No. 71878
Details of information obtained since last rate filing - On Site Review
Current Amortization from on site review

SCHEDULE OF AGREEMENTS, INCLUDING ICFS's

Line No.		(A) 2004	(B) 2005	(C) 2006	(D) 2007	(E) 2008	(F) 2009	(G) 2010	(H) 2011	(I) TOTAL
1	**Santa Cruz and Palo Verde Utilities**									
3	Santa Cruz and Palo Verde original CC&N	$ 4,757,941	$ 10,068,311	$ 8,164,494	$ 767,844	$ 87,750	$ 2,722,149	$ 175,515	$ 99,421	$ 26,843,425
5	Santa Cruz and Palo Verde Eastern Exp	165,625	6,127,681	-	2,982,915	1,319,600	-	-	-	10,595,821
7	Santa Cruz and Palo Verde Southwest Exp	-	280,017	4,763,450	-	612,500	-	98,225	150,000	5,904,192
9	Santa Cruz and Palo Verde 387 District	-	3,792,300	3,874,408	-	-	602,300	-	-	8,269,008
11	Santa Cruz and Palo Verde Southeast Exp	-	-	262,800	-	-	-	-	-	262,800
13	Santa Cruz and Palo Verde N/NW2nd SW Exp	-	-	22,925	23,300	26,250	321,803	-	2,263,145	2,657,423
15	Santa Cruz and Palo Verde Future Southeast	-	-	-	882,411	1,000,000	-	-	-	1,882,411
17	TOTAL Santa Cruz / Palo Verde	$ 4,923,566	$ 20,268,309	$ 17,088,077	$ 4,656,470	$ 3,046,100	$ 3,646,252	$ 273,740	$ 2,512,566	$ 56,415,080

	ALLOCATION - SANTA CRUZ / PALO VERDE	THRU YR 2008	2009 to 2011	TOTALS	
23	Allocated to Palo Verde	$ 25,440,969	3,274,155	$ 28,715,124	
24	Allocated to Santa Cruz	$ 24,541,553	$ 3,158,403	$ 27,699,956	
25	**Total ICFS's Funds Collected**	$ 49,982,522	$ 6,432,558	$ 56,415,080	See Columns (A) thru (I) L17

	FURTHER ALLCOATION BASED ON CIAC / EXCESS CAPACITY - SANTA CRUZ			
31	Funds Excluded from CIAC / Excess Capacity	$ 17,941,477	$ -	$ 17,941,477
33	Funds Included in CIAC	$ 6,600,076	$ 3,158,403	$ 9,758,479
35	Total ICFA funds from last rate case	$ 24,541,553	$ 3,158,403	$ 27,699,956

	FURTHER ALLCOATION BASED ON CIAC / EXCESS CAPACITY - PALO VERDE			
42	Funds Excluded from CIAC / Excess Capacity	$ 14,449,844	$ -	$ 14,449,844
44	Funds Included in CIAC	$ 10,991,125	$ 3,274,155	$ 14,265,280
46	Total ICFA funds from last rate case	$ 25,440,969	$ 3,274,155	$ 28,715,124

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COMPANY PLANT BALANCES SINCE LAST RATE CASE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Total Plant Value 2008	(B) Additions	(C) Other Costs	(D) Disposals	(E) Balance 2009	(F) Additions 2010	(G) Other Costs 2010	(H) Disposals	(I) Balance 2010	(J) Additions 2011	(K) Other Costs 2011	(L) Disposals	(M) Balance 2011
1	303	Land and Land Rights	$ 44,856	$ 334	$ -	$ -	$ 45,190	$ 319	$ -	$ -	$ 45,508	$ 17,338	$ -	$ -	$ 62,847
2	304	Structures and Improvements	9,447,338	(10,660)	125,487	-	9,562,165	2,200	-	-	9,564,365	1,739	-	-	9,566,105
3	305	Collecting and impounding Reservoirs	-				-		-		-				-
4	306	Lake, River and Other Intakes	1,855	-	-	-	1,855	-	-	-	1,855	-	-	-	1,855
5	307	Wells and Springs	3,694,926	(3)	-	(8,173)	3,686,749	21,511	-	-	3,708,260	751,217	-	-	4,459,478
6	308	Infiltration Galleries	-				-		-		-				-
7	309	Supply Mains	2,086,246	-	-	-	2,086,246	97,997	-	-	2,184,243	156,531	-	-	2,340,773
7	310	Power Generation Equipment	323,093	1,059	-	-	324,152	-	-	-	324,152	803	-	-	324,955
8	311	Pumping Equipment	6,353,511	259,155	(31,723)	-	6,580,943	65,227	-	-	6,646,169	136,373	-	-	6,782,543
8	320	Water Treatment Equipment	12,554	-	-	-	12,554	-	-	-	12,554	14,541	-	-	27,095
9	330	Distribution Reservoirs and Standpipes	1,367,063	6,528	-	-	1,373,591	-	-	-	1,373,591	4,683	-	-	1,378,274
10	331	Transmission and Distribution Mains	44,478,940	112,186	(25,450)	(289,411)	44,276,266	94,071	-	-	44,370,337	28,246	-	-	44,398,583
11	333	Services	4,598,396	46,741	-	-	4,645,137	-	-	-	4,645,137	303	-	-	4,645,440
12	334	Meters and Meter Installations	3,553,579	143,507	-	(2,546)	3,694,539	64,457	-	(21,310)	3,737,686	60,669	-	(5,500)	3,792,855
13	335	Hydrants	4,305,040	25,725	-	(14,770)	4,315,994	-	-	-	4,315,994	-	-	(11,500)	4,304,494
14	336	Backflow Prevention Devices	26,572	-	-	-	26,572	-	-	(14,910)	11,662	3,482	-	-	15,144
15	339	Other Plant and Miscellaneous Equipment	122,823	-	-	-	122,823	27,512	-	-	150,335	1,488	-	(64)	151,759
16	340	Office Furniture And Equipment	1,033,413	-	-	-	1,033,413	3,954	-	-	1,037,367	-	-	-	1,037,367
17	340.1	Computers and Software	43,296	50,116	-	-	93,412	2,879	-	-	96,292	(3,096)	-	-	93,195
18	341	Transportation Equipment	596,576	-	-	(20,483)	576,093	-	-	-	576,093	9,102	-	-	585,195
19	342	Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
20	343	Tools, Shop And Garage Equip	65,276	5,107	-	-	70,383	-	-	-	70,383	1,742	-	-	72,125
21	344	Laboratory Equipment	107,172	-	-	(4,109)	103,063	-	-	-	103,063	-	-	-	103,063
22	345	Power Operated Equipment	60,372	-	-	-	60,372	-	-	-	60,372	-	-	-	60,372
23	346	Communication Equipment	565,936	42,452	-	-	608,388	7,716	-	-	616,104	13,609	-	-	629,714
24	347	Miscellaneous Equipment	80,859	2,913	-	-	83,772	-	-	(835)	82,937	2,290	-	-	85,226
25	348	Other Tangible Equipment	4,783,710	343,336	-	-	5,127,046	14627.38	-	-	5,141,673	-	-	-	5,141,673
26		Office (Incorrect Account No)	-			(1,545)	(1,545)				(1,545)				(1,545)
27												11,131			11,131
28															
29															
30		Total Plant in Service	$ 87,753,402	$ 1,028,495	$ 68,314	$ (341,038)	$ 88,509,173	$ 402,470	$ -	$(37,056)	$ 88,874,587	$ 1,212,191	$ -	$ (17,064)	$ 90,069,714

References:
Column (A) agrees with Decision No. 71878
Column (B) through (M) RUCO Data Request 1.14

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	90,069,499	$ 306,892	$ -	$ -	$ 90,376,391
2	Accumulated Depreciation	(19,047,719)	-	-	-	(19,047,719)
3	Net Utility Plant In Service (L1 + L2)	$ 71,021,780	$ 306,892	$ -	$ -	$ 71,328,672
4	Advances In Aid Of Const.	$ (33,414,961)	$ -	$ -	$ -	$ (33,414,961)
5	Contribution In Aid Of Const.	$ (26,299,864)	$ -	$ 20,152,432	$ 6,070,139	$ (77,293)
6	Accumulated Amortization Of CIAC	-	-	-	-	-
7	NET CIAC (L5 + L6)	$ (26,299,864)	$ -	$ 20,152,432	$ 6,070,139	$ (77,293)
8	Customer Meter Deposits	$ (1,193,499)	$ -	$ -	$ -	$ (1,193,499)
9	Deferred Income Taxes & Credits	$ 11,487,555	$ -	$ (7,774,472)	$ (2,341,758)	$ 1,371,325
10	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 21,601,011	$ 306,892	$ 12,377,960	$ 3,728,381	$ 38,014,244

References:
Column (A): Company Schedule B-1
Column (B); Company Schedule B-2-1
Column (E); Columns (A) through (D)

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year' Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
	Revenues:						
1	461	Metered Water Revenues	$ 10,083,750	$ -	$ 10,083,750	$ 1,454,179	$ 11,537,929
2	460	Unmetered Water Revenues	-	-	-	-	-
3	474	Other Water Revenues	379,710	-	379,710	-	379,710
4		TOTAL OPERATING REVENUE	$ 10,463,460	$ -	$ 10,463,460	$ 1,454,179	$ 11,917,639
	Operating Expenses:						
5	601	Salaries And Wages - Employees	$ 1,268,835	(142,858)	$ 1,125,977	$ -	$ 1,125,977
6	610	Purchased Water	-	-	-	-	-
7	615	Purchased Power	768,901	-	768,901	-	768,901
8	618	Chemicals	53,341	-	53,341	-	53,341
9	620	Materials And Supplies	47,783	-	47,783	-	47,783
10	621	Office Supplies and Expense	90,035	-	90,035	-	90,035
11	630	Outside Services	1,053,640	-	1,053,640	-	1,053,640
12	635	Contractural Services - Testing	32,871	-	32,871	-	32,871
	636	Contractural Services - Other	-	-	-	-	-
13	641	Rental of Building / Real Property	121,973	-	121,973	-	121,973
14	650	Transportation Expenses	67,733	-	67,733	-	67,733
15	657	Insurance - General Liability	74,487	-	74,487	-	74,487
16	659	Insurance - Other	26,232	-	26,232	-	26,232
17	666	Regulatory Comm. Exp. - Rate Case	105,801	(53,558)	52,243	-	52,243
18	670	Bad Debt Expense	53,925	19,433	73,358	10,195	83,553
19	675	Miscellaneous Expense	373,190	(194,371)	178,819	-	178,819
20	403	Depreciation Expense	3,617,417	14,588	3,632,005	-	3,632,005
21	403	Depreciation Expense - CIAC Amort.	(3,770)	271,414	267,644	-	267,644
22	408	Taxes Other than Income	40,010	-	40,010	-	40,010
23	408.1	Taxes Other that Income - Property	897,129	(85,441)	811,688	33,653	845,341
24	409	Income Taxes	98,898	178,950	277,848	540,016	817,864
25			-	-	-	-	-
26			-				
27			-				
28			-				
29		Total Operating Expenses	$ 8,788,431	$ 8,157	$ 8,796,588	$ 583,864	$ 9,380,451
30		Operating Income (Loss)	$ 1,675,029		$ 1,666,872		$ 2,537,188

References:

Column (A): Company Schedule C-1
Column (B): RBM-8, Columns (B) Thru (J)
Column (C): Column (A) + Column (B)
Column (D): Sch. RBM-1, Column (B), L8: Sch RBM-1 page 2 L52
Column (E): Column (C) + Column (D)

Global Utilities
Docket No. W-01212A-12-309 et al
Test Year Ended December 31, 2011

Santa Cruz Water Company
Schedule RBM-8
Page 1

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	Acct No.	Description	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Left Blank	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 7 Property Taxes	(I) Adj. No 8 Income Taxes	(J) Total Pro Forma Adjustments	(K) Company As Adjusted Test Year
		Revenues:											
1	461	Metered Water Revenues	$ 10,083,750	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ 10,083,750
2	460	Other Water Revenues	-	-	-	-	-	-	-	-	-		$ -
3	474	Unmetered Water Revenues	379,710	-	-	-	-	-	-	-	-		$ 379,710
4		TOTAL OPR'G REV.	$ 10,463,460	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 10,463,460
		Operating Expenses:											
5	601	Salaries And Wages - Employees	$ 1,268,835					$ (142,858)				$ (142,858)	1,125,977
6	610	Purchased Water	-									-	-
7	615	Purchased Power	768,901									-	768,901
8	618	Chemicals	53,341									-	53,341
9	620	Materials And Supplies	47,783									-	47,783
10	621	Office Supplies and Expense	90,035									-	90,035
11	630	Outside Services	1,053,640									-	1,053,640
12	635	Contractural Services - Testing	32,871									-	32,871
13	636	Contractural Services - Other	-									-	-
14	641	Rental of Building / Real Property	121,973									-	121,973
15	650	Transportation Expenses	67,733									-	67,733
16	657	Insurance - General Liability	74,487									-	74,487
17	659	Insurance - Other	26,232									-	26,232
18	666	Regulatory Comm. Exp. - Rate Case	105,801	(53,558)								(53,558)	52,243
19	670	Bad Debt Expense	53,925				19,433					19,433	73,358
20	675	Miscellaneous Expense	373,190						(194,371)			(194,371)	178,819
21	403	Depreciation Expense	3,617,417			14,588						14,588	3,632,005
22	403	Depreciation Expense - CIAC Amort.	(3,770)			271,414						271,414	267,644
23	408	Taxes Other than Income	40,010									-	40,010
24	408.1	Taxes Other that Income - Property	897,129							(85,441)		(85,441)	811,688
25	409	Income Taxes	98,898								178,950	178,950	277,848
26			-										-
27			-										-
28			-										-
			-										-
29		Total Operating Expenses	$ 8,788,431	$ (53,558)	$ -	$ 286,002	$ 19,433	$ (142,858)	$ (194,371)	$ (85,441)	$ 178,950	$ 8,157	$ 8,796,588
			-										
30		Operating Income (Loss)	$ 1,675,029	$ 53,558	$ -	$ (286,002)	$ (19,433)	$ 142,858	$ 194,371	$ 85,441	$ (178,950)	$ (8,157)	$ 1,666,872

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH COMPANY ADJUSTMENTS

Line No	Acct No.	Description	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Rate Case Expense	(D) Adj. No 3 Low Income Relief	(E) Adj. No 4 Customer Count	(F) Adj. No 5 Accrued Revenue	(G) Adj. No 6 ICAC / CIAC Depre Adj	(H) Adj. No 7 Reclass of Revenues	(I) Adj. No 8 Post Test Yr Depre	(J) Adj. No 9 Bad Debt Expense	(K) Adj. No 10 Property Taxes	(L) Adj. No 11 License Fees	(M) Adj. No 12 Income Taxes	(N) Adj. No 13 Self Billed Revenuea	(O) Adj. No 14 Billing Credits	(P) Company Adjustments Test Year	(Q) Company As Adjusted Test Year
		Revenues:																	
1	461	Metered Water Revenues	$ 8,606,347	$ -	$ -	$ -	$ (83,647)	$ (312,254)	$ -	$ 1,719,769	$ -					$ 8,974	$ 144,561	$ 1,477,403	$ 10,083,750
2	460	Other Water Revenues	1,719,769	-	-	-	-	-	-	(1,719,769)	-							(1,719,769)	-
3	474	Unmetered Water Revenues	379,710	-	-	-	-	-	-	-	-							-	379,710
4		TOTAL REVENUES	$ 10,705,826	$ -	$ -	$ -	$ (83,647)	$ (312,254)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 8,974	$ 144,561	$ (242,366)	$ 10,463,460
		Operating Expenses:																	
5	601	Salaries And Wages - Employees	$ 1,268,835	$ -		$ -		$ -		$ -								$ -	1,268,835
6	610	Purchased Water	-	-		-		-		-								-	-
7	615	Purchased Power	765,602	-		-	3,299	-	-	-								3,299	768,901
8	618	Chemicals	53,087	-		-	254	-		-								254	53,341
9	620	Materials And Supplies	47,783	-		-		-		-								-	47,783
10	621	Office Supplies and Expense	90,035	-		-		-		-								-	90,035
11	630	Outside Services	1,053,640	-		-		-		-								-	1,053,640
12	635	Contractural Services - Testing	32,871	-		-		-		-								-	32,871
13	636	Contractural Services - Other	-	-		-		-		-								-	-
14	641	Rental of Building / Real Property	121,973	-		-		-		-								-	121,973
15	650	Transportation Expenses	67,733	-		-		-		-								-	67,733
16	657	Insurance - General Liability	74,487	-		-		-		-								-	74,487
17	659	Insurance - Other	26,232	-	-	-		-		-								-	26,232
18	666	Regulatory Comm. Exp. - Rate Case	53,333	(53,333)	105,801	-		-		-								52,468	105,801
19	670	Bad Debt Expense	55,174	-		-		-		-		(1,249)						(1,249)	53,925
20	675	Miscellaneous Expense	386,465	-		(8,295)		-		-				(4,980)				(13,275)	373,190
21	403	Depreciation Expense	3,602,072	-		-		-		-	15,345							15,345	3,617,417
22	403	Depreciation Expense - CIAC Amort.	(278,000)	-		-		-	274,230	-								274,230	(3,770)
23	408	Taxes Other than Income	40,010	-		-		-		-								-	40,010
24	408	Taxes Other that Income - Property	724,598	-		-		-		-			172,531					172,531	897,129
25	409	Income Taxes	935,304	-		-		-		-					(836,406)			(836,406)	98,898
26			-	-		-		-		-								-	-
27			-	-		-		-		-								-	-
28			-	-		-		-		-								-	-
29		TOTAL OPERATING EXPENSES	$ 9,121,234	$ (53,333)	$ 105,801	$ (8,295)	$ 3,553	$ -	$ 274,230	$ -	$ 15,345	$ (1,249)	$ 172,531	$ (4,980)	$ (836,406)	$ -		$ (332,803)	$ 8,788,431
30		OPERATING INCOME (LOSS)	$ 1,584,592	$ 53,333	$ (105,801)	$ 8,295	$ (87,200)	$ (312,254)	$ (274,230)	$ -	$ (15,345)	$ 1,249	$ (172,531)	$ 4,980	$ 836,406	$ 8,974	$ -	$ 90,437	$ 1,675,029

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor (L31)			37.41%
4				
5	Santa Cruz Water Company			$ 156,730
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 52,243.23
10				
11	Company Amortized Rate Case Expense for Santa Cruz as Filed (Sch. C-2.2)			$ 105,801
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (53,558)
14				
15	RUCO Adjustment			$ (53,558)
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
18	Decision No. 71878, dated September 15, 2010, approved amount			
19	$400,000 forGlobal Water.		$ 400,000	
20				
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) Ln 27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
29					
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

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OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Prior Dec Dep Rate	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) RUCO Depreciation Expense	(G) Company Reported Depreciation Expense
1	303	Land and Land Rights	0.00%	$ 45,508	17,338	-	-	-	
2	304	Structures and Improvements	3.33%	$ 9,564,365	1,739	-	-	318,522	319,091
3		Collecting and impounding Reservoirs	2.50%	-				-	
4	306	Lake, River and Other Intakes	2.50%	1,855	-	-	-	46	
5	307	Wells and Springs	3.33%	$ 3,708,260	751,217	-	-	135,993	136,019
6	308	Infiltration Galleries	6.67%					-	
7	309	Supply Mains	2.00%	$ 2,184,243	156,531	-	-	45,250	45,299
8	310	Power Generation Equipment	5.00%	$ 324,152	803	-	-	16,228	21,311
9	311	Pumping Equipment	12.50%	$ 6,646,169	136,373	-	-	839,295	770,239
10	320	Water Treatment Equipment	3.33%	$ 12,554	14,541	-	-	660	1,850
11	330.1	Distribution Reservoirs and Standpipes	2.22%	$ 1,373,591	4,683	-	-	30,546	45,791
12	331	Transmission and Distribution Mains	2.00%	$ 44,370,337	28,246	-	-	887,689	883,922
13	333	Services	3.33%	$ 4,645,137	303	-	-	154,688	154,710
14	334	Meters and Meter Installations	8.33%	$ 3,737,686	60,669	-	(5,500)	313,647	325,467
15	335	Hydrants	2.00%	$ 4,315,994	-	-	(11,500)	86,205	86,300
16	336	Backflow Prevention Devices	6.67%	$ 11,662	3,482	-	-	894	954
17	339	Other Plant and Miscellaneous Equipment	6.67%	$ 722,621	1,488	-	(64)	48,246	16,524
18	340	Office Furniture And Equipment	6.67%	$ 508,378	-	-	-	33,909	23,957
19	340.1	Computers and Software	33.33%	$ 52,996	(3,096)	-	-	17,147	98,655
20	341	Transportation Equipment	20.00%	$ 576,093	9,102	-	-	116,129	54,349
21	342	Stores Equipment	4.00%	-	-	-	-	-	
22	343	Tools, Shop And Garage Equipment	5.00%	$ 70,383	1,742	-	-	3,563	3,569
23	344	Laboratory Equipment	10.00%	$ 103,063	-	-	-	10,306	10,396
24	345	Power Operated Equipment	5.00%	$ 60,372	-	-	-	3,019	3,018
25	346	Communication Equipment	10.00%	$ 616,104	13,609	-	-	62,291	76,005
26	347	Miscellaneous Equipment	10.00%	$ 82,937	2,290	-	-	8,408	9,145
27	348	Other Tangible Equipment	10.00%	$ 5,141,673	-	-	-	514,167	512,957
28	390.1	Computer Hardware	33.33%					-	-
29	396	SCADA	33.33%		11,131	-	-	1,855	2,545
		Calculated Depreciation Expense						$ 3,648,703	$ 3,602,073
		Company Reported Depreciation Expense							$ 3,602,073
		Adjustment for Post Test Yr. Plant Depreciation							14,588
		RUCO Adjusted Test Year Depreciation Expense							3,616,661

References:
- Column A : Order 71878
- Column B : RUCO Schedule RBM-5.4
- Column C, D, E : RUCO DR 1.14
- Column F : (A x B)+((C:E) *A*.5))
- Column (G) Depreciation Expense as Reported by Company
- Line 34: Company Schedule B2.1 and RUCO Schedule RBM 3.2

NOTE: (1) Company calculated depreciation expense on an asset by asset basis and when an item is fully depreciated no additional depreciation expense is calculated. Therefore, RUCO accepted Company's calculation.

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
14						
15		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense	Acct No.	(A) COMPANY SELECTED EXPENSES	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	-
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (L23)			37.406%	
12					
13	Santa Cruz Water Company Allocation			$ (142,858)	
14					
15	Personnel Expense as Filed			$ 1,268,835	
16					
17	RUCO Pro Forma Expense (L15 + L13)			$ 1,125,977	
18					
19	RUCO Adjustment (L17-L15)			$ (142,858)	
20					
21	Allocation Factor Based on Test Year Revenue		Operating Revenue	Percent of Total	Adjustment by System
22	Palo Verde Utilities Co.		11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company		10,705,825	37.406%	(142,858)
24	Valencia Town Water Company		4,940,530	17.262%	(65,926)
25	Willow Valley Water Company		717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah		214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility		479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale		151,196	0.528%	(2,018)
29	Total Revenue Percentages		28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08
Column (C) -- Company Schedules C-2

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

Line No	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	Allocation: (D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94025	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970.41)	(11,480.96)	(152.11)	(216.03)	(482.33)	(10,770.58)	(721.57)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	$ (194,371)	$ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water L	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Percei	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (D) thru (J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 10,463,460	$ 10,463,460
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 20,926,920	$ 20,926,920
4a	Adjusted Test Year Revenues	10,463,460	
4b	Recommended Revenue, Per Schedule		11,917,639
5	Subtotal (L3 + L4a)	$ 31,390,380	$ 32,844,559
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 10,463,460	$ 10,948,186
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 20,926,920	$ 21,896,373
10	Plus: 10% of CWIP Per Company Schedule E	2,492,608	2,492,608
11	Less: Net Book Value of Licensed Vehicles	36,699	36,699
12	Full Cash Value (Line 9 + L10 - L11)	$ 23,382,828	$ 24,352,281
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 4,442,737	$ 4,626,933
15	Composite Property Tax Rate	18.2700%	18.2700%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 811,688	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedule)	897,129	
18	RUCO Test Year Adjustment (L16-L17)	$ (85,441)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 845,341
20	RUCO Test Year Adjusted Property Tax Expense (L16)		811,688
21	Increase/(Decrease) to Property Tax Expense		$ 33,653
22	Increase/(Decrease) to Property Tax Expense		$ 33,653
23	Increase in Revenue Requirement		1,454,179
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		0.023142

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Exp. As Filed by Company (RBM-8 Col (A) Ln 25)	$	98,898
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO (RBM-1(2), Col (A) Ln 52		277,848
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	178,950

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ 50,745,824	$ -	$ 50,745,824	54.50%	6.58%	3.59%
3	Common Equity	$ 42,364,815	$ -	$ 42,364,815	45.50%	8.50%	3.87%
4	TOTAL CAPITAL	$ 93,110,639	$ -	$ 93,110,639	100.00%		
5	COST OF CAPITAL						7.46%

References:
Columns (A) Thru (F): Testimony, WAR

Global Utilities
Docket No. W-20445A-12-0309 et al
Test Year Ended December 31, 2011

Valencia Water Company, Inc. - Town Division

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RBM-17	1	OPERATING INCOME ADJUSTMENT NO. 8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ 2,323,476	$ 1,650,906
2			
3	Adjusted Operating Income (Loss)	$ (263,809)	$ 14,305
4			
5	Current Rate Of Return (L2 / L1)	-11.35%	0.87%
6			
7	Required Operating Income (L5 X L1)	$ 238,621	$ 130,642
8			
9	Required Rate Of Return On Fair Value Rate Base	10.27%	7.91%
10			
11	Operating Income Deficiency (L4 - L2)	$ 502,430	$ 116,337
12			
13	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6389	1.5169
14			
15	Increase In Gross Revenue Requirement (L7 X L6)	$ 823,425	$ 176,472
16			
17	Adjusted Test Year Revenue	$ 4,940,316	$ 4,924,303
18			
19	Proposed Annual Revenue (L8 + L9)	$ 5,763,741	$ 5,100,775
20			
21	Required Percentage Increase In Revenue (L8 / L9)	16.67%	3.58%
22			
23	Rate Of Return On Common Equity	11.44%	8.50%

References:

Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A]	[B]	[C]
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor	0.3348%		
3	Revenues (L1 - L2)	99.6652%		
4	Combined Federal and State Income Tax and Property Tax Rate (L23)	33.7413%		
5	Subtotal (L3 - L4)	65.9239%		
6	**Revenue Conversion Factor (L1 / L5)**	1.516900		
	Calculation of Uncollecttible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (L17)	32.6407%		
9	One Minus Combined Income Tax Rate (L7 - L8)	67.3593%		
10	Uncollectible Rate	0.00497		
11	Uncollectible Factor (L9 * L10)	0.33475%		
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.5000%		
14	Federal Taxable Income (L12 - L13)	93.5000%		
15	Applicable Federal Income Tax Rate (Col [C] L53)	27.9580%		
16	Effective Federal Income Tax Rate (L14 x L15)	26.1407%		
17	Combined Federal and State Income Tax Rate (L13 + L16)		32.6407%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (Col. [B], L17)	32.6407%		
20	One Minus Combined Income Tax Rate (L18-L19)	67.3593%		
21	Property Tax Factor (Sch. RBM-16, Col. [B], L24)	1.6340%		
22	Effective Property Tax Factor (L20 x L21)		1.1007%	
23	Combined Federal and State Income Tax and Property Tax Rate (Col. (B), L17 + L22)			33.7413%
24	Required Operating Income (Sch. RBM-1, Col. (B) L7)	$ 130,642		
25	Adjusted Test Year Operating Income (Loss) (Sch. RBM-1, Col (B) L3)	14,305		
26	Required Increase in Operating Income (L24 - L25)		$ 116,337	
27	Income Taxes on Recommended Revenue (Col. [C], L52)	$ 53,906		
28	Income Taxes on Test Year Revenue (Col. (A), L52)	(2,468)		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		56,374	
30	Recommended Revenue Requirement (Sch. RBM-1, Col. (B), L30	$ 5,100,775		
31	Uncollectible Rate (L10)	0.00497		
32	Uncolllectible Expense on Recommended Revenue (L30 x L31)	$ 25,349		
33	Adjusted Test Year Uncollectible Expense(Sch. RBM-8, Col. (K), L31)	$ 24,472		
34	Required Increase in Revenue to Provide for Uncollectible Exp. (L32 - L33)		877	
35	Property Tax with Recommended Revenue (Sch. RBM -8, Col. (K), L36)	$ 249,714		
36	Property Tax on Test Year Revenue (Sch. RBM-8, Col. (Q), L32)	246,830		
37	Increase in Property Tax Due to Increase in Revenue (L35 - 36)		2,884	
38	Total Required Increase in Revenue (Col. [B], L26 + L29 + L34 + L37)		$ 176,472	

	Calculation of Income Tax:	Test Year		RUCO Recommended
39	Revenue (Sch.RBM-7 Col [C] L4 and Col (D) L4	$ 4,924,303	$ 176,472	$ 5,100,775
40	Operating Expenses Excluding Income Taxes	$ 4,912,466		$ 4,916,227
41	Synchronized Interest (Col. [C], L57)	$ 20,097		$ 20,097
42	Arizona Taxable Income (L39 - L40 - L41)	$ (8,260)		$ 164,451
43	Arizona State Income Tax Rate	6.5000%		6.5000%
44	Arizona Income Tax (L42 x L43)	$ (537)		$ 10,689
45	Federal Taxable Income (L42 - L44)	$ (7,723)		$ 153,762
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ (1,931)		$ 7,500
47	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ -		$ 6,250
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ -		$ 8,500
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ -		$ 20,967
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ -		$ -
51	Total Federal Income Tax	$ (1,931)		$ 43,217
52	Combined Federal and State Income Tax (L44 + L51)	$ (2,468)		$ 53,906
53	Applicable Federal Income Tax Rate [Col. [C], L46 - Col. [A], L46] / [Col. [C], L40 - Col. [A], L40]			27.9580%
54	Synchronized Interest Calculation			
55	Rate Base			$ 1,650,906
56	Weighted Average Cost of Debt			1.22%
57	Synchronized Interest			$ 20,097

SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO ADJUSTMENTS

Line No.	Description	(A) Company As Filed OCRB/FVRB	(B) Adj No. 1 Post Test Year Plant	(C) Adj No. 2 Accumulated Depreciation	(D) Adj No. 3 BLANK	(C) RUCO As Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	$ 53,624,734	$ (672,570)	$ -		$ 52,952,164
		-				
2	Accumulated Depreciation	(9,419,952)	-	-		(9,419,952)
3	Net Utility Plant In Service (L1 + L2)	$ 44,204,782	$ (672,570)	$ -		$ 43,532,212
4	Advances In Aid Of Const.	$ (39,299,151)				$ (39,299,151)
		-				
5	Contribution In Aid Of Const.	$ (1,587,941)				$ (1,587,941)
6	Accumulated Amortization Of CIAC	-				-
7	NET CIAC (L5 + L6)	$ (1,587,941)				$ (1,587,941)
8	Customer Meter Deposits	$ (395,015)				$ (395,015)
9	Deferred Income Taxes & Credits	$ (599,199)				$ (599,199)
10	Unamortized Finance Charges	$ -				$ -
11	Deferred Regulatory Assets	$ -				$ -
12	Allowance For Working Capital	$ -				$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 2,323,476	$ (672,570)	$ -	$ -	$ 1,650,906

References:
Column (A) Company Schedule B-1
Column (B): RBM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

RUCO POST TEST YEAR PLANT ADJUSTMENTS

	(A)	(B)	(C)	(D)	(E)		(F)
	Company's Initial Filing			Co. Follow Up Response			RUCO Adjustment
	Date Const Began	Date Const est to be Completed	Included in Rate Base Initial Est	Date Const Actually Completed	Final Costs/ as of March 31, 2013		
1 **Global Water - Santa Cruz**							
2 Edison Rd Waterline Ext	Aug 2012	Aug 2012	$ 300,742	Dec 2012	$ 240,224		$ (300,742)
3 RED WDC Chl Sys Replacement	Jan 2012	Jan 2012	6,149	April 2012	15,129		8,980
4 TOTALS			$ 306,891		$ 255,353		$ (291,762)
5							
6 **Willow Valley Water Company**							
7 WVR SCADA - WVWC	Oct 2012	Oct 2012	$ 80,436	Not Started	-		$ (80,436)
8 TOTALS			$ 80,436		-		$ (80,436)
9							
10 **Water Utility of Greater Tonopah**							
11 West Phoenix 6 Elec Upgrades	Nov 2012	Dec 2012	$ 3,076	Dec 2012	$ 3,501		$ (3,076)
12 West Phoenix 6 Fluoride	Nov 2012	Dec 2012	8,625	Jan 2013	18,693		(8,625)
13 WPE 6 Tank and Well Replacmt	May 2012	June 2012	95,082	Dec 2012	128,934		(95,082)
14 TOTALS			$ 106,783		$ 151,128		$ (106,783)
15							
16 **Valencia Water Company**							
17 Bales Fill Line	July 2012	July 2012	$ 78,750	In Progress	$ 12,027	Note (1)	$ (78,750)
18 Buena Vista Fill Line	July 2012	July 2012	203,702	In Progress	20,004	Note (1)	(203,702)
19 Pima Road Waterline	April 2012	April 2012	182,563	Sept 2012	195,474	Note (1)	(182,563)
20 WVR SCADA Command Sta Imp	July 2012	July 2012	136,029	Jan 2013	21,962	Note (1)	(136,029)
21 SVWDC Optimization	June 2012	June 2012	71,526	Feb 2013	48,565	Note (1)	(71,526)
22 TOTALS			$ 672,570		$ 298,032		$ (672,570)
23							
24 **Global Water - Palo Verde Utilities**							
25 Campus I WRF Ph 3 Exp	Nov 2008	June 2012	$ 119,810	Dec 2011	$ 119,810		$ -
26 PVUC In Pipe Odor Control	Mar 2012	June 2012	52,022	Nov 2012	57,397		(52,022)
27 PVUC Lagoon Clean Closure	April 2012	July 2012	406,949	Dec 2012	543,461		(406,949)
28 PVUC PEQB	April 2012	July 2012	12,564	Dec 2012	48,475		(12,564)
29 SRW MH Rehab and LS Imp Ph I	Dec 2010	Feb 2012	6,408	Dec 2012	3,295		(6,408)
30 PVUC WRF Headworks Rehab	Sept 2012	Sept 2012	69,132	Dec 2012	84,155		(69,132)
31 Sewer Manhole Rehab	Oct 2012	Oct 2012	66,509	Dec 2012	68,199		(66,509)
32 Edison Rd Sewer Ln Ext	Aug 2012	Aug 2012	85,000	Dec 2012	110,734		(85,000)
33			$ 818,394		$ 1,035,526		$ (698,584)

References:

Columns (A), (B), (C) - Mr. Fleming's Testimony pages 21 and 22. Company included in rate base.

Columns (D), (E) - Company Response to RUCO Data Request No. 2.01

NOTE (1): See Column (F) The costs for projects not completed and placed in service by June 30, 2012, were adjusted and excluded from rate base by RUCO

RUCO POST TEST YEAR PLANT DEPRECIATION & A/D ADJUSTMENTS

	(A) Company Initial Filing Included in Rate Base Initial Est	(B) Date Const Actually Completed	(C) Company Final Costs/ as of March 31, 2013	(D) RUCO Adjustment PTY Plant	(E) Company Calculated Depreciation	(F) RUCO Calculated Depreciation	(G) RUCO Adjustment Depre & A/D
Global Water - Santa Cruz							
Edison Rd Waterline Ext	$ 300,742	Dec 2012	$ 240,224	$ (300,742)			
RED WDC Chl Sys Replacement	6,149	April 2012	15,129	8,980			
TOTALS	$ 306,891		$ 255,353	$ (291,762)	$ 15,345	$ 757	$ (14,588)
Willow Valley Water Company							
WVR SCADA - WVWC	$ 80,436	Not Started	-	$ (80,436)			
TOTALS	$ 80,436		-	$ (80,436)	$ 4,022	$ -	$ (4,022)
Water Utility of Greater Tonopah							
West Phoenix 6 Elec Upgrades	$ 3,076	Dec 2012	$ 3,501	$ (3,076)			
West Phoenix 6 Fluoride	8,625	Jan 2013	18,693	(8,625)			
WPE 6 Tank and Well Replacmt	95,082	Dec 2012	128,934	(95,082)			
TOTALS	$ 106,783		$ 151,128	$ (106,783)	$ 5,339	$ -	$ (5,339)
Valencia Water Company							
Bales Fill Line	$ 78,750	In Progress	$ 12,027	$ (78,750)			
Buena Vista Fill Line	203,702	In Progress	20,004	(203,702)			
Pima Road Waterline	182,563	Sept 2012	195,474	(182,563)			NOTE (1)
WVR SCADA Command Sta Imp	136,029	Jan 2013	21,962	(136,029)			
SVWDC Optimization	71,526	Feb 2013	48,565	(71,526)			
TOTALS	$ 672,570		$ 298,032	$ (672,570)	$ 33,629	$ -	$ (33,629)
Global Water - Palo Verde Utilities							
Campus I WRF Ph 3 Exp	$ 119,810	Dec 2011	$ 119,810	$ -			
PVUC In Pipe Odor Control	52,022	Nov 2012	57,397	(52,022)			
PVUC Lagoon Clean Closure	406,949	Dec 2012	543,461	(406,949)			
PVUC PEQB	12,564	Dec 2012	48,475	(12,564)			
SRW MH Rehab and LS Imp Ph I	6,408	Dec 2012	3,295	(6,408)			
PVUC WRF Headworks Rehab	69,132	Dec 2012	84,155	(69,132)			
Sewer Manhole Rehab	66,509	Dec 2012	68,199	(66,509)			
Edison Rd Sewer Ln Ext	85,000	Dec 2012	110,734	(85,000)			
	$ 818,394		$ 1,035,526	$ (698,584)	$ 40,920	$ 5,991	$ (34,929)

References:
Columns (A), (B), (C), (D) - See Sch RBM-3 page 1
Columns (E) - Company Schedules and testimony of Mr. Brett Higgabotham

NOTE (1): RUCO Depreciation and A/D adjustment calculated as follows:

Column (E) / Column (A)	33,629 / 672,570	5.00%	Depreciation allowance as calculated by Company
Column (A) less Column (D)	$ 672,570		
	$ 672,570		
	$ -	$ -	Test Year Plant as proposed by RUCO
Depreciation expense proposed by RUCO		$ -	
Depreciation expense proposed by Company		$ 33,629	
RUCO proposed depreciation adjustment		$ (33,629)	A/D adjustment not required. See Note 1

NOTE 1
An adjustment would have been made reducing Accumulated Depreciation by $33,629. When reviewing the post test year accounting entries, and adjustment was made recognizing Depreciation Expense, however, no correcponding entry was made for A/D. No adjustment is required to A/D.

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COMPANY PLANT BALANCES SINCE LAST RATE CASE

LINE NO.	ACCT. NO.	ACCOUNT NAME	Gross Pant From Year 2008	(B) Additions	(C) Other Costs	(D) Disposals	(E) Balance 2009	(F) Additions 2010	(G) Other Costs 2010	(H) Disposals	(I) Balance 2010	(J) Additions 2011	(K) Other Costs 2011	(L) Disposals	(M) Balance 2011
1	303	Land and Land Rights	$ 148,446	$ 1,986	$ -	-	$ 150,432	-	$ -	-	$ 150,432	-	-	-	$ 150,432
2	304	Structures and Improvements	945,383	25,994	-	-	971,377	3,850	-	-	975,227	62,387	-	-	1,037,614
3	305	Collecting and impounding Reservoirs	-	-	-	-	-	-	-	-	-	-	-	-	-
4	306	Lake, River and Other Intakes	-	-	-		-	-	-	-	-	-	-	-	-
5	307	Wells and Springs	775,544	1,057,014	-	-	1,832,558	7,797	-	-	1,840,355	19,260	-	-	1,859,615
6	308	Infiltration Galleries	-	-	-	-	-	-	-	-	-	-	-	-	-
7	309	Supply Mains	-	-	-	-	-	-	-	-	-	46,790	-	-	46,790
7	310	Power Generation Equipment	20,612	-	-	-	20,612	-	-	-	20,612	41,643	-	-	62,255
8	311	Pumping Equipment	7,803,214	176,718	-	-	7,979,932	119,034	-	(6,226)	8,092,740	131,326	-	(6,500)	8,217,566
8	320	Water Treatment Equipment	3,892,532	179,703	-	-	4,072,235	13,134	-	-	4,085,369	6,474	-	-	4,091,843
9	330	Distribution Reservoirs and Standpipes	3,439,680	1,321,972	-	-	4,761,652	23,115	-	-	4,784,766	15,643	-	-	4,800,409
10	331	Transmission and Distribution Mains	19,407,008	1,652,082	-	-	21,059,090	(26,013)	-	(236)	21,032,841	421,152	-	-	21,453,993
11	333	Services	2,795,075	483,859	-	-	3,278,934	-	-	-	3,278,934	-	-	-	3,278,934
12	334	Meters and Meter Installations	1,562,332	65,281	-	(258,258)	1,369,354	59,130	-	(1,356)	1,427,129	44,707	-	(433)	1,471,403
13	335	Hydrants	1,900,270	80,362	-	-	1,980,632	-	-	-	1,980,632	-	-	-	1,980,632
14	336	Backflow Prevention Devices	12,674	-	-	-	12,674	-	-	-	12,674	1,242	-	-	13,916
15	339	Other Plant and Miscellaneous Equipment	114,439	10,160	-	-	124,599	41,516	-	-	166,115	3,404	-	-	169,519
16	340	Office Furniture And Equipment	46,206	2,750.00	-	-	48,956	12,688	-	-	61,644	-	-	-	61,644
17	340.1	Computers and Software	-	-	-	-	-	-	-	-	-	-	-	-	-
18	341	Transportation Equipment	275,038	-	-	-	275,038	-	-	-	275,038	44,312	-	-	319,350
19	342	Stores Equipment	-	-	-	-	-	-	-	-	-	-	-	-	-
20	343	Tools, Shop And Garage Equip	90,582	1,798.87	-	-	92,381	1,205	-	-	93,586	697	-	-	94,283
21	344	Laboratory Equipment	42,171	-		-	42,171	427	-	-	42,598	-	-	-	42,598
22	345	Power Operated Equipment	55,588	-	-	-	55,588	-	-	-	55,588	5,919.18	-	-	61,507
23	346	Communication Equipment	20,584	-	-	-	20,584	3,016	-	(900)	22,700	108,050	-	(1,017)	129,733
24	347	Miscellaneous Equipment	15,371	-		-	15,371	1,939	-	-	17,310	-	-	-	17,310
25	348	Other Tangible Equipment	2,514,672	355,012		-	2,869,684	54,513		-	2,924,197	590	-	-	2,924,787
26							-				-	480	-		480
27							-				-	660,299	-		660,299
28											-				
29	TOTAL PLANT IN SERVICE		$ 45,877,421	$ 5,414,691	$ -	$ (258,258)	$ 51,033,853	315,354	$ -	$ (8,718)	##########	$ 1,614,375	$ -	$ (7,950)	$ 52,946,913
30															
31		Company As Filed													$ 52,952,163
32		Difference													$ (5,250)

References:
Column (A) agrees with Decision No. 71878
Column (B) through (M) RUCO Data Request 1.14

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	52,952,163	$ 672,571	$ -	$ -	$ 53,624,734
2	Accumulated Depreciation	(9,419,952)	-	-	-	(9,419,952)
3	Net Utility Plant In Service (L1 + L2)	$ 43,532,211	$ 672,571	$ -	$ -	$ 44,204,782
4	Advances In Aid Of Const.	$ (39,299,151)	$ -	$ -	$ -	$ (39,299,151)
5	Contribution In Aid Of Const.	$ (1,587,941)	$ -	$ -	$ -	$ (1,587,941)
6	Accumulated Amortization Of CIAC	-	-	-	-	-
7	NET CIAC (L5 + L6)	$ (1,587,941)	$ -	$ -	$ -	$ (1,587,941)
8	Customer Meter Deposits	$ (395,015)	$ -	$ -	$ -	$ (395,015)
9	Deferred Income Taxes & Credits	$ (599,199)	$ -	$ -	$ -	$ (599,199)
10	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 1,650,905	$ 672,571	$ -	$ -	$ 2,323,476

References:
Column (A): Company Schedule B-1
Column (B); Company Schedule B-2-1
Column (E); Columns (A) through (D)

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
	Revenues:						
1	461	Metered Water Revenues	$ 4,787,361	$ -	$ 4,787,361	$ 176,472	$ 4,963,833
2	460	Unmetered Water Revenues	-	-	-	-	-
3	474	Other Water Revenues	136,942	-	136,942	-	136,942
4		TOTAL OPERATING REVENUE	$ 4,924,303	$ -	$ 4,924,303	$ 176,472	$ 5,100,775
	Operating Expenses:						
5	601	Salaries And Wages - Employees	$ 893,501	(65,926)	$ 827,575	$ -	$ 827,575
6	610	Purchased Water	269	-	269	-	269
7	615	Purchased Power	464,075	(87,064)	377,011	-	377,011
8	618	Chemicals	33,613	-	33,613	-	33,613
9	620	Materials And Supplies	79,398	-	79,398	-	79,398
10	621	Office Supplies and Expense	62,865	-	62,865	-	62,865
11	630	Outside Services	531,316	-	531,316	-	531,316
12	635	Contractural Services - Testing	14,571	-	14,571	-	14,571
13	641	Rental of Building / Real Property	43,412	-	43,412	-	43,412
14	650	Transportation Expenses	88,775	-	88,775	-	88,775
15	657	Insurance - General Liability	33,142	-	33,142	-	33,142
16	659	Insurance - Other	5,460	-	5,460	-	5,460
17	666	Regulatory Comm. Exp. - Rate Case	35,298	(11,189)	24,109	-	24,109
18	670	Bad Debt Expense	30,898	(6,426)	24,472	877	25,349
19	675	Miscellaneous Expense	79,463	(64,729)	14,734	-	14,734
20	403	Depreciation Expense	2,832,046	(278,619)	2,553,427	-	2,553,427
21	403	Depreciation Expense - CIAC Amort.	(63,825)	-	(63,825)	-	(63,825)
22	408	Taxes Other than Income	15,312	-	15,312	-	15,312
23	408.1	Taxes Other that Income - Property	273,680	(26,850)	246,830	2,884	249,714
24	409	Income Taxes	(249,144)	246,676	(2,468)	56,374	53,906
25			-				
26			-				
27			-				
28			-				
29		Total Operating Expenses	$ 5,204,125	$ (294,127)	$ 4,909,998	$ 60,135	$ 4,970,133
30		Operating Income (Loss)	$ (279,822)		$ 14,305		$ 130,642

References:

Column (A): Company Schedule C-1
Column (B): RLM-8, Columns (B) Thru (I)
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)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Pur. Power Expense	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 7 Property Taxes	(I) Adj. No 8 Income Taxes	(J) Total Pro Forma Adjustments	(K) Test Year Adjusted Results
	Revenues:											
1	461 Metered Water Revenues	$ 4,787,361	$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ 4,787,361
2	460 Other Water Revenues	-	-	-	-	-	-	-			-	-
3	474 Unmetered Water Revenues	136,942	-	-	-	-	-	-			-	136,942
4	TOTAL OPR'G REV.	$ 4,924,303	$ -	$ -	$ -	$ -	$ -					$ 4,924,303
	Operating Expenses:											
5	601 Salaries And Wages - Employees	$ 893,501					$ (65,926)				$ (65,926)	$ 827,575
6	610 Purchased Water	269									-	269
7	615 Purchased Power	464,075		(87,064)							(87,064)	377,011
8	618 Chemicals	33,613									-	33,613
9	620 Materials And Supplies	79,398									-	79,398
10	621 Office Supplies and Expense	62,865									-	62,865
11	630 Outside Services	531,316									-	531,316
12	635 Contractural Services - Testing	14,571									-	14,571
13	641 Rental of Building / Real Property	43,412									-	43,412
14	650 Transportation Expenses	88,775									-	88,775
15	657 Insurance - General Liability	33,142									-	33,142
16	659 Insurance - Other	5,460									-	5,460
17	666 Regulatory Comm. Exp. - Rate Case	35,298	(11,189)								(11,189)	24,109
18	670 Bad Debt Expense	30,898				(6,426)					(6,426)	24,472
19	675 Miscellaneous Expense	79,463						(64,729)			(64,729)	14,734
20	403 Depreciation Expense	2,832,046			(278,619)						(278,619)	2,553,427
21	403 Depreciation Expense - CIAC Amort.	(63,825)									-	(63,825)
22	408 Taxes Other than Income	15,312									-	15,312
23	408.1 Taxes Other that Income - Property	273,680							(26,850)		(26,850)	246,830
24	409 Income Taxes	(249,144)								246,676	246,676	(2,468)
25		-									-	-
26		-									-	-
27		-									-	-
28		-									-	-
		-									-	-
29	Total Operating Expense	$ 5,204,125	$ (11,189)	$ (87,064)	$ (278,619)	$ (6,426)	$ (65,926)	$ (64,729)	$ (26,850)	$ 246,676	$ (540,803)	$ 4,909,998
		-										
30	Operating Income (Loss)	$ (279,822)	$ 11,189	$ 87,064	$ 278,619	$ 6,426	$ 65,926	$ 64,729	$ 26,850	$ -	$ 540,803	$ 14,305

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH COMPANY ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Rate Case Expense	(D) Adj. No 3 Low Income Relief	(E) Adj. No 4 Customer Count	(F) Adj. No 5 Accrued Revenue	(G) Adj. No 6 Adjust Pur. Pwr.	(H) Adj. No 7 Reclass of Revenues	(I) Adj. No 8 Post Test Yr Depre	(J) Adj. No 9 Bad Debt Expense	(K) Adj. No 10 Property Taxes	(L) Adj. No 11 Income Taxes	(M) Adj. No 12 Income Taxes	(N) Adj. No 13 Income Taxes	(O) Company Adjustments Test Year	(P) Company As Adjusted Test Year
	Revenues:																
1	461 Metered Water Revenues	$ 3,452,481	$ -	$ -	$ -	$ 97,384	$ (113,611)	$ -	$ 1,351,107	$ -						$ 1,334,880	$ 4,787,361
2	460 Other Water Revenues	1,351,107	-	-	-	-	-	-	(1,351,107)	-						(1,351,107)	-
3	474 Unmetered Water Revenues	136,942	-	-	-	-	-	-	-	-						-	136,942
4	TOTAL OPR'G REV.	$ 4,940,530	$ -	$ -	$ -	$ 97,384	$ (113,611)		$ -								$ 4,924,303
	Operating Expenses:																
5	601 Salaries And Wages - Employees	$ 893,501	$ -		$ -		$ -		$ -							$ -	$ 893,501
6	610 Purchased Water	269	-		-		-		-							-	269
7	615 Purchased Power	364,411	-		-	12,600	-	87,064	-							99,664	464,075
8	618 Chemicals	33,220	-		-	393	-		-							393	33,613
9	620 Materials And Supplies	79,398	-		-		-		-							-	79,398
10	621 Office Supplies and Expense	62,865	-		-		-		-							-	62,865
11	630 Outside Services	531,316	-		-		-		-							-	531,316
12	635 Contractural Services - Testing	14,571	-		-		-		-							-	14,571
13	641 Rental of Building / Real Property	43,412	-		-		-		-							-	43,412
14	650 Transportation Expenses	88,775	-		-		-		-							-	88,775
15	657 Insurance - General Liability	33,142	-		-		-		-							-	33,142
16	659 Insurance - Other	5,460	-		-		-		-							-	5,460
17	666 Regulatory Comm. Exp. - Rate Case	18,667	(18,667)	35,298	-		-		-							16,631	35,298
18	670 Bad Debt Expense	30,899	-		-		-		-		(1)					(1)	30,898
19	675 Miscellaneous Expense	82,224	-		(2,761)		-		-							(2,761)	79,463
20	403 Depreciation Expense	2,798,417	-		-		-		-	33,629						33,629	2,832,046
21	403 Depreciation Expense - CIAC Amort.	(63,825)	-		-		-		-							-	(63,825)
22	408 Taxes Other than Income	15,312	-		-		-		-							-	15,312
	408 Taxes Other that Income - Property	164,216	-		-		-		-			109,464				109,464	273,680
24	409 Income Taxes	(184,029)	-		-		-		-				(65,115)			(65,115)	(249,144)
25		-	-		-		-		-							-	-
26		-	-		-		-		-							-	-
27		-	-		-		-		-							-	-
28		-	-		-		-		-							-	-
																-	-
29	TOTAL OPR'G EXP.	$ 5,012,221	$ (18,667)	$ 35,298	$ (2,761)	$ 12,993	$ -	$ 87,064	$ -	$ 33,629	$ (1)	$ 109,464	$ (65,115)	$ -	$ -	$ 191,904	$ 5,204,125
30	OPR'G INC. (LOSS)	$ (71,691)	$ 18,667	$ (35,298)	$ 2,761	$ 84,391	$ (113,611)	$ (87,064)	$ -	$ (33,629)	$ 1	$ (109,464)	$ 65,115	$ -	$ -	$ (191,904)	$ (279,822)

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor (L34)			17.26%
4				
5	Valencia Town Water Company			$ 72,328
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 24,109
10				
11	Company Amortized Rate Case Expense for Valencia Town as Filed (Sch. C-2.2)			$ 35,298
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (11,189)
14				
15	RUCO Adjustment			$ (11,189)
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
18	Decision No. 71878, dated September 15, 2010, approved amount			
19	$400,000 forGlobal Water.		$ 400,000	
20				
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) Ln 27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
29					
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

OPERATING INCOME ADJUSTMENT NO. 2
PURCHASED POWER

Line No.	System	Service Provider	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Valencia Town	Arizona Public Service	$ 464,075	$ (87,064)	$ 377,011
2					
3	Valencia Greater Buckeye	Arizona Public Service	27,670	(4,063)	23,607
4					
5	Greater Tonopah	Arizona Public Service	22,407	(4,062)	18,345
6					
7	Willow Valley	Mohave Electric Cooperative	43,747	(3,308)	40,439
8					
9		Total	557,899 -	(98,497) -	459,402

References
Column (A): Company Schedules C-2
Column (B): Company Schedules C-2.6

OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Prior Dec Dep Rate	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) Plant Balance 12/31/2011	(G) RUCO Depreciation Expense
1	303	Land and Land Rights	0.00%	$ 150,432	-	-	-	150,432	-
2	304	Structures and Improvements	3.33%	975,227	62,387	-	-	1,037,614	33,514
3		Collecting and impounding Reservoirs	2.50%	-	-	-	-	-	-
4	306	Lake, River and Other Intakes	2.50%	-	-	-	-	-	-
5	307	Wells and Springs	3.33%	1,840,355	19,260	-	-	1,859,615	61,604
6	308	Infiltration Galleries	6.67%	-	-	-	-	-	-
7	309	Supply Mains	2.00%	-	46,790	-	-	46,790	468
8	310	Power Generation Equipment	5.00%	20,612	41,643	-	-	62,255	2,072
9	311	Pumping Equipment	12.50%	8,092,740	131,326	-	(6,500)	8,217,566	1,019,394
10	320	Water Treatment Equipment	3.33%	4,085,369	6,474	-	-	4,091,843	136,151
11	330.1	Distribution Reservoirs and Standpipes	2.22%	4,784,766	15,643	-	-	4,800,409	106,395
12	331	Transmission and Distribution Mains	2.00%	21,032,841	421,152	-	-	21,453,993	424,868
13	333	Services	3.33%	3,278,934	-	-	-	3,278,934	109,189
14	334	Meters and Meter Installations	8.33%	1,427,129	44,707	-	(433)	1,471,403	120,724
15	335	Hydrants	2.00%	1,980,632	-	-	-	1,980,632	39,613
16	336	Backflow Prevention Devices	6.67%	12,674	1,242	-	-	13,916	887
17	339	Other Plant and Miscellaneous Equipment	6.67%	166,115	3,404	-	-	169,519	11,193
18	340	Office Furniture And Equipment	6.67%	61,644	-	-	-	61,644	4,112
19	340.1	Computers and Software	33.33%	-	-	-	-	-	-
20	341	Transportation Equipment	20.00%	275,038	44,312	-	-	319,350	59,439
21	342	Stores Equipment	4.00%	-	-	-	-	-	-
22	343	Tools, Shop And Garage Equipment	5.00%	93,586	697	-	-	94,283	4,697
23	344	Laboratory Equipment	10.00%	42,598	-	-	-	42,598	4,260
24	345	Power Operated Equipment	5.00%	55,588	5,919.18	-	-	61,507	2,927
25	346	Communication Equipment	10.00%	22,700	108,050	-	(1,017)	129,733	7,622
26	347	Miscellaneous Equipment	10.00%	17,310	-	-	-	17,310	1,731
27	348	Other Tangible Equipment	10.00%	2,924,197	590	-	-	2,924,787	292,449
28	390.1	Computer Hardware	33.33%		480	-		480	80
29	396	SCADA	33.33%		660,299	-		660,299	110,039
30									
31		Depreciation Expense as Calculated							$ 2,553,427
32		Depreciation Expense per Company Schedule C-2							2,798,417
33		RUCO's Initial Adjustment							(244,990)
34		Depreciation - Post Test Year Plant							(33,629)
35									
36		RUCO's Depreciation Expense Adjustment							(278,619)

References:
Column A : Order 71878
Column B : RUCO Schedule RBM-5
Column C, D, E : RUCO DR 1.14
Column F : (A x B)+((C:E) *A*.5))
Line 34: Company Schedule B2.1 and RUCO Schedule RBM 3.2

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
14						
15		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense	Acct. No.	(A) COMPANY SLECTED EXPENSES	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	-
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (B24)			17.262%	
12					
13	Valencia Town Water Company Allocation			$ (65,926)	
14					
15	Personnel Expense as Filed			$ 893,501	
16					
17	RUCO Pro Forma Expense (B15 + B13)			$ 827,575	
18					
19	RUCO Adjustment (B17-B15)			$ (65,926)	
20					

	Allocation Factor Based on Test Year Revenue	Operating Revenue	Percent of Total	Adjustment by System
21				
22	Palo Verde Utilities Co.	11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company	10,705,825	37.406%	(142,858)
24	Valencia Town Water Company	4,940,530	17.262%	(65,926)
25	Willow Valley Water Company	717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah	214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility	479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale	151,196	0.528%	(2,018)
29	Total Revenue Percentages	28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08
Column (C) -- Company Schedules C-2

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	Allocation: (D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94025	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970.41)	(11,480.96)	(152.11)	(216.03)	(482.33)	(10,770.58)	(721.57)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	# $ (194,371)	# $ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water L	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Percei	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (B-J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 4,924,303	$ 4,924,303
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 9,848,606	$ 9,848,606
4a	Adjusted Test Year Revenues	4,924,303	
4b	Recommended Revenue, Per Schedule		5,100,775
5	Subtotal (L3 + L4a)	$ 14,772,909	$ 14,949,381
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 4,924,303	$ 4,983,127
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 9,848,606	$ 9,966,254
10	Plus: 10% of CWIP Per Company Schedule E	265,232	265,232
11	Less: Net Book Value of Licensed Vehicles	43,247	43,247
12	Full Cash Value (Line 9 + L10 - L11)	$ 10,070,591	$ 10,188,239
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 1,913,412	$ 1,935,765
15	Composite Property Tax Rate (Per RUCO Effective Property Tax Calculation Analysis W/P)	12.9000%	12.9000%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 246,830	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedule)	273,680	
18	RUCO Test Year Adjustment (L16-L17)	$ (26,850)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 249,714
20	RUCO Test Year Adjusted Property Tax Expense (L16)		246,830
21	Increase/(Decrease) to Property Tax Expense		$ 2,884
22	Increase/(Decrease) to Property Tax Expense		$ 2,884
23	Increase in Revenue Requirement		176,472
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		1.63400%

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No.	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Expense As Filed by Company - RBM-7 Col (A) Ln 27	$	(249,144)
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO RBM-7 Col (C) Ln 27		(2,468)
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	246,676
7			

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 188,558	$ -	$ 188,558	1.17%	5.95%	0.07%
2	Long-term Debt	$ 3,248,406	$ -	$ 3,248,406	20.17%	5.69%	1.15%
3	Common Equity	$ 12,667,946	$ -	$ 12,667,946	78.66%	8.50%	6.69%
4	TOTAL CAPITAL	$ 16,104,910	$ -	$ 16,104,910	100.00%		
5	COST OF CAPITAL						7.91%

References:
Columns (A) Thru (F): Testimony, WAR

Global Utilities
Docket No. W-01212A-12-309 ET AL
Test Year Ended December 31, 2011

Water Utility of Greater Tonopah, Inc.

TABLE OF CONTENTS TO RBM SCHEDULES

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RBM-3	1 of 2	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT WITH RUCO ADJUSTMENTS
RBM-3	2 of 2	RATE BASE ADJUSTMENT NO. 2 - POST TEST YEAR PLANT DEPRECIATION & ACCUMULATE DEPRECIATION
RBM-4	1	RATE BASE ADJUSTMENT NO. 3 - INFRASTRUCTURE COORDINATION AND FINANCING AGREEMENTS
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RBM-10	1	OPERATING INCOME ADJUSTMENT NO. 1 - RATE CASE EXPENSE
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RBM-17	1	OPERATING INCOMEADJUSTMENT NO. 8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ 2,206,816	$ (1,437,481)
2			
3	Adjusted Operating Income (Loss)	$ (175,170)	$ (499,923)
4			
5	Current Rate Of Return (L3 / L1)	-7.94%	NA
6			
7	Required Operating Income (L9 X L1)	$ 236,571	$ 19,549
8			
9	Required Rate Of Return On Fair Value Rate Base	10.72%	8.19%
10			
11	Operating Income Deficiency (L7 - L3)	$ 411,741	NA
12			
13	Gross Revenue Conversion Factor (RBM-1, Pg 2)	1.6451	1.9400
14			
15	Increase In Gross Revenue Requirement (L11 X L13)	$ 677,349	$ 32,753
16			
17	Adjusted Test Year Revenue	$ 207,705	$ 207,705
18			
19	Proposed Annual Revenue (L15 + L17)	$ 885,054	$ 240,458
20			
21	Required Percentage Increase In Revenue (L15 / L17)	326.11%	15.77%
22			
23	Rate Of Return On Common Equity	8.50%	7.31%

References:
Column (A) Company Schedule A-1

References:
Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO 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	$ 5,766,393	$ (106,783)	$ 5,659,610
		-		
2	Accumulated Depreciation	(1,863,416)	-	(1,863,416)
3	Net Utility Plant In Service (L1 + L2)	$ 3,902,977	$ (106,783)	$ 3,796,194
4	Advances In Aid Of Const.	$ (1,619,985)	$ -	$ (1,619,985)
		-		
5	Contribution In Aid Of Const.	$ (59,465)	$ (7,523,359)	$ (7,582,824)
6	Accumulated Amortization Of CIAC	-	1,055,498	1,055,498
7	NET CIAC (L5 + L6)	$ (59,465)	$ (6,467,861)	$ (6,527,326)
8	Customer Meter Deposits	$ (22,030)	$ -	$ (22,030)
9	Deferred Income Taxes - Credits	$ 5,318	$ 2,930,348	$ 2,935,666
10	Unamortized Finance Charges	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 2,206,815	$ (3,644,296)	$ (1,437,481)

References:
Column (A): Company Schedule B-1
Column (B): RBM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

RUCO POST TEST YEAR PLANT ADJUSTMENTS

	(A)	(B)	(C)	(D)	(E)		(F)
	Company's Initial Filing			Co. Follow Up Response			RUCO Adjustment
	Date Const Began	Date Const est to be Completed	Included in Rate Base Initial Est	Date Const Actually Completed	Final Costs/ as of March 31, 2013		
Global Water - Santa Cruz							
Edison Rd Waterline Ext	Aug 2012	Aug 2012	$ 300,742	Dec 2012	$ 240,224		$ (300,742)
RED WDC Chl Sys Replacement	Jan 2012	Jan 2012	6,149	April 2012	15,129		8,980
TOTALS			$ 306,891		$ 255,353		$ (291,762)
Willow Valley Water Company							
WVR SCADA - WVWC	Oct 2012	Oct 2012	$ 80,436	Not Started	-		$ (80,436)
TOTALS			$ 80,436		-		$ (80,436)
Water Utility of Greater Tonopah							
West Phoenix 6 Elec Upgrades	Nov 2012	Dec 2012	$ 3,076	Dec 2012	$ 3,501	Note (1)	$ (3,076)
West Phoenix 6 Fluoride	Nov 2012	Dec 2012	8,625	Jan 2013	18,693	Note (1)	(8,625)
WPE 6 Tank and Well Replacmt	May 2012	June 2012	95,082	Dec 2012	128,934	Note (1)	(95,082)
TOTALS			$ 106,783		$ 151,128		$ (106,783)
Valencia Water Company							
Bales Fill Line	July 2012	July 2012	$ 78,750	In Progress	$ 12,027		$ (78,750)
Buena Vista Fill Line	July 2012	July 2012	203,702	In Progress	20,004		(203,702)
Pima Road Waterline	April 2012	April 2012	182,563	Sept 2012	195,474		(182,563)
WVR SCADA Command Sta Imp	July 2012	July 2012	136,029	Jan 2013	21,962		(136,029)
SVWDC Optimization	June 2012	June 2012	71,526	Feb 2013	48,565		(71,526)
TOTALS			$ 672,570		$ 298,032		$ (672,570)
Global Water - Palo Verde Utilities							
Campus I WRF Ph 3 Exp	Nov 2008	June 2012	$ 119,810	Dec 2011	$ 119,810		$ -
PVUC In Pipe Odor Control	Mar 2012	June 2012	52,022	Nov 2012	57,397		(52,022)
PVUC Lagoon Clean Closure	April 2012	July 2012	406,949	Dec 2012	543,461		(406,949)
PVUC PEQB	April 2012	July 2012	12,564	Dec 2012	48,475		(12,564)
SRW MH Rehab and LS Imp Ph I	Dec 2010	Feb 2012	6,408	Dec 2012	3,295		(6,408)
PVUC WRF Headworks Rehab	Sept 2012	Sept 2012	69,132	Dec 2012	84,155		(69,132)
Sewer Manhole Rehab	Oct 2012	Oct 2012	66,509	Dec 2012	68,199		(66,509)
Edison Rd Sewer Ln Ext	Aug 2012	Aug 2012	85,000	Dec 2012	110,734		(85,000)
			$ 818,394		$ 1,035,526		$ (698,584)

References:
Columns (A), (B), (C) - Fleming Testimony pages 21 and 22. Company included in rate base.
Columns (D), (E) - Company Response to RUCO Data Request No. 2.01
NOTE (1): See Column (F) The costs for projects not completed and placed in service by June 30, 2012, were adjusted and excluded from rate base by RUCO

RUCO POST TEST YEAR PLANT DEPRECIATION & A/D ADJUSTMENTS

	(A) Company Initial Filing Included in Rate Base Initial Est	(B) Date Const Actually Completed	(C) Company Final Costs/ as of March 31, 2013	(D) RUCO Adjustment PTY Plant	(E) Company Calculated Depreciation	(F) RUCO Calculated Depreciation	(G) RUCO Adjustment Depre & A/D
Global Water - Santa Cruz							
Edison Rd Waterline Ext	$ 300,742	Dec 2012	$ 240,224	$ (300,742)			
RED WDC Chl Sys Replacement	6,149	April 2012	15,129	8,980			
TOTALS	$ 306,891		$ 255,353	$ (291,762)	$ 15,345	$ 757	$ (14,588)
Willow Valley Water Company							
WVR SCADA - WVWC	$ 80,436	Not Started	-	$ (80,436)			
TOTALS	$ 80,436		-	$ (80,436)	$ 4,022	$ -	$ (4,022)
Water Utility of Greater Tonopah							
West Phoenix 6 Elec Upgrades	$ 3,076	Dec 2012	$ 3,501	$ (3,076)			NOTE (1)
West Phoenix 6 Fluoride	8,625	Jan 2013	18,693	(8,625)			
WPE 6 Tank and Well Replacmt	95,082	Dec 2012	128,934	(95,082)			
TOTALS	$ 106,783		$ 151,128	$ (106,783)	$ 5,339	$ -	$ (5,339)
Valencia Water Company							
Bales Fill Line	$ 78,750	In Progress	$ 12,027	$ (78,750)			
Buena Vista Fill Line	203,702	In Progress	20,004	(203,702)			
Pima Road Waterline	182,563	Sept 2012	195,474	(182,563)			
WVR SCADA Command Sta Imp	136,029	Jan 2013	21,962	(136,029)			
SVWDC Optimization	71,526	Feb 2013	48,565	(71,526)			
TOTALS	$ 672,570		$ 298,032	$ (672,570)	$ 33,629	$ -	$ (33,629)
Global Water - Palo Verde Utilities							
Campus I WRF Ph 3 Exp	$ 119,810	Dec 2011	$ 119,810	$ -			
PVUC In Pipe Odor Control	52,022	Nov 2012	57,397	(52,022)			
PVUC Lagoon Clean Closure	406,949	Dec 2012	543,461	(406,949)			
PVUC PEQB	12,564	Dec 2012	48,475	(12,564)			
SRW MH Rehab and LS Imp Ph I	6,408	Dec 2012	3,295	(6,408)			
PVUC WRF Headworks Rehab	69,132	Dec 2012	84,155	(69,132)			
Sewer Manhole Rehab	66,509	Dec 2012	68,199	(66,509)			
Edison Rd Sewer Ln Ext	85,000	Dec 2012	110,734	(85,000)			
	$ 818,394		$ 1,035,526	$ (698,584)	$ 40,920	$ 5,991	$ (34,929)

References:
Columns (A), (B), (C), (D) - See Sch RBM-2
Columns (E) - Company Schedules and testimony of Mr. Brett Higgabotham

NOTE (1): RUCO Depreciation and A/D adjustment calculated as follows:

Column (E) / Column (A)	5,339 / 106,783	5.00%	Depreciation allowance as calculated by Company
Column (A) less Column (D)	$ 106,783		
	$ 106,783		
	$ -	$ -	Test Year Plant as proposed by RUCO

Depreciation expense proposed by RUCO	$ -
Depreciation expense proposed by Company	$ 5,339
RUCO proposed depreciation and A/D adjustment related to Post Test Year Plant	$ (5,339)

POST TEST YEAR ADJUSTMENT NO. 3
INFRASTRUCTURE COORDINATION AND CONSTRUCTION AGREEMENTS

Line No.		SANTA CRUZ (A) Total Fees Collected	SANTA CRUZ (B) Allocated to Excess Cap.	SANTA CRUZ (C) Allocated to CIAC	PALO VERDE (A) Total Fees Collected	PALO VERDE (B) Allocated to Excess Cap.	PALO VERDE (C) Allocated to CIAC	TONOPAH (A) Total Fees Collected	TONOPAH (B) Allocated to Hassayampa	TONOPAH (C) Allocated to CIAC
1										
2	ICFA Fees Collected									
3										
4	Included in last rate filing	$ 24,541,553	$ 17,941,477	$ 6,600,076	$ 25,440,969	$ 14,449,844	$ 10,991,125	$ 9,226,100	$ 2,140,455	$ 7,085,645
5										
6	Fees Collected Since Last Rate Case	3,158,403	2,370,881	787,522	3,274,155	1,699,111	1,575,044	569,940	132,226	437,714
7										
8	Total ICFA Fees Collected	$ 27,699,956	$ 20,312,358	$ 7,387,598	$ 28,715,124	$ 16,148,955	$ 12,566,169	$ 9,796,040	$ 2,272,681	$ 7,523,359
9										
10	Calculation of ICFA Amortization									
11										
12	Amortization Expense Last Rate Filing	$ -	$ -	$ 494,849	$ -	$ -	$ 667,381	$ -	$ -	$ 236,248
13										
14	Amortization from 2008 thru 2011	-	-	822,610	-	-	$ 1,052,281	$ -	$ -	$ 819,250
15										
16	Total ICFA Accu. Amortization Expense thru Test Year			$ 1,317,459			$ 1,719,622			$ 1,055,498
17										
18										
19	**Amortization Expense for Test Year 2011**									
20										
21	First Quarter	$ 6,600,076	$ 66,951		First Quarter	$ 10,991,128	$ 88,221	First Quarter	$ 7,523,359	$ 54,921
22	Second Quarter	6,600,076	66,888		Second Quarter	11,057,409	85,406	Second Quarter	7,523,359	148,210
23	Third Quarter	6,633,216	66,607		Third Quarter	11,057,409	91,757	Third Quarter	7,523,359	130,154
24	Fourth Quarter	7,387,598	70,968		Fourth Quarter	12,566,172	94,794	Fourth Quarter	7,523,359	134,668
25										
26	Total Amortization Expense		$ 271,414		Total Amortization Expense		$ 360,178	Total Amortization Expense		$ 467,953

Reference:
Balances from last rate filing - See Decision No. 71878
Details of information obtained since last rate filing - On Site Review
Current Amortization from on site review

PLANT SCHEDULES
YEAR ENDED DECEMBER 31, 2011

LINE NO.	ACCT. NO.	ACCOUNT NAME	Gross Pant From Year 2010	(A) Additions	(B) Plant Retirements	(D) Gross Plant Value 2011
1	303	Land and Land Rights	$ 66,651	$ 110,779	$ -	$ 177,430
2	304	Structures and Improvements	46,704	973	-	47,677
3	305	Collecting and impounding Reservoirs	-	-	-	
4	306	Lake, River and Other Intakes	-	-	-	
5	307	Wells and Springs	299,601	-	-	299,601
6	308	Infiltration Galleries	-	-	-	
7	309	Supply Mains	-	-	-	
7	310	Power Generation Equipment	-	-	-	
8	311	Pumping Equipment	1,758,896	29,195	(454)	1,787,637
8	320	Water Treatment Equipment	1,621,120	5,400	-	1,626,520
9	330	Distribution Reservoirs and Standpipes	185,007	45,380	(1,732)	228,655
10	331	Transmission and Distribution Mains	889,254	1,689	-	890,943
11	333	Services	43,069	-	-	43,069
12	334	Meters and Meter Installations	145,261	1,917	-	147,178
13	335	Hydrants	38,386	-	-	38,386
14	336	Backflow Prevention Devices	5,894	-	-	5,894
15	339	Other Plant and Miscellaneous Equipment	5,424	-	-	5,424
16	340	Office Furniture And Equipment	-	-	-	
17	340.1	Computers and Software	-	-	-	
18	341	Transportation Equipment	32,617	-	(32,617)	
19	342	Stores Equipment	-	-	-	
20	343	Tools, Shop And Garage Equip	1,688	289	-	1,977
21	344	Laboratory Equipment	663	-		663
22	345	Power Operated Equipment	845	-	-	845
23	346	Communication Equipment	12,408	-	-	12,408
24	347	Miscellaneous Equipment	5,210	-		5,210
25	348	Other Tangible Equipment	340,097			340,097
	TOTAL PLANT IN SERVICE		$ 5,498,795	$ 195,622	$ (34,803)	$ 5,659,614
	Company As Filed					
	Difference					

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	5,659,611	$ 106,782	$ -	$ -	$ 5,766,393
2	Accumulated Depreciation	(1,863,416)	-	-	-	(1,863,416)
3	Net Utility Plant In Service (L1 + L2)	$ 3,796,195	$ 106,782	$ -	$ -	$ 3,902,977
4	Advances In Aid Of Const.	$ (1,619,985)	$ -	$ -	$ -	$ (1,619,985)
5	Contribution In Aid Of Const.	$ (6,215,057)	$ -	$ 2,109,071	$ 4,046,521	$ (59,465)
6	Accumulated Amortization Of CIAC	-	-	-	-	-
7	NET CIAC (L5 + L6)	$ (6,215,057)	$ -	$ 2,109,071	$ 4,046,521	$ (59,465)
8	Customer Meter Deposits	$ (22,030)	$ -	$ -	$ -	$ (22,030)
9	Deferred Income Taxes & Credits	$ 2,386,853	$ -	$ (815,978)	$ (1,565,557)	$ 5,318
10	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ (1,674,024)	$ 106,782	$ 1,293,093	$ 2,480,964	$ 2,206,815

References:
Column (A): Company Schedule B-1
Column (B); Company Schedule B-2-1
Column (E); Columns (A) through (D)

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year' Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
	Revenues:						
1	461	Metered Water Revenues	$ 202,202	$ -	$ 202,202	32753	$ 234,955
2	460	Unmetered Water Revenues	-	-	-		-
3	474	Other Water Revenues	5,503	-	5,503		5,503
4		TOTAL OPERATING REVENUE	$ 207,705	$ -	$ 207,705	$ 32,753	$ 240,458
5							
6	Operating Expenses:						
7	601	Salaries And Wages - Employees	$ 75,753	(2,865)	$ 72,888	$ -	$ 72,888
8	610	Purchased Water	960	-	960	-	960
9	615	Purchased Power	22,407	(4,062)	18,345	-	18,345
10	618	Chemicals	10,522	-	10,522	-	10,522
11	620	Materials And Supplies	20,175	-	20,175	-	20,175
12	621	Office Supplies and Expense	3,591	-	3,591	-	3,591
13	630	Outside Services	26,415	-	26,415	-	26,415
14	635	Contractural Services - Testing	5,109	-	5,109	-	5,109
15	636	Contractural Services - Other	-	-	-	-	-
16	641	Rental of Building / Real Property	2,597	-	2,597	-	2,597
17	650	Transportation Expenses	5,733	-	5,733	-	5,733
18	657	Insurance - General Liability	1,557	-	1,557	-	1,557
19	659	Insurance - Other	269	-	269	-	269
20	666	Regulatory Comm. Exp. - Rate Case	2,140	(1,093)	1,047	-	1,047
21	670	Bad Debt Expense	4,769	(1,018)	3,751	-	3,751
22	675	Miscellaneous Expense	7,221	(3,940)	3,281	-	3,281
23	403	Depreciation Expense	380,785	(16,741)	364,044	-	364,044
24	403	Depreciation Expense - CIAC Amort.	(2,151)	467,953	465,802	-	465,802
25	408	Taxes Other than Income	1,553	-	1,553	-	1,553
26	408.1	Taxes Other that Income - Property	11,254	(1,071)	10,183	507	10,689
27	409	Income Taxes	(197,785)	(112,408)	(310,193)	(487,225)	(797,418)
28							
29							
30							
31							
32							
33		TOTAL OPERATING EXPENSES	$ 382,874	$ 324,754	$ 707,628	$ (486,718)	$ 220,909
34							
35		OPERATING INCOME (LOSS)	$ (175,169)		$ (499,923)		$ 19,549

References:

Column (A): Company Schedule C-1
Column (B): RBM-8, Columns (B) Thru (J)
Column (C): Column (A) + Column (B)
Column (D): Sch. RBM-1, Column (B), L8: Sch RBM-1 page 2 L52
Column (E): Column (C) + Column (D)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Pur. Power Expense	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 7 Property Taxes	(I) Adj. No 8 Income Taxes	(O) Total Pro Forma Adjustments	(P) Test Year Adjusted Results
	Revenues:											
1	461 Metered Water Revenues	$ 202,202	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 202,202
2	460 Other Water Revenues	-	-	-	-	-	-	-	-	-	-	-
3	474 Unmetered Water Revenues	5,503	-	-	-	-	-	-	-	-	-	5,503
4	Total Operating Expenses	$ 207,705	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 207,705
5	Operating Expenses:											
6	601 Salaries And Wages - Employees	$ 75,753					$ (2,865)				$ (2,865)	$ 72,888
7	610 Purchased Water	960									-	960
8	615 Purchased Power	22,407		(4,062)							(4,062)	18,345
9	618 Chemicals	10,522									-	10,522
10	620 Materials And Supplies	20,175									-	20,175
11	621 Office Supplies and Expense	3,591									-	3,591
12	630 Outside Services	26,415									-	26,415
13	635 Contractural Services - Testing	5,109									-	5,109
14	636 Contractural Services - Other	-										-
15	641 Rental of Building / Real Property	2,597									-	2,597
16	650 Transportation Expenses	5,733									-	5,733
17	657 Insurance - General Liability	1,557									-	1,557
18	659 Insurance - Other	269									-	269
19	666 Regulatory Comm. Exp. - Rate Case	2,140	(1,093)								(1,093)	1,047
20	670 Bad Debt Expense	4,769				(1,018)					(1,018)	3,751
21	675 Miscellaneous Expense	7,221						(3,940)			(3,940)	3,281
22	403 Depreciation Expense	380,785			(16,741)						(16,741)	364,044
23	403 Depreciation Expense - CIAC Amort.	(2,151)			467,953						467,953	465,802
24	408 Taxes Other than Income	1,553									-	1,553
25	408.1 Taxes Other that Income - Property	11,254							(1,071)		(1,071)	10,183
26	409 Income Taxes	(197,785)								(112,408)	(112,408)	(310,193)
27		-									-	-
28		-									-	-
29		-									-	-
30		-									-	-
31		-									-	-
32	Total Operating Expenses	$ 382,874	$ (1,093)	$ (4,062)	$ 451,212	$ (1,018)	$ (2,865)	$ (3,940)	$ (1,071)	$ (112,408)	$ 324,754	$ 707,628
33												
34												
35	Operating Income (Loss)	$ (175,169)	$ 1,093	$ 4,062	$ (451,212)	$ 1,018	$ 2,865	3,940	$ 1,071	112,408		$ (499,923)

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH COMPANY ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Rate Case Expense	(D) Adj. No 3 Low Income Re;ief	(E) Adj. No 4 Customer Count	(F) Adj. No 5 Accrued Revenue	(G) Adj. No 6 Adjust Pur. Pwr.	(H) Adj. No 7 IFCA / CIAC Depre	(I) Adj. No 8 Reclass of Revenues	(J) Adj. No 9 Post Test Yr Depre	(K) Adj. No 10 Bad Debt	(L) Adj. No 11 Property Taxes	(M) Adj. No 12 Income Taxes	(N) Adj. No 13 BLANK	(O) Company Adjustments Test Year	(P) Company As Adjusted Test Year
	Revenues:																
1	461 Metered Water Revenues	$ 177,314	$ -	$ -	$ -	$ (1,319)	$ (5,712)	$ -	$ -	$ 31,919	$ -	$ -	$ -	$ -	$ -	$ 24,888	$ 202,202
2	460 Other Water Revenues	31,919	-	-	-	-	-	-	-	(31,919)	-	-	-	-	-	(31,919)	-
3	474 Unmetered Water Revenues	5,503	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,503
4	Total Operating Expenses	$ 214,736	$ -	$ -	$ -	$ (1,319)	$ (5,712)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (7,031)	$ 207,705
5	Operating Expenses:																
6	601 Salaries And Wages - Employees	$ 75,753	$ -		$ -		$ -		$ -							$ -	$ 75,753
7	610 Purchased Water	960	-		-		-		-							-	960
8	615 Purchased Power	18,395	-		-	(50)	-	4,062	-							4,012	22,407
9	618 Chemicals	10,551	-		-	(29)	-		-							(29)	10,522
10	620 Materials And Supplies	20,175	-		-		-		-							-	20,175
11	621 Office Supplies and Expense	3,591	-		-		-		-							-	3,591
12	630 Outside Services	26,415	-		-		-		-							-	26,415
13	635 Contractural Services - Testing	5,109	-		-		-		-							-	5,109
14	636 Contractural Services - Other	-															-
15	641 Rental of Building / Real Property	2,597	-		-		-		-							-	2,597
16	650 Transportation Expenses	5,733	-		-		-		-							-	5,733
17	657 Insurance - General Liability	1,557	-		-		-		-							-	1,557
18	659 Insurance - Other	269	-		-		-		-							-	269
19	666 Regulatory Comm. Exp. - Rate Case	1,333	(1,333)	2,140	-		-		-							807	2,140
20	670 Bad Debt Expense	4,930	-		-		-		-			(161)				(161)	4,769
21	675 Miscellaneous Expense	7,393	-		(172)		-		-							(172)	7,221
22	403 Depreciation Expense	375,446	-		-		-		-		5,339					5,339	380,785
23	403 Depreciation Expense - CIAC Amort.	(358,046)	-		-		-		355,895							355,895	(2,151)
24	408 Taxes Other than Income	1,553	-		-		-		-							-	1,553
25	408.1 Taxes Other that Income - Property	7,752	-		-		-		-				3,502			3,502	11,254
26	409 Income Taxes	(11,324)	-		-		-		-					(186,461)		(186,461)	(197,785)
27		-	-		-		-		-							-	-
28		-	-		-		-		-							-	-
29		-	-		-		-		-							-	-
30		-	-		-		-		-							-	-
31																-	-
32	Total Operating Expenses	$ 200,142	$ (1,333)	$ 2,140	$ (172)	$ (79)	$ -	$ 4,062	$ 355,895	$ -	$ 5,339	$ (161)	$ 3,502	$ (186,461)	$ -	$ 182,732	$ 382,874
33																	
34																	
35	Operating Income (Loss)	$ 14,594	$ 1,333	$ (2,140)	$ 172	$ (1,240)	$ (5,712)	(4,062)	$ (355,895)	-	$ (5,339)	$ 161	$ (3,502)	$ 186,461			$ (175,169)

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor (L34)			0.75%
4				
5	Valencia Town Water Company			$ 3,144
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 1,047.89
10				
11	Company Amortized Rate Case Expense for Valencia Town as Filed (Sch. C-2.2)			$ 2,140
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (1,093)
14				
15	RUCO Adjustment			$ (1,093)
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
18	Decision No. 71878, dated September 15, 2010, approved amount			
19	$400,000 forGlobal Water.		$ 400,000	
20				
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) Ln 27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
29					
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

OPERATING INCOME ADJUSTMENT NO. 2
PURCHASED POWER

Line No.	System	Service Provider	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Valencia Town	Arizona Public Service	$ 464,075	$ (87,064)	$ 377,011
2					
3	Valencia Greater Buckeye	Arizona Public Service	27,670	(4,063)	23,607
4					
5	Greater Tonopah	Arizona Public Service	22,407	(4,062)	18,345
6					
7	Willow Valley	Mohave Electric Cooperative	43,747	(3,308)	40,439
8					
9		Total	$ 557,899	$ (98,497)	$ 459,402

References
Column (A): Company Schedules C-2

Global Utilities
Docket No. W-01212A-12-309 ET AL
Test Year Ended December 31, 2011

Water Utility of Greater Tonopah, Inc.
Schedule RBM-12

OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Prior Dec Dep Rate	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) RUCO Depreciation Expense
1	303	Land and Land Rights	0.00%	$ 66,651	110,779		-	$ -
2	304	Structures and Improvements	3.33%	46,704	973		-	1,571
3		Collecting and impounding Reservoirs	2.50%	-	-		-	-
4	306	Lake, River and Other Intakes	2.50%	-	-		-	-
5	307	Wells and Springs	3.33%	299,601	-		-	9,977
6	308	Infiltration Galleries	6.67%	-	-		-	-
7	309	Supply Mains	2.00%	-	-		-	-
8	310	Power Generation Equipment	5.00%	-	-		-	-
9	311	Pumping Equipment	12.50%	1,758,896	29,195		(454)	221,658
10	320	Water Treatment Equipment	3.33%	1,621,120	5,400		-	54,073
11	330.1	Distribution Reservoirs and Standpipes	2.22%	185,007	45,380		(1,732)	4,592
12	331	Transmission and Distribution Mains	2.00%	889,254	1,689		-	17,802
13	333	Services	3.33%	43,069	-		-	1,434
14	334	Meters and Meter Installations	8.33%	145,261	1,917		-	12,180
15	335	Hydrants	2.00%	38,386	-		-	768
16	336	Backflow Prevention Devices	6.67%	5,894	-		-	393
17	339	Other Plant and Miscellaneous Equipment	6.67%	5,424	-		-	362
18	340	Office Furniture And Equipment	6.67%	-	-		-	-
19	340.1	Computers and Software	33.33%	-	-		-	-
20	341	Transportation Equipment	20.00%	32,617	-		(32,617)	3,262
21	342	Stores Equipment	4.00%	-	-		-	-
22	343	Tools, Shop And Garage Equipment	5.00%	1,688	289		-	92
23	344	Laboratory Equipment	10.00%	663	-		-	66
24	345	Power Operated Equipment	5.00%	845	-		-	42
25	346	Communication Equipment	10.00%	12,408	-		-	1,241
26	347	Miscellaneous Equipment	10.00%	5,210	-		-	521
27	348	Other Tangible Equipment	10.00%	340,097			-	34,010
28	390.1	Computer Hardware	33.33%				-	
29	396	SCADA	33.33%					
30								$ 364,044
31		Calculated Depreciation Expense		$ 5,498,795				
32								375,446
33		Company Reported Depreciation Expense						(11,402)
34								
35		Adjustment for Post Test Yr. Plant Depreciation						(5,339)
36		RUCO Adjusted Test Year Depreciation Expense						(16,741)

References:
Column A : Order 71878
Column B : RUCO Schedule RBM-5.4
Column C, D, E : RUCO DR 1.14
Column F : (A x B)+((C:E) *A*.5))
Column (G) Depreciation Expense as Reported by Company
Line 34: Company Schedule B2.1 and RUCO Schedule RBM 3.2

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
14						
15		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense	Acct. No.	(A) COMPANY SLECTED EXPENSES	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (L26)			0.750%	
12					
13	Valencia Town Water Company Allocation			$ (2,865)	
14					
15	Personnel Expense as Filed			$ 75,753	
16					
17	RUCO Pro Forma Expense (L15 + L13)			$ 72,888	
18					
19	RUCO Adjustment (L17-L15)			$ (2,865)	
20					
21	Allocation Factor Based on Test Year Revenue		Operating Revenue	Percent of Total	Adjustment by System
22	Palo Verde Utilities Co.		11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company		10,705,825	37.406%	(142,858)
24	Valencia Town Water Company		4,940,530	17.262%	(65,926)
25	Willow Valley Water Company		717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah		214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility		479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale		151,196	0.528%	(2,018)
29	Total Revenue Percentages		28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08
Column (C) -- Company Schedules C-2

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

Ln No	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	Allocation: (D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94205	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970.41)	(11,480.96)	(152.11)	(216.03)	(482.33)	(10,770.58)	(721.57)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	# $ (194,371)	# $ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water L	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Perce	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (B-J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 207,705	$ 207,705
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 415,410	$ 415,410
4a	Adjusted Test Year Revenues	207,705	
4b	Recommended Revenue, Per Schedule		240,458
5	Subtotal (L3 + L4a)	$ 623,115	$ 655,868
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 207,705	$ 218,623
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 415,410	$ 437,245
10	Plus: 10% of CWIP Per Company Schedule E	23,514	23,514
11	Less: Net Book Value of Licensed Vehicles	-	-
12	Full Cash Value (Line 9 + L10 - L11)	$ 438,924	$ 460,759
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 83,396	$ 87,544
15	Composite Property Tax Rate	12.2100%	12.2100%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 10,183	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedul	11,254	
18	RUCO Test Year Adjustment (L16-L17)	$ (1,071)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 10,689
20	RUCO Test Year Adjusted Property Tax Expense (L16)		10,183
21	Increase/(Decrease) to Property Tax Expense		$ 507
22	Increase/(Decrease) to Property Tax Expense		$ 507
23	Increase in Revenue Requirement		(32,753)
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		-0.015466

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Exp. As Filed by Company (RBM-8 Col (A) Ln 25)	$	(197,785)
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO (RBM-1(2), Col (A) Ln 52		(310,193)
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	(112,408)

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 25,759	$ -	$ 25,759	0.82%	6.22%	0.05%
2	Long-term Debt	$ 415,230	$ -	$ 415,230	13.18%	6.33%	0.83%
3	Common Equity	$ 2,708,518	$ -	$ 2,708,518	86.00%	8.50%	7.31%
4	TOTAL CAPITAL	$ 3,149,507	$ -	$ 3,149,507	100.00%		
5	COST OF CAPITAL						8.19%

References:
Columns (A) Thru (F): Testimony, WAR

TABLE OF CONTENTS TO RBM SCHEDULES

SCH. NO.	PAGE NO.	TITLE
RBM-1	1 of 2	REVENUE REQUIREMENT
RBM-1	2 of 2	GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION
RBM-2	1	SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO ADJUSTMENTS
RBM-3	1 of 2	RATE BASE ADJUSTMENT NO. 1 - POST TEST YEAR PLANT WITH RUCO ADJUSTMENTS
RBM-3	2 of 2	RATE BASE ADJUSTMENT NO. 2 - POST TEST YEAR PLANT DEPRECIATION & ACCUMULATE DEPRECIATION
RBM-4	1	INTENTIONALLY LEFT BLANK
RBM-5	1	COMPANY PLANT BALANCES SINCE LAST RATE CASE
RBM-6	1	SUMMARY ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS
RBM-7	1	SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS
RBM-8	1	DETAIL OF OPERATING INCOME WITH RUCO ADJUSTMENTS
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RBM-10	1	OPERATING INCOME ADJUSTMENT NO. 1 - RATE CASE EXPENSE
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RBM-12	1	OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE
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RBM-14	1	OPERATING INCOME ADJUSTMENT NO. 5 - PERSONNEL EXPENSE
RBM-15	1	OPERATING INCOME ADJUSTMENT NO. 6 - MISCELLANEOUS EXPENSE
RBM-16	1	OPERATING INCOME ADJUSTMENT NO. 7 - PROPERTY TAXES
RBM-17	1	OPERATING INCOMEADJUSTMENT NO. 8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ 2,359,391	$ 2,278,955
2			
3	Adjusted Operating Income (Loss)	$ (58,493)	$ (73,977)
4			
5	Current Rate Of Return (L3 / L1)	-2.48%	-3.25%
6			
7	Required Operating Income (L9 X L1)	$ 250,024	$ 182,894
8			
9	Required Rate Of Return On Fair Value Rate Base	10.60%	8.03%
10			
11	Operating Income Deficiency (L7 - L3)	$ 308,517	$ 256,871
12			
13	Gross Revenue Conversion Factor (RBM-1, Pg 2)	1.6451	1.5427
14			
15	Increase In Gross Revenue Requirement (L11 X L13)	$ 507,537	$ 396,281
16			
17	Adjusted Test Year Revenue	$ 702,652	$ 702,653
18			
19	Proposed Annual Revenue (L15 + L17)	$ 1,210,189	$ 1,098,934
20			
21	Required Percentage Increase In Revenue (L15 / L17)	72.20%	56.40%
22			
23	Rate Of Return On Common Equity	11.44%	8.50%

References:

Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A]	[B]	[C]
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor	0.4135%		
3	Revenues (L1 - L2)	99.5865%		
4	Combined Federal and State Income Tax and Property Tax Rate (L23)	34.7661%		
5	Subtotal (L3 - L4)	64.8204%		
6	**Revenue Conversion Factor (L1 / L5)**	1.542724		
	Calculation of Uncollecttible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (L17)	34.4112%		
9	One Minus Combined Income Tax Rate (L7 - L8)	65.5888%		
10	Uncollectible Rate	0.00630		
11	Uncollectible Factor (L9 * L10)	0.4135%		
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.5000%		
14	Federal Taxable Income (L12 - L13)	93.5000%		
15	Applicable Federal Income Tax Rate (Col [C] L53)	29.8516%		
16	Effective Federal Income Tax Rate (L14 x L15)	27.9112%		
17	Combined Federal and State Income Tax Rate (L13 + L16)		34.4112%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (Col. [B], L17)	34.4112%		
20	One Minus Combined Income Tax Rate (L18-L19)	65.5888%		
21	Property Tax Factor (Sch. RBM-16, Col. [B], L24)	0.5410%		
22	Effective Property Tax Factor (L20 x L21)		0.3549%	
23	Combined Federal and State Income Tax and Property Tax Rate (Col. (B), L17 + L22)			34.7661%
24	Required Operating Income (Sch. RBM-1, Col. (B) L7)	$ 182,894		
25	Adjusted Test Year Operating Income (Loss) (Sch. RBM-1, Col (B) L3)	(73,977)		
26	Required Increase in Operating Income (L24 - L25)		$ 256,871	
27	Income Taxes on Recommended Revenue (Col. [C], L52)	$ 98,259		
28	Income Taxes on Test Year Revenue (Col. (A), L52)	(36,509)		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		134,768	
30	Recommended Revenue Requirement (Sch. RBM-1, Col. (B), L19	$ 1,098,934		
31	Uncollectible Rate (L10)	0.00630		
32	Uncollectible Expense on Recommended Revenue (L30 x L31)	$ 6,928		
33	Adjusted Test Year Uncollectible Expense(Sch. RBM-8, Col. (K), L31)	4,430		
34	Required Increase in Revenue to Provide for Uncollectible Exp. (L32 - L33)		2,498	
35	Property Tax with Recommended Revenue (Sch. RBM -8, Col. (Q), L24)	$ 32,844		
36	Property Tax on Test Year Revenue (Sch. RBM-8, Col. (A), L24)	30,700		
37	Increase in Property Tax Due to Increase in Revenue (L35 - 36)		2,144	
38	Total Required Increase in Revenue (Col. [B], L26 + L29 + L34 + L37)		$ 396,281	

	Calculation of Income Tax:	Test Year		RUCO Recommended
39	Revenue (Sch.RBM-7 Col [C] L4 and Col (D) L4	$ 702,653	$ 396,281	$ 1,098,934
40	Operating Expenses Excluding Income Taxes	$ 813,139		$ 817,781
41	Synchronized Interest (Col. [C], L57)	$ 13,472		$ 13,472
42	Arizona Taxable Income (L39 - L40 - L41)	$ (123,958)		$ 267,681
43	Arizona State Income Tax Rate	6.5000%		6.5000%
44	Arizona Income Tax (L42 x L43)	$ (8,057)		$ 17,399
45	Federal Taxable Income (L42 - L44)	$ (115,901)		$ 250,282
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ (7,500)		$ 7,500
47	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ (6,250)		$ 6,250
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ (8,500)		$ 8,500
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ (6,201)		$ 58,610
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ -		$ -
51	Total Federal Income Tax	$ (28,451)		$ 80,860
52	Combined Federal and State Income Tax (L44 + L51)	$ (36,509)		$ 98,259
53	Applicable Federal Income Tax Rate			29.8516%
54	Synchronized Interest Calculation			
55	Rate Base			$ 2,278,955
56	Weighted Average Cost of Debt			0.59%
57	Synchronized Interest			$ 13,472

SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO ADJUSTMENTS

Line No.	Description	(A) Company As Filed OCRB/FVRB	(B) Adj No. 1 Post Test Year Plant	(C) RUCO As Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	$ 5,113,538	$ (80,436)	$ 5,033,102
2				
3	Accumulated Depreciation	(1,742,556)	-	(1,742,556)
4	Net Utility Plant In Service (L1 + L3)	3,370,982	(80,436)	3,290,546
5				
6	Advances In Aid Of Const.	(610,760)	-	(610,760)
7				
8	Contribution In Aid Of Const.	-	-	-
9	Accumulated Amortization Of CIAC	-	-	-
10	NET CIAC (L8 + L9)	-	-	-
11				
12	Customer Meter Deposits	(36,233)	-	(36,233)
13				
14	Deferred Income Taxes & Credits	(364,598)	-	(364,598)
15				
16	Unamortized Finance Charges	-	-	-
17				
18	Deferred Regulatory Assets	-	-	-
19				
20	Allowance For Working Capital	-	-	-
21				
22				
23	TOTAL RATE BASE (Sum L's 4,6,10-20)	$ 2,359,391	$ (80,436)	$ 2,278,955

References:
Column (A) Company Schedule B-1
Column (B) RBM-3 page 1

References:
Column (A): Company Schedule B-1
Column (B): RBM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

RATE BASE ADJUSTMENT NO.1
POST TEST YEAR PLANT WITH RUCO ADJUSTMENTS

	(A)	(B)	(C)	(D)	(E)		(F)
	Company's Initial Filing			Co. Follow Up Response			RUCO Adjustment
	Date Const Began	Date Const est to be Completed	Included in Rate Base Initial Est	Date Const Actually Completed	Final Costs/ as of March 31, 2013		
1 **Global Water - Santa Cruz**							
2 Edison Rd Waterline Ext	Aug 2012	Aug 2012	$ 300,742	Dec 2012	$ 240,224		$ (300,742)
3 RED WDC Chl Sys Replacement	Jan 2012	Jan 2012	6,149	April 2012	15,129		8,980
4 TOTALS			$ 306,891		$ 255,353		$ (291,762)
5							
6 **Willow Valley Water Company**							
7 WVR SCADA - WVWC	Oct 2012	Oct 2012	$ 80,436	Not Started	-	Note (1)	$ (80,436)
8 TOTALS			$ 80,436		-		$ (80,436)
9							
10 **Water Utility of Greater Tonopah**							
11 West Phoenix 6 Elec Upgrades	Nov 2012	Dec 2012	$ 3,076	Dec 2012	$ 3,501		$ (3,076)
12 West Phoenix 6 Fluoride	Nov 2012	Dec 2012	8,625	Jan 2013	18,693		(8,625)
13 WPE 6 Tank and Well Replacmt	May 2012	June 2012	95,082	Dec 2012	128,934		(95,082)
14 TOTALS			$ 106,783		$ 151,128		$ (106,783)
15							
16 **Valencia Water Company**							
17 Bales Fill Line	July 2012	July 2012	$ 78,750	In Progress	$ 12,027		$ (78,750)
18 Buena Vista Fill Line	July 2012	July 2012	203,702	In Progress	20,004		(203,702)
19 Pima Road Waterline	April 2012	April 2012	182,563	Sept 2012	195,474		(182,563)
20 WVR SCADA Command Sta Imp	July 2012	July 2012	136,029	Jan 2013	21,962		(136,029)
21 SVWDC Optimization	June 2012	June 2012	71,526	Feb 2013	48,565		(71,526)
22 TOTALS			$ 672,570		$ 298,032		$ (672,570)
23							
24 **Global Water - Palo Verde Utilities**							
25 Campus I WRF Ph 3 Exp	Nov 2008	June 2012	$ 119,810	Dec 2011	$ 119,810		$ -
26 PVUC In Pipe Odor Control	Mar 2012	June 2012	52,022	Nov 2012	57,397		(52,022)
27 PVUC Lagoon Clean Closure	April 2012	July 2012	406,949	Dec 2012	543,461		(406,949)
28 PVUC PEQB	April 2012	July 2012	12,564	Dec 2012	48,475		(12,564)
29 SRW MH Rehab and LS Imp Ph I	Dec 2010	Feb 2012	6,408	Dec 2012	3,295		(6,408)
30 PVUC WRF Headworks Rehab	Sept 2012	Sept 2012	69,132	Dec 2012	84,155		(69,132)
31 Sewer Manhole Rehab	Oct 2012	Oct 2012	66,509	Dec 2012	68,199		(66,509)
32 Edison Rd Sewer Ln Ext	Aug 2012	Aug 2012	85,000	Dec 2012	110,734		(85,000)
33			$ 818,394		$ 1,035,526		$ (698,584)
34							

References:
Columns (A), (B), (C) - Fleming Testimony pages 21 and 22. Company included in rate base.
Columns (D), (E) - Company Response to RUCO Data Request No. 2.01
NOTE (1): See Column (F) The costs for projects not completed and placed in service by June 30, 2012, were adjusted and excluded from rate base by RUCO

RATE BASE ADJUSTMENT NO. 2
RUCO POST TEST YEAR PLANT DEPRECIATION & A/D ADJUSTMENTS

		(A) Company Initial Filing Included in Rate Base Initial Est	(B) Date Const Actually Completed	(C) Company Final Costs/ as of March 31, 2013	(D) RUCO Adjustment PTY Plant	(E) Company Calculated Depreciation	(F) RUCO Calculated Depreciation	(G) RUCO Adjustment Depre & A/D
1	**Global Water - Santa Cruz**							
2	Edison Rd Waterline Ext	$ 300,742	Dec 2012	$ 240,224	$ (300,742)			
3	RED WDC Chl Sys Replacement	6,149	April 2012	15,129	8,980			
4	TOTALS	$ 306,891		$ 255,353	$ (291,762)	$ 15,345	$ 757	$ (14,588)
5								
6	**Willow Valley Water Company**							NOTE (1)
7	WVR SCADA - WVWC	$ 80,436	Not Started	-	$ (80,436)			
8	TOTALS	$ 80,436		-	$ (80,436)	$ 4,022	$ -	$ (4,022)
9								
10	**Water Utility of Greater Tonopah**							
11	West Phoenix 6 Elec Upgrades	$ 3,076	Dec 2012	$ 3,501	$ (3,076)			
12	West Phoenix 6 Fluoride	8,625	Jan 2013	18,693	(8,625)			
13	WPE 6 Tank and Well Replacmt	95,082	Dec 2012	128,934	(95,082)			
14	TOTALS	$ 106,783		$ 151,128	$ (106,783)	$ 5,339	$ -	$ (5,339)
15								
16	**Valencia Water Company**							
17	Bales Fill Line	$ 78,750	In Progress	$ 12,027	$ (78,750)			
18	Buena Vista Fill Line	203,702	In Progress	20,004	(203,702)			
19	Pima Road Waterline	182,563	Sept 2012	195,474	(182,563)			
20	WVR SCADA Command Sta Imp	136,029	Jan 2013	21,962	(136,029)			
21	SVWDC Optimization	71,526	Feb 2013	48,565	(71,526)			
22	TOTALS	$ 672,570		$ 298,032	$ (672,570)	$ 33,629	$ -	$ (33,629)
23								
24	**Global Water - Palo Verde Utilities**							
25	Campus I WRF Ph 3 Exp	$ 119,810	Dec 2011	$ 119,810	$ -			
26	PVUC In Pipe Odor Control	52,022	Nov 2012	57,397	(52,022)			
27	PVUC Lagoon Clean Closure	406,949	Dec 2012	543,461	(406,949)			
28	PVUC PEQB	12,564	Dec 2012	48,475	(12,564)			
29	SRW MH Rehab and LS Imp Ph I	6,408	Dec 2012	3,295	(6,408)			
30	PVUC WRF Headworks Rehab	69,132	Dec 2012	84,155	(69,132)			
31	Sewer Manhole Rehab	66,509	Dec 2012	68,199	(66,509)			
32	Edison Rd Sewer Ln Ext	85,000	Dec 2012	110,734	(85,000)			
33		$ 818,394		$ 1,035,526	$ (698,584)	$ 40,920	$ 5,991	$ (34,929)
34								

35 NOTE (1): RUCO Depreciation and A/D adjustment calculated as follows:

36	Column (E) / Column (A)	4,022		
37		80,436	5.00%	Depreciation allowance as calculated by Company
38				
39	Column (A) less Column (D)	$ 80,436		
40		$ 80,436		
41		$ -	$ -	Test Year Plant as proposed by RUCO
42				
43	Depreciation expense proposed by RUCO		$ -	
44	Depreciation expense proposed by Company		$ 4,022	
45	RUCO proposed depreciation and A/D adjustment			NOTE 1 Global recorded post test year depreciation (See Company - Sch C-
46	related to Post Test Year Plant		$ (4,022)	2), however,did not record Accumulated Depreciation as an adjustment.

References:
Columns (A), (B), (C), (D) - See Sch RBM-2
Columns (E) - Company Schedules and testimony of Mr. Brett Higgabotham

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Willow Valley Water Companyu
Docket No. W-01212A-12-309 ET AL
Test Year Ended December 31, 2011

COMPANY PLANT BALANCES SINCE LAST RATE CASE

Line No.	Acct No	Account Description	(A) Total Plant Value 12/31/2008	(B) Additions	(C) Other Costs	(D) Disposals	(E) Balance 12/31/2009	(F) Additions	(G) Other Costs	(H) Disposals	(I) Balance 12/31/2010	(J) Additions	(K) Other Costs	(L) Disposals	(M) Balance 12/31/2011
1	303	Land and Land Rights	$ 18,100				18,100				18,100	193	-	-	18,293
2	304	Structures and Improvements	197,952				197,952				197,952	266,117	-	-	464,069
3		Collecting and impounding Reservoirs	-				-				-				-
4	306	Lake, River and Other Intakes	-				-				-				-
5	307	Wells and Springs	1,622,446				1,622,446				1,622,446	1,295	-	-	1,623,741
6	308	Infiltration Galleries	-												
7	309	Supply Mains	2,118				2,118				2,118	3,323	-	-	5,441
8	310	Power Generation Equipment	10,751				10,751	311			11,062				11,062
9	311	Pumping Equipment	492,405	9,043			501,448				501,448	11,909	-	-	513,357
10	320	Water Treatment Equipment	263,210	9,421			272,631	14,481			287,111	273,452	-	-	560,564
11	330	Distribution Reservoirs and Standpipes	265,882				265,882	8,960			274,842	232	-	(676)	274,398
12	331	Transmission and Distribution Mains	620,830	3,218			624,048				624,048	20,639	-	-	644,688
13	333	Services	95,359				95,359				95,359				95,359
14	334	Meters and Meter Installations	220,733	693			221,426	309,135			530,561	2,456	-	-	533,017
15	335	Hydrants	37,179				37,179				37,179	9,386	-	-	46,565
16	336	Backflow Prevention Devices	1,024				1,024				1,024				1,024
17	339	Other Plant and Miscellaneous Equipment	19,310				19,310				19,310	1,007	-	-	20,317
18	340	Office Furniture And Equipment	22,526				22,526				22,526	120	-	-	22,646
19	340.1	Computers and Software	-				-				-				-
20	341	Transportation Equipment	20,846	68,433		(5,799)	83,480			(2,367)	81,113	-	-	(3,035)	78,078
21	342	Stores Equipment	-				-				-				-
22	343	Tools, Shop And Garage Equip	42,909				42,909				42,909	479	-	-	43,388
23	344	Laboratory Equipment	9,508				9,508				9,508				9,508
24	345	Power Operated Equipment	38,925				38,925				38,925				38,925
25	346	Communication Equipment	2,654		6,584		9,238	825			10,063				10,063
26	347	Miscellaneous Equipment	8,273				8,273	1,950			10,223				10,223
27	348	Other Tangible Equipment	3,937				3,937				3,937				3,937
28			-												-
29	396		-									4,440	-	-	4,440
30		TOTAL PLANT IN SERVICE	$ 4,016,877	90,808	6,584	(5,799)	4,108,470	335,662	-	(2,367)	4,441,764	595,046	-	(3,711)	5,033,100

References:
Column (A) agrees with Decision No. 71878
Column (B) through (M) RUCO Data Request 1.14

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	5,033,102	$ 80,436	$ -	$ -	$ 5,113,538
2	Accumulated Depreciation	(1,742,556)	-	-	-	(1,742,556)
3	Net Utility Plant In Service (L1 + L2)	$ 3,290,546	$ 80,436	$ -	$ -	$ 3,370,982
4	Advances In Aid Of Const.	$ (610,760)	$ -	$ -	$ -	$ (610,760)
5	Contribution In Aid Of Const.	$ -	$ -	$ -	$ -	$ -
6	Accumulated Amortization Of CIAC	-	-	-	-	-
7	NET CIAC (L5 + L6)	$ -	$ -	$ -	$ -	$ -
8	Customer Meter Deposits	$ (36,233)	$ -	$ -	$ -	$ (36,233)
9	Deferred Income Taxes & Credits	$ (364,598)	$ -	$ -	$ -	$ (364,598)
10	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 2,278,955	$ 80,436	$ -	$ -	$ 2,359,391

References:
Column (A): Company Schedule B-1
Column (B); Company Schedule B-2-1
Column (E); Columns (A) through (D)

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year' Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
		Revenues:					
1	461	Metered Water Revenues	$ 689,275	$ -	$ 689,275	$ 396,281	$ 1,085,556
2	460	Unmetered Water Revenues	-	-	-		-
3	474	Other Water Revenues	13,378	-	13,378		13,378
4		Total Operating Income	$ 702,653	$ -	$ 702,653	$ 396,281	$ 1,098,934
		Operating Expenses:					
5	601	Salaries And Wages - Employees	$ 263,312	(9,571)	$ 253,741	$ -	$ 253,741
6	610	Purchased Water	-	-	-	-	-
7	615	Purchased Power	43,747	(1,582)	42,165	-	42,165
8	618	Chemicals	55,422	-	55,422	-	55,422
9	620	Materials And Supplies	36,002	-	36,002	-	36,002
10	621	Office Supplies and Expense	27,025	-	27,025	-	27,025
11	630	Outside Services	97,501	-	97,501	-	97,501
12	635	Contractural Services - Testing	20,993	-	20,993	-	20,993
13	641	Rental of Building / Real Property	10,241	-	10,241	-	10,241
14	650	Transportation Expenses	24,173	-	24,173	-	24,173
15	657	Insurance - General Liability	7,125	-	7,125	-	7,125
16	659	Insurance - Other	4,218	-	4,218	-	4,218
17	666	Regulatory Comm. Exp. - Rate Case	9,923	(6,423)	3,500	-	3,500
18	670	Bad Debt Expense	8,251	(3,821)	4,430	2,498	6,928
19	675	Miscellaneous Expense	24,562	(26,087)	(1,525)	-	(1,525)
20	403	Depreciation Expense	200,668	(4,022)	196,646	-	196,646
21	403	Depreciation Expense - CIAC Amort.	-	-	-	-	-
22	408	Taxes Other than Income	782	-	782	-	782
23	408.1	Taxes Other that Income - Property	33,931	(3,231)	30,700	2,144	32,844
24	409	Income Taxes	(106,730)	70,221	(36,509)	134,768	98,259
25							
26							
27							
28							
29		Total Operating Income	$ 761,146	$ 15,484	$ 776,630	$ 139,410	$ 916,040
30		Operating Income (Loss)	$ (58,493)	$ (15,484)	$ (73,977)	$ 256,871	$ 182,894

References:

Column (A): Company Schedule C-1
Column (B): RBM-8, Columns (B) Thru (J)
Column (C): Column (A) + Column (B)
Column (D): Sch. RBM-1, Column (B), L8: Sch RBM-1 page 2 L52
Column (E): Column (C) + Column (D)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Pur. Power Expense	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 7 Property Taxes	(I) Adj. No 8 Income Taxes	(J) Total Pro Forma Adjustments	(K) Test Year Adjusted Results
	Revenues:											
1	461 Metered Water Revenues	$ 689,275	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 689,275
2	460 Other Water Revenues	-	-	-							-	-
3	474 Unmetered Water Revenues	13,378	-	-	-	-	-	-	-	-	-	13,378
4	TOTAL OPR'G REV.	$ 702,653	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 702,653
5	Operating Expenses:											
6	601 Salaries And Wages - Employees	$ 263,312					$ (9,571)				$ (9,571)	$ 253,741
7	610 Purchased Water	-									-	-
8	615 Purchased Power	43,747		(1,582)							(1,582)	42,165
9	618 Chemicals	55,422									-	55,422
10	620 Materials And Supplies	36,002									-	36,002
11	621 Office Supplies and Expense	27,025									-	27,025
12	630 Outside Services	97,501									-	97,501
13	635 Contractural Services - Testing	20,993									-	20,993
14	641 Rental of Building / Real Property	10,241									-	10,241
15	650 Transportation Expenses	24,173									-	24,173
16	657 Insurance - General Liability	7,125									-	7,125
17	659 Insurance - Other	4,218									-	4,218
18	666 Regulatory Comm. Exp. - Rate Case	9,923	(6,423)								(6,423)	3,500
19	670 Bad Debt Expense	8,251				(3,821)					(3,821)	4,430
20	675 Miscellaneous Expense	24,562						(26,087)			(26,087)	(1,525)
21	403 Depreciation Expense	200,668			-4022						(4,022)	196,646
22	403 Depreciation Expense - CIAC Amort.	-									-	-
23	408 Taxes Other than Income	782									-	782
24	408.1 Taxes Other that Income - Property	33,931							(3,231)		(3,231)	30,700
25	409 Income Taxes	(106,730)								70,221	70,221	(36,509)
26		-									-	-
27		-									-	-
28		-									-	-
29		-									-	-
30		-									-	-
31	Total Operating Expenses	$ 761,146	$ (6,423)	$ (1,582)	$ (4,022)	$ (3,821)	$ (9,571)	$ (26,087)	$ (3,231)	$ 70,221	$ 15,484	$ 776,630
32												
33	Operating Income (Loss)	$ (58,493)	$ 6,423	$ 1,582	$ 4,022	$ 3,821	$ 9,571	$ 26,087	$ 3,231	$ (70,221)	$ (15,484)	$ (73,977)

References:
Column (A) See Company Schedule C-1; RBM-9
Columns (B) through (K) See RBM-10 through RBM-18

DETAIL OF OPERATING INCOME ADJUSTMENTS - WITH COMPANY ADJUSTMENT

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Rate Case Expense	(D) Adj. No 3 Low Income Relief	(E) Adj. No 4 Customer Count	(F) Adj. No 5 Accrued Revenue	(G) Adj. No 6 Adjust Pur. Pwr.	(H) Adj. No 7 Reclass of Revenues	(I) Adj. No 8 Post Test Yr Depre
	Revenues:									
1	461 Metered Water Revenues	$ 659,351	$ -	$ -	$ -	$ (1,974)	$ (16,480)	$ -	$ 44,501	$ -
2	460 Other Water Revenues	44,501	-	-	-	-	-	-	(44,501)	-
3	474 Unmetered Water Revenues	13,378	-	-	-	-	-	-	-	-
4	TOTAL OPR'G REV.	$ 717,230	$ -	$ -	$ -	$ (1,974)	$ (16,480)		$ -	$ -
5	Operating Expenses:									
6	601 Salaries And Wages - Employees	$ 263,312	$ -		$ -		$ -		$ -	
7	610 Purchased Water	-	-		-		-		-	
8	615 Purchased Power	40,485	-		-	(46)	-	3,308	-	
9	618 Chemicals	18,800	-		-	(21)	-		-	
10	620 Materials And Supplies	36,002	-		-		-		-	
11	621 Office Supplies and Expense	27,025	-		-		-		-	
12	630 Outside Services	97,501	-		-		-		-	
13	635 Contractural Services - Testing	20,993	-		-		-		-	
14	641 Rental of Building / Real Property	10,241	-		-		-		-	
15	650 Transportation Expenses	24,173	-		-		-		-	
16	657 Insurance - General Liability	7,125	-		-		-		-	
17	659 Insurance - Other	4,218	-		-		-		-	
18	666 Regulatory Comm. Exp. - Rate Case	5,333	(5,333)	9,923	-		-		-	
19	670 Bad Debt Expense	8,422	-		-		-		-	
20	675 Miscellaneous Expense	25,404	-		(842)		-		-	
21	403 Depreciation Expense	196,646	-		-		-		-	4,022
22	403 Depreciation Expense - CIAC Amort.	-	-		-		-		-	
23	408 Taxes Other than Income	782	-		-		-		-	
24	408.1 Taxes Other that Income - Property	22,674	-		-		-		-	
25	409 Income Taxes	(43,147)	-		-		-		-	
26		-	-		-		-		-	
27		-	-		-		-		-	
28		-	-		-		-		-	
29		-	-		-		-		-	
30										
31	Total Operating Expenses	$ 765,989	$ (5,333)	$ 9,923	$ (842)	$ (67)	$ -	$ 3,308	$ -	$ 4,022
32										
33	Operating Income (Loss)	$ (48,759)	$ 5,333	$ (9,923)	$ 842	$ (1,907)	$ (16,480)	$ (3,308)	$ -	$ (4,022)

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

DETAIL OF OPERATING INCOME ADJUSTMENTS - WITH COMPANY ADJUSTMENT

Line No	DESCRIPTION	(J) Adj. No 9 Bad Debt Expense	(K) Adj. No 10 Property Taxes	(L) Adj. No 11 Income Taxes	(M) Adj. No 12 Additional Treatment	(N) Adj. No 13 Adjust Credits	(O) Adj. No 14 Income Taxes	(P) Company Adjustments Test Year	(Q) Company As Adjusted Test Year
	Revenues:								
1	461 Metered Water Revenues	$ -	$ -	$ -		$ 1,473	$ 2,404	$ 29,924	$ 689,275
2	460 Other Water Revenues	-	-	-		-	-	(44,501)	-
3	474 Unmetered Water Revenues							-	13,378
4	TOTAL OPR'G REV.	$ -	$ -	$ -		$ 1,473	$ 2,404	$ (14,577)	$ 702,653
5	Operating Expenses:								
6	601 Salaries And Wages - Employees							$ -	$ 263,312
7	610 Purchased Water							-	-
8	615 Purchased Power							3,262	43,747
9	618 Chemicals				36,643			36,622	55,422
10	620 Materials And Supplies							-	36,002
11	621 Office Supplies and Expense							-	27,025
12	630 Outside Services							-	97,501
13	635 Contractural Services - Testing							-	20,993
14	641 Rental of Building / Real Property							-	10,241
15	650 Transportation Expenses							-	24,173
16	657 Insurance - General Liability							-	7,125
17	659 Insurance - Other							-	4,218
18	666 Regulatory Comm. Exp. - Rate Case							4,590	9,923
19	670 Bad Debt Expense	(171)						(171)	8,251
20	675 Miscellaneous Expense							(842)	24,562
21	403 Depreciation Expense							4,022	200,668
22	403 Depreciation Expense - CIAC Amort.							-	-
23	408 Taxes Other than Income							-	782
24	408.1 Taxes Other that Income - Property		11,257					11,257	33,931
25	409 Income Taxes			(63,583)				(63,583)	(106,730)
26								-	-
27								-	-
28								-	-
29								-	-
30								-	-
31	Total Operating Expenses	$ (171)	$ 11,257	$ (63,583)	$ 36,643	$ -	$ -	$ (4,843)	$ 761,146
32									
33	Operating Income (Loss)	$ 171	$ (11,257)	$ 63,583	$ (36,643)	$ 1,473	$ 2,404	$ (9,734)	$ (58,493)

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Sche
Column (O); Sum of Columns (B) throug
Column (P); Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor - Column (B) L33			2.51%
4				
5	Willow Valley Water Company - L1 (L1 X L3)			$ 10,500
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 3,500
10				
11	Company Amortized Rate Case Expense for Valencia Town as Filed (Sch. C-2.2)			$ 9,923
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (6,423)
14				
15	RUCO Adjustment			$ (6,423)
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
18	Decision No. 71878, dated September 15, 2010, approved amount			
19	$400,000 forGlobal Water.		$ 400,000	
20				
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) L27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

OPERATING INCOME ADJUSTMENT NO. 2
PURCHASED POWER

Line No.	System	Service Provider	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Valencia Town	Arizona Public Service	$ 464,075	$ (62,786)	$ 401,289
2					
3	Valencia Greater Buckeye	Arizona Public Service	27,670	(2,562)	25,108
4					
5	Greater Tonopah	Arizona Public Service	22,407	(2,881)	19,526
6					
7	Willow Valley	Mohave Electric Cooperative	43,747	(1,582)	42,165
8					
9		Total	$ 557,899	$ (69,811)	$ 488,088

References
Column (A): Company Schedules C-2
Column (B): Company Schedules C-2.6

OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Prior Dec Dep Rate	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) Plant Balance 12/31/2011	(G) Calculated Depreciation Expense	(H) Company Depreciation Expense
1	303	Land and Land Rights	0.00%	$ 18,100	$ 192.50	$ -	$ -	$ 18,292.50	$ -	$ -
2	304	Structures and Improvements	3.33%	$ 197,952	266,117	-	-	464,069	11,023	7,875
3		Collecting and impounding Reservoirs	2.50%	-	-	-	-	-	-	
4	306	Lake, River and Other Intakes	2.50%	-				-	-	
5	307	Wells and Springs	3.33%	$ 1,622,446	1,295	-	-	1,623,741	54,049	1,946
6	308	Infiltration Galleries	6.67%	-				-	-	
7	309	Supply Mains	2.00%	$ 2,118	3,323	-	-	5,441	76	33
8	310	Power Generation Equipment	5.00%	$ 11,062				11,062	553	-
9	311	Pumping Equipment	12.50%	$ 501,448	11,909	-	-	513,357	63,425	3,874
10	320	Water Treatment Equipment	3.33%	$ 287,111	273,452	-	-	560,564	14,114	35,780
11	330.1	Distribution Reservoirs and Standpipes	2.22%	$ 274,842	232	-	(676)	274,398	6,097	5,552
12	331	Transmission and Distribution Mains	2.00%	$ 624,048	20,639	-	-	644,688	12,687	10,087
13	333	Services	3.33%	$ 95,359				95,359	3,175	2,944
14	334	Meters and Meter Installations	8.33%	$ 530,561	2,456	-	-	533,017	44,298	31,247
15	335	Hydrants	2.00%	$ 37,179	9,386	-	-	46,565	837	662
16	336	Backflow Prevention Devices	6.67%	$ 1,024				1,024	68	-
17	339	Other Plant and Miscellaneous Equipment	6.67%	$ 19,310	1,007	-	-	20,317	1,322	371
18	340	Office Furniture And Equipment	6.67%	$ 22,526	120	-	-	22,646	1,506	158
19	340.1	Computers and Software	33.33%	$ -				-	-	
20	341	Transportation Equipment	20.00%	$ 81,113	-	-	(3,035)	78,078	15,919	93,079
21	342	Stores Equipment	4.00%	-				-	-	
22	343	Tools, Shop And Garage Equipment	5.00%	$ 42,909	479	-	-	43,388	2,157	499
23	344	Laboratory Equipment	10.00%	$ 9,508				9,508	951	-
24	345	Power Operated Equipment	5.00%	$ 38,925				38,925	1,946	779
25	346	Communication Equipment	10.00%	$ 10,063				10,063	1,006	833
26	347	Miscellaneous Equipment	10.00%	$ 10,223				10,223	1,022	195
27	348	Other Tangible Equipment	10.00%	$ 3,937				3,937	394	507
28	390.1	Computer Hardware	33.33%					-	-	
29	396	SCADA	33.33%		4,440	-	-	4,440	740	221
30								-	-	
31				$ 4,441,764	$ 595,046	$ -	$ (3,711)	$ 5,033,100		
32		Calculated Depreciation Expense							$ 237,366	
33										
34		Company Reported Depreciation Expense								196,642
35										
36		Adjustment for Post Test Yr. Plant Depreciation								4,022
37		RUCO Adjusted Test Year Depreciation Expense								200,664
38										

References:
Column (A) Decision 71878
Column (B) RUCO Schedule RBM-5.4
Column (C), (D), (E)RUCO DR 1.14
Column (F) = (A x B)+((C:E) *A*.5))
Column (G) Depreciation Expense as Reported by Company

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
14						
15		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense Category	Acct No	(A) Company Selected Expenses	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	-
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (L24)			2.506%	
12					
13	Willow Valley Water Company			$ (9,571)	
14					
15	Personnel Expense as Filed			$ 263,312	
16					
17	RUCO Pro Forma Expense (L15 + L13)			$ 253,741	
18					
19	RUCO Adjustment (L17-L15)			$ (9,571)	
20					
21	Allocation Factor Based on Test Year Revenue		Operating Revenue	Percent of Total	Adjustment by System
22	Palo Verde Utilities Co.		11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company		10,705,825	37.406%	(142,858)
24	Valencia Town Water Company		4,940,530	17.262%	(65,926)
25	Willow Valley Water Company		717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah		214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility		479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale		151,196	0.528%	(2,018)
29	Total Revenue Percentages		28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	(D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94025	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970)	(11,481)	(152)	(216)	(482)	(10,771)	(722)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	$ (194,371)	$ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water Utility	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Percentages	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (B) Thru (J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 702,653	$ 702,653
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 1,405,306	$ 1,405,306
4a	Adjusted Test Year Revenues	702,653	
4b	Recommended Revenue, Per Schedule		1,098,934
5	Subtotal (L3 + L4a)	$ 2,107,959	$ 2,504,240
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 702,653	$ 834,747
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 1,405,306	$ 1,669,494
10	Plus: 10% of CWIP Per Company Schedule E	47	47
11	Less: Net Book Value of Licensed Vehicles	340	340
12	Full Cash Value (Line 9 + L10 - L11)	$ 1,405,013	$ 1,669,200
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 266,952	$ 317,148
15	Composite Property Tax Rate (Per RUCO Effective Property Tax Calculation Analysis W/P)	11.5000%	10.3559%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 30,700	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedule)	33,931	
18	RUCO Test Year Adjustment (L16-L17)	$ (3,231)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 32,844
20	RUCO Test Year Adjusted Property Tax Expense (L16)		30,700
21	Increase/(Decrease) to Property Tax Expense		$ 2,144
22	Increase/(Decrease) to Property Tax Expense		$ 2,144
23	Increase in Revenue Requirement		396,281
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		0.5410%

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No.	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Expense As Filed by Company - RBM-7 Col (A) Ln 24	$	(106,730)
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO RBM-7 Col (C) Ln 24		(36,509)
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	70,221
7			

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 29,470	$ -	$ 29,470	0.89%	5.17%	0.05%
2	Long-term Debt	$ 387,538	$ -	$ 387,538	11.65%	4.68%	0.55%
3	Common Equity	$ 2,908,686	$ -	$ 2,908,686	87.46%	8.50%	7.43%
4	TOTAL CAPITAL	$ 3,325,694	$ -	$ 3,325,694	100.00%		
5	COST OF CAPITAL						8.03%

References:
Columns (A) Thru (F): Testimony, WAR

Global Utilities
Docket No. W-01212A-12-309 ET AL
Test Year Ended December 31, 2011
12-0313

Valencia Water Utility of Greater Buckeye, Inc.

TABLE OF CONTENTS TO RBM SCHEDULES

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RBM-2	1	SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO ADJUSTMENTS
RBM-3	1	INTENTIONALLY LEFT BLANK
RBM-3	2 of 2	INTENTIONALLY LEFT BLANK
RBM-4	1	INTENTIONALLY LEFT BLANK
RBM-5	1	COMPANY PLANT BALANCES SINCE LAST RATE CASE
RBM-6	1	SUMMARY ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS
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RBM-14	1	OPERATING INCOME ADJUSTMENT NO. 5 - PERSONNEL EXPENSE
RBM-15	1	OPERATING INCOME ADJUSTMENT NO. 6 - MISCELLANEOUS EXPENSE
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RBM-17	1	OPERATING INCOME ADJUSTMENT NO.8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ 634,978	$ 634,979
2			
3	Adjusted Operating Income (Loss)	$ 49,158	$ 61,801
4			
5	Current Rate Of Return (L3 / L1)	7.74%	9.73%
6			
7	Required Operating Income (L9 X L1)	$ 70,795	$ 53,258
8			
9	Required Rate Of Return On Fair Value Rate Base	11.18%	8.39%
10			
11	Operating Income Deficiency (L7 - L3)	$ 21,817	$ (8,543)
12			
13	Gross Revenue Conversion Factor (RBM-1, Pg 2)	1.6694	1.4522
14			
15	Increase In Gross Revenue Requirement (L11 X L13)	$ 36,422	$ (12,406)
16			
17	Adjusted Test Year Revenue	$ 462,043	$ 462,043
18			
19	Proposed Annual Revenue (L15 + L17)	$ 497,654	$ 449,637
20			
21	Required Percentage Increase In Revenue (L15 / L17)	7.70%	-2.69%
22			
23	Rate Of Return On Common Equity	11.44%	8.50%

References:

Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A]	[B]	[C]
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor	0.7293%		
3	Revenues (L1 - L2)	99.2707%		
4	Combined Federal and State Income Tax and Property Tax Rate (L23)	30.4088%		
5	Subtotal (L3 - L4)	68.8619%		
6	**Revenue Conversion Factor (L1 / L5)**	1.452182		
	Calculation of Uncollecttible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (L17)	29.8750%		
9	One Minus Combined Income Tax Rate (L7 - L8)	70.1250%		
10	Uncollectible Rate	0.01040		
11	Uncollectible Factor (L9 * L10)	0.7293%		
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.5000%		
14	Federal Taxable Income (L12 - L13)	93.5000%		
15	Applicable Federal Income Tax Rate (Col [C] L53)	25.0000%		
16	Effective Federal Income Tax Rate (L14 x L15)	23.3750%		
17	Combined Federal and State Income Tax Rate (L13 + L16)		29.8750%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (Col. [B], L17)	29.8750%		
20	One Minus Combined Income Tax Rate (L18-L19)	70.1250%		
21	Property Tax Factor (Sch. RBM-16, Col. [B], L24)	0.7613%		
22	Effective Property Tax Factor (L20 x L21)		0.5338%	
23	Combined Federal and State Income Tax and Property Tax Rate (Col. (B), L17 + L22)			30.4088%
24	Required Operating Income (Sch. RBM-1, Col. (B) L7)	$ 53,258		
25	Adjusted Test Year Operating Income (Loss) (Sch. RBM-1, Col (B) L3)	61,801		
26	Required Increase in Operating Income (L24 - L25)		$ (8,543)	
27	Income Taxes on Recommended Revenue (Col. [C], L52)	$ 14,694		
28	Income Taxes on Test Year Revenue (Col. (A), L52)	18,333		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		(3,640)	
30	Recommended Revenue Requirement (Sch. RBM-1, Col. (B), L30	$ 449,637		
31	Uncollectible Rate (L10)	0.01040		
32	Uncollectible Expense on Recommended Revenue (L30 x L31)	$ 4,676		
33	Adjusted Test Year Uncollectible Expense(Sch. RBM-8, Col. (K), L31)	$ 4,805		
34	Required Increase in Revenue to Provide for Uncollectible Exp. (L32 - L33)		(129)	
35	Property Tax with Recommended Revenue (Sch. RBM -7 , Col. (E), L23)	$ 10,458		
36	Property Tax on Test Year Revenue (Sch. RBM-8, Col. (C), L23)	10,552		
37	Increase in Property Tax Due to Increase in Revenue (L35 - 36)		(94)	
38	Total Required Increase in Revenue (Col. [B], L26 + L29 + L34 + L37)		$ (12,406)	

	Calculation of Income Tax:	Test Year		RUCO Recommended
39	Revenue (Sch.RBM-7 Col [C] L4 and Col (D) L4	$ 462,043	$ (12,406)	$ 449,637
40	Operating Expenses Excluding Income Taxes	$ 381,909		$ 381,685
41	Synchronized Interest (Col. [C], L57)	$ 2,032		$ 2,032
42	Arizona Taxable Income (L39 - L40 - L41)	$ 78,103		$ 65,920
43	Arizona State Income Tax Rate	6.5000%		6.5000%
44	Arizona Income Tax (L42 x L43)	$ 5,077		$ 4,285
45	Federal Taxable Income (L42 - L44)	$ 73,026		$ 61,635
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ 7,500		$ 7,500
47	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ 5,756		$ 2,909
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ -		$ -
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ -		$ -
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ -		$ -
51	Total Federal Income Tax	$ 13,256		$ 10,409
52	Combined Federal and State Income Tax (L44 + L51)	$ 18,333		$ 14,694
53	Applicable Federal Income Tax Rate [Col. [C], L46 - Col. [A], L46] / [Col. [C], L40 - Col. [A], L40]			25.0000%
54	Synchronized Interest Calculation			
55	Rate Base			$ 634,979
56	Weighted Average Cost of Debt			0.32%
57	Synchronized Interest			$ 2,032

SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO 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	$ 3,079,206	$ -	$ 3,079,206
		-		
2	Accumulated Depreciation	(1,372,116)	-	(1,372,116)
3	Net Utility Plant In Service (L1 + L2)	$ 1,707,090	$ -	$ 1,707,090
4	Advances In Aid Of Const.	$ (722,274)	$ -	$ (722,274)
		-		
5	Contribution In Aid Of Const.	$ (236,097)	$ -	$ (236,097)
6	Accumulated Amortization Of CIAC	-	-	-
7	NET CIAC (L5 + L6)	$ (236,097)	$ -	$ (236,097)
8	Customer Meter Deposits	$ (43,597)	$ -	$ (43,597)
9	Deferred Income Taxes & Credits	$ (70,143)	$ -	$ (70,143)
10	Unamortized Finance Charges	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 634,979	$ -	$ 634,979

References:
Column (A): Company Schedule B-1
Column (B): RBM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

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PLANT SCHEDULES
YEAR ENDED DECEMBER 31, 2011

LINE NO.	ACCT. NO.	ACCOUNT NAME	Gross Pant From Year 2010	(A) Additions	(B) Plant Retirements	(D) Gross Plant Value 2011
1	303	Land and Land Rights	$ 27,898	$ -	$ -	$ 27,898
2	304	Structures and Improvements	39,169	128	-	39,297
3	305	Collecting and impounding Reservoirs	-	-	-	-
4	306	Lake, River and Other Intakes	-	-	-	-
5	307	Wells and Springs	115,895	-	-	115,895
6	308	Infiltration Galleries	-	-	-	-
7	309	Supply Mains	-	-	-	-
7	310	Power Generation Equipment	1,738	-	-	1,738
8	311	Pumping Equipment	538,770	4,922	-	543,692
8	320	Water Treatment Equipment	844,989	-	-	844,989
9	330	Distribution Reservoirs and Standpipes	588,494	-	-	588,494
10	331	Transmission and Distribution Mains	765,133	1,360	-	766,493
11	333	Services	37,406	-	-	37,406
12	334	Meters and Meter Installations	37,738	-	-	37,738
13	335	Hydrants	40,757	-	-	40,757
14	336	Backflow Prevention Devices	5,432	-	-	5,432
15	339	Other Plant and Miscellaneous Equipment	4,284	-	-	4,284
16	340	Office Furniture And Equipment	-	-	-	-
17	340.1	Computers and Software	-	-	-	-
18	341	Transportation Equipment	-	-	-	-
19	342	Stores Equipment	-	-	-	-
20	343	Tools, Shop And Garage Equip	1,650	-	-	1,650
21	344	Laboratory Equipment	-	-		-
22	345	Power Operated Equipment	-	-	-	-
23	346	Communication Equipment	4,225	-	-	4,225
24	347	Miscellaneous Equipment	10,089	-		10,089
25	348	Other Tangible Equipment	8,533			8,533
26			-			-
27			-	526		526
28						
29	TOTAL PLANT IN SERVICE		$ 3,072,200	$ 6,410	$ -	$ 3,079,136
30						
31		Company As Filed				3,079,206
32		Difference				$ (70)

References:
Columns (A) (B): Company Workpapers
Column (C): [(Col. (A) + Col. (B)) X RLM-4, Page 1, Col. (A) X 1/2 yr. conv.] + [RLM-4, Page 1, Col. (B) X RLM-4, Page 1, Col. (A)]
Column (D): Schedule RLM-4, Page 1, Column (B) + Column (A) + Column (B)
Column (E): Schedule RLM-4, Page 1, Column (C) + Column (B) + Column (C)
Column (F): Column (D) + Column (E)

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	3,079,206	$ -	$ -	$ -	$ 3,079,206
2	Accumulated Depreciation	(1,372,116)	-	-	-	(1,372,116)
3	Net Utility Plant In Service (L1 + L2)	$ 1,707,090	$ -	$ -	$ -	$ 1,707,090
4	Advances In Aid Of Const.	$ (722,274)	$ -	$ -	$ -	$ (722,274)
5	Contribution In Aid Of Const.	$ (236,097)	$ -	$ -	$ -	$ (236,097)
6	Accumulated Amortization Of CIAC	-	-	-	-	-
7	NET CIAC (L5 + L6)	$ (236,097)	$ -	$ -	$ -	$ (236,097)
8	Customer Meter Deposits	$ (43,597)	$ -	$ -	$ -	$ (43,597)
9	Deferred Income Taxes & Credits	$ (70,143)	$ -	$ -	$ -	$ (70,143)
10	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ 634,979	$ -	$ -	$ -	$ 634,979

References:
Company Schedules and RUCO Data Request 1.14

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year' Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
	Revenues:						
1	461	Metered Water Revenues	$ 449,915	$ -	$ 449,915	$ (12,406)	$ 437,509
2	460	Unmetered Water Revenues	-	-	-		-
3	474	Other Water Revenues	12,128	-	12,128		12,128
4		TOTAL OPERATING REVENUE	$ 462,043	$ -	$ 462,043	$ (12,406)	$ 449,637
	Operating Expenses:						
5	601	Salaries And Wages - Employees	$ 108,598	(6,397)	$ 102,201	$ -	$ 102,201
6	610	Purchased Water	51,353	-	51,353	-	51,353
7	615	Purchased Power	27,670	(2,562)	25,108	-	25,108
8	618	Chemicals	5,234	-	5,234	-	5,234
9	620	Materials And Supplies	(2,816)	-	(2,816)	-	(2,816)
10	621	Office Supplies and Expense	5,458	-	5,458	-	5,458
11	630	Outside Services	36,433	-	36,433	-	36,433
12	635	Contractural Services - Testing	3,252	-	3,252	-	3,252
13	641	Rental of Building / Real Property	4,216	-	4,216	-	4,216
14	650	Transportation Expenses	9,090	-	9,090	-	9,090
15	657	Insurance - General Liability	2,836	-	2,836	-	2,836
16	659	Insurance - Other	1,509	-	1,509	-	1,509
17	666	Regulatory Comm. Exp. - Rate Case	4,142	(1,802)	2,340	-	2,340
18	670	Bad Debt Expense	11,295	(6,490)	4,805	(129)	4,676
19	675	Miscellaneous Expense	13,302	(6,831)	6,471	-	6,471
20	403	Depreciation Expense	137,751	-	137,751	-	137,751
21	403	Depreciation Expense - CIAC Amort.	(25,606)	-	(25,606)	-	(25,606)
22	408	Taxes Other than Income	1,722	-	1,722	-	1,722
23	408.1	Taxes Other that Income - Property	11,663	(1,111)	10,552	(94)	10,458
24	409	Income Taxes	5,781	12,552	18,333	(3,640)	14,694
25			-	-	-	-	-
26			-				
27			-				
28			-				
29		Total Operating Expenses	$ 412,883	$ (12,641)	$ 400,242	$ (3,863)	$ 396,379
30		Operating Income (Loss)	$ 49,160		$ 61,801		$ 53,258

References:

Column (A): Company Schedule C-1
Column (B): RBM-8, Columns (B) Thru (J)
Column (C): Column (A) + Column (B)
Column (D): Sch. RBM-1, Column (B), L8: Sch RBM-1 page 2 L52
Column (E): Column (C) + Column (D)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Pur. Power Expense	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 7 Property Taxes	(I) Adj. No 8 Income Taxes	(J) Total Pro Forma Adjustments	(K) Test Year Adjusted Results
	Revenues:											
1	461 Metered Water Revenues	$ 449,915	$ -	$ -	$ -			$ -	$ -	$ -	$ -	$ 449,915
2	460 Other Water Revenues	-	-	-	-	-	-	-	-	-	-	-
3	474 Unmetered Water Revenues	12,128	-	-	-	-	-	-	-	-	-	12,128
4	TOTAL OPR'G REV.	$ 462,043	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 462,043
	Operating Expenses:											
5	601 Salaries And Wages - Employees	$ 108,598					$ (6,397)				$ (6,397)	$ 102,201
6	610 Purchased Water	51,353									-	51,353
7	615 Purchased Power	27,670		(2,562)							(2,562)	25,108
8	618 Chemicals	5,234									-	5,234
9	620 Materials And Supplies	(2,816)									-	(2,816)
10	621 Office Supplies and Expense	5,458									-	5,458
11	630 Outside Services	36,433									-	36,433
12	635 Contractural Services - Testing	3,252									-	3,252
13	641 Rental of Building / Real Property	4,216									-	4,216
14	650 Transportation Expenses	9,090									-	9,090
15	657 Insurance - General Liability	2,836									-	2,836
16	659 Insurance - Other	1,509									-	1,509
17	666 Regulatory Comm. Exp. - Rate Case	4,142	(1,802)								(1,802)	2,340
18	670 Bad Debt Expense	11,295				(6,490)					(6,490)	4,805
19	675 Miscellaneous Expense	13,302						(6,831)			(6,831)	6,471
20	403 Depreciation Expense	137,751			-						-	137,751
21	403 Depreciation Expense - CIAC Amort.	(25,606)									-	(25,606)
22	408 Taxes Other than Income	1,722									-	1,722
23	408.1 Taxes Other that Income - Property	11,663							(1,111)		(1,111)	10,552
24	409 Income Taxes	5,781								12,552	12,552	18,333
25		-									-	-
26		-									-	-
27		-									-	-
28		-									-	-
		-									-	-
29	Total Operating Expenses	$ 412,883	$ (1,802)	$ (2,562)	$ -	$ (6,490)	$ (6,397)	$ (6,831)	$ (1,111)	$ 12,552	$ (12,641)	$ 400,242
		-										
30	Operating Income (Loss0	$ 49,160	$ 1,802	$ 2,562	$ -	$ 6,490	$ 6,397	$ 6,831	$ 1,111	$ (12,552)	$ 12,641	$ 61,801

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

Global Utilities
Docket No. W-01212A-12-309 ET AL
Test Year Ended December 31, 2011

Valencia Water Utility of Greater Buckeye, Inc.
Schedule RBM-9
Page 1

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH COMPANY ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Rate Case Expense	(D) Adj. No 3 Low Income Relief	(E) Adj. No 4 Customer Count	(F) Adj. No 5 Accrued Revenue	(G) Adj. No 6 Adjust Pur. Pwr.	(H) Adj. No 7 Reclass of Revenues	(I) Adj. No 8 BLANK	(J) Adj. No 9 Bad Debt Expense	(K) Adj. No 10 Property Taxes	(L) Adj. No 11 Income Taxes	(M) Adj. No 12 Income Taxes	(N) Adj. No 13 Income Taxes	(O) Company Adjustments Test Year	(P) Company As Adjusted Test Year
	Revenues:																
1	461 Metered Water Revenues	$ 466,071	$ -	$ -	$ -	$ (494)	$ (16,890)	$ -	$ 1,228	$ -	$ -	$ -	$ -	$ -	$ -	$ (16,156)	$ 449,915
2	460 Other Water Revenues	1,228	-	-	-	-	-	-	(1,228)	-	-	-	-	-	-	(1,228)	-
3	474 Unmetered Water Revenues	12,128	-	-	-	-	-	-	-	-						-	12,128
4	TOTAL OPR'G REV.	$ 479,427	$ -	$ -	$ -	$ (494)	$ (16,890)		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (17,384)	$ 462,043
	Operating Expenses:																
5	601 Salaries And Wages - Employees	$ 108,598	$ -		$ -		$ -		$ -							$ -	$ 108,598
6	610 Purchased Water	51,353	-		-		-		-							-	51,353
7	615 Purchased Power	23,611	-		-	(4)	-	4,063	-							4,059	27,670
8	618 Chemicals	5,235	-		-	(1)	-		-							(1)	5,234
9	620 Materials And Supplies	(2,816)	-		-		-		-							-	(2,816)
10	621 Office Supplies and Expense	5,458	-		-		-		-							-	5,458
11	630 Outside Services	36,433	-		-		-		-							-	36,433
12	635 Contractural Services - Testing	3,252	-		-		-		-							-	3,252
13	641 Rental of Building / Real Property	4,216	-		-		-		-							-	4,216
14	650 Transportation Expenses	9,090	-		-		-		-							-	9,090
15	657 Insurance - General Liability	2,836	-		-		-		-							-	2,836
16	659 Insurance - Other	1,509	-		-		-		-							-	1,509
17	666 Regulatory Comm. Exp. - Rate Case	1,333	(1,333)	4,142	-		-		-							2,809	4,142
18	670 Bad Debt Expense	11,720	-		-		-		-		(425)					(425)	11,295
19	675 Miscellaneous Expense	13,636	-		(334)		-		-							(334)	13,302
20	403 Depreciation Expense	137,751	-		-		-		-	-						-	137,751
21	403 Depreciation Expense - CIAC Amort.	(25,606)	-		-		-		-							-	(25,606)
22	408 Taxes Other than Income	1,722	-		-		-		-							-	1,722
23	408.1 Taxes Other that Income - Property	19,177	-		-		-		-			(7,514)				(7,514)	11,663
24	409 Income Taxes	23,499	-		-		-		-				(17,718)			(17,718)	5,781
25		-	-		-		-		-							-	-
26		-	-		-		-		-							-	-
27		-	-		-		-		-							-	-
28		-	-		-		-		-							-	-
																-	-
29	TOTAL OPR'G EXP.	$ 432,007	$ (1,333)	$ 4,142	$ (334)	$ (5)	$ -	$ 4,063	$ -	$ -	$ (425)	$ (7,514)	$ (17,718)	$ -	$ -	$ (19,124)	$ 412,883
30	OPR'G INC. (LOSS)	$ 47,420	$ 1,333	$ (4,142)	$ 334	$ (489)	$ (16,890)	$ (4,063)	$ -	$ -	$ 425	$ 7,514	$ 17,718	$ -	$ -	$ 1,740	$ 49,160

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor (L35)			1.68%
4				
5	Valencia Buckeye Water Company			$ 7,019
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 2,340
10				
11	Company Amortized Rate Case Expense for Valencia Buckey as Filed (Sch. C-2.2)			$ 4,142
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ (1,802)
14				
15	RUCO Adjustment			$ (1,802)
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
18	Decision No. 71878, dated September 15, 2010, approved amount			
19	$400,000 forGlobal Water.		$ 400,000	
20				
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) Ln 27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
29					
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

OPERATING INCOME ADJUSTMENT NO. 2
PURCHASED POWER

Line No.	System	Service Provider	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Valencia Town	Arizona Public Service	$ 464,075	$ (62,786)	$ 401,289
2					
3	Valencia Greater Buckeye	Arizona Public Service	27,670	(2,562)	25,108
4					
5	Greater Tonopah	Arizona Public Service	22,407	(2,881)	19,526
6					
7	Willow Valley	Mohave Electric Cooperative	43,747	(1,582)	42,165
8					
9		Total	557,899	(69,811)	488,088

References
Column (A): Company Schedules C-2
Column (B): Company Schedules C-2.6

OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Prior Dec Dep Rate	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) RUCO Depreciation Expense
1	303	Land and Land Rights	0.00%	$ 27,898		-	-	-
2	304	Structures and Improvements	3.33%	39,169	128	-	-	1,306
3		Collecting and impounding Reservoirs	2.50%	-	-	-	-	-
4	306	Lake, River and Other Intakes	2.50%	-	-	-	-	-
5	307	Wells and Springs	3.33%	115,895	-	-	-	3,859
6	308	Infiltration Galleries	6.67%	-	-	-	-	-
7	309	Supply Mains	2.00%	-	-	-	-	-
8	310	Power Generation Equipment	5.00%	1,738	-	-	-	87
9	311	Pumping Equipment	12.50%	538,770	4,992	-	-	67,658
10	320	Water Treatment Equipment	3.33%	844,989	-	-	-	28,138
11	330.1	Distribution Reservoirs and Standpipes	2.22%	588,494	-	-	-	13,065
12	331	Transmission and Distribution Mains	2.00%	765,133	1,360	-	-	15,316
13	333	Services	3.33%	37,406	-	-	-	1,246
14	334	Meters and Meter Installations	8.33%	37,738	-	-	-	3,144
15	335	Hydrants	2.00%	40,757	-	-	-	815
16	336	Backflow Prevention Devices	6.67%	5,432	-	-	-	362
17	339	Other Plant and Miscellaneous Equipment	6.67%	4,284	-	-	-	286
18	340	Office Furniture And Equipment	6.67%	-	-	-	-	-
19	340.1	Computers and Software	33.33%	-	-	-	-	-
20	341	Transportation Equipment	20.00%	-	-	-	-	-
21	342	Stores Equipment	4.00%	-	-	-	-	-
22	343	Tools, Shop And Garage Equipment	5.00%	1,650	-	-	-	83
23	344	Laboratory Equipment	10.00%	-	-	-	-	-
24	345	Power Operated Equipment	5.00%	-	-	-	-	-
25	346	Communication Equipment	10.00%	4,225	-	-	-	423
26	347	Miscellaneous Equipment	10.00%	10,089	-	-	-	1,009
27	348	Other Tangible Equipment	10.00%	8,533	-	-	-	853
28	390.1	Computer Hardware	33.33%	-	-	-	-	-
29	396	SCADA	33.33%	-	526	-	-	88
30								
31		Total Depreciation Expense						$ 137,751
32		Company Depreciation As Filed		$ 3,072,200				137,751

References:
Column A : Order 71878
Column B : RUCO Schedule RBM-5.4
Column C, D, E : RUCO DR 1.14
Column F : (A x B)+((C:E) *A*.5))

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
14						
15		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense	Acct. No.	(A) COMPANY SLECTED EXPENSES	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (L24)			1.675%	
12					
13	Valencia Town Water Company Allocation			$ (6,397)	
14					
15	Personnel Expense as Filed			$ 108,598	
16					
17	RUCO Pro Forma Expense (L15 + L13)			$ 102,201	
18					
19	RUCO Adjustment (L17-L15)			$ (6,397)	
20					
21	Allocation Factor Based on Test Year Revenue		Operating Revenue	Percent of Total	Adjustment by System
22	Palo Verde Utilities Co.		11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company		10,705,825	37.406%	(142,858)
24	Valencia Town Water Company		4,940,530	17.262%	(65,926)
25	Willow Valley Water Company		717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah		214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility		479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale		151,196	0.528%	(2,018)
29	Total Revenue Percentages		28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08
Column (C) -- Company Schedules C-2

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	Allocation: (D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94025	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970.41)	(11,480.96)	(152.11)	(216.03)	(482.33)	(10,770.58)	(721.57)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	# $ (194,371)	# $ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water U	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Percei	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (B-J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 462,043	$ 462,043
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 924,086	$ 924,086
4a	Adjusted Test Year Revenues	462,043	
4b	Recommended Revenue, Per Schedule		449,637
5	Subtotal (L3 + L4a)	$ 1,386,129	$ 1,373,723
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 462,043	$ 457,908
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 924,086	$ 915,815
10	Plus: 10% of CWIP Per Company Schedule E	-	-
11	Less: Net Book Value of Licensed Vehicles	-	-
12	Full Cash Value (Line 9 + L10 - L11)	$ 924,086	$ 915,815
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 175,576	$ 174,005
15	Composite Property Tax Rate	6.0100%	6.0100%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 10,552	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedule)	11,663	
18	RUCO Test Year Adjustment (L16-L17)	$ (1,111)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 10,458
20	RUCO Test Year Adjusted Property Tax Expense (L16)		10,552
21	Increase/(Decrease) to Property Tax Expense		$ (94)
22	Increase/(Decrease) to Property Tax Expense		$ (94)
23	Increase in Revenue Requirement		(12,406)
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		0.007613

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Exp. As Filed by Company (RBM-8 Col (A) Ln 25)	$	5,781
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO (RBM-1(2), Col (A) Ln 52		18,333
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	12,552

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ 12,886	$ -	$ 12,886	0.49%	6.78%	0.03%
2	Long-term Debt	$ 121,380	$ -	$ 121,380	4.61%	6.24%	0.29%
3	Common Equity	$ 2,499,277	$ -	$ 2,499,277	94.90%	8.50%	8.07%
4	TOTAL CAPITAL	$ 2,633,543	$ -	$ 2,633,543	100.00%		
5	COST OF CAPITAL						8.39%

References:
Columns (A) Thru (F): Testimony, WAR

Global Utilities
Docket No. W-01212A-12-309 ET AL
Test Year Ended December 31, 2011

Northern Scottsdale, Inc.

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RBM-3	1 of 2	INTENTIONALLY LEFT BLANK
RBM-3	2 of 2	INTENTIONALLY LEFT BLANK
RBM-4	1	INTENTIONALLY LEFT BLANK
RBM-5	1	COMPANY PLANT BALANCES SINCE LAST RATE CASE
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RBM-11	1	INTENTIONALLY LEFT BLANK
RBM-12	1	OPERATING INCOME ADJUSTMENT NO. 3 - DEPRECIATION EXPENSE
RBM-13	1	OPERATING INCOME ADJUSTMENT NO. 4 - BAD DEBT EXPENSE
RBM-14	1	OPERATING INCOME ADJUSTMENT NO. 5 - PERSONNEL EXPENSE
RBM-15	1	OPERATING INCOME ADJUSTMENT NO. 6 - MISCELLANEOUS EXPENSE
RBM-16	1	OPERATING INCOME ADJUSTMENT NO. 7 - PROPERTY TAXES
RBM-17	1	OPERATING INCOMEADJUSTMENT NO. 8 - ADJUSTED TEST YEAR INCOME TAX EXPENSE
RBM-18	1	COST OF CAPITAL

REVENUE REQUIREMENT

Line No.	Description	(A) Company OCRB/FVRB Cost	(B) RUCO OCRB/FVRB Cost
1	Fair Value Rate Base	$ (181,978)	$ (181,978)
2			
3	Adjusted Operating Income (Loss)	$ 21,301	$ 28,273
4			
5	Current Rate Of Return (L3 / L1)	-11.71%	NA
6			
7	Recommended Operating Income (RBM-7, Col (N) Ln 4) X 8.50%	$ 21,301	$ 11,077
8			
9	Required Rate Of Return On Fair Value Rate Base	14.44%	NA
10			
11	Operating Income Deficiency (L7 - L3)	$ -	NA
12			
13	Gross Revenue Conversion Factor (RBM-1, Pg 2)	1.6290	1.2863
14			
15	Increase In Gross Revenue Requirement (L11 X L13)	$ 2,844	$ (17,196)
16			
17	Adjusted Test Year Revenue	$ 147,513	$ 147,513
18			
19	Proposed Annual Revenue (L15 + L17)	$ 148,244	$ 130,317
20			
21	Required Percentage Increase In Revenue (L15 / L17)	1.93%	-11.66%
22			
23	Rate Of Return On Common Equity	N/A	8.50%

References:

Column (A): Company Schedules A-1 and C-1
Column (B): RUCO Schedule RBM-2, RBM-6 and RBM-10

GROSS REVENUE CONVERSION FACTOR / INCOME TAX CALCULATION

LINE NO.	DESCRIPTION	[A]	[B]	[C]
	Calculation of Gross Revenue Conversion Factor:			
1	Revenue	100.0000%		
2	Uncollecible Factor	1.2289%		
3	Revenues (L1 - L2)	98.7711%		
4	Combined Federal and State Income Tax and Property Tax Rate (L23)	21.0293%		
5	Subtotal (L3 - L4)	77.7417%		
6	**Revenue Conversion Factor (L1 / L5)**	1.286311		
	Calculation of Uncollecttible Factor:			
7	Unity	100.0000%		
8	Combined Federal and State Tax Rate (L17)	20.5250%		
9	One Minus Combined Income Tax Rate (L7 - L8)	79.4750%		
10	Uncollectible Rate	0.01546		
11	Uncollectible Factor (L9 * L10)	1.2289%		
	Calculation of Effective Tax Rate:			
12	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%		
13	Arizona State Income Tax Rate	6.5000%		
14	Federal Taxable Income (L12 - L13)	93.5000%		
15	Applicable Federal Income Tax Rate (Col [C] L53)	15.0000%		
16	Effective Federal Income Tax Rate (L14 x L15)	14.0250%		
17	Combined Federal and State Income Tax Rate (L13 + L16)		20.5250%	
	Calculation of Effective Property Tax Factor			
18	Unity	100.0000%		
19	Combined Federal and State Income Tax Rate (Col. [B], L17)	20.5250%		
20	One Minus Combined Income Tax Rate (L18-L19)	79.4750%		
21	Property Tax Factor (Sch. RBM-16, Col. [B], L24)	0.6346%		
22	Effective Property Tax Factor (L20 x L21)		0.5043%	
23	Combined Federal and State Income Tax and Property Tax Rate (Col. (B), L17 + L22)			21.0293%
24	Required Operating Income (Sch. RBM-1, Col. (B) L7)	$ 11,077		
25	Adjusted Test Year Operating Income (Loss) (Sch. RBM-1, Col (B) L3)	28,273		
26	Required Increase in Operating Income (L24 - L25)		$ (17,196)	
27	Income Taxes on Recommended Revenue (Col. [C], L52)	$ 3,772		
28	Income Taxes on Test Year Revenue (Col. (A), L52)	7,302		
29	Required Increase in Revenue to Provide for Income Taxes (L27 - L28)		N/A	
30	Recommended Revenue Requirement (Sch. RBM-1, Col. (B), L30	$ 130,317		
31	Uncollectible Rate (L10)	0.01546		
32	Uncolllectible Expense on Recommended Revenue (L30 x L31)	$ 2,015		
33	Adjusted Test Year Uncollectible Expense(Sch. RBM-8, Col. (K), L31)	$ 2,281		
34	Required Increase in Revenue to Provide for Uncollectible Exp. (L32 - L33)		N/A	
35	Property Tax with Recommended Revenue (Sch. RBM -8, Col. (K), L36)	$ 2,699		
36	Property Tax on Test Year Revenue (Sch. RBM-8, Col. (Q), L32)	2,808		
37	Increase in Property Tax Due to Increase in Revenue (L35 - 36)		N/A	
38	Total Required Increase in Revenue (Col. [B], L26 + L29 + L34 + L37)		$ (17,196)	

	Calculation of Income Tax:	Test Year		RUCO Recommended
39	Revenue (Sch.RBM-7 Col [C] L4 and Col (D) L4	$ 147,513	$ (17,196)	$ 130,317
40	Operating Expenses Excluding Income Taxes	$ 111,939		$ 111,939
41	Synchronized Interest (Col. [C], L57)	$ -		$ -
42	Arizona Taxable Income (L39 - L40 - L41)	$ 35,574		$ 18,379
43	Arizona State Income Tax Rate	6.5000%		6.5000%
44	Arizona Income Tax (L42 x L43)	$ 2,312		$ 1,195
45	Federal Taxable Income (L42 - L44)	$ 33,262		$ 17,184
46	Federal Tax on First Income Bracket ($1 - $50,000) @ 15%	$ 4,989		$ 2,578
47	Federal Tax on Second Income Bracket ($51,001 - $75,000) @ 25%	$ -		$ -
48	Federal Tax on Third Income Bracket ($75,001 - $100,000) @ 34%	$ -		$ -
49	Federal Tax on Fourth Income Bracket ($100,001 - $335,000) @ 39%	$ -		$ -
50	Federal Tax on Fifth Income Bracket ($335,001 -$10,000,000) @ 34%	$ -		$ -
51	Total Federal Income Tax	$ 4,989		$ 2,578
52	Combined Federal and State Income Tax (L44 + L51)	$ 7,302	N/A	$ 3,772
53	Applicable Federal Income Tax Rate [Col. [C], L46 - Col. [A], L46] / [Col. [C], L40 - Col. [A], L40]			15.0000%
54	Synchronized Interest Calculation			
55	Rate Base			$ -
56	Weighted Average Cost of Debt			-
57	Synchronized Interest			$ -

SUMMARY OF ORIGINAL COST RATE BASE WITH RUCO 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	$ 1,921,063	$ -	$ 1,921,063
		-		
2	Accumulated Depreciation	(424,824)	-	(424,824)
3	Net Utility Plant In Service (L1 + L2)	$ 1,496,239	$ -	$ 1,496,239
4	Advances In Aid Of Const.	$ (1,824,411)	$ -	$ (1,824,411)
		-		
5	Contribution In Aid Of Const.	$ -	$ -	$ -
6	Accumulated Amortization Of CIAC	-	-	-
7	NET CIAC (L5 + L6)	$ -	$ -	$ -
8	Customer Meter Deposits	$ (10,765)	$ -	$ (10,765)
9	Deferred Income Taxes & Credits	$ 156,959	$ -	$ 156,959
10	Unamortized Finance Charges	$ -	$ -	$ -
11	Deferred Regulatory Assets	$ -	$ -	$ -
12	Allowance For Working Capital	$ -	$ -	$ -
13	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ (181,978)	$ -	$ (181,978)

References:
Column (A): Company Schedule B-1
Column (B): RBM-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

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COMPANY PLANT BALANCES

Line No.	Acct No	Account Description	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) RUCO Depreciation Expense
1	303	Land and Land Rights	$ 30,374	-	1,727	-	$ 32,101
2	304	Structures and Improvements	20,000	-	-	-	20,000
3		Collecting and impounding Reservoirs	-	-	-	-	-
4	306	Lake, River and Other Intakes	-	-	-	-	-
5	307	Wells and Springs	130,000	-	-	-	130,000
6	308	Infiltration Galleries	-	-	-	-	-
7	309	Supply Mains	-	-	-	-	-
8	310	Power Generation Equipment	-	-	-	-	-
9	311	Pumping Equipment	216,158	-	-	-	216,158
10	320	Water Treatment Equipment	377	-	-	-	377
11	330.1	Distribution Reservoirs and Standpipes	182,972	-	-	-	182,972
12	331	Transmission and Distribution Mains	1,155,497	-	-	-	1,155,497
13	333	Services	60,047	-	-	-	60,047
14	334	Meters and Meter Installations	11,303	-	-	-	11,303
15	335	Hydrants	108,312	-	-	-	108,312
16	336	Backflow Prevention Devices	775	-	-	-	775
17	339	Other Plant and Miscellaneous Equipment	2,390	-	-	-	2,390
18	340	Office Furniture And Equipment	-	-	-	-	-
19	340.1	Computers and Software	-	-	-	-	-
20	341	Transportation Equipment		-	-	-	-
21	342	Stores Equipment		-	-	-	-
22	343	Tools, Shop And Garage Equipment	515	-	-	-	515
23	344	Laboratory Equipment		-	-	-	-
24	345	Power Operated Equipment		-	-	-	-
25	346	Communication Equipment		-	-	-	-
26	347	Miscellaneous Equipment		-	-	-	-
27	348	Other Tangible Equipment		-	-	-	-
28	390.1	Computer Hardware	2,343	-	-	-	2,343
29	396	SCADA		-	-	-	-
		Total Plant in Service	$ 1,921,063				$ 1,922,790

References:
Company Schedules and RUCO Data Request 1.14

SUMMARY OF ORIGINAL COST RATE BASE WITH COMPANY ADJUSTMENTS

Line No.	Description	(A) Actual Test Year OCRB/FVRB	(B) Adjust No. 1 Post Test Year Plant	(C) Adjust No. 2 BLANK	(D) Adjust No. 3 BLANK	(E) Test Year Adjusted OCRB/FVRB
1	Gross Utility Plant In Service	1,921,063	$ -	$ -	$ -	$ 1,921,063
2						
3	Accumulated Depreciation	(424,824)	-	-	-	(424,824)
4	Net Utility Plant In Service (L1 + L2)	$ 1,496,239	$ -	$ -	$ -	$ 1,496,239
5						
6	Advances In Aid Of Const.	$ (1,824,411)	$ -	$ -	$ -	$ (1,824,411)
7						
8	Contribution In Aid Of Const.	$ -	$ -	$ -	$ -	$ -
9	Accumulated Amortization Of CIAC	-	-	-	-	-
10	NET CIAC (L5 + L6)	$ -	$ -	$ -	$ -	$ -
11						
12	Customer Meter Deposits	$ (10,765)	$ -	$ -	$ -	$ (10,765)
13						
14	Deferred Income Taxes & Credits	$ 156,959	$ -	$ -	$ -	$ 156,959
15						
16	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -
17						
18	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -
19						
20	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -
21						
22						
23	TOTAL RATE BASE (Sum L's 3, 4, 7, 8 Thru 12)	$ (181,978)	$ -	$ -	$ -	$ (181,978)

References:
Column (A): Company Schedule B-1
Column (B); Company Schedule B-2-1
Column (E); Columns (A) through (D)

SUMMARY OPERATING INCOME WITH RUCO ADJUSTMENTS

Line No.		Description	(A) Actual Test Year as Filed	(B) RUCO Test Year' Adjustments	(C) RUCO Test Year As Adjusted	(D) RUCO Proposed Changes	(E) RUCO As Recommended
	Revenues:						
1	461	Metered Water Revenues	$ 145,963	$ -	$ 145,963	$ (17,196)	$ 128,767
2	460	Unmetered Water Revenues	-	-	-	-	-
3	474	Other Water Revenues	1,550	-	1,550	-	1,550
4		TOTAL OPERATING REVENUE	$ 147,513	$ -	$ 147,513	$ (17,196)	$ 130,317
5							
6	Operating Expenses:						
7	601	Salaries And Wages - Employees	$ 19,787	(2,018)	$ 17,769	$ -	$ 17,769
8	610	Purchased Water	-	-	-	-	-
9	615	Purchased Power	10,050	-	10,050	-	10,050
10	618	Chemicals	1,286	-	1,286	-	1,286
11	620	Materials And Supplies	(779)	-	(779)	-	(779)
12	621	Office Supplies and Expense	1,494	-	1,494	-	1,494
13	630	Outside Services	4,483	-	4,483	-	4,483
14	635	Contractural Services - Testing	728	-	728	-	728
15	636	Contractural Services - Other	-	-	-	-	-
16	641	Rental of Building / Real Property	504	-	504	-	504
17	650	Transportation Expenses	1,508	-	1,508	-	1,508
18	657	Insurance - General Liability	475	-	475	-	475
19	659	Insurance - Other	664	-	664	-	664
20	666	Regulatory Comm. Exp. - Rate Case	502	236	738	-	738
21	670	Bad Debt Expense	-	2,281	2,281	-	2,281
22	675	Miscellaneous Expense	4,137	(1,858)	2,279	-	2,279
23	403	Depreciation Expense	64,552	773	65,325	-	65,325
24	403	Depreciation Expense - CIAC Amort.	-	-	-	-	-
25	408	Taxes Other than Income	326	-	326	-	326
26	408.1	Taxes Other that Income - Property	3,104	(296)	2,808	-	2,808
27	409	Income Taxes	13,391	(6,089)	7,302	-	7,302
28							
29							
30							
31							
32							
33		Total Operating Expenses	$ 126,212	$ (6,972)	$ 119,240	$ -	$ 119,240
34							
35		Operating Income (Loss)	$ 21,301	$ 6,972	$ 28,273	$ (17,196)	$ 11,077

References:
- Column (A): Company Schedule C-1
- Column (B): RBM-8, Columns (B) Thru (J)
- Column (C): Column (A) + Column (B)
- Column (D): Sch. RBM-1, Column (B), L8: Sch RBM-1 page 2 L52
- Column (E): Column (C) + Column (D)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH RUCO ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Left Blank	(D) Adj. No 3 Depreciation Expense	(E) Adj. No 4 Bad Debt Expense	(F) Adj. No 5 Personnel Expense	(G) Adj. No 6 Misc. Expense	(H) Adj. No 10 Property Taxes	(I) Adj. No 13 Income Taxes	(J) Total Pro Forma Adjustments	(K) Test Year Adjusted Results
	Revenues:											
1	461 Metered Water Revenues	$ 145,963	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 145,963
2	460 Other Water Revenues	-	-		-	-	-	-	-	-	-	$ -
3	474 Unmetered Water Revenues	1,550	-	-	-	-	-	-	-	-	-	$ 1,550
4	TOTAL OPR'G REV.	$ 147,513	$ -	$ -	$ -	$ -	$ -		$ -	$ -	$ -	$ 147,513
	Operating Expenses:											
5	601 Salaries And Wages - Employees	$ 19,787					$ (2,018)				(2,018)	17,769
6	610 Purchased Water	-									-	-
7	615 Purchased Power	10,050									-	10,050
8	618 Chemicals	1,286									-	1,286
9	620 Materials And Supplies	(779)									-	(779)
10	621 Office Supplies and Expense	1,494									-	1,494
11	630 Outside Services	4,483									-	4,483
12	635 Contractural Services - Testing	728									-	728
13	636 Contractural Services - Other	-									-	-
14	641 Rental of Building / Real Property	504									-	504
15	650 Transportation Expenses	1,508									-	1,508
16	657 Insurance - General Liability	475									-	475
17	659 Insurance - Other	664									-	664
18	666 Regulatory Comm. Exp. - Rate Case	502	236								236	738
19	670 Bad Debt Expense	-				2,281					2,281	2,281
20	675 Miscellaneous Expense	4,137						(1,858)			(1,858)	2,279
21	403 Depreciation Expense	64,552			773						773	65,325
22	403 Depreciation Expense - CIAC Amort.	-									-	-
23	408 Taxes Other than Income	326									-	326
24	408.1 Taxes Other that Income - Property	3,104							(296)		(296)	2,808
25	409 Income Taxes	13,391								(6,089)	(6,089)	7,302
26		-										-
27		-										-
28		-										-
		-										-
29	Total Operating Expenses	$ 126,212	$ 236	$ -	$ 773	$ 2,281	$ (2,018)	$ (1,858)	$ (296)	$ (6,089)	$ (6,972)	$ 119,240
		-										
30	Operating Income (Loss)	$ 21,301	$ (236)	$ -	$ (773)	$ (2,281)	$ 2,018	$ 1,858	$ 296	$ 6,089	$ 6,972	$ 28,273

References:
Column (A): Company Schedule C-1
Column (B) through (N); Company Schedules C-2 pg. 1 through pg. 16
Column (O); Sum of Columns (B) through (N)
Column (P); Column (A) - Column (O)

DETAIL OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED WITH COMPANY ADJUSTMENTS

Line No	DESCRIPTION	(A) Actual Test Year	(B) Adj. No 1 Rate Case Expense	(C) Adj. No 2 Customer Count	(D) Adj. No 3 Accrued Revenue	(E) Adj. No 4 Property Tax	(F) Adj. No 5 Income Taxes	(G) Adj. No 6 BLANK	(H) Adj. No 7 BLANK	(I) Adj. No 8 BLANK	(J) Adj. No 9 BLANK	(K) Adj. No 10 BLANK	(L) Adj. No 11 BLANK	(M) Adj. No 12 BLANK	(N) Adj. No 13 BLANK	(O) Adj. No 14 BLANK	(P) Company Adjustments Test Year	(Q) Company As Adjusted Test Year
	Revenues:																	
1	461 Metered Water Revenues	$ 149,646	$ -	$ 2,115	$ (5,798)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (3,683)	$ 145,963
2	460 Other Water Revenues	-	-		-	-	-	-	-	-	-	-	-	-	-	-	-	-
3	474 Unmetered Water Revenues	1,550	-	-	-	-	-	-	-	-							-	1,550
4	TOTAL OPR'G REV.	$ 151,196	$ -	$ 2,115	$ (5,798)	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	(3,683)	$ 147,513
	Operating Expenses:																	
5	601 Salaries And Wages - Employees	$ 19,787	$ -		$ -		$ -		$ -								-	19,787
6	610 Purchased Water	-	-		-		-		-								-	-
7	615 Purchased Power	9,918	-	132	-		-	-	-								132	10,050
8	618 Chemicals	1,270	-	16	-		-		-								16	1,286
9	620 Materials And Supplies	(779)	-		-		-		-								-	(779)
10	621 Office Supplies and Expense	1,494	-		-		-		-								-	1,494
11	630 Outside Services	4,483	-		-		-		-								-	4,483
12	635 Contractural Services - Testing	728	-		-		-		-								-	728
13	636 Contractural Services - Other	-	-		-		-		-								-	-
14	641 Rental of Building / Real Property	504	-		-		-		-								-	504
15	650 Transportation Expenses	1,508	-		-		-		-								-	1,508
16	657 Insurance - General Liability	475	-		-		-		-								-	475
17	659 Insurance - Other	664	-	-	-		-		-								-	664
18	666 Regulatory Comm. Exp. - Rate Case	-	502	-	-		-		-								502	502
19	670 Bad Debt Expense	-	-		-		-		-								-	-
20	675 Miscellaneous Expense	4,137	-		-		-		-								-	4,137
21	403 Depreciation Expense	64,552	-		-		-		-								-	64,552
22	403 Depreciation Expense - CIAC Amort.	-	-		-		-		-								-	-
23	408 Taxes Other than Income	326	-		-		-		-								-	326
24	408 Taxes Other that Income - Property	3,694	-		-	(590)	-		-								(590)	3,104
25	409 Income Taxes	14,854	-		-		(1,463)		-								(1,463)	13,391
26		-	-		-		-		-								-	-
27		-	-		-		-		-								-	-
28		-	-		-		-		-								-	-
29	Total Operating Expenses	$ 127,615	$ 502	$ 148	$ -	$ (590)	$ (1,463)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ (1,403)	$ 126,212
30	Operating Income (Loss)	$ 23,581	$ (502)	$ 1,967	$ (5,798)	$ 590	$ 1,463	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -		$ (2,280)	$ 21,301

References:
Column (A): Company Schedule C-1
Column (B) through (N): Company Schedules C-2 pg. 1 through pg. 16
Column (O): Sum of Columns (B) through (N)
Column (P): Column (A) - Column (O)

OPERATING INCOME ADJUSTMENT NO. 1
RATE CASE EXPENSE

Line No.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Rate Case Expense Total for Global Water	$ 787,174	$ (368,174)	$ 419,000
2				
3	Allocation Factor (L36)			0.53%
4				
5	Northern Scottsdale Water Company			$ 2,213
6				
7	Amortization Period - 3 years			3
8				
9	RUCO Adjusted Rate Case Expense (L5 / L7)			$ 738
10				
11	Company Amortized Rate Case Expense for Northern Scottsdale as Filed (Sch. C-2.2)			$ 502
12				
13	RUCO Pro Forma Rate Case Expense (L9 - L11)			$ 236
14				
15	RUCO Adjustment			$ 236
16				
17	RUCO's Rate Case Expense Adjustment Calculation:			
19	$400,000 forGlobal Water.		$ 400,000	
21	Inflation factor from October 1, 2010 to July 1, 2012			
22	Per Consumer Price Index		4.75%	
23				
24	Reasonable Amount of Rate Case Expense based on			
25	Decision No. 71878.		$ 419,000	
26				
27	RUCO Adjustment (Col. (B) Ln 27 - Col. (A) L 1)		$ (368,174)	
28				

	Allocation Factor Based on System Revenue	Operating Revenue	%t of Total	Company Amortized Amt.	Adjustment by System
29					
30	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 104,585	$ (48,896)
31	Santa Cruz Water Company	10,705,825	37.41%	105,801	(53,558)
32	Valencia Town Water Company	4,940,530	17.26%	35,298	(11,189)
33	Willow Valley Water Company	717,230	2.51%	9,923	(6,423)
34	Water Utility of Greater Tonopah	214,736	0.75%	2,140	(1,092)
35	Valencia of Greater Buckeye Water Utility	479,427	1.68%	4,142	(1,802)
36	Water Utility of Northern Scottsdale	151,196	0.53%	502	236
37	Total System Revenud and Percentages	$ 28,620,876	100.00%	$ 262,391	$ (122,724)

References:
Column (A) Company Schedules C-2.2
Column (B) CPI Information from Inflation.com

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OPERATING INCOME ADJUSTMENT NO. 3
CALCULATION OF DEPRECIATION EXPENSE

Line No.	Acct No	Account Description	(A) Prior Dec Dep Rate	(B) Plant Balance 12/31/2010	(C) Additions	(D) Other Costs	(E) Disposals	(F) RUCO Depreciation Expense
1	303	Land and Land Rights	0.00%	$ 30,374	-	1,727	-	-
2	304	Structures and Improvements	3.33%	20,000	-	-	-	666
3		Collecting and impounding Reservoirs	2.50%	-	-	-	-	-
4	306	Lake, River and Other Intakes	2.50%	-	-	-	-	-
5	307	Wells and Springs	3.33%	130,000	-	-	-	4,329
6	308	Infiltration Galleries	6.67%	-	-	-	-	-
7	309	Supply Mains	2.00%	-	-	-	-	-
8	310	Power Generation Equipment	5.00%	-	-	-	-	-
9	311	Pumping Equipment	12.50%	216,158	-	-	-	27,020
10	320	Water Treatment Equipment	3.33%	377	-	-	-	13
11	330.1	Distribution Reservoirs and Standpipes	2.22%	182,972	-	-	-	4,062
12	331	Transmission and Distribution Mains	2.00%	1,155,497	-	-	-	23,110
13	333	Services	3.33%	60,047	-	-	-	2,000
14	334	Meters and Meter Installations	8.33%	11,303	-	-	-	942
15	335	Hydrants	2.00%	108,312	-	-	-	2,166
16	336	Backflow Prevention Devices	6.67%	775	-	-	-	52
17	339	Other Plant and Miscellaneous Equipment	6.67%	2,390	-	-	-	159
18	340	Office Furniture And Equipment	6.67%	-	-	-	-	-
19	340.1	Computers and Software	33.33%	-	-	-	-	-
20	341	Transportation Equipment	20.00%		-	-	-	-
21	342	Stores Equipment	4.00%		-	-	-	-
22	343	Tools, Shop And Garage Equipment	5.00%	515	-	-	-	26
23	344	Laboratory Equipment	10.00%		-	-	-	-
24	345	Power Operated Equipment	5.00%		-	-	-	-
25	346	Communication Equipment	10.00%		-	-	-	-
26	347	Miscellaneous Equipment	10.00%		-	-	-	-
27	348	Other Tangible Equipment	10.00%		-	-	-	-
28	390.1	Computer Hardware	33.33%	2,343	-	-	-	781
29	396	SCADA	33.33%		-	-	-	-
		Calculated Depreciation Expense						$ 65,324
		Company Reported Depreciation Expense						64,552
		RUCO Adjusted Test Year Depreciation Expense						$ 773

References:
Column A : Order 71878
Column B : RUCO Schedule RBM-5.4
Column C, D, E : RUCO DR 1.14
Column F : (A x B)+((C:E) *A*.5))
Column (G) Depreciation Expense as Reported by Company
Line 34: Company Schedule B2.1 and RUCO Schedule RBM 3.2

OPERATING INCOME ADJUSTMENT NO. 4
BAD DEBT EXPENSE

Line No.	System	(A) COMPANY BAD DEBT EXPENSE	(B) COMPANY TEST YEAR ADJUSTMENT, REVENUE CHG.	(C) COMPANY AS FILED	(D) ACTUAL BAD DEBT WRITE-OFF	(E) RUCO ADJUSTMENT (D - C)
1	Valencia Town	$ 30,899	$ (1)	$ 30,898	$ 24,472	$ (6,426)
2						
3	Palo Verde	72,207	10,729	82,936	71,312	(11,624)
4						
5	Greater Tonopah	4,930	(161)	4,769	3,751	(1,018)
6						
7	Valencia Greater Buckeye	11,720	(425)	11,295	4,805	(6,490)
8						
9	Santa Cruz	55,174	(1,249)	53,925	73,358	19,433
10						
11	Willow Valley	8,422	(171)	8,251	4,430	(3,821)
12						
13	Northern Scottsdale	-	-	-	2,281	2,281
14						
15		$ 183,352	$ 8,722	$ 192,074	$ 184,409	$ (7,665)

References:
Column (A) & (C) Company Schedules C-2
Column (B) Company Schedule C-2.11
Column (D) RUCO Data Request 3.01

OPERATING INCOME ADJUSTMENT NO.5
PERSONNEL EXPENSE

Line No.	Expense	No.	(A) COMPANY SELECTED EXPENSES	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED
1	Overtime Hours	80101	$ 95,796	$ (47,898)	$ 47,898
2					
3	Bonuses Operations	80107	1,160	(580)	580
4					
5	Deferred Compensation	80500	293,306	(293,306)	
6					
7	Employee Hiring & Moving	80901	80,264	(40,132)	40,132
8					
9	Total		$ 470,526	$ (381,916)	$ 88,610
10					
11	Allocation Factor (L28)			0.528%	
12					
13	Northern Scottsdale Water Company Allocation			$ (2,018)	
14					
15	Personnel Expense as Filed			$ 19,787	
16					
17	RUCO Pro Forma Expense (L15 + L13)			$ 17,769	
18					
19	RUCO Adjustment (L17-L15)			$ (2,018)	
20					
21	Allocation Factor Based on Test Year Revenue		Operating Revenue	Percent of Total	Adjustment by System
22	Palo Verde Utilities Co.		11,411,932	39.873%	$ (152,280)
23	Santa Cruz Water Company		10,705,825	37.406%	(142,858)
24	Valencia Town Water Company		4,940,530	17.262%	(65,926)
25	Willow Valley Water Company		717,230	2.506%	(9,571)
26	Water Utility of Greater Tonopah		214,736	0.750%	(2,865)
27	Valencia of Greater Buckeye Water Utility		479,427	1.675%	(6,397)
28	Water Utility of Northern Scottsdale		151,196	0.528%	(2,018)
29	Total Revenue Percentages		28,620,876	100.00%	$ (381,916)

References:
Column (A) -- RUCO DR 1.08
Column (C) -- Company Schedules C-2

OPERATING INCOME ADJUSTMENT NO. 6
MISCELLANEOUS EXPENSE

	Account No.	Expense Category	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENT	(C) RUCO AS ADJUSTED	Allocation: (D) Valencia Town	(E) Palo Verde	(F) N. Scottsdale	(G) Greater Tonopah	(H) Valencia Buckeye	(I) Santa Cruz	(J) Willow
1	88077	Investor Relations	$ 57,595	$ (57,595)	$ -	$ (7,734)	$ (22,956)	$ (108)	$ (476)	$ (897)	$ (23,226)	$ (2,198)
2												
3	94037	Charitable Contributions	6,268	$ (6,268)	-	(53)	(2,976)				(3,239)	
4												
5	94041	Dues & Subscriptions	43,056	$ (43,011)	45	(6,104)	(16,816)	(136)	(400)	(684)	(17,400)	(1,471)
6												
7	94043	Promotions & Advertising	28,763	$ (28,763)	-	(3,595)	(10,454)	(53)	(222)	(416)	(12,999)	(1,024)
8												
9	94045	Employee Relations	32,955	$ (32,955)	-	(5,128)	(11,961)	(106)	(396)	(546)	(13,365)	(1,453)
10												
11	80500	Board Compensation	26,396	$ (26,396)	-	(4,556)	(10,525)	(139)	(198)	(442)	(9,874)	(661)
12												
13	94022	Travel & Entertainment	74,400	(74,400)	-	(9,391)	(27,635)	(415)	(673)	(954)	(27,039)	(8,293)
14												
15	94023	Meals	42,101	(42,101)	-	(6,294)	(13,014)	(249)	(631)	(733)	(13,315)	(7,865)
16												
17	94036	Business Development	26,161	(26,161)	-		627				(26,788)	
18												
19	93941	Sales Tax Late Fee	1,636	(1,636)	-	(553)	(22)		(17)	(90)	(928)	(27)
20												
21	94025	Professional Fees - Other	94,713	(94,713)	-	(16,349)	(37,765)	(500)	(711)	(1,587)	(35,428)	(2,373)
22												
23	80503	Other Compensation	28,794	(28,794)	-	(4,970.41)	(11,480.96)	(152.11)	(216.03)	(482.33)	(10,770.58)	(721.57)
24												
25		**Total**	$ 462,838	$ (462,793)	$ 45	$ (64,729)	$ (164,977)	$ (1,858)	$(3,940)	$ (6,831)	# $ (194,371)	# $ (26,087)
26												

27	Allocation Factor By System Revenue	Operating Revenue	%t of Total Revenue	Allowed Dues
28	Palo Verde Utilities Co.	$ 11,411,932	39.87%	$ 17.94
29	Santa Cruz Water Company	10,705,825	37.41%	16.83
30	Valencia Town Water Company	4,940,530	17.26%	7.77
31	Willow Valley Water Company	717,230	2.51%	1.13
32	Water Utility of Greater Tonopah	214,736	0.75%	0.34
33	Valencia of Greater Buckeye Water L	479,427	1.68%	0.75
34	Water Utility of Northern Scottsdale	151,196	0.53%	0.24
35	Total System Revenue and Percei	$ 28,620,876	100.00%	$ 45.00

References:
Column (A) RUCO Data Requests 5.02, 6 & 1.08
Columns (B-J) RUCO Data Requests 5.02, 6 & 1.09

OPERATING INCOME ADJUSTMENT NO. 7
PROPERTY TAXES

LINE NO.	Property Tax Calculation	[A] RUCO AS ADJUSTED	[B] RUCO RECOMMENDED
1	Adjusted Test Year Revenues	$ 147,513	$ 147,513
2	Multiplied by 2	2	2
3	Subtotal (L1 X L2)	$ 295,026	$ 295,026
4a	Adjusted Test Year Revenues	147,513	
4b	Recommended Revenue, Per Schedule		130,317
5	Subtotal (L3 + L4a)	$ 442,539	$ 425,343
6	Number of Years	3	3
7	Three Year Average (L5 / L6)	$ 147,513	$ 141,781
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (L7 X L8)	$ 295,026	$ 283,562
10	Plus: 10% of CWIP Per Company Schedule E	-	-
11	Less: Net Book Value of Licensed Vehicles	-	-
12	Full Cash Value (Line 9 + L10 - L11)	$ 295,026	$ 283,562
13	Assessment Ratio	19.0%	19.0%
14	Assessed Value (L12 * L13)	$ 56,055	$ 53,877
15	Composite Property Tax Rate	5.0100%	5.0100%
16	RUCO Adjusted Test Year Property Tax Expense (L14 * L15)	$ 2,808	
17	Company Adjusted Test Year Property Tax (Per Company C-1 Schedule)	3,104	
18	RUCO Test Year Adjustment (L16-L17)	$ (296)	
19	Property Tax - RUCO Recommended Revenue (L14 * L15)		$ 2,699
20	RUCO Test Year Adjusted Property Tax Expense (L16)		2,808
21	Increase/(Decrease) to Property Tax Expense		$ (109)
22	Increase/(Decrease) to Property Tax Expense		$ (109)
23	Increase in Revenue Requirement		(17,196)
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (L22 / L23)		0.006346

OPERATING INCOME ADJUSTMENT NO. 8
ADJUSTED TEST YEAR INCOME TAX EXPENSE

Line No.	Description		Amount
1			
2	Total Adjusted Test Year Income Tax Expense As Filed by Company	$	13,391
3			
4	Total Adjusted Test Year Income Tax Expense Per RUCO		7,302
5			
6	RUCO Adjusted Test Year Income Tax Expense Adjustment	$	(6,089)
7			

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST RATE
1	Short-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	Long-term Debt	$ -	$ -	$ -	0.00%	0.00%	0.00%
3	Common Equity	$ (233,834)	$ -	$ (233,834)	100.00%	8.50%	8.50%
4	TOTAL CAPITAL	$ (233,834)	$ -	$ (233,834)	100.00%		
5	COST OF CAPITAL						8.50%

References:
Columns (A) Thru (F): Testimony, WAR

GLOBAL UTILITIES

DOCKET NO. W-01212A-12-0309 ET AL.

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 8, 2013

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8 Water Company Infrastructure Costs

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10 of Pennsylvania

11 Attachment C – Increasing Use of Surcharges on Consumer Utility Bills,
12 Prepared by Larkin & Associates, PLLC for AARP

EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of the applications for a permanent rate increase ("Applications") of Global Water - Palo Verde Utilities Company ("Palo Verde"); Global Water - Santa Cruz Water Company ("Santa Cruz"); Global Water - Valencia Water Company - Town Division ("VWCT"); Water Utility of Greater Tonopah, Inc. ("WUGT"); Willow Valley Water Company, Inc. ("Willow Valley"); Valencia Water Company - Greater Buckeye Division ("VWCGB"); and Global Water - Water Utility of Northern Scottsdale ("WUNS") (collectively "Applicants," "Global Utilities," or "Company") which were filed with the Arizona Corporation Commission ("ACC" or "Commission") on July 9, 2012, RUCO recommends the following:

RUCO recommends that the Arizona Corporation Commission reject the Applicants' request for a Distribution System Improvement Charge and a Collection System Improvement Charge.

INTRODUCTION

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

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for 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 utility regulation and your educational background.

A. I have been involved with utility 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. Appendix 1, which is attached to my direct testimony on the cost of capital issues In this case, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved in.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present RUCO's position on requests for a water system Distribution System Improvement Charge ("DSIC") and a wastewater system Collection System Improvement Charge ("CSIC") presented in the applications for a permanent rate increase

("Applications") of Global Water - Palo Verde Utilities Company ("Palo Verde"); Global Water - Santa Cruz Water Company ("Santa Cruz"); Global Water - Valencia Water Company - Town Division ("VWCT"); Water Utility of Greater Tonopah, Inc. ("WUGT"); Willow Valley Water Company, Inc. ("Willow Valley"); Valencia Water Company - Greater Buckeye Division ("VWCGB"); and Global Water - Water Utility of Northern Scottsdale ("WUNS") (collectively "Applicants," "Global Utilities," or "Company") which were filed with the Arizona Corporation Commission ("ACC" or "Commission") on July 9, 2012,

Q. Will RUCO be filing testimony on the required revenue, rate design and cost of capital issues associated with AWC's Application?

A. Yes. RUCO witness Robert B. Mease will provide direct testimony presenting RUCO's recommendations on required revenue and will address other issues in the case including RUCO's recommended treatment of Infrastructure Coordination and Financing Agreements ("ICFAs") and acquisition adjustments. Mr. Mease will also sponsor RUCO's direct testimony on rate design which is scheduled to be filed on July 15, 2013. As I noted above, I have also filed, under separate cover, direct testimony on the cost of capital issues in this case.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Please summarize the specific issues that you will address in your direct testimony.

A. My direct testimony will address the Applicants DSIC and CSIC requests.

Q. Please provide a brief summary of RUCO's recommendations.

A. RUCO recommends that the Commission reject the Applicants' requests for DSIC and CSIC mechanisms for the reasons that I will present in my direct testimony.

DSIC AND CSIC REQUESTS

Q. What water and wastewater systems are the Company requesting DSIC and CSIC mechanisms for?

A. The Company is requesting DSIC mechanisms for all its water systems with the exception of WUNS, and a CSIS for the Palo Verde wastewater system. Both mechanisms will allow the Applicants to recover the costs of specific plant additions that are placed into service between general rate case proceedings through a surcharge.

Q. Have you reviewed the direct testimony of Paul Walker that addresses the requests for the DSIC and CSIC mechanisms?

A. Yes.

Q. Briefly explain the Company's DSIC and CSIC requests.

A. The Company is proposing that supply mains, distribution and transmission mains, services and meters recorded in National Association of Regulatory Utility Commissioners ("NARUC") Accounts numbered 309, 332, 333 and 334 be eligible for recovery through a water system DSIC mechanism. For the wastewater CSIC, qualifying assets would include Collection Sewers - Force, Collection Sewers – Gravity, Special Collecting Structures, Services to Customers, Flow measuring Devices, Flow Measuring Installations and Outfall Sewer Lines recorded in NARUC Accounts numbered 360, 361, 362, 363, 364, 365 and 382.

According to Mr. Walker's direct testimony, the Applicants would submit a Proposed System Improvement Plan that would specify five- and ten-year replacement plans for eligible assets financed by debt and equity that would be updated every two years. The Applicants would then file requests on an annual basis, for ACC Staff's review, to place completed projects into rate base and earn a return that is equal to the rate of return authorized in the last rate case.

Q. Have there been any developments regarding a mechanism similar to the DSIC and CSIC that the Applicants are requesting?

A. Yes. Since Mr. Walker's testimony was filed on July 9, 2012, the ACC has issued Decision No. 73938, which approved an Arizona Water Company

("AWC") Eastern Group settlement agreement that adopts a System Improvement Benefits ("SIB") surcharge mechanism for the Eastern Group water systems.[1] Like the DSIC and CSIC mechanisms being requested in this case, the SIB allows for recovery of qualifying water system plant additions that are placed into service between general rate case proceedings. Global Utilities was a party to the AWC Eastern Group settlement agreement as were a number of other Arizona water providers.

Q. Was RUCO a signatory to the AWC Eastern Group settlement agreement?

A. No. RUCO was not a signatory to the Eastern Group settlement agreement. RUCO's Director, Patrick J. Quinn, and I testified against the settlement agreement during the AWC Eastern Group Phase 2 evidentiary hearing on the SIB mechanism.

Q. Have there been any other cases in which a SIB mechanism has been approved by the Commission?

A. No. A settlement agreement that adopts a SIB mechanism for AWC's Northern Group water systems is before the Commission at this time, but has not yet been approved by the Commission. RUCO also opposed the AWC Northern Group settlement agreement as well.[2]

---

[1] Docket Number W-01445A-11-0310

[2] Docket Number W-01445A-12-0348

Q. Has the Commission approved a SIB mechanism or a CSIC for a wastewater utility, such as Palo Verde, to date?

A. No.

Q. What is RUCO's recommendation regarding the Company-proposed DSIC and CSIC?

A. RUCO recommends that the Commission reject the Company-proposed DSIC and CSIC for the same reasons that it opposed the SIB mechanism adopted in the aforementioned AWC Eastern and Northern Group settlement agreements. The SIB mechanism approved by the Commission for the AWC Eastern Group is intended to be a template for mechanisms such as the DSIC and CSIC that the Applicants are requesting in this case. For this reason I will include the SIB in the discussion that follows.

Q. Please discuss RUCO's reasons for opposing the adoption of the SIB, DSIC and CSIC mechanisms.

A. There are four reasons[3] why RUCO is opposed to the adoption of the SIB, DSIC and CSIC mechanisms. First, each of the mechanisms allow for the recovery of routine plant improvements outside of a rate case that would normally be recovered in a general rate case proceeding. Second, the

[3] There are also legal concerns with the implementation of the DSIC which, if necessary, RUCO will address in its legal briefs.

SIB, DSIC and CSIC are one-sided mechanisms that work only in the interest of shareholders. While they allow accelerated cost recovery for new plant, they fail to adequately consider reduced operations and maintenance expense ("O&M") savings attributable to the new plant. Third, there is no federal or state requirement mandating the types of routine plant additions that the SIB, DSIC and CSIC mechanisms recover through a surcharge. Fourth, neither AWC nor the Applicants in this case have proven that they would not be able to ensure safe and reliable water service or achieve cost recovery absent the adoption of a SIB, DSIC or CSIC. Therefore, there is no need for the Commission to adopt a special surcharge for such routine additions.

Q. In regard to RUCO's first reason for rejecting the Company-proposed DSIC and CSIC, are the types of infrastructure improvements that would be recovered through the SIB, DSIC and CSIC extraordinary in nature?

A. No. Like the AWC Eastern and Northern Group SIBs, the types of infrastructure improvements for which the Company-proposed DSIC and CSIC mechanism are intended to recover are routine in nature. These are plant improvements that any regulated utility would normally make as existing assets reach the end of their useful lives. There is nothing extraordinary about these types of plant additions. Normal regulatory procedures allow cost recovery for these types of plant additions after a

determination of prudency and that the additions meet the used and useful standard during a general rate case proceeding when all of the various ratemaking elements are taken into consideration. RUCO has consistently opposed the use of cost recovery mechanisms that do not allow for the type of thorough analysis that takes place in a general rate case proceeding.

Q. Why is it important to consider all of the ratemaking elements when setting new rates?

A. Because the addition of new plant that replaces aging plant can have an impact on operating expenses which are recovered by a utility on a dollar-for-dollar basis in new rates. For example, new additions may be responsible for lower purchased pumping power costs as a result of improved system efficiency and lower employee wage expense as a result of less time spent on repairing aging plant items after normal hours. Under the Company-proposed DSIC and CSIC, the Applicants would enjoy the benefit of receiving a return on and a return of its investment in new plant through a surcharge established between general rate case proceedings. Unfortunately, ratepayers receive no benefit from any cost savings that are related to the plant additions that they will be paying for through the SIB, DSIC and CSIC. Any cost savings resulting from new plant additions recovered through the Company-proposed DSIC and

CSIC would be pocketed by the Applicants between general rate case proceedings.

Q. In regard to RUCO's third reason for rejecting the Company-proposed DSIC and CSIC, are there any federal or state regulations that require the Commission to approve a mechanism that is similar to the ACRM?

A. No. Unlike the circumstances surrounding plant that was required for reducing the level of arsenic in drinking water, there are no federal or state requirements that warrant the implementation of a mechanism similar to the Arsenic Cost Recovery Mechanism ("ACRM")[4] for the recovery of aging plant between general rate cases. RUCO believes that adjustor mechanisms are extraordinary rate recovery devices that are permitted for certain narrow circumstances. In RUCO's view, the routine replacement of aging infrastructure, that would be recovered through the SIB or the Company-proposed DSIC and CSIC, does not qualify as an extraordinary circumstance that requires a mechanism such as the ACRM which was specifically designed to address a one-time event that impacted dozens of Arizona water companies simultaneously. RUCO believes that more mainstream issues, such as excessive water loss, are something that water providers should keep in check as a matter of

[4] The ACRM was adopted by the Commission in order to allow Arizona water providers to recover the costs associated with meeting more stringent arsenic level standards imposed by the federal government.

routine cost management. A water provider's failure to perform ordinary maintenance is not a reason for the institution of a SIB, DSIC or CSIC in RUCO's opinion.

Q. Please discuss RUCO's fourth reason for rejecting the DSIC.

A. RUCO believes that AWC should replace aging infrastructure as part of the Company's normal course of infrastructure improvements to ensure continued safety and reliability. RUCO, however, does not find that a SIB, DSIC or CSIC surcharge is necessary for AWC to meet the Company's obligation to provide safe and reliable water service. The Applicants do not contend that the denial of a DSIC or CSIC would change its ability to meet the Company's statutory and regulatory commitments and the Applicants do not allege that it is financially unable to make necessary and prudent infrastructure replacements without the DSIC or CSIC.

Q. Does the National Association of State Consumer advocates ("NASUCA") endorse mechanisms similar to the SIB, DSIC or CSIC?

A. No. NASUCA issued a resolution in 1999 (Attachment A) that opposes the adoption and implementation of mechanisms such as the Company-proposed DSIC and CSIC. The resolution lists a number of sound reasons why such mechanisms should be rejected by state utility commissions.

Q. Can you cite any research that illuminates the deficiencies in the SIB, and the Company-proposed DSIC and CSIC surcharges?

A. Yes. In September of 2009, Ken Costello, a Principal with the National Regulatory Research Institute ("NRRI"), published a survey report on cost trackers (similar to the SIB and the Company-proposed DSIC and CSIC). In his report, Mr. Costello noted the following:

> "Cost trackers can, in various ways, result in higher utility costs. First, they undercut the positive effects of regulatory lag on a utility's costs. "Regulatory lag" refers to the time gap between when a utility undergoes a change in cost or sales levels and when the utility can reflect these changes in new rates. Economic theory predicts that the longer the regulatory lag, the more a utility has to control its costs; when a utility incurs costs, the longer it has to wait to recover those costs, the lower its earnings are in the interim. The utility, consequently, would have an incentive to minimize additional costs. Commissions rely on regulatory lag as an important tool for motivating utilities to act efficiently. As economist and regulator Alfred Kahn once remarked:
>
> > "Freezing rates for the period of the lag imposes penalties for inefficiency, excessive conservatism, and wrong guesses, and offers rewards to their opposites; companies can for a time keep the higher profit they reap from a superior performance and have to suffer the losses for a poor one."
>
> Rational utility management, as a general rule, would exert minimal effort in controlling costs if it has no effect on the utility's profits. This condition occurs when a utility is able to pass through (with little or no regulatory scrutiny) higher costs to customers with minimal consequences for sales. Cost containment constitutes a real cost to management. Without any expected benefits, management would exert minimum effort on cost containment. The difficult problem for the regulator is to detect when management is lax. Regulators should concern themselves with this problem; lax management translates into a higher cost of service and, if undetected, higher rates to the utilities' customers. Regulators should closely monitor and

> scrutinize costs, such as those subject to cost trackers, t hat utilities have little incentive to control."[5]

Q. Can you cite other cases or testimony that supports RUCO's position on this issue?

A. Yes. In April of 2009, Sonny Popowsky, the Consumer Advocate for the State of Pennsylvania, offered testimony before the Pennsylvania House Consumer Affairs Committee regarding a House Bill that would have approved a mechanism similar to the SIB and the Company-proposed DSIC and CSIC for natural gas utilities (Attachment B). In his testimony, to support his argument against the adoption of the natural gas mechanism, Mr. Popowski quoted Commonwealth Court Judge Leavitt in her opinion on a CSIC, being sought by Pennsylvania-American Water Company:

> "The surcharge is quite different from a base rate. In Pennsylvania, as in most jurisdictions, rates for public utilities are set using what is known as the test year concept, which requires taking a snapshot of the utility's revenues, expenses and capital costs during a one-year period. The object of using a test year is to reflect typical conditions. Test year expenses may be adjusted or normalized where atypical or non-recurring. Under the test year concept, revenues, expenses and capital costs are to be simultaneously reviewed for the same period of time so that a utility may prove its new rates are "just and reasonable."

Mr. Popowski went on to state the following:

> "Unlike a traditional base rate case, in which all costs and all revenues are considered simultaneously, a DSIC is a one way street that can only increase rates between rate cases, even if a

[5] Costello, Ken, "How Should Regulators View Cost Trackers?" Washington, DC: National Regulatory Research Institute, Pages 4-5 [footnotes excluded]

utility's other costs are going down or its revenues are going up. In setting utility rates, it is important to look at all the utility's costs and revenues, not just a single utility cost item that may be added between rate cases."

Q. Can RUCO cite any other studies that dispute the benefits of adjustor mechanisms such as the SIB or the Company-proposed DSIC and CSIC mechanisms discussed in your testimony?

A. Yes. In May of 2012, Ralph Smith of Larkin & Associates, PLLC, who has testified in a number of rate case proceedings on behalf of ACC Staff and RUCO, recently authored a report on the increasing use of surcharges on consumer utility bills for the American Association of Retired Persons ("AARP") which I've attached to my direct testimony (Attachment C). In his report, Mr. Smith explains how, for many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from investment in new gas pipelines to environmental compliance costs. Mr. Smith points out that that these types of surcharges are departures from the traditional utility rate setting process. He also warns that surcharges, such as a SWIP or DSIC, can result not only in increased costs to consumers, but additional undesirable consequences such as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers.

...

Q. Has the Commission rejected such mechanisms in prior cases?

A. Yes, in a prior Arizona-American Water Company rate case proceeding, the Commission adopted the recommendations of ACC Staff and RUCO and rejected a similar cost recovery mechanism identified as an Infrastructure Improvement Surcharge ("IIS"). Decision No. 72047 stated the following:

> "The Company admits the surcharge would cover routine investments in such items as meters, mains, hydrants, tanks and booster stations, and while the Company proposed a cap on the increase between rates, the Company has not quantified the amount of the proposed surcharge. We agree with RUCO and Staff that the recovery of expenditures for plant additions and improvements does not warrant the extraordinary ratemaking device of an adjuster mechanism, and will therefore not grant the request for institution of an IIS."

Q. Do the customer bill impacts justify the adoption of the SIB or the Company-proposed DSIC and CSIC?

A. No. While proponents argue that surcharge mechanisms such as the SIB or the Company-proposed DSIC and CSIC result in gradual rate increases that would be more palatable to both ACC Commissioners and to ratepayers, if the Commission were to adopt such mechanisms for the Applicants, ratepayers could be looking at a rate increase in every year between general rate cases. Municipal systems don't even impose such frequent rate hikes on their water and wastewater customers. This steady stream of rate increases is certainly a departure from the Commission's prior preference for rate stability between general rate cases. While it is possible that the adoption of a SIB or the Company-proposed DSIC and

CSIC may mitigate rate shock in future general rate cases, the Commission would have to weigh this with the fact that this steady stream of rate increases will benefit the Company more than AWC ratepayers given the fact that the surcharge amounts will not reflect any dollar-for-dollar cost reductions in operating expenses that are associated with the new plant.

Because ACC Staff, and intervenors, such as RUCO, will not have the opportunity to look closely at the plant additions being placed into service between rate cases, the possibility exists that imprudent expenditures would not be discovered until a general rate case proceeding. By then ratepayers could have been overcharged for imprudent plant expenditures for a number of years. Furthermore, ratepayers who leave the affected systems will not even see any savings from new rates, established in a general rate case proceeding, that reflect lower operating costs or the disallowance of imprudent plant expenditures. For the reasons that I've given above, I believe that the Commission should reject a SIB or the Company-proposed DSIC and CSIC.

Q. Is there any way to mitigate the problems with the SIB or the DSIC and CSIC that you discussed above?

A. Possibly. In July 2011, David D. Dismukes, Ph.D. (who recently testified for ACC Staff in the recent Southwest Gas Corporation rate case

proceeding), filed testimony[6] on a surcharge mechanism similar to the Company-proposed DSIC and CSIC in a proceeding before the Maryland Public Service Commission. As an alternative to an accelerated natural gas pipe replacement plan that was being proposed in that proceeding by WGL Holdings, Inc., Mr. Dismukes recommended an Operations & Maintenance ("O&M") expense offset that would apply a specified dollar credit to every mile of replaced pipe. A similar credit could be applied to every foot of replacement line that AWC would recover through the Company-proposed DSIC. Mr. Dismukes recommendation makes good sense from the standpoint that O&M expense would drop as aging infrastructure is replaced. In this case, an O&M credit would have the effect of lowering the increased pro-forma level of O&M expense that it is being proposed by AWC in this case which would be embedded in base rates. The adoption of an O&M credit, that would be applied to customer bills at the same time that potential DSIC surcharges go into effect, would produce fairer rates in RUCO's view.

Q. Did the Maryland Public Service Commission approve the surcharge portion of the plan being proposed by WGL Holdings, Inc.?

A. No. In its final decision[7] on the matter, the Maryland Public Service Commission stated that "although the Commission does agree with WGL

[6] Dismukes, David E., Ph.D., Direct Testimony on Behalf of the Maryland Office of People's Counsel, Case no. 9267, filed July 27, 2011
[7] Maryland Public Service Commission Order No. 84475 issued on November 14, 2011

[Holdings, Inc.] that "safe and reliable infrastructure is its highest priority," it maintains that 'infrastructure investments do not justify a surcharge' to be imposed on customers. The Maryland Commission authorized WGL Holdings, Inc. to implement the initial phase of its proposed accelerated natural gas pipe replacement plan but stated that it would address cost recovery in appropriate future rate cases.

Q. Doesn't the SIB adopted in the AWC Eastern group settlement agreement have an efficiency credit that provides a reduction that is similar to the O&M credit discussed above?

A. Yes. However, as RUCO's Director, Patrick J. Quinn, stated during the Phase 2 AWC Eastern Group hearing, the SIB efficiency credit does not go far enough.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of the Applicants' witnesses constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your direct testimony on Global Utilities' rate case filing?

A. Yes, it does.

ATTACHMENT A

National Association of State Utility Consumer Advocates
R E S O L U T I O N

Discouraging State Regulatory Commissions from Adopting Automatic Adjustment Charges for Water Company Infrastructure Costs

WHEREAS, certain regulated water companies have recently proposed mechanisms for automatically increasing water rates, prior to regulatory review, based upon isolated items of expense related to infrastructure projects; and
WHEREAS, the National Association of State Utility Consumer Advocates (NASUCA) believes that public interest is still best served by rate of return regulation of investor-owned water companies and that such automatic adjustment mechanisms contradict several sound rate of return ratemaking principles, including the matching principle, because increases to items of rate base are recognized far outside of the test year from which all other rate base, as well as revenues, expenses, and cost of capital items that are used when calculating rates, allowing 'piecemeal ratemaking' and preventing the recognition of any simultaneous offsetting reductions in other items; and

WHEREAS, automatic adjustment mechanisms also circumvent regulatory review of increases to rate base for prudence and reasonableness; and

WHEREAS, automatic adjustment mechanisms further create bad public policy by eliminating the built-in regulatory incentive to control costs between rate cases and, generates incentives to increase spending in order to avoid reduction of the surcharge which occurs if the water company's authorized return is reached; and

WHEREAS, when an automatic adjustment clause is adopted, rate stability is reduced and proper price signals are distorted by frequent rate increases, and no convincing evidence has been shown to support the claim that the frequency of rate case proceedings is reduced by such clauses; and

WHEREAS, special incentives are not needed in order ensure adequate water quality, pressure, and a proper reduction of service interruptions; and

WHEREAS, automatic adjustment mechanisms can inappropriately reward water companies that have imprudently fallen behind in infrastructure improvements; and

WHEREAS, it is inappropriate to tilt the regulatory balance against consumers and shift business risk away from water companies simply for the purpose of creating an incentive for these companies to fulfill their basic obligation to provide safe and adequate service;

THEREFORE, BE IT RESOLVED, that NASUCA strongly recommends state legislatures and state public utility commissions avoid the implementation of automatic adjustments charges for water company infrastructure costs; and

BE IT FURTHER RESOLVED, that NASUCA authorizes its Executive Committee to develop specific positions and to take appropriate actions consistent with the terms of this resolution. The Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:

June, 1999, Baltimore, Maryland

Submitted By:

NASUCA Ad Hoc Water Committee

Christine Maloni Hoover, PA, Chair
Wes Blakley, IN
Robert Brabston, NJ
John Coffman, MO
Brian Gallagher, DE
Donald Rogers, MD
Dale Stransky, NV
James Warden, Jr., NY

ATTACHMENT B

BEFORE THE PENNSYLVANIA HOUSE CONSUMER AFFAIRS COMMITTEE

Testimony of

SONNY POPOWSKY
CONSUMER ADVOCATE

Regarding

House Bill 744
Natural Gas Distribution System Improvement Charge

Harrisburg, PA
April 23, 2009

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111172

Chairman Preston, Chairman Godshall
and Members of the House Consumer Affairs Committee

My name is Sonny Popowsky. I have served as the Consumer Advocate of Pennsylvania since 1990, and I have worked at the Office of Consumer Advocate since 1979. Thank you for this opportunity to present testimony to this Committee regarding House Bill 744, which would allow natural gas utilities in Pennsylvania to increase their rates automatically to reflect the capital costs of distribution plant that is added to service between base rate cases. As currently drafted, House Bill 744 would allow automatic increases in rates to reflect the value of new plant additions, but would not reflect reductions in the value of existing distribution plant resulting from depreciation and retirements during the same period. As such, the proposed distribution system improvement charge (DSIC) contained in HB 744 is one-sided and unfair to consumers. In addition, HB 744 contains no limit on the overall level of rate increases that can be obtained by natural gas utilities through these automatic adjustment clauses, which means that rates can be increased indefinitely without a Commission review of the utility's overall base rates. If the General Assembly chooses to proceed with HB 744, then I would respectfully submit that the legislation must be amended in order to correct these flaws.

As you know, the model used to support the proposed natural gas distribution system improvement charge is found in a Public Utility Code provision that was added for water companies in 1996 to allow water utilities to increase rates between base rate cases in order to cover the costs of new distribution improvements. At that time, many water utilities were filing base rate cases almost annually to cover the cost of new infrastructure required to meet state and federal safe drinking water laws.

In contrast, until 2008, several of our major natural gas utilities had not filed base rate cases in decades. Prior to 2008, the last base rate increase for PECO Gas was in 1988, twenty years earlier. The last base rate case filed by Columbia before 2008 was in 1995 and the last Equitable case prior to 2008 was in 1997. To this day, UGI and Dominion (Peoples) have not filed a base rate case since 1995. I am not aware of any evidence that these utilities have been unable to maintain safe natural gas service and make necessary infrastructure improvements during those many years in which their base rates remained unchanged. When Pennsylvania natural gas utilities have been able to provide service to customers without increasing their base rates for 10, 15 or 20 years, why would we pass a law that allows them to raise those rates automatically every three months?

This is not a hypothetical question. In November 2007, PECO Gas issued a press release announcing that it had just completed $12.3 million in upgrades to its suburban Philadelphia natural gas facilities, including the replacement of 58,000 feet of cast iron and bare steel mains. And, PECO Gas did all this without raising its base rates and without a DSIC. In the press release announcing the system improvements that PECO issued on November 6, 2007, the Company stated:

> During the past 20 years, PECO has made significant upgrades to its natural gas delivery system and expanded capacity, serving about 7,000 new customers each year – all without an increase in the company's delivery and service charges since 1988. By saving customers money through the use of new technologies, increasing sales, operational mergers and other efficiencies PECO charges remain among the lowest in Pennsylvania.

That is how ratemaking is supposed to work. Between base rate cases, a utility makes needed investments that increase costs, but the utility may also add customers who provide more

revenues, or it may operate more efficiently to reduce costs in other areas. Most importantly, the level of investment in its existing infrastructure goes down in value due to depreciation and retirements. In a base rate case, both the increases and decreases are taken into account.

In a base rate case, all of the utility's costs and revenues are looked at together in order to determine whether the company needs to increase its base rates. In contrast, a distribution system improvement charge simply takes out of context one cost element – the cost of new pipes – and raises the utility's overall rates to reflect that additional cost, without considering any offsetting changes.

It is true that improvements to our natural gas infrastructure cost money, and utilities that make prudent investments that are used to serve the public are permitted an opportunity to recover a return of and earn a fair return on those investments. That does not mean, however, that we need to remove the protections of the Public Utility Code in order to make it easier for utilities to increase their rates between rate cases, without hearings and without any meaningful ability for customers to oppose such increases.

Traditionally, utilities in Pennsylvania and across the Nation have recovered the cost of infrastructure improvements through base rate cases, in which all of the utilities' investments, expenses, and revenues are examined at the same point in time. As I mentioned earlier, in 1996, the General Assembly created an exception to this process for water utilities at a time when water companies contended that they were subject to very substantial new infrastructure requirements. The investments recovered through these surcharges, which are permitted to increase every three months, are subject to Commission audit to ensure that they are correctly calculated and accounted for, but they are not reviewed by the Commission to determine whether the investments are needed or are prudently incurred before their costs are

placed in rates. That is why these provisions are called "automatic adjustment" clauses in both the existing Section 1307 of the Public Utility Code and in the proposed House Bill 744. Initially, the DSIC surcharges for water utilities were limited by the PUC to no more than 5% of the utility's revenues, but in 2007, the Commission approved – over the objection of my Office, the Office of Small Business Advocate, the Office of Trial Staff, and the Company's large industrial customers -- an increase in the DSIC surcharge of Pennsylvania American Water Company (PAWC) from 5% to 7.5%. Indeed, it appears from the Commission's Order in that case, that the Commission believes it has the discretion to allow the surcharge to increase to 10% or even higher if it chooses to do so.

As you may be aware, PAWC also sought to implement a surcharge for its wastewater (sewer) division called a Collection System Improvement Charge (or CSIC). The PUC approved that surcharge and my Office successfully appealed on the ground that the automatic capital recovery surcharges permitted under the Public Utility Code are limited to water utilities. The Commonwealth Court agreed with my Office that the CSIC was not permitted under the Public Utility Code, but the Court also discussed the policy objections to a clause that allows a utility to recover capital expenditures through an automatic surcharge mechanism. As stated by Judge Leavitt in her Opinion for the Commonwealth Court:

> Utility's Wastewater Charge will entail regulatory oversight that amounts to no more than a mathematical exercise. The after-the-fact audit will require Utility to show only that it did, in actuality, spend the funds for the intended purpose and not, for example, that a new pumping station was needed and was operating effectively.....
>
> .... the "cursory" review undertaken for a surcharge is not a substitute for the review undertaken in a base rate case to determine whether a rate is just and reasonable.

Popowsky v. PA PUC, 869 A.2d 1144, 1156 (Comm. Ct. 2005).

More important than the lack of prior substantive Commission review, in my opinion, is the fact that a surcharge for capital expenditures is contrary to the general concept of just and reasonable rates because it allows recovery of a single cost increase, while ignoring all of the other changes, both positive and negative, that occur between base rate cases. Again, to quote from Judge Leavitt's opinion for the Commonwealth Court in the PAWC CSIC case:

> The surcharge is quite different from a base rate. In Pennsylvania, as in most jurisdictions, rates for public utilities are set using what is known as the test year concept, which requires taking a snapshot of the utility's revenues, expenses and capital costs during a one-year period. The object of using a test year is to reflect typical conditions. Test year expenses may be adjusted or normalized where atypical or non-recurring. Under the test year concept, revenues, expenses and capital costs are to be simultaneously reviewed for the same period of time so that a utility may prove its new rates are "just and reasonable."

869 A.2d at 1152.

Unlike a traditional base rate case, in which all costs and all revenues are considered simultaneously, a DSIC is a one-way street that can only increase rates between rate cases, even if a utility's other costs are going down or its revenues are going up. In setting utility rates, it is important to look at all the utility's costs and revenues, not just a single utility cost item that may be added between rate cases.

While I strongly oppose the enactment of a DSIC, I would respectfully urge the General Assembly to consider a number of amendments to House Bill 744 in the event that the General Assembly chooses to go forward with this legislation.

First, I would suggest that the DSIC should only reflect the net increase in distribution plant between rate cases; that is, the cost of new capital additions in the relevant

categories, minus the depreciation and retirements from the same categories of plant during the same time period. In that way, if a natural gas utility is truly making substantial new capital additions that exceed the normal reductions in plant value that occur between rate cases, then the company can charge the customers a positive DSIC. Second, there should be a percentage cap on the total level of DSIC rate increases, and that cap should be based on the utility's distribution revenues, not on total revenues, which include highly volatile natural gas commodity costs that are not related in any way to the distribution system improvements. I would suggest that the cap be set at 5%, which is where the PUC initially set the cap for the water DSIC's, but which the Commission subsequently allowed Pennsylvania American Water Company to increase to 7.5%. Third, I would propose that any natural gas DSIC be preceded by a full base rate case in which the company's total costs and revenues would be examined by the PUC before any automatic increases are permitted. In that way, a utility that has not filed a base rate case in 15 years could not simply walk in to the Commission and start increasing its rates every three months without any prior examination of whether its current rates are just and reasonable.

In order to assist the members of this Committee I have attached three amendments to this testimony that I believe would address these issues. As always, I would be pleased to work with the members and staff of this Committee to develop legislation that I hope would best serve Pennsylvania's utility consumers.

Thank you again for permitting me to testify at this hearing. I would be happy to answer any questions you may have at this time.

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AMENDMENTS TO HOUSE BILL NO. 744

Printer's No. 830

Amend Section 2, page 2, line 25, by inserting after "of"

the net change in

Amend Section 2, page 2, line 30, by inserting after "proceedings"

, minus any decreases in net distribution plant resulting from depreciation and retirements of the same categories of existing distribution plant during the same period.

Amend Section 2, page 3, by inserting between lines 4 and 5

(3) The revenue collected in any year pursuant to an automatic rate adjustment mechanism established pursuant to this subsection shall not exceed five percent of the amount a natural gas distribution company billed its customers for distribution service in the previous calendar year.

Amend Section 2, page 3, line 4, by inserting after "mechanism"

The commission shall include as part of that regulation or order a requirement that a natural gas distribution company shall not initially establish an automatic rate adjustment mechanism pursuant to this subsection unless the commission has established the natural gas distribution company's rates in a general rate case as set out in section 1308(d) (relating to voluntary changes in rates), filed after the effective date of this subsection.

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ATTACHMENT C

Increasing Use of Surcharges on Consumer Utility Bills

PREPARED BY LARKIN & ASSOCIATES, PLLC FOR AARP | MAY 2012

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EXECUTIVE SUMMARY

For many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from the investment in new gas pipelines to environmental compliance costs. The imposition of these surcharges are a departure from the traditional utility rate setting process, and regulators need to carefully evaluate utility requests for additional surcharges on a case-by-case basis to determine whether there is a proper balance of meeting utility needs and assuring ratepayer protections.

A surcharge is an additional fee imposed on a ratepayer's utility bill in addition to the base rate charge for utility service. In the past, surcharges were only approved by regulators in rare circumstances to address substantial, volatile and uncontrollable costs that, if *not* addressed outside of a base rate case, could threaten to harm a utility's financial health. Examples of such surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for other types of surcharges and tracking mechanisms by utilities have significantly increased.[1] Indeed, the National Regulatory Research Institute characterizes the use of cost trackers and mechanisms as the "latest trend."[2]

Utilities have requested surcharge rate mechanisms as a means to accelerate the recovery of a variety of costs, many of which are not volatile or uncontrollable. In some instances, the use of surcharges and other tracking mechanisms have proliferated so as to be baffling and expensive for consumers and burdensome for regulators to monitor.

Utilities say the surcharges are needed so they can make investments in aging infrastructure and comply with environmental regulations, among other claims, without compromising their financial health. Utilities also claim that the surcharges will result in smaller and less frequent rate increases as well as reduce the frequency of their general rate cases, which can be time consuming and costly to process.

But the increasing imposition of surcharges and other alternative ratemaking mechanisms can also defeat some of the primary principles of the rate-setting and regulatory review process. Besides increased costs to consumers, surcharges can also result in such additional undesirable consequences as reducing utility incentives to control costs and shifting utility business risks away from investors and onto customers.

Regulators need to carefully evaluate utility requests for additional surcharges on a case-by-case basis to determine whether there is a proper balance of utility and ratepayer needs. If the regulator decides to approve a utility's request to impose new surcharges on ratepayers, adequate safeguards to protect consumers are a must.

INTRODUCTION

For many consumers, home utility bills are becoming more and more cluttered with new fees and surcharges to pay for everything from the investment in new gas pipelines to environmental compliance costs. Not only are these charges often confusing and frustrating to consumers, they also represent a shift from the traditional utility ratesetting process. A surcharge is an additional cost added to utility customers' bills. Surcharges are also referred to by other terms such as riders, adjustment clauses, recovery mechanisms, and cost trackers. The proliferation of additional fees and surcharges generally shifts risks away from utility investors and onto consumers. This report describes why consumers should be concerned about the shift toward utilities collecting more costs outside of the traditional rate structure. Descriptions of some types of fees and surcharges proposed and/or collected by the nation's major utilities are outlined in Appendix I of this report.

HOW FEES AND SURCHARGES DIVERGE FROM THE TRADITIONAL METHOD OF SETTING UTILITY RATES

Utilities must petition state regulators to increase utility rates. Utilities submit a formal request to regulators containing their proposed rates to charge customers. The utility's request is reviewed in a formal proceeding, which is called a "rate case." Interested parties, such as representatives of residential or business customers, are allowed to intervene and review the utility's documentation to determine if the utility's request is reasonable. The case is resolved by a hearing and the regulators issue a formal decision.

The utility's requested rate is called a "revenue requirement" which is the amount necessary for the utility to cover its financial obligations associated with providing safe, reliable service to customers, along with earning a reasonable "return." Basic accounting and ratemaking principles serve as the foundation in setting rates to be charged by utilities to provide safe, reliable service. The primary purpose of utility ratemaking is to establish rates that allow a utility to recover its prudently[3] incurred operating and maintenance expenses, plus a fair return on its investment in assets that are used and useful[4] in providing utility service. Rates are calculated based on a "test-year" which is a 12-month period to be representative of operating conditions when the rates being established will be in effect.[5] Utilities are generally required to "net" all costs and benefits of operation at the time rates are set to avoid "cherry-picking" individual cost increases that may be offset by other cost decreases.[6] Under traditional ratemaking, utilities cannot change rates charged to customers outside of a rate case.[7]

Consumers are most familiar with seeing the "base rate" charge on their bills. The base rate is defined as the rate gas and electric utilities charge customers for the cost of providing safe and reliable service, which includes an opportunity for the utility to earn a fair return on its prudently incurred utility plant investment. The base rates are set by state regulators in a rate case, and are often segregated between the basic service charge, distribution, transmission and, for electric service, generation.[8]

In addition to base rates, most utilities assess a fuel surcharge (gas cost adjustment or fuel and purchased power adjustment) and revenue-based taxes in addition to the base rate charge. Typical "standard" charges that appear on a customer's electric utility bill may include:

- Customer Charge: The basic charge to recover costs for billing, meter reading, equipment, maintenance, etc. (state regulated)

- Generation Charge (or Commodity Charge): Charges for the production of electricity, based on usage (state regulated in non-deregulated states)

- Transmission Charge: Charges for moving high voltage electricity from a generation facility to the distribution lines of an electric distribution company [regulated by the Federal Energy Regulatory Commission ("FERC")]

- Distribution Charge: Charges for the use of local wires, transformers, substations, and other equipment used to deliver electricity to end-use consumers from the high voltage transmission lines (state regulated, only shown as a separate charge in deregulated states)

- Fuel and Purchased Power Charges
- State Taxes

Typical standard charges that appear on a customer's gas utility bill may include:

- Customer Charge
- Gas Transmission or Distribution charge
- Commodity Charge
- Purchased Gas Adjustment (true-up)
- State Taxes

Other fees and surcharges fall into the category of "single issue ratemaking," which is a deviation from traditional ratemaking. Single issue ratemaking involves "singling out" specific expenditures from a company's base rates and allowing a utility to separately recover those costs from ratepayers. Singling out specific costs can make the traditional ratemaking formula unbalanced. For example, if a utility replaces a large piece of equipment at its plant, the new equipment will affect multiple aspects of the business. The utility's rate base plant will increase, and revenues may increase, if the plant addition is to serve new customers. Future maintenance expenses may decrease if the addition improves efficiency. The lower maintenance costs, which would reduce rates for ratepayers, may not be reflected within a surcharge that focuses only on the new investment.

In the past, single issue ratemaking was typically approved by regulators only in limited situations for costs that were considered:

1. Largely outside the control of the utility,
2. Unpredictable and volatile, and
3. Substantial and reoccurring, and which would have the potential to adversely impact the utility's financial health if cost recovery is not addressed outside of a traditional rate case.

Examples of such volatile and unpredictable costs traditionally include fuel costs and purchased power costs for electric utilities, and purchased gas costs for gas utilities. In contrast, capital investments for plant additions or replacing aging infrastructure are not generally considered to be highly volatile, uncontrollable and/or unpredictable. Management can control these costs to some extent by comparison shopping materials and contractors. The timing of projects can also be adjusted based on availability of funds.

Yet in recent years, many other types of costs are being proposed by utilities to be recovered through surcharges that do not meet the above criteria.[9] The National Regulatory Research Institute characterizes the use of cost trackers and mechanisms as the "latest trend."[10]

Allowing a utility to recover lost revenues or discrete increased costs through a surcharge can also diminish the utility's incentive to control or reduce expenses because the utility is assured of full cost recovery. Since the utility is passing the cost on to customers, it has less incentive to seek ways to reduce the expense. Furthermore, in a rate case, the utility's costs are carefully scrutinized, whereas cost increases recovered in surcharges can become part of utility rates on an expedited basis, without being subjected to the same degree of review. In rate cases, utilities must provide documentation justifying its requested costs or they may be disallowed. Reviews of costs recovered via surcharges are usually done on a much more limited basis. By allowing a utility to recover cost changes through a surcharge, rider or balancing account, the utility is assured of the recovery of such costs, therefore diminishing the utility's incentive to control expenses, and reducing the utility's financial risk.

SURCHARGES, TRACKERS AND OTHER COST RECOVERY MECHANISMS

DEFINITIONS

There are different types of "single issue ratemaking" which include surcharges, trackers, riders, and other cost recovery mechanisms.[11]

Surcharge: A surcharge allows a utility to separately charge customers for costs that would have otherwise been part of the utility's standard base rates. This means the utility recovers dollar-for-dollar the level of costs incurred or estimated to be incurred. A surcharge appears as an additional charge on a ratepayer's utility bill, above and beyond the base rates, fuel surcharge and taxes. Some surcharges are a flat rate while others fluctuate, either based on usage or changes in the surcharge rate.

Surcharges are also referred to as riders, adjustment clauses, recovery mechanisms, and cost trackers, etc. Many utilities use the term "rider" in their tariffs with respect to surcharges. However, some utilities use the term "rider" to designate rates for a particular class of service. For example, Georgia Power defines "rider" as a modification to an existing tariff rate.[12] In these instances the "rider" is a type of rate on a customer's bill associated to that type of specific utility service, rather than an additional "surcharge". Therefore, one must read the Company's applicable tariff sheet to understand what the rider or surcharge actually represents. Utility tariff sheets may be written in technical language, and this may be hard to understand for many consumers.

Sometimes the entire cost recovered by a surcharge is excluded from base rates and recovered separately through the surcharge (e.g., fuel costs). In other instances, only the incremental portion or the difference between what is included in the base rates and the changes in the cost (e.g., in some states vegetation management or storm damage costs) are recovered through the surcharge. For instance, if a utility is allowed to recover $10 million in base rates for tree trimming expenses, but actually spends $11 million, and the utility has a surcharge mechanism in place for such costs, the $1 million difference would be assessed as a surcharge to ratepayers.

A surcharge can either be a fixed rate or adjusted periodically as the cost element it covers changes (i.e., monthly, quarterly or annually). Changes in costs addressed by the surcharge are typically reviewed by regulators periodically (e.g., annually or quarterly). However, the level of review of utility costs charged to customers through surcharges is usually more informal, expedited and less rigorous than in contrast to the in-depth review that would typically be conducted in a full utility rate case.

For example, in a recent utility case in Nebraska the utility requested three adjustment mechanisms (weather normalization, a billing adjustment factor and an inflation factor). However, the state regulator denied the surcharges:

> Such automatic mechanisms can lead to excessive rates, an inappropriate shifting of risks from stockholders to ratepayers, and decreased incentives to operative efficiently.
>
> ...
>
> Therefore the rate mechanisms should be denied.[13]

Balancing Accounts: Another form of single issue ratemaking, referred to as "balancing accounts," also can result in new surcharges on bills for utility service. A balancing account tracks the difference in a certain cost allowed in base rates and the actual cost.[14] California is one state regulatory jurisdiction that makes extensive use of balancing accounts.[15] The ratemaking regime in California has become particularly complex. The extensive use of balancing accounts and cost trackers has made it challenging and difficult for the regulators to adequately audit the proliferation of special mechanisms being used by utilities. California utilities have a traditional three-year General Rate Case ("GRC") cycle, though the cycle has been extended beyond that in some instances. The utility's base rates are developed using

forecasted amounts and typically are adjusted annually for inflation. An added complexity is that many issues affecting the utility's base rates may also be addressed separately in other dockets. The California utilities also utilize a variety of mechanisms to recover costs separately from base rates: surcharges, adjustment mechanisms, balancing accounts and memorandum accounts.[16]

Some believe that the use of balancing (and memorandum accounts) by California utilities has become excessive. A recent California American Water Company ("CalAm") General Rate Case demonstrates how the use of surcharges and other alternative rate mechanisms can get out of control. In Application No. A.10-07-007, CalAm had 79 existing balancing and memorandum accounts. CalAm had requested six additional balancing and memorandum accounts, which if approved, would bring the total to 84. The Department of Ratepayer Advocates ("DRA"), which is charged with looking out for the consumer interest, acknowledged that it did not have the resources to fully review the Company's numerous accounts:

> These advice letters are generally approved without audit. There is little opportunity to review the recorded amounts for reasonableness before the balances are recovered, unless DRA requests the opportunity to audit the balances or request for a suspension of the advice letter.[17]

Exhibit 1 is a table summarizing the number of balancing and memorandum accounts utilized by some of the larger California utilities:[18]

EXHIBIT 1

UTILITY	BALANCING ACCOUNTS	MEMO ACCOUNTS	OTHER ACCOUNTS	TOTAL
Southern California Edison (SCE)	21	24	16	61
Southern California Gas Co. (SoCal)	22	24	10	56
San Diego Gas & Electric (SDG&E)	22	33	7	62
Pacific Gas & Electric (PG&E)	32	35	15	82
California American Water Company	*	*	*	79
Golden State Water Company	9	29		38
Total Accounts for Regulators to Review	106	145	48	299

* Information regarding the breakdown of the different accounts was not located; as noted above, CalAm's requests, if approved, would increase the total to 84.

Trackers: Another single issue ratemaking mechanism is a "tracker" which involves recording or "tracking" costs in a specified account, which are later reviewed by regulators. The costs are not initially included in the utility's base rates, but are accumulated or "set aside" for future review. They may be incorporated into the development of the utility's base rates in its next base rate case or may show up as a separate charge on ratepayers' bills. This type of mechanism is sometimes utilized to "track" whether the authorized level is being spent. In some situations, underspending by a utility of a "tracked costs" is eventually returned to ratepayers.

An example of utility expenses that have been "tracked" are vegetation management (tree trimming) costs. For example, a utility may have issues with its reliability and regulators may decide to monitor the level of the utility's tree trimming expenditures as a means of assessing whether the utility is conducting an adequate level of maintenance near its wires and poles.

Another example of a cost that has been "tracked" and deferred by a utility for future review are storm damage costs. A utility may incur substantial repair costs to its distribution system as a result of a catastrophic storm. Some utilities have petitioned regulators to accumulate and defer the extraordinary storm repair costs for review and inclusion in rates at a later date, rather than merely recording such costs as expenses in the current period, which may result in utility investors bearing the risk of such costs if they result in the utility reporting lower earnings for that accounting period.

Depending on the definition of "tracker" in a particular jurisdiction, by allowing a utility to recover costs through a tracker account, the utility may effectively be guaranteed recovery of the tracked expense. Sometimes the deferrals are limited to a pre-specified level; in other cases, the subsequent recovery by the utility of the tracked cost may be subject to an "earnings test". An earnings test may prevent the utility from subsequently charging all of the tracked/deferred costs to ratepayers if it would result in excess earnings.

SURCHARGES HAVE BEEN IMPOSED THROUGH REGULATION AND LEGISLATION

A utility must obtain permission from its state regulator to apply an additional surcharge to customers' bills. Typically, a utility will present the mechanics for its proposed surcharge to the regulator for approval. Consumer advocates and intervenors may participate in the proceeding and make recommendations to adjust or modify the utility's proposal. The regulator will weigh the information and make its decision. Again, if a surcharge mechanism is approved, there are time and resource limits to the review of the costs, making it difficult for intervenors to participate. Once cost categories are approved for recovery in a surcharge, the categories can no longer be questioned, and the only aspect that can be disputed is whether the level of such costs are reasonable and prudently incurred to provide utility service. Some jurisdictions allow use of surcharges consistently between utilities, while others approve surcharges on a case-by-case basis.

In several states, surcharges have been adopted through legislation, often requiring the use of a surcharge and limiting the discretion of regulators. An example of where legislation now limits what the state utility regulatory commissions can do is the state of Virginia. Virginia has passed legislation allowing utilities to recover many types of costs through surcharges, includ-

ing environmental costs, costs for constructing new generation, generation and demand side management, and other types of costs.

In Utah, legislation has been passed allowing gas or electric utilities to recover the costs of major plant additions by filing an application for approval of a major plant addition within 150 days from the capital addition's scheduled in-service date. The statute defines "major plant addition" as "any single capital investment project of a gas corporation or an electrical corporation that in total exceeds 1% of the gas corporation's or electrical corporation's rate base."[19]

On October 26, 2011, the Illinois legislature overrode the Governor's veto of Senate Bill 1652, which became effective as Public Act 97-0616. Among those changes was the addition of a new Section 16-108.5 entitled "Infrastructure Investment and Modernization; Regulatory Reform." This legislation provides for utilities to file for a performance based formula rate plan process. On November 8, 2011 Commonwealth Edison Company, the state's largest utility, filed for a new tariff called Rate DSPP (Delivery Service Pricing and Performance), pursuant to that legislation. A formula rate plan is a mechanism or "formula" which resets a utility's rates annually, and is used in place of a rate case.

Due to the utility mergers and acquisitions over the years, many local utilities are now subsidiaries of large holding companies that have utility operations in multiple state jurisdictions. These large corporations have the resources to effectively lobby their positions to benefit their operations.

American Electric Power Company ("AEP"), one of the nation's largest electric utilities, affirms this by stating in its 2010 Form 10-K:

> Given the long lead times in construction, the high costs of plant and equipment and difficult capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process.

As another example, Xcel Energy, stated in its 2010 Form 10-K that:

> Xcel Energy files periodic rate cases and establishes formula rate or automatic rate adjustment mechanisms with state and federal regulators to earn a return on its investments and recover costs of operations.

A utility's proposal for cost recovery under the legislatively authorized mechanisms are typically reviewed via the regulatory process, albeit on a limited basis, as described above. The review may be primarily performed by utility commission staff as active participation in reviewing a proliferation of utility surcharges by resource constrained consumer advocate groups is difficult to sustain.

Exhibit 2 is a table summarizing types of costs utilities are charging customers through surcharges. This is not a comprehensive listing, but rather a summary to illustrate various types of surcharges that were identified in the process of preparing this report.

EXHIBIT 2: EXAMPLES OF SURCHARGES	
DESCRIPTION	STATES
Aging infrastructure	GA, KY, MO, NJ, OH
Decoupling/Weather Normalization	CA, GA, KS, KY, LA, MD, MS, NJ, NV, TN, TX, VA
Energy Efficiency/DSM/Conservation	CA, OR, MD, MA, SC, NC, IN, AR, KY, MI, OH, OK, TX, CO, IA, GA, FL, IL, MO
Environmental Compliance	WA, DE, NJ, IA, IN, KY, MN, SD, MI, OH, TN, TX, VA, GA, NJ, IL
Franchise Fees	MN, TX, AR, KY, LA, MI, VA, WV, GA, NJ, TN, IL, CO
New Plant (Coal, Nuclear)	AL, AR, GA, IN, MS
Pension/OPEB	MA, SC
Property Taxes	KS, MS
Renewable Energy	IL, NC, OH, MA, CA, IA, OR, UT, WA, CO, MN, NM
Smart Meters/Smart Grid	CO, OH, TX
Storm Damage	MA, OH, OK
Stranded Costs	CT, NH, NJ, MA
System Reliability/Vegetation Management	KS, OH, OK, TN, TX
Transmission Investment	OH, TX, VA
Uncollectibles	IA, IL, OH, NV
Universal Service/Low Income	AZ, CA, CO, DC, TX, GA, IL, OH, OR, UT, WA, MD

WHY DO SURCHARGES, RIDERS AND ADJUSTMENT MECHANISMS PUT CONSUMERS AT RISK?

In many instances surcharges are unnecessary and are not beneficial to ratepayers. Surcharges are costs added to utility customers' bills in addition to the basic charge for providing safe and reliable utility service. Surcharges can effectively guarantee utilities recovery of their fluctuating costs, thereby, shifting financial risk away from the investors and onto consumers. The surcharge is often applied to consumers' bills without first being subject to a thorough review by regulators and consumer groups. Additionally, some surcharges may recover costs that are not necessary for providing basic safe and reliable service. Surcharges may put consumers are at risk for being overcharged by utilities for basic utility service.

Reasons why surcharges pose a risk for consumers include:

REDUCES THE UTILITY'S INCENTIVE TO CONTROL COSTS

In a rate case a utility is allowed a reasonable level of revenues to recover its operating expenses as well as an opportunity to earn a fair return on its prudently incurred investment in used and useful plant. In between rate cases, the benefit of any cost reductions would flow back to the utility as higher profits. For costs that are to be "tracked" through a surcharge, the utility is usually required to return any under-spending to ratepayers, so the utility is not benefitted by cost-cutting efforts. The surcharge can thus remove or reduce the utility's incentive to reduce costs. Guaranteeing recovery of a specific expense reduces the utility's incentives to control costs, and thus shifts the burden of cost increases between rate cases from shareholders onto ratepayers.

REVIEW OF SURCHARGES IS TYPICALLY MORE LIMITED

Utilities typically submit reports to regulators for costs recovered via a surcharge on an annual or quarterly basis. This usually involves submitting some calculations and workpapers identifying and supporting the amounts. The review by regulators is typically conducted on an expedited basis, as opposed to the thorough review that would typically occur in a full rate case. In rate case, a thorough review of costs can also be conducted by intervening parties, and the utility must adequately support its costs or they risk being disallowed.

VIOLATION OF THE MATCHING PRINCIPLE, A FUNDAMENTAL ACCOUNTING AND RATEMAKING PRINCIPLE

A key concept in accounting and ratemaking is the matching principle. The matching principle involves matching revenues with related expenses and investments in the time period they occur. Accounting and ratemaking require the cost of capital investments to be spread over the period in which they will be used. Capital investments, such as replacement of equipment at the utility's plant can produce efficiencies such as reducing future O&M costs or enable new revenues. If the cost of the capital expenditure is recovered through a surcharge, these efficiencies may not be captured in the surcharge. Recovering capital investments via a surcharge can thus violate the matching principal.

UTILITY MAY OVER-COLLECT THESE COSTS

In some cases, the utility may overestimate the costs to be recovered. Therefore, it may over-collect these costs from ratepayers. For example, if a utility collects a surcharge to fund

the cost of a new plant or a large piece of equipment while it is still being constructed, the amount being collected from customers may be more than the actual cost. While the funds should ultimately be returned to ratepayers, until then, these funds can be used by the utility and represent a source of cost-free capital to the utility.

For example, San Diego Gas & Electric Company stated in its current 2012 general rate case ("GRC"), in its direct testimony, that its Advanced Metering Infrastructure Balancing Account (AMIBA) was forecasted to be $48.546 million overcollected on the electric side and $6.33 million overcollected on the gas side at December 31, 2011. This means that the utility collected $54.876 million more from customers than it needed. The Company also stated that it forecasted its Distribution Integrity Management Program Balancing Account (DIMPBA) and Research Development & Demonstration Expense Account (RDDEA) to be over-recovered by $3.304 million and $0.191 million, respectively. The RDDEA was authorized in D. 08-07-046 and went into effect on January 1, 2008. The Company was collecting the surcharge from customers for most of the year; however, the Company stated the related R&D program spending did not begin until late in 2008.[20]

There is also the risk that overpayment of costs may be not be returned to customers, because if the surcharge costs are reviewed only on a cursory basis, any errors or overcharges may not be detected and/or returned to customers.

JUSTIFICATIONS FOR SURCHARGES DO NOT HOLD UP

Below are some reasons utilities may use to justify the use of surcharges, along with a comment concerning why the reasoning may be invalid.

FREQUENCY OF GENERAL RATE CASES

Utilities may cite reduced frequency of general rate cases, which can be costly to litigate, as a reason for surcharges. The purpose of general rate cases is to thoroughly evaluate the utility's rates and costs for reasonableness. Eliminating or bypassing that opportunity to review the utility's costs may result in costs being charged to ratepayers without adequate regulatory scrutiny. Implementation of surcharges may also result in burdening regulators with additional work, as they will need to review these surcharges between general rate cases.

"RATE SHOCK"

Utilities will sometimes argue that surcharges and trackers reduce "rate shock" because the surcharge produces smaller, more frequent rate increases, rather than a future sharp hike in rates from a base rate case. In a rate case, many factors comprise a utility's base rates: capital structure, capital investments, and operating expenses. While some costs may increase, they could be offset by decreases in other expenses. A rate case review may not necessarily result in a rate increase. A utility may be found to be over-earning and rate decrease may be ordered. Therefore, one cannot assume that utility base rate cases will always result in larger rate increases.

AGING INFRASTRUCTURE

Many utilities have requested surcharges to recover the costs of investments to upgrade aging infrastructure. However, utility capital expenditures are not volatile or outside the control of a utility. Management is able to influence the timing and extent of these costs. Utilities, similar to

other non-regulated companies, issue bids for large scale projects to evaluate the most cost-effective options. Maintaining and upgrading the utility infrastructure is a normal aspect of operating a utility. Also, cost efficiencies may result from the improvements, but such savings may not be recognized as an element that reduces the surcharge.

COMPLIANCE WITH ENVIRONMENTAL REGULATIONS

Similarly, a utility might cite expenditures that it must make to comply with environmental regulations as a reason to implement a surcharge. This is not a new concept. Environmental regulations have been in existence for many years and are continuously evolving. Complying with environmental regulations is also a normal aspect of operating a utility. How best to deploy capital and O&M resources to comply with these regulations is not entirely outside the control of a utility. Also, cost efficiencies associated with the environmental investment may not be recognized as an offsetting element that reduces the surcharge.

SITUATIONS WHERE TRACKING MECHANISMS BENEFIT CUSTOMERS

There have been limited situations where surcharges have benefited customers. As one example of this, in the 1980s, Entergy implemented a return sharing mechanism in Arkansas which was primarily weather driven. The effects of the hot summer weather that had not been captured in the base rate case generated higher revenues for the Company and customers received credits on their bills.

RECOMMENDED CONSUMER SAFEGUARDS

When regulators are considering whether to allow certain expenditures to be recovered via a surcharge or other special rate mechanism the following consumer protections should be considered, and included, if a surcharge is approved:

COST RECOVERY SHOULD BE SPECIFIC

If a surcharge is approved, it should be strictly for the specific expenditure. The surcharge should not contain multiple types of costs or be vaguely defined, which will make reviews difficult. The surcharge should not be allowed to be expanded at a later date to include additional items. As an example, of surcharge coverage expansion, Atlanta Gas Light was permitted to implement a pipeline replacement surcharge to recover costs associated with implementing an aging pipeline replacement program over a ten year period. The need to replace aging pipe to address safety issues resulted from an investigation of the utility's alleged violations of minimum federal safety standards. Years later, the utility proposed and was allowed to expand this surcharge to include other types of capital costs associated with installing new distribution pipeline and infrastructure upgrades that were not strictly related to addressing the public safety concerns that were the basis for allowing the original surcharge.

NUMBER OF SURCHARGES SHOULD BE LIMITED

A utility should not be permitted to have a complex myriad of surcharges and trackers. This defeats the purpose of reducing rate cases and the rate setting process in general and places a bigger burden on the regulator to have to monitor numerous surcharges outside of rate cases.

The extensive use of surcharges, trackers, memorandum accounts, and other recovery mechanisms by California utilities has resulted in an almost overwhelming burden on regulators and consumer advocates.

TIME PERIOD OF SURCHARGE SHOULD BE DEFINED, NOT INDEFINITE

The surcharge or tracker should be for a set time period rather than indefinitely. For example, some states have implemented revenue decoupling as a pilot. After the pilot period, regulators can then review the results to determine the cost-effectiveness of implementing the special rate mechanism and determine whether it should continue.

MECHANICS OF SURCHARGES SHOULD BE STRUCTURED TO BENEFIT THE RATEPAYER

The surcharge should be structured so that cost overruns are absorbed by the utility and under-spending is returned to ratepayers. Some of the utility cost tacking accounts used by California utilities have this feature. A "one-way" balancing account, for example tracks and returns utility under-spending for the tracked cost (such as tree-trimming) to ratepayers.

RELATED COST SAVINGS AND EFFICIENCY IMPACTS SHOULD BE INCORPORATED

If the surcharge is to recover costs associated with replacing plant equipment, or for investments which improve efficiency, an efficiency factor to reflect lower O&M costs should be considered.

LOWER RETURN ON EQUITY ("ROE") TO REFLECT REDUCED RISK

A utility's ROE is the return investors expect, or require, in order to invest in the Company. In a rate case, utilities request a specific ROE percentage which is reviewed by the parties and a fair and reasonable ROE is authorized by the Commission. While a utility's ROE is based on several factors, depending on the utility's specific circumstances, a reduction in ROE may be appropriate if a surcharge is approved. A portion of the Company's business risk has been transferred from investors and is now being borne by ratepayers.

REDUCE FREQUENCY OF RATE CASES

Many utilities allege that surcharges will reduce the frequency of rate cases or large rate increases. A possible condition for approving a surcharge could be that the utility agrees to not file for a base rate increase for a specified period. Conversely, if a utility has annual rate cases or multi-year rates, a surcharge may not be necessary as the utility's rates are already being adjusted more frequently.

AVOID APPROVAL OF NEW SURCHARGES IN A SETTLEMENT

Although settlements are typically non-precedential (i.e., non-authoritative) if a surcharge is approved in a settlement, it may be unlikely or difficult to have it reversed or denied in future proceedings. Also, other utilities may imitate and cite the use by the existing utility as justification for their proposed surcharges for similar costs.

AUDIT/REVIEW FOR PRUDENCE AND REASONABLENESS

If a surcharge is approved to recover costs associated with a substantial project such as construction of a new power plant, significant environmental retrofits, or Smart Grid, a recommendation could be made that a full audit or a detailed review of the prudence and reasonableness of the costs should be conducted. For example, the Mississippi PSC is conducting

a prudence review of the costs associated with Mississippi Power Company's (MPCo) Integrated Coal-Gasification Combined Cycle ("IGCC") Plant that is currently under construction in Kemper County. MPCo is proposing to recover the Construction Work In Progress ("CWIP") financing costs associated with the Kemper Project through a surcharge.

RECENTLY PROPOSED SURCHARGES THAT HAVE BEEN DENIED

Regulators are still relying on traditional ratesetting and have not been persuaded by utilities' requests to implement surcharges. Below is a brief discussion of some recent instances:

PENSION/OTHER POST RETIREMENT BENEFITS (OPEB)

Narragansett Electric (d/b/a National Grid), Rhode Island; Docket No. 4065 (2010). The Company proposed a mechanism to recover pension and other post employment benefits expense incurred each year over the amount included in base rates. The Rhode Island Commission denied Narragansett's request. The Order stated:

> ...the Commission finds that this expense is a business risk that should be managed by the Company like any other business risk facing a business enterprise. Also important to note is that the State of Rhode Island, whose pension fund is severely underfunded, has not proposed that the Rhode Island taxpayers be burdened with a reconciling mechanism to ensure adequate funding of the state pension program. The General Assembly has proactively modified the existing plan to address this underfunding by changing the benefit eligibility, increasing the level of employee contributions, among other options under consideration.

Delmarva, Maryland; Docket No. 9093 (2007). The Company requested a Pension and Other Post-Employment Benefits ("POPEB") rider, to capture yearly differences between the pension and OPEB costs embedded in the Company's base rates and the actual expenses properly chargeable to the Company's distribution operating costs. The Maryland Commission denied the Company's request. The final Order stated:

> Implementation of a tracker mechanism is an extraordinary form of ratemaking usually reserved for very large expense items that have the potential to impair seriously a utility's financial well-being, which is not the case here for OPEB and pension costs. We therefore deny the Company's request for a POPEB rider.

Delmarva, Delaware; Docket No. 09-414 (2011). Delmarva proposed a surcharge mechanism called a Volatility Mitigation Rider ("Rider VM") to collect a rolling three-year average of pension, OPEB and uncollectible expenses, which it claimed were volatile and largely beyond its control. The Delaware Commission denied the Company's request and stated in its Decision:

> These are normal utility expenses; allowing dollar for dollar recovery of them would depart from traditional ratemaking practices and would reduce Delmarva's incentive to try to control them. We also note that our sister commissions in Maryland and

> the District of Columbia rejected the same proposal when Delmarva and its affiliates presented it to them, and we find their reasoning convincing. Thus, for the reasons advanced by Staff and the DPA, we reject Delmarva's request to implement Rider VM.

ENVIRONMENTAL COMPLIANCE COSTS

Kansas City Power & Light, (KCPL) Case No. 11-KCPE-581-PRE (2011)

KCPL requested recovery of environmental upgrade costs at its La Cygne Plant through a surcharge. The Commission's decision to deny the surcharge was based in part on an observation that "the potential future cost that utility companies will undoubtedly expect customers to bear is presently unforeseeable or speculative at best, but undoubtedly will be significant."

DECOUPLING

Many utilities have claimed that they require "revenue decoupling" in order to eliminate disincentives which prevent them from vigorously promoting energy-efficiency.

Despite the utility industry's attempt to convince regulators that decoupling is the latest concept, several states are still reluctant to implement decoupling mechanisms.[21] For example, Connecticut denied two utilities' requests for decoupling, despite legislation enacted permitting decoupling (Connecticut Light & Power; Docket No. 09-12-05; 2010, and Connecticut Natural Gas; Docket No. 08-12-06; 2009).

The following states have also rejected decoupling mechanisms:

- Indiana, Southern Indiana Gas; Cause No. 43839 (2011)
- Montana, Northwestern Energy; Docket No. D2009-0-129 (2011)
- Tennessee, Piedmont Natural Gas; Docket No. 09-00104 (2010)
- Rhode Island, Narragansett Electric (d/b/a National Grid), Docket No. 3493 (2009)

In the above cases, the regulators decided to reject decoupling because benefits to customers were speculative and the risk was shifted away from the company and onto customers.

Notably, the regulator's order in the Narragansett case stated:

> Revenue decoupling would protect the Company from revenue declines attributable to any causes, not only conservation and efficiency efforts. . . . Over the last four years, decoupling would have resulted in an additional $34 million payment to the Company.

One of the concerns about decoupling is that it insulates utilities from economic conditions such as the impacts of a recession. As Dr. David Dismukes has explained:

> Decreases in sales associated with economic downturns have nothing to do with energy efficiency programs offered by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times of, or alternatively, businesses and industries idling or shutting down their operations. Under revenue decoupling, ratepayers would be required to make a utility whole for

> revenue losses during these economic downturns, whereas under traditional regulation, utilities bear the risk of these economic contractions, just like many other types of businesses and industries.[22]

On January 26, 2009, Detroit Edison Company ("DTE") filed an application with the Michigan Public Service Commission ("MPSC"), Case No. U-15768. Among other things, DTE requested that the MPSC approve an electric rate decoupling mechanism and an advanced metering infrastructure ("AMI") program. Both of those requests were approved by the MPSC in its January 11, 2010 order. On April 10, 2012, DTE's electric rate decoupling mechanism and the AMI program funding mechanism were rejected by the Michigan Court of Appeals.[23] The Court ruled that the MPSC did not have the authority to direct or approve decoupling for electric utilities, but only had authority to conduct research and report on the operations of a decoupling mechanism with electric utilities. Michigan Statute MCL 460.1097(4) states that:

> [T]he commission shall submit a report on the potential rate impacts on all classes of customers if the electric providers whose rates are regulated by the commission decouple rates. . . . The commission's report shall review whether decoupling would be cost-effective and would reduce the overall consumption of fossil fuels in this state.

The Court also ruled that DTE's AMI program funding that had been approved by the MPSC "was unreasonable, because it was not supported by 'competent, material and substantial evidence on the whole record'".[24] The Court noted that the Manager of the Energy Efficiency Section in the Electric Reliability Division of the MPSC had agreed that the AMI was not commercially tested, and required large amounts of capital, which could result in great economic risk and highly impact rates. No alternative considerations were discussed, nor were the needs for AMI or the net-benefits (if any) to the affected customers. The Court also stated that in reviewing the MPSC's decision, it "will not rubber stamp a decision permitting such a substantial expenditure—a cost to be borne by the citizens of this state—that is not properly supported."[25]

CAPITAL ADDITIONS

In New Mexico, in a 2011 decision, the commission rejected a stipulated capital additions rider for Public Service New Mexico Company, stating such a rider would represent "a major departure from and violation of the Commission's long-standing policy against piecemeal ratemaking."

In a recent Washington Gas Light Company ("WGL") rate case (Case No. 9267) the Maryland Public Service Commission's order issued on November 14, 2011 rejected WGL's request for an automatic surcharge on all customers to improve its distribution system. In denying that request, the Commission found that WGL was capable of carrying out a pipeline replacement program and ensuring the safety and reliability of its distribution system without getting automatic cost recovery through a surcharge:

> Although we agree fully with the Company that safe and reliable infrastructure is its highest priority and that it should accelerate its program to replace pipe, we decline to authorize a surcharge for the recovery of future pipe replacement expenses. Based on the record in this case, we find that the Company has historically demonstrated the ability to replace its

infrastructure when necessary to ensure safety and reliability, and that it can do so using traditional ratemaking procedures without compromising its ability to earn an appropriate return. The Company's witnesses confirm that WGL has the operational and financial ability to accelerate its existing pipe replacement program, and we authorize the Company to do so. But the mere fact that the Company plans increased infrastructure investments does not justify a surcharge, which would represent a fundamental shift from long-standing rate-making principles. To the contrary, the record in this case demonstrates that the Company can invest significant amounts in infrastructure and can readily recover those costs in rates with an appropriate return. . . . We recognize that accelerating its pipe replacement program may require the Company to file somewhat more frequent rate cases than it would prefer. That is not, in our view, a negative outcome—rate cases afford all parties, and this Commission, the opportunity to ensure that rates are just and reasonable, and we understand that accelerated infrastructure investment may require more frequent adjustments. But ratepayers and the Company are better served if base rates are adjusted more frequently in smaller increments, and waiting longer between rate cases could lead to other undesirable results, including greater mismatches between costs and rates.

CONCLUSION

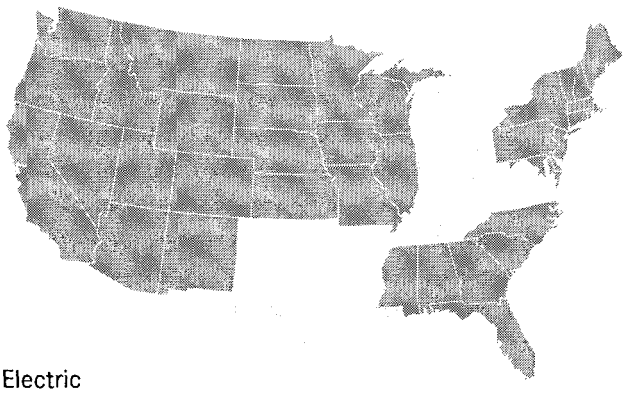
In the past, surcharges were only permitted in limited circumstances for costs that were substantial, volatile and uncontrollable, and that could harm the utilities' financial health. Examples of such traditional surcharges include fuel and purchased power adjustment mechanisms for electric utilities and gas cost recovery mechanisms for natural gas distribution utilities. In recent years, however, requests for surcharges and tracking mechanisms by utilities have significantly increased, for many different types of costs, including capital investments, for specific operating and maintenance expenses and even for revenue losses. In some instances, the use of special ratemaking mechanisms such as surcharges and other tracking mechanisms have proliferated to the point of becoming excessive and burdensome for regulators to monitor. The use of surcharges is a deviation from traditional ratemaking and puts customers at risk for overpaying for safe and reliable utility service. The use of numerous alternative ratemaking mechanisms and surcharges can defeat some of the primary principles of the rate-setting and regulatory review process. Surcharges can also result in undesirable consequences, such as reducing utility incentives to control costs, and shifting utility business risks away from investors and onto customers.

COMPARISON OF SURCHARGES USED BY COMPANIES WITH MULTI-STATE UTILITY OPERATIONS

Many of the larger utility companies serve customers in multiple states. The following section illustrates the surcharges assessed by these companies to residential customers in the states in which the utility provides service. As can be seen from the tables, the use of surcharges for most utilities varies among the states it serves. Some companies have similar surcharges for the states they serve, while the use of surcharges varies among jurisdictions for others. Whether specific surcharges are approved by regulators appears to be based on the regulatory regime in the state, not whether the company has similar existing surcharges in other states.[26] The following sections contain maps illustrating the states in which the utility serves customers.[27]

AMERICAN ELECTRIC POWER (ELECTRIC)

American Electric Power ("AEP") Company is headquartered in Columbus, Ohio. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. AEP has approximately 5.3 million retail customers. AEP serves customers in the following states:



Electric

The public utility subsidiaries and jurisdictions of AEP Company include:

- Appalachian Power Company
- Columbus Southern Power Company
- Indiana Michigan Power Company
- Ohio Power Company
- Public Service Company of Oklahoma
- Southwestern Electric Power Company

Exhibit 3 is a comparison of costs recovered through surcharges in AEP's jurisdictions:

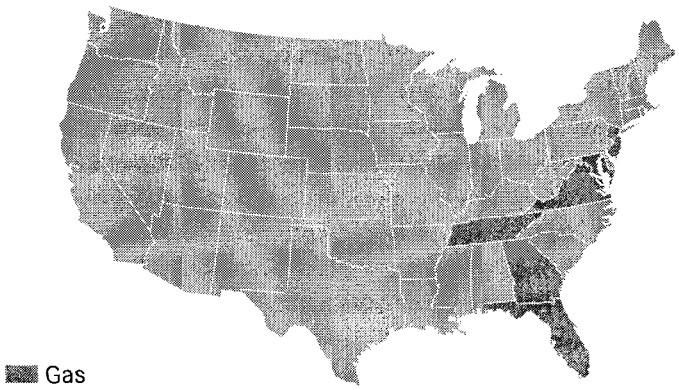
EXHIBIT 3

DESCRIPTION	AR	IN	KY	LA	MI	OH	OK	TN	TX	VA	WV
Advanced Metering (Voluntary)									●		
Alternative Generation	●										
Capital Expenditures											●
Capacity Charge			●								
Clean Coal Technology		●									
Energy Efficiency/DSM	●	●	●		●	●	●		●		●
Environmental Investment/ Compliance		●	●		●	●		●	●	●	
Federal Litigation Consulting Fees	●					●					
Franchise/Municipal Taxes	●		●	●	●					●	●
Inspection Fee								●			
Off System Sales		●									
PJM Cost		●									
Rate Case Expense									●[1]		
Reliability Expenditures/ Vegetation Management	●					●	●	●	●		
Sales & Use Tax			●					●		●	
Smart Grid						●					
Storm Expenses							●				
System Benefits/Universal Service									●		
Transmission Cost Recovery						●			●	●	
True-Up Case Expense									●		

[1]Two rate case expense surcharges
Source: 2010 Form 10-K and tariffs

AGL RESOURCES (GAS)

AGL is headquartered in Atlanta.[28] AGL Resources is an energy services company whose principal business is the distribution of natural gas in six states. AGL's six utilities serve approximately 2.3 million end-use customers.[29] AGL serves customers in the following states:



The public utility subsidiaries of AGL Resources include:

- Atlanta Gas Light
- Chattanooga Gas
- Elizabethtown Gas
- Elkton Gas
- Virginia Natural Gas
- Florida City Gas

Exhibit 4 is a comparison of revenues and costs recovered through surcharges in AGL's jurisdictions.

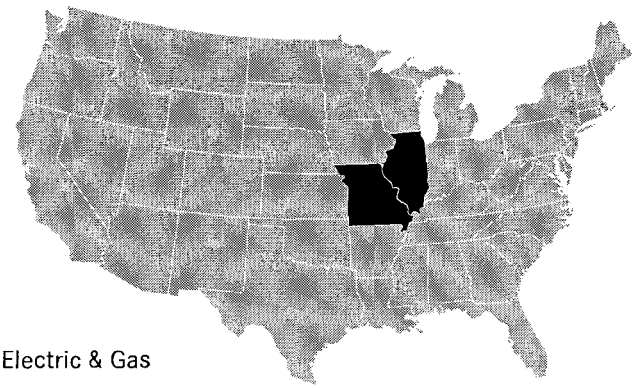
EXHIBIT 4

DESCRIPTION	FL	GA	MD	NJ	TN	VA
Conservation	●					
Environmental/Green House Gas Initiative		●		●		
Franchise Fees		●		●	●	
Pipeline Replacement/Utility Infrastructure Enhancement		●		●		
Revenue Normalization			●		●	●
Social Responsibility/Societal Benefits		●		●[1]		
Transitional Energy Facility Adj.				●		
Weather Normalization				●	●	●

[1]In NJ, Societal Benefits includes costs for clean energy program, environmental remediation and universal service
Source: 2010 Form 10-K and tariffs

AMEREN CORPORATION (ELECTRIC & GAS)

Ameren is a public utility holding company headquartered in St. Louis, Missouri. Ameren's subsidiaries operate rate-regulated electric generation, transmission, and distribution businesses, rate-regulated natural gas transmission and distribution businesses, and merchant generation businesses.[30] Ameren has approximately 2.4 million electric customers and 900,000 natural gas customers.[31] Ameren serves customers in Missouri and Illinois.



The public utility subsidiaries of Ameren include:

- Union Electric Company (electric & gas)
- Ameren Illinois (electric & gas)

Exhibit 5 is a comparison of costs recovered through surcharges in Ameren's jurisdictions.

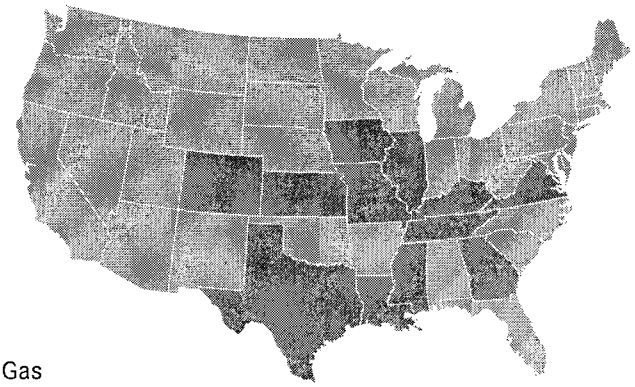
EXHIBIT 5

	ILLINOIS		MISSOURI	
DESCRIPTION	Electric	Gas	Electric	Gas
Coal Tar Cleanup[1]		•		
Energy Efficiency Costs	•	•		
Environmental Costs	•	•		
Excess Franchise Fees	•	•		
Government Compliance Costs	•	•		
Hazardous Materials (Asbestos)	•			
Infrastructure Maintenance	•			
Infrastructure Replacement				•
Uncollectibles	•	•		

[1]Zone 3 customers only
Source: 2010 Form 10-K and tariffs

ATMOS ENERGY CORPORATION (GAS)

Atmos Energy Corporation, headquartered in Dallas, Texas, is engaged primarily in the regulated natural gas distribution and transmission and storage businesses as well as other non-regulated natural gas businesses. The Company's primary service areas are located in Colorado, Kansas, Kentucky, Louisiana, Mississippi, Tennessee and Texas. It also has more limited service areas in Georgia, Illinois, Iowa, Missouri and Virginia. In addition, Atmos transports natural gas for others through its distribution system. Atmos has approximately three million residential, commercial, public authority and industrial customers in 12 states located primarily in the South. Atmos serves customers in the following states:



Atmos' natural gas distribution segments include:

- Mid-Tex Division
- Kentucky/Mid-States Division
- Louisiana Division
- West Texas Division
- Colorado-Kansas Division
- Mississippi Division

Exhibit 6 is a comparison of costs recovered through surcharges in Atmos' jurisdictions:

EXHIBIT 6

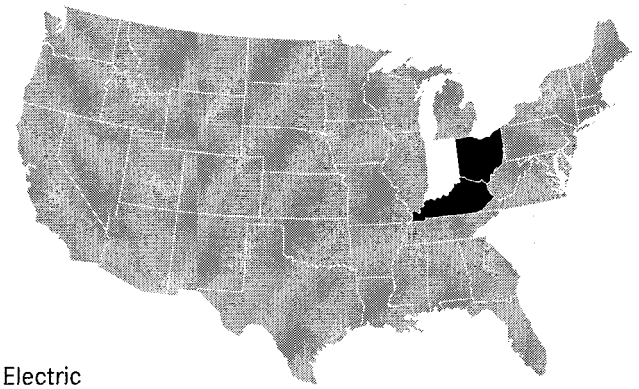
DESCRIPTION	CO	GA	IA	IL	KS	KY	LA	MO	MS	TN	MID TX	WEST TX	VA
Ad Valorem					●								
Automated Metering Incentive	●												
Demand Side Management	●					●							
Energy Efficiency			●								●	●	
Environmental										●			
Franchise Fee	●	●											
Low Income				●									
Municipal Fee											●		
Performance Based Rate Mechanism (experimental)						●							
Pipe Replacement		●				●							
Rate Case Expense											●		
Rate Stabilization/ Rate Review[1]							●		●			●	
Renewable Energy				●									
Research & Development[2]						●							
System Reliability					●								
Taxes				●							●		
Transportation Service Cost	●												
Uncollectibles			●										
Weather Normalization		●			●	●	●		●	●	●	●	●

[1]Atmos' Louisiana and Mississippi jurisdictional base rates are based on Formula Rates, which are adjusted annually, as opposed to a rate case.
[2]Voluntary participation by the Company in R&D funding for Gas Technology Institute or other research facilities.
Source: 2010 Form 10-K and tariffs

DUKE ENERGY (ELECTRIC AND GAS)

Duke Energy Corporation is an energy company that operates in the United States primarily through its direct and indirect wholly-owned subsidiaries. The Company is headquartered in North Carolina. Duke Energy supplies and delivers energy to approximately 4 million customers in the U.S.

Duke serves customers in the following states:



Duke has created a "virtual power plant" model, which combines cost recovery, lost revenue recovery and incentives into an avoided cost charge, which has been approved in the Carolinas and Ohio. Duke has proposed similar mechanisms in Indiana.

Electric
Electric & gas

The public utility subsidiaries of Duke Energy currently include:

- Duke Energy Carolinas (electric)
- Duke Energy Indiana (electric)
- Duke Energy Ohio (electric and gas)

On January 8, 2011, Duke Energy Corporation ("Duke Energy") entered into a Merger Agreement and Plan of Merger between and among Diamond Acquisition Corporation, a North Carolina corporation and Duke Energy's wholly-owned subsidiary (Merger Sub) and Progress Energy, Inc., a North Carolina corporation.[32] Progress Energy includes two major electric utilities that serve about 3.1 million customers in the Carolinas and Florida.[33] The merger is still pending.

Exhibit 7 is a comparison of costs recovered through surcharges in Duke's jurisdictions:

EXHIBIT 7

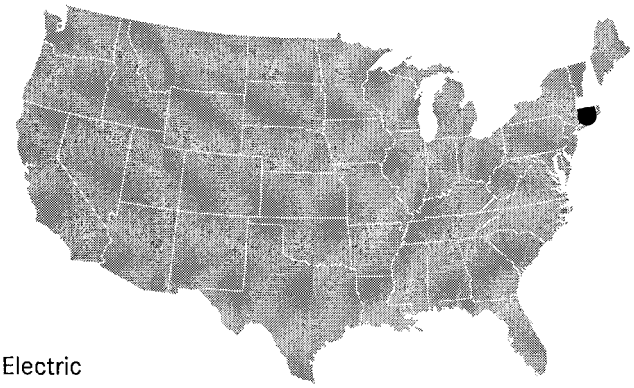
	KY		IN	NC	OH		SC
DESCRIPTION	ELEC	GAS	ELEC	ELEC	ELEC	GAS	ELEC
Accelerated Main Replacement						•	
Annually Adjusted Component					•		
Clean Coal Operating Cost Revenue Adjustment			•				
Demand Side Management	•	•	•	•			
Economic Competitiveness					•		
Emmission Allowances			•				
Energy Efficiency				•	•		•
Excise Tax					•	•	
Franchise Fee	•	•					
Infrastructure Modernization					•		
New Generation			•				
Non-fuel purchased power				•			
Off-system Power sales & Emission Allowance Sales Profit Sharing	•						
Pension Costs							•
Pollution Control			•				
Regulatory Transition Charge					•		
Reliability Adj (Capacity)			•				
Renewable Energy				•	•		
State Tax					•		
Storm Recovery					•		
System Reliability Tracker					•		
Transmission Cost					•		
Uncollectible					•	•	
Universal Service					•		

Source: 2010 Form 10-K and tariffs

NORTHEAST UTILITIES (ELECTRIC AND GAS)

Northeast Utilities ("NU") is a public utility holding company headquartered in Connecticut. The Company is engaged primarily in the energy delivery business through its wholly-owned utility subsidiaries.

NU serves customers in Connecticut, Massachusetts and New Hampshire.



Electric
Electric & gas

The public utility subsidiaries of NU include:

- Connecticut Light & Power
- Public Service Company of New Hampshire
- Western Massachusetts
- Yankee Gas

On October 18, 2010, NU and NSTAR announced a Merger Agreement to combine the two companies. The post-transaction company will provide electric and natural gas energy delivery service to nearly 3.5 million electric and natural gas customers through six regulated electric and natural gas utilities in Connecticut, Massachusetts and New Hampshire, representing over half of all the customers in New England. The merger is still pending.

Exhibit 8 is a comparison of costs and revenues recovered through surcharges in NU's jurisdictions:

EXHIBIT 8

	CT		NH	MA
DESCRIPTION	ELEC	GAS	ELEC	ELEC
Competitive Transition Assessment[1]	•		•	•
Decoupling				•
Electricity Consumption Tax			•	
Energy Efficiency Programs				•[2]
Exogenous Costs				•
FERC Congestion Charge	•			
Low Income				•
Pension/PBOP				•
Renewable Energy				•
Storm Recovery Costs				•
System Benefit			•	

[1]Stranded investment, conservation load management, renewable energy
[2]Two separate charges for energy efficiency & DSM
Source: 2010 Form 10-K and tariffs

MIDAMERICAN ENERGY HOLDINGS COMPANY (ELECTRIC AND GAS)

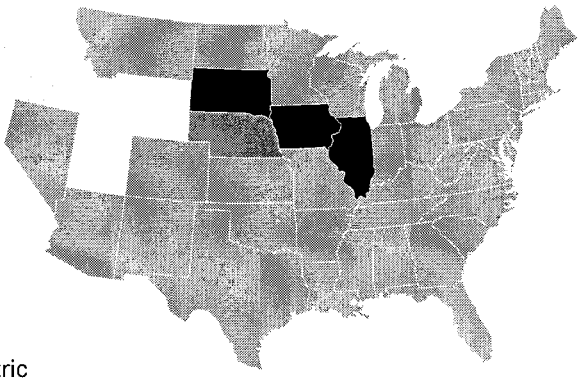
MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

The Company's operations are organized and managed as eight distinct platforms: PacifiCorp, MidAmerican Funding, LLC, Northern Natural Gas Company, Kern River Gas Transmission Company, CE ElectricUKFunding Company, CalEnergy Philippines, CalEnergy U.S. and HomeServices of America, Inc. Through these platforms, the Company owns and operates an electric utility company in the Western United States, an electric and natural gas utility company in the Midwestern United States, two interstate natural gas pipeline companies in the United States, two electricity distribution companies in Great Britain, a diversified portfolio of independent power projects and the second largest residential real estate brokerage firm in the United States.

As of December 31, 2010, MEHC's electric and natural gas utility subsidiaries served 6.2 million electricity customers and end-users and 0.7 million natural gas customers. MEHC's natural gas pipeline subsidiaries operate interstate natural gas transmission systems that transported approximately 8% of the total natural gas consumed in the United States during 2010.

PacifiCorp, an indirect wholly owned subsidiary of MEHC, is a United States regulated electric utility company headquartered in Oregon that serves 1.7 million retail electric customers. PacifiCorp is principally engaged in the business of generating, transmitting, distributing and selling electricity.

MEHC serves customers in:



Electric
Gas
Electric & gas

The public utility subsidiaries of MEHC include:

- PacifiCorp
- Pacific Power (electric)
- Rocky Mountain Power (electric)
- MidAmerican Energy (electric & gas)
- Northern Natural Gas (gas-regulated by FERC)

Exhibit 9 is a comparison of costs recovered through surcharges in MEHC's jurisdictions:

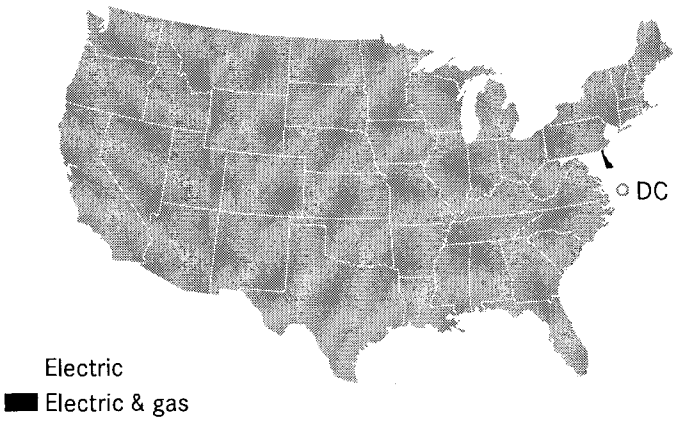
EXHIBIT 9

	CA	IA		ID	IL		NE	OR	SD		UT	WA	WY
DESCRIPTION	Elec	Elec	Gas	Elec	Elec	Gas	Gas	Elec	Elec	Gas	Elec	Elec	Elec
Alternate Energy Producer Cost Recovery		●											
Btu Adjustment			●				●			●			
Capital Investments		●											
Carbon Reduction Costs			●									●	
CARE Program	●												
Catastrophic Event Memo Account	●												
Commission Fees/ Government Fees	●	●											
Energy Efficiency/DSM [2,3]	●	●	●		●	●		●	●	●	●	●	●
Franchise Fees						●						●	
GridWest Regulatory Asset								●					
Hydro Cost Deferral												●	
Independent Evaluator Cost								●					
Intervenor Funding								●					
Klamath Dam Removal								●					
Klamath Rate Reconciliation Adjustment								●					
Low Income	●					●		●			●	●	
Nuclear Decommissioning					●								
Property Sales								●					
Public Purpose Charge								●					
Rate Mitigation Adjustment			●					●					
Renewable Energy/Solar Energy Programs/Research[1]	●	●			●	●		●			●	●	
Severance-Regulatory Asset								●					
Taxes		●	●		●	●	●	●	●	●		●	
Transition Balancing Account (includes franchise fees & uncollectibles)	●											●	●

[1]Voluntary in IA, IL and UT
[2]DSM charge in SD does not apply to all customers
[3]DSM suspended in Wyoming
Source: 2010 Form 10-K and tariffs

PEPCO HOLDINGS, INC. (ELECTRIC AND GAS)

Pepco Holdings Inc. ("PHI") is a diversified energy company that through its operating companies is engaged primarily in two businesses: the distribution, transmission and default supply of electricity and the delivery and supply of natural gas (power delivery), conducted through its regulated public utility companies. PHI has approximately 1.9 million customers in the following jurisdictions: Delaware, Maryland, New Jersey, and the District of Columbia.



The public utility subsidiaries of PHI include:

- Potomac Electric Power Company (electric)
- Atlantic City Electric (electric)
- Delmarva Power & Light (electric & gas)

Exhibit 10 is a comparison of revenues and costs recovered via surcharges in PHI's jurisdictions:

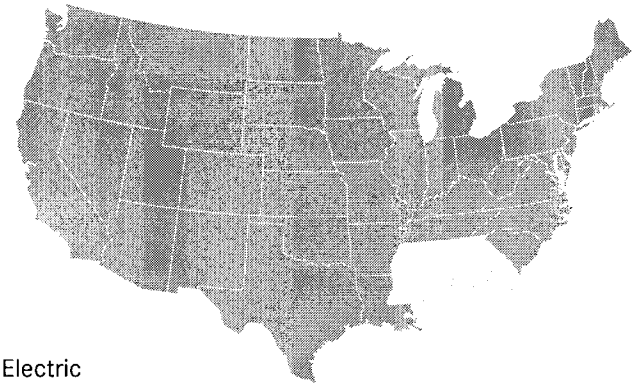
EXHIBIT 10

	DC	DE		MD	NJ
DESCRIPTION	ELEC	ELEC	GAS	ELEC	ELEC
Bill Stabilization	•			•	
Corporate Business Tax					•
Delivery Tax	•				
Demand Side Management				•	
Energy Assistance Fund[3]	•				
Environmental Expenses			•		•
Infrastructure Investment					•
Public Space Occupancy Fees	•				
Regulatory Assets Recovery[1]					•
Sales and Use Tax					•
Securitization of Stranded Costs					•
Societal Benefits[3]	•				•
Sustainable Energy Fund	•				
Transitional Facility Assessment					•
Universal Service Costs	•			•	

[1]Asbestos removal, FAS 106 Costs and other regulatory assets
[2]A new Reliability Investment Recovery Mechanism (RIM) surcharge is currently being proposed in all of PHI's regulated electric utility operating jurisdictions.
[3]Customer will pay either Societal Benefits Charge or the Energy Assistance Fund Charge, not both
Source: 2010 Form 10-K and tariffs

SOUTHERN COMPANY (ELECTRIC)

Southern Company was incorporated under the laws of Delaware on November 9, 1945 and is headquartered in Atlanta. Its traditional operating companies (which are also referred to as the Southern Company System) supply electric service to approximately 4.4 million customers, in four southeastern states: [34]



Electric

The public utility subsidiaries of Southern Company include:

- Alabama Power Company
- Georgia Power Company
- Gulf Power (serves utility customers in the Florida panhandle)
- Mississippi Power

Exhibit 11 is a comparison of costs recovered via surcharges in Southern Company's jurisdictions:

EXHIBIT 11

DESCRIPTION	AL[1]	FL	GA	MS
Ad Valorem				•
Demand Side Management/ Conservation		•	•	
Environmental Compliance		•	•	•
New Plant Construction Costs	•		•	•[2]
Performance Evaluation Plan				•
Regulatory Taxes				•
System Restoration				•
Taxes (franchise, gross receipts, etc.)	•	•	•	

[1]Alabama Power's rates are adjusted annually by the Rate Stabilization and Equalization Factor (a formula rate plan) since 1982, as opposed to setting rates based on the traditional rate case process

[2]Rider CNP to recover Construction Work In Progress costs associated with the Kemper Plant, is pending in Mississippi.

Source: 2010 Form 10-K and tariffs

SOUTHWEST GAS CORPORATION (GAS)

Southwest Gas ("SWG") is engaged in the business of purchasing, distributing and transporting natural gas in portions of Arizona, Nevada, and California. SWG is the largest distributor of natural gas in Arizona and Nevada. As of December 31, 2010, SWG purchased and distributed or transported natural gas to 1,837,000 residential, commercial and industrial customers.[35]

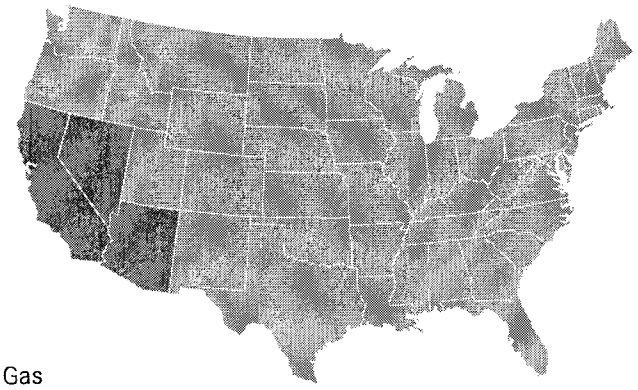


Exhibit 12 a comparison of revenues and costs recovered though surcharges in SWG's jurisdictions:

EXHIBIT 12

DESCRIPTION	AZ	CA	NV
California Alternate Rates for Energy Balancing Account		•	
Catastrophic Event Memorandum Account		•	
Customer Owned Yard Line (COYL) Cost Recovery Mechanism	•		
CPUC Reimbursement Fee		•	
Decoupling	•	•	•
Demand Side Management (DSM) Surcharge	•		
Energy Efficiency/Renewable Energy Tariff Plan	•		
Facilities Surcharge		•	
Fixed Cost Adjustment		•	
Intrastate Transportation Cost Balancing Account		•	
Low Income	•		
Low Income Energy Efficiency Balancing Account		•	
Public Interest R&D Balancing Account		•	
Research and Development Surcharge	•		
Taxes (not included in rates)			•
Transportation Franchise Fee		•	
TRIMP Surcharge	•		
Uncollectibles			•

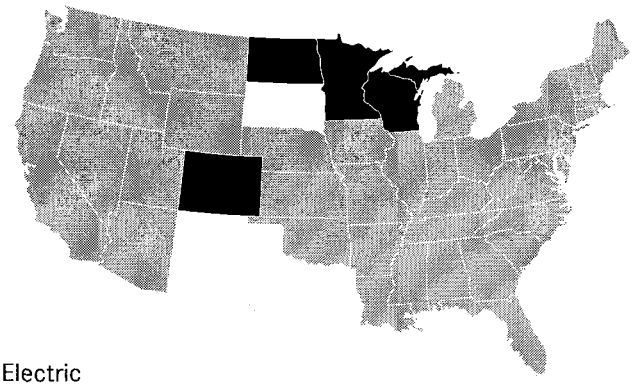
Source: 2010 Form 10-K and tariffs. In SWG's most recent rate case, Docket No. G-01551A-10-0458 before the Arizona Corporation Commission, a full revenue decoupling mechanism alternative was adopted from a settlement agreement that had been reached by most of the parties to the rate case.

Some consumer safeguards adopted in Docket No. G-01551A-10-0458 require SWG to:

- Starting April 30, 2012, file quarterly reports regarding the decoupling mechanism's performance.
- Starting April 2013, file annual reports permitting the Commission and all parties the opportunity to review the decoupling mechanism's performance.
- Be subject to an annual earnings test that would prohibit SWG from recovering any decoupling deferral amounts to the extent that the deferral recovery would increase its earnings above the authorized return on common equity.
- Provide $75,000 for the hiring of an independent consultant to conduct the annual Staff review of SWG's annual filing.
- Cap at 5 percent any surcharge developed through the decoupling mechanism that would result in a non-gas revenue surcharge of greater than 5 percent, and SWG will carry the deferral account balance forward for recovery in the following and subsequent years with no carrying charge; however, there will be no cap on annual surcharge decreases.
- Not to file a general rate application prior to April 30, 2016, with a test year ending no earlier than November 30, 2015.
- Submit a proposed customer outreach/education plan to Staff for review and approval, to outline how SWG intends to explain decoupling to customers.[36]

XCEL ENERGY (ELECTRIC AND GAS)

Xcel Energy is a holding company, with subsidiaries engaged primarily in the utility business. In 2010, Xcel Energy's continuing operations included the activity of four wholly-owned utility subsidiaries that serve electric and natural gas customers in eight states. Along with WYCO, a joint venture formed with Colorado Interstate Gas Company (CIG) to develop and lease natural gas pipeline, storage, and compression facilities, and WGI, an interstate natural gas pipeline company, these companies comprise the continuing regulated utility operations.[37] Xcel Energy serves 1.36 million electricity customers and 1.3 million natural gas customers.[38] Xcel serves customers in the following states:



Electric
Electric & gas

The public utility subsidiaries of Xcel include:

- Northern States Power
- Public Service Company of Colorado
- United Water
- SPS

Exhibit 13 is a comparison of costs recovered thorough surcharges in Xcel's jurisdictions:

EXHIBIT 13

	CO		MI		MN		ND		NM	SD	TX	WI	
DESCRIPTION	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Gas	Elec	Elec	Elec	Elec	Gas
Conservation/Energy Efficiency Program					●	●			●				
Demand Side Management	●	●											
Energy Optimization			●	●									
Environmental Improvement					●					●			
Facilities Fees					●								
Franchise Fees	●	●			●	●					●		
General Rate Schedule Adjustment	●	●											
Interim Rate					●		●						
Low Income (Pilot)	●	●											
Mercury Emmissions Reduction					●								
Other Taxes/Fees	●	●			●	●	●	●		●			
Pipeline System Integrity Adjustment		●											
Renewable Development					●								
Renewable Energy Standard	●				●				●				
State Energy Policy					●	●							
Transmission Capital Costs	●				●					●			

Source: 2010 Form 10-K and tariffs

APPENDIX I – DESCRIPTIONS OF TYPES OF COSTS BEING ASSESSED AS SURCHARGES

The following discussion focuses on proposed surcharges which would appear as an additional charge on ratepayers' bills, above and beyond the basic service charge and charges for fuel and taxes. Below are examples of various surcharges proposed and employed by utilities and a brief description of the costs being recovered through surcharges.

LOST REVENUES

Lost revenue surcharges are an added charge to ratepayers' bills which serve to compensate the utility for loss of revenue due to various factors. Some lost revenue surcharges include:

REVENUE DECOUPLING

Revenue decoupling helps assure that the utility's actual earnings will be at the level of authorized earnings. Under some forms of full decoupling, customers' rates are automatically adjusted to insulate the utility's earnings from fluctuations in sales. The rational for this that it removes existing disincentives which make utility management reluctant to aggressively promote energy conservation. Revenue decoupling can take on different approaches, including: decoupling true up plans, lost revenue adjustment mechanisms, and fixed/variable pricing rate design, which shifts costs into the "fixed" portion of the customer's bill and out of the "variable" portion of the bill.

Straight Fixed Variable or (SFV) is a rate design where fixed costs of service would be collected through fixed charges and only variable costs of service would be collected through usage charges. This approach would require very high basic service charges.[39]

Fixed costs are the portion of utility costs that do not change with the level of energy consumption. Within each rate class that does not have a demand charge, each customer is charged the same amount for fixed costs. Variable costs are those costs that differ depending on the amount a customer consumes (e.g., the volumetric charge per kilowatt-hour). Some items that would be considered a variable charge include fuel, some maintenance, and often purchased power. By separating these two charges, a utility's ability to recover its revenue requirement is completely separated from sales volume. By ensuring the recovery of all fixed charges, the revenue level of the company under SFV remains fairly consistent, providing a high level of certainty for investors. Additionally, SFV insulates the utility company from feeling the effects of external forces such as loss of sales due to poor weather or customer investment in energy efficiency would typically have on revenues. Alternatively, the utility company's upside from increased sales is limited.

The use of SFV can reduce savings experienced by customers from energy efficiency investments as presented in the following example[40]:

Reduction of Monthly Customer Usage from 1,000 to 900 Units Energy Efficiency Investment of $200

	STANDARD TWO-PART TARIFF	SFV
	$15 Fixed Charge	$50 Fixed Charge
	$0.075/kWh	$0.04/kWh
1,000 Units	Fixed: $15.00 Variable: $17.00 Total: $90.00	Fixed: $50.00 Variable: $40.00 Total: $90.00
900 Units	Fixed: $15.00 Variable: $67.50 Total: $82.50	Fixed: $50.00 Variable: $36.00 Total: $86.00
Savings	$7.50/month $90/year	$4/month $48/year

WEATHER NORMALIZATION ADJUSTMENT (PARTIAL FORM OF DECOUPLING)

A weather normalization adjustment ("WNA") applies a surcharge to ratepayers' bills so that the bills reflect an amount that would be billed for utility services under normal weather conditions. For example, if gas utility customers use less gas for space heating because winter is warmer than normal, their savings are limited to the avoided gas commodity charges, and the rest of their utility bill effectively reflects the higher usage that is based on "normal" weather. Similarly, if electric customers use less air conditioning during a cooler than normal summer, what would have been their savings is reduced by having to pay the utility as if the normal hot summer weather had occurred. The opposite is also true; higher utility bills from extreme weather can be somewhat mitigated by a WNA surcredit. Weather normalization is a regulatory procedure that removes weather-related volatility from customer bills; that is, adjusts the non-gas (or distribution) charges on customers' bills to reflect normal weather instead of actual weather which may be colder or warmer than normal.[41]

EARNINGS SHARING MECHANISM/RATE OF RETURN TRACKER

An earnings sharing mechanism is a single adjustment based on the utility's rate of return. Adjustments are made outside of rate cases when actual costs deviate from test year costs and/or actual revenues deviate from test year revenues, in a manner that affects utility earnings.[42] Some earnings sharing mechanisms are based upon whether the utility earns within a band

around its authorized rate of return. As an illustrative example, if a utility's authorized return on equity was 10%, an earnings sharing mechanism could have a "band" of 50 basis points (plus or minus) around that authorized ROE, earnings above a 10.5% ROE are "shared" with ratepayers via the earnings sharing mechanism as a credit, while earnings below 9.5% would result in a surcharge.

TRANSITION ADJUSTMENT

A transition or stranded cost surcharge recovers revenues lost to utilities when customers purchase their energy supply through independent marketers. The rationale for this type of surcharge is that the migration to another supplier creates "stranded costs" for the utility.

CAPITAL EXPENDITURES

GAS PIPELINE/AGING INFRASTRUCTURE REPLACEMENT

Infrastructure surcharges provide for utility recovery of capital investments made to upgrade a utility's aging electric distribution infrastructure or gas distribution pipeline system.

ATLANTA GAS LIGHT

In 1998, AGL was permitted to implement a surcharge to recover prudently incurred costs associated with a ten-year pipe replacement program ("PRP") to address specific pipeline safety violations. The PRP was scheduled to be completed but was extended to 2013 as part of a settlement in Docket No. 85616-U. The residential surcharge was $1.29 per month in years 7-9 of the PRP and increased to $1.95 in years 10-13. In 2009, the Company filed a request to rename the existing surcharge to the Strategic Infrastructure Development and Enhancement ("STRIDE") Program surcharge so that it would include the PRP costs as well as the Integrated System reinforcement Program ("i-SRP") costs and costs for expanding the distribution system. The Commission approved the Company's request for the STRIDE surcharge in its final decision dated in Docket No. 29950, dated January 20, 2010.

In contrast, Washington Gas Light ("WGL") recently sought, as part of its rate base increase, approval of an Accelerated Pipe Replacement Plan ("APRP") and a related cost recovery mechanism ("Rider") to accelerate the replacement of aging pipes, increase safety and reliability and provide environmental benefits through the reduction of greenhouse gas emissions. The APRP was approved by the regulators but the surcharge was denied by regulators because it departed from traditional ratemaking. In its order, the Maryland PSC stated it would rather review these costs in the context of a rate case, even if the filing of rate cases would be more frequent.

NEW GENERATION PLANT INVESTMENT (COAL FIRED, SOLAR, RENEWABLE, NUCLEAR GENERATION)

Some utilities have been authorized surcharges to recover investments made for the purposes of adding generation or capacity to serve more customers or meet increased demand, or for the investments in specific types of generation such as renewables or solar. For example, Progress Energy Florida ("PEF") obtained regulators' approval this year to recover $86 million from ratepayers for the costs of constructing nuclear Units Levy 1 and 2. The estimated 2012 monthly cost to ratepayers is about $2.93 for the first 1,000 kilowatt hours (kwh) for PEF customers.

Florida Power & Light Company ("FP&L") also received regulators' approval to recover $196 million for costs associated with construction of two new units at its Turkey Point Plant and adding capacity to existing units at Turkey Point and St. Lucie Plants.[43]

SMART METERS/SMART GRID

"Smart Meters"[44] and "Smart Grid" generally refer to technology to convert and automate utility electricity delivery systems, and enable new functions, such as grid monitoring and time-of-use metering. Many utilities are proposing to rapidly implement these technologies, but some utilities and regulators have found that the costs are much higher than anticipated and/or ratepayer benefits were not commensurate. There have been requests by electric utilities for surcharge recovery of costs for Advanced metering Infrastructure ("AMI"). In 2010, regulators in Texas allowed Oncor Utilities to implement a monthly surcharge of $2.19 per customer for 11 years to pay for the costs associated with installing smart meter as well as a public education campaign.[45]

The New York PSC authorized Con Edison to recover Smart Grid costs through a surcharge. While the monthly surcharge averages about 28¢/customer, or less than 0.3% of the average monthly bill, the surcharge will collect over $145 million for the company. The surcharge continues at least until Con Edison's next rate case, in April 2013, when it may be reset.[46]

However, other states have disallowed surcharges to recover these substantial and speculative costs:

MARYLAND

Baltimore Gas & Electric Proposed a SmartGrid Plan in Case No. 9208, Order 83410, and requested that the $835 million cost to implement be recovered from customers via a surcharge. The Commission denied the company's Smart Grid Plan and surcharge recovery. The Commission's decision stated:

> The Proposal asks BGE's ratepayers to take significant financial and technological risks and adapt to categorical changes in rate design, all in exchange for savings that are largely indirect, highly contingent and a long way off. We are not persuaded that this bargain is cost-effective or serves the public interest, at least in its current form.
>
> ...
>
> The Proposal is a 'no-lose proposition' for the Company and its investors.[47]

BGE submitted a modified SmartGrid plan in Case No. 9208. The Commission approved BGE's modified SmartGrid plan, but again did not permit recovery of the project through a surcharge. The Commission supported intervenor, the Maryland Energy Administration's (MEA), position that AMI deployment is analogous to an investment in a power plant, an investment of similar (or greater) magnitude that historically would be recovered through traditional ratemaking.[48]

RENEWABLE ENERGY

Renewable energy surcharges recover costs related to capital expenditures or purchased power contracts associated with a utility's renewable energy program. Renewable energy is defined as

energy that can be replenished, such as wind, solar, geothermal, hydro, photovoltaic, wood and waste. Renewable energy typically also has environmental benefits. To encourage the development of renewable energy, many jurisdictions provide for utility cost recovery via surcharges. Non-renewable energy sources are finite, such as coal, oil, and gas.[49]

TRANSMISSION INFRASTRUCTURE

Transmission surcharges can include provisions for utility recovery of capital expenditures to upgrade a utility's aging transmission infrastructure and/or transmission cost increases which the utility incurs based on transmission costs approved by the FERC. Some state regulatory commission prefer to isolate the impacts on utility customer bills resulting from federal mandates, including FERC decisions, so those impacts are transparent to customers and are distinguished from state regulatory decision impacts.

OPERATION AND MAINTENANCE EXPENSES

PIPELINE SAFETY PROGRAM FEES

Utilities have proposed surcharges to recover costs associated with inspecting gas distribution pipelines and safety related issues.

VEGETATION MANAGEMENT

Vegetation management activities can include: tree pruning (trimming), right-of-way mowing and clearing, and herbicide application.[50] A major cause of power outages can be due to improperly maintained vegetation or trees that can come in contact with power lines during severe storms.

ENVIRONMENTAL COMPLIANCE

Environmental compliance costs can include remediation costs associated with site investigation and removal of pollution or contaminants from soil or groundwater[51] or costs to implement environmental controls mandated by state and federal regulations.[52] A common example of environmental compliance costs is the emission control equipment that electric generation utilities are required to install on coal-fired plants to meet air quality standards.

UNCOLLECTIBLE CHARGES

Some utilities have requested surcharges to collect customers' bad debts. Some surcharges allow a utility to collect from (or refund) the difference between the uncollectible (or bad debt) expense allowed in base rates and the utility's actual prior calendar year uncollectible expense. Some utility uncollectible surcharges recover only the fuel or gas cost portion of uncollectible accounts.[53] In some cases, the uncollectible expense may be collected though the utility's fuel or gas clause.

PENSION/OTHER POST RETIREMENT BENEFITS ("OPEB")

Prior to 2008, many utilities' defined benefit pension plans were well funded. However, due to the sharp decline of the stock market in late 2008 with the onset of the world-wide financial crisis, many utilities' pension plans suffered substantial losses. In the following

years, some utilities requested substantial increases to their pension expense to replenish the funding of their pension plans, some via a surcharge. The stock market has since stabilized.

STORM DAMAGE

A catastrophic storm may cause significant damage to a utility's infrastructure (wires, poles, substations, etc.). Some utilities have petitioned regulators to recover the costs associated with repairing its infrastructure via a surcharge mechanism. Traditionally, utility storm damage repair costs have been addressed in base rates.

ENERGY EFFICIENCY/CONSERVATION/DEMAND SIDE MANAGEMENT (DSM) PROGRAMS

Costs associated with implementing energy efficiency, conservation and demand side management programs are increasingly being addressed for ratemaking purposes in utility surcharge mechanisms.

UNIVERSAL SERVICE COSTS (LOW INCOME PROGRAM COSTS)

A universal service cost is a fee paid by users of a utility service in some states to support the provision of providing utility service for low-income users. The fees help eligible customers pay their electricity bills and may also provide for energy conservation measures and weatherization.[54]

MUNICIPAL FEES/FRANCHISE FEES

Some utilities pass through fees imposed on the utility by the municipality for franchise, occupation taxes/fees, or any other tax/fee imposed on the company by the municipality to conduct business within the city limits and on the cities' rights-of-way to its customers.[55] Typically, special surcharges for municipal fees or taxes would be applicable to utility customers residing within the municipality that is imposing such surcharges on the utility.

AD VALOREM TAXES

Ad Valorem taxes are taxes based on assessed value of property (i.e., property taxes).

OTHER TAXES

Some utilities impose a surcharge to collect other taxes such as sales and use tax, gross receipts tax, etc.

STRANDED COSTS

Costs incurred by utilities to serve their customers that potentially may be unrecoverable in a newly-created market.[56] Stranded costs can be defined as the estimated decline in the value of electricity-generating assets due to restructuring of the industry.[57]

SOCIETAL BENEFITS CHARGE OR SYSTEM BENEFITS CHARGE

In some jurisdictions, such as New Jersey and Arizona, utilities collect from customers a "societal benefits charge" which allows the utility to recover a combination of costs: e.g., clean energy program costs, manufactured gas plant remediation expenses, universal service fund and other allowed costs.[58]

REGULATORY FEES

These fees can include rate case costs, regulator fees, etc.

LITIGATION COSTS

Legal fees and costs associated with a trial, if significant or unusual, would be the subject of a special surcharge request by a utility. Traditionally, utility legal costs are addressed in the determination of the utilities' base rates.

CAPITAL/O&M COMBINED

ECONOMIC STIMULUS PROGRAM ("ESP")

In some jurisdictions, such as New Jersey, costs and associated carrying costs incurred on behalf of the utility for reliability focused and energy efficiency focused infrastructure projects are within the Economic Stimulus Program ("ESP"), which is a specific utility cost recovery mechanism. ESP Costs include: (1) the carrying costs (depreciation and return on net investment, including tax effects) on capital investments and (2) the incremental operation and maintenance expenses associated with the infrastructure programs.

ENVIRONMENTAL COMPLIANCE

Capital expenditures and O&M associated with installing environmentally compliant plant equipment that reduces or removes the level of harmful substances being emitted into the atmosphere. This can include costs for environmental remediation (i.e., clean-up).

SYSTEM HARDENING/RELIABILITY COSTS

Proactive measures to increase a utility's transmission and distribution system to withstand the effects of high winds and storms. This can also include investments to upgrade or underground the infrastructure.

SECURITY COSTS

Security costs include proactive measures to protect a utility's infrastructure from security threats. After the September 11, 2001 terrorist attacks on the World Trade Center, some utilities began requesting special cost recovery for the increased costs for security threats to water supply and treatment facilities and to other potential terrorist targets such as nuclear generating plants.

ABOUT THE AUTHORS

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END NOTES

[1] Public Utilities Commission of Minnesota, Utility Rates Study, 2010, Talking Points on Cost Trackers, The National Regulatory Research Institute Presentation, November 2009.

[2] The Two Sides of Cost Trackers: Why Regulators Must Consider Both, October 27, 2009.

[3] The International Accounting Standards Board (IASB) Framework lists prudence as a sub-quality of reliability, calling prudence "the inclusion of a degree of caution in the exercise of the judgments needed in making the estimates required under conditions of uncertainty, such that assets or income are not overstated and liabilities or expenses are not understated" (paragraph 37). Also, Financial Accounting Standards Board ("FASB") Concepts Statement 2 discusses conservatism—meaning prudence—at length in paragraphs 91–97.

[4] Used and useful is defined by the Edison Electric Institute's 2005 Glossary of Electric Terms as "A regulatory specification typically used to determine whether an item of "Plant" may be included in a utility's rate base.

[5] http://nrri2.org/index.php?option=com_content&task=view&id=97&Itemid=48. Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[6] Cost Recovery Mechanisms for Smart Grid Investment, Carl Peterson, Center for Business and Regulation, University of Illinois Springfield.

[7] Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[8] http://www.nj.gov/bpu/residential/glossary/ In states which have restructured their retail electric markets, the transmission and distribution rates remain regulated.

[9] Public Utilities Commission of Minnesota, Utility Rates Study, 2010.

[10] The Two Sides of Cost Trackers: Why Regulators Must Consider Both, October 27, 2009.

[11] The terms used may vary slightly between different jurisdictions and are not used uniformly by utility regulators.

[12] http://www.georgiapower.com/pricing/glossary.asp#rider

[13] Aquila, Order in Application No. NG-0041

[14] Balancing accounts are usually classified as "one way" (or "asymmetrical") where underspending is returned to ratepayers, but overspending is absorbed by company. Under a two-way ("or symmetrical") balancing account, the impact of underspending and overspending, if deemed to be prudent, is ultimately passed on to the ratepayer.

[15] A balancing account may be recorded as a regulatory asset or a deferred asset on the utility's books. Qualifying costs are charged to the balancing account and the surcharge revenues collected are credited to the account. Balances in some balancing accounts earn the 90-day commercial payment rate.

[16] Memorandum ("memo") accounts are used extensively by California utilities, with more limited or no use in other jurisdictions. The costs being tracked may later be converted to a balancing account upon approval by the regulator. In California, information regarding memorandum accounts are reported by filing "Advice Letters".

[17] A.10-07-007

[18] This information was obtained from the tariffs on the utilities' websites during the time-frame of this report.

[19] Utah Code Annotated Section 54-7-13(4)

[20] Direct Testimony of Greg Shimansky, GDS-1, A. 10-12-005

[21] Direct Testimony of Jodi Jerich, on behalf of RUCO, Docket No. G-04204A-11-0158

[22] Testimony of David Dismukes, Docket No. 09-00183, Testimony of Jodi Jerich, G-04204A-11-0158

[23] http://coa.courts.mi.gov/documents/OPINIONS/FINAL/COA/20120410_C296374_47_296374.OPN.PDF

[24] *Id.*, at 8

[25] *Id.*, at 8

[26] The array of surcharges being proposed and implemented by utilities is continuously evolving. Information for the utilities listed is believed to be accurate at the time the research was conducted, but is subject to change as new regulatory developments occur.

[27] It should be noted that the utility may only serve customers in a portion of the states shown.

[28] http://www.aglresources.com/about/about_us.aspx

[29] AGL Resources 2010 Form 10-K p. 4

[30] 2010 Form 10-K

[31] http://www.ameren.com/aboutameren/pages/aboutus.aspx

[32] 2010 Form 10-K

[33] https://www.progress-energy.com/company/about-us/index.page?

[34] http://www.southerncompany.com/aboutus/home.aspx

[35] Southwest Gas Corporation, Form 10-K, 2010

[36] Proposed Decision dated November 28, 2011

[37] 2010 Form 10-K

[38] http://www.metrodenver.org/investor-center/2011/xcel-energy.html

[39] Direct Testimony of Leland Snook on behalf of APS, Docket No. E-01345A-11-0224

[40] Source: https://aep.com/about/IssuesAndPositions/Financial/Regulatory/AlternativeRegulation/StraightFixedVariable.aspx

[41] Ralph Miller Direct Testimony, Brooks Congdon, on behalf of Southwest Gas Corp., Docket No. G-01551A-07-0504

[42] Utility Rates Study, July 22, 2010 by the Minnesota Public Utilities Commission to the Senate Energy, Utilities, Technology & Communications Committee.

[43] http://citrusdaily.com/psc-approves-nuclear-cost-recovery-progress-energy-fpl/2011/10/25/87681.html

[44] Also referred to as "Advanced Meters".

[45] http://www.greentechmedia.com/articles/read/smart-grid-cost-recovery-make-the-consumer-care/

[46] www.smartgridtoday.com/public/2174print.cfm, Order in Case 09-E-0310, http://www.coned.com/documents/elec/159-164a.pdf

[47] MD PSC Order No. 83410, pp. 1,3, dated June 21, 2010.

[48] MD PSC Order No. 83531, pp. 32-41.

[49] 2005 EEI Glossary.

[50] http://www.oncor.com/community/vegetation/default.aspx

[51] http://en.wikipedia.org/wiki/Environmental_remediation

[52] http://www.georgiapower.com/pricing/glossary.asp#r1

[53] Atmos Energy

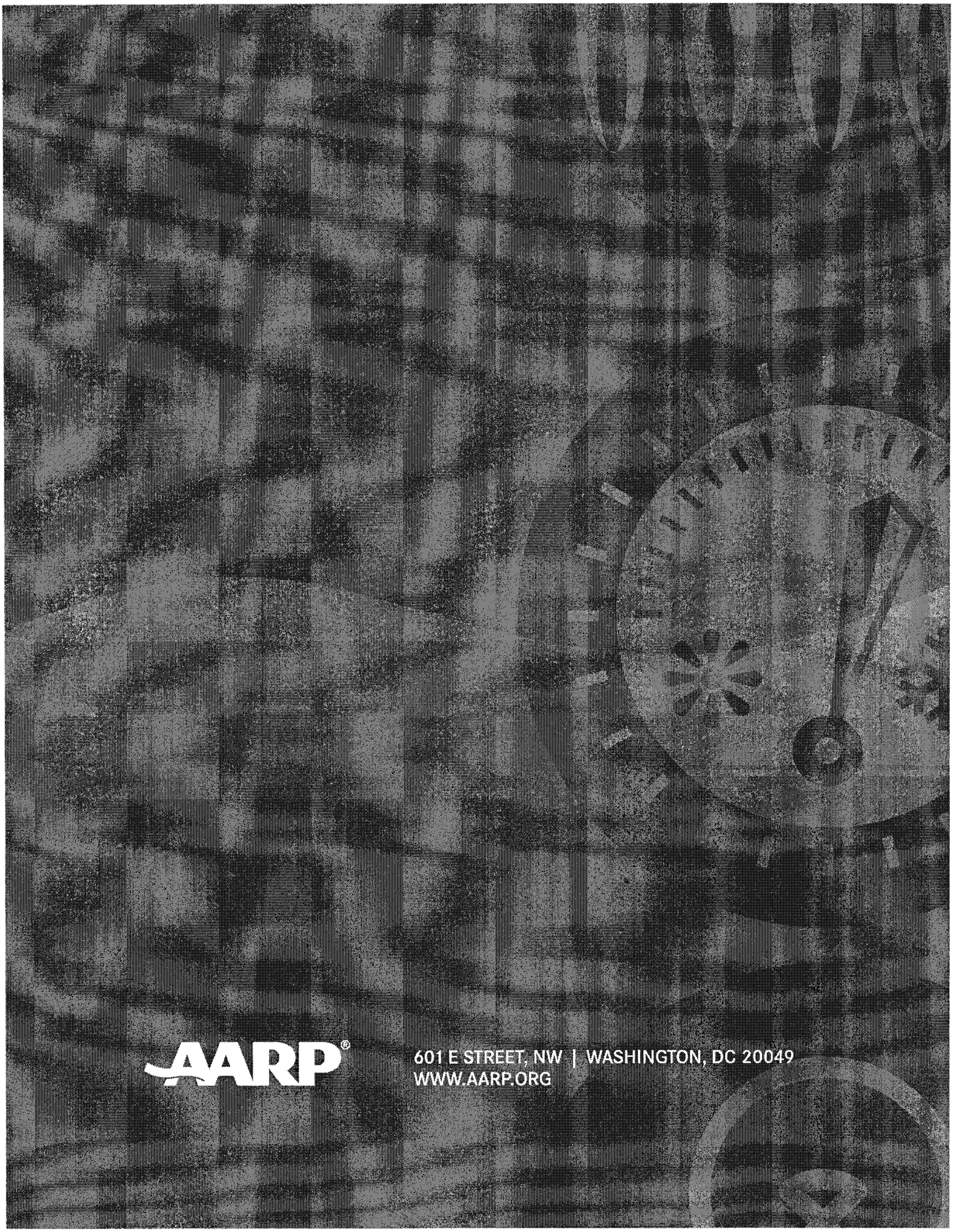
[54] http://www.nj.gov/bpu/residential/glossary/

[55] http://www.georgiapower.com/pricing/glossary.asp#r2

[56] 2005 EEI Glossary

[57] http://www.cbo.gov/doc.cfm?index=976&type=0

[58] South Jersey Gas



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GLOBAL UTILITIES

DOCKET NO. W-01212A-12-0309 ET AL

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON

COST OF CAPITAL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JULY 8, 2013

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EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of the applications for a permanent rate increase ("Applications") of Global Water - Palo Verde Utilities Company ("Palo Verde"); Global Water - Santa Cruz Water Company ("Santa Cruz"); Global Water - Valencia Water Company - Town Division ("VWCT"); Water Utility of Greater Tonopah, Inc. ("WUGT"); Willow Valley Water Company, Inc. ("Willow Valley"); Valencia Water Company - Greater Buckeye Division ("VWCGB"); and Global Water - Water Utility of Northern Scottsdale ("WUNS") (collectively "Applicants," "Global Utilities," or "Company") which were filed with the Arizona Corporation Commission ("ACC" or "Commission") on July 9, 2012, RUCO recommends the following:

Cost of Common Equity – RUCO recommends that the Commission adopt an 8.50 percent cost of common equity. This 8.50 percent figure falls within the range of results obtained in RUCO's cost of equity analysis, and is 294 basis points lower than the 11.44 percent cost of equity capital proposed by the Company in its application for a permanent rate increase.

Costs of Debt – RUCO recommends that the Commission adopt the Company-proposed following costs of short-term and long-term debt:

	Short-term	Long-term
Palo Verde	0.00%	6.36%
Santa Cruz	0.00%	6.58%
VWCT	5.95%	5.69%
WUGT	6.22%	6.33%
Willow Valley	5.17%	4.68%
VWCGB	6.78%	6.24%
WUNS	0.00%	0.00%

Capital Structures – RUCO recommends that the Commission adopt the Company-proposed capital structures of the Applicants as follows:

	S-T Debt	L-T Debt	Equity
Palo Verde	0.00%	51.73%	48.27%
Santa Cruz	0.00%	54.50%	45.50%
VWCT	1.17%	20.17%	78.66%
WUGT	0.82%	13.18%	86.00%
Willow Valley	0.89%	11.65%	87.46%
VWCGB	0.49%	4.61%	94.90%
WUNS	0.00%	0.00%	100.00%

Weighted Average Costs of Capital – RUCO recommends that the Commission adopt the following weighted average costs of capital ("WACC") which are the weighted costs of RUCO's recommended costs of short-term debt and long-term debt and cost of common equity:

	WACC
Palo Verde	7.39%
Santa Cruz	7.46%
VWCT	7.91%
WUGT	8.19%
Willow Valley	8.03%
VWCGB	8.39%
WUNS	8.50%

RUCO is also recommending that its WACC for WUGT and WUNS be adopted as operating margins due to the fact that both systems have negative rate bases.

RUCO disagrees with a number of inputs that the Company's cost of capital consultant relied on in both the discounted cash flow ("DCF") model and the capital asset pricing model ("CAPM") which were used to develop a proposed cost of common equity estimate of 11.44 percent.

RUCO also disagrees with the Company's heavy reliance on comparable earnings and its use of a 120 basis point Arizona risk premium.

INTRODUCTION

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

A. My Name is William A. Rigsby. I am the Chief of Accounting and Rates for 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 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 a permanent rate increase ("Applications") of Global Water - Palo Verde Utilities Company ("Palo Verde"); Global Water - Santa Cruz Water Company ("Santa Cruz"); Global Water - Valencia Water Company - Town Division ("VWCT"); Water Utility of Greater Tonopah, Inc. ("WUGT"); Willow Valley Water Company, Inc. ("Willow Valley"); Valencia Water Company - Greater Buckeye Division ("VWCGB"); and Global Water - Water Utility of Northern Scottsdale ("WUNS") (collectively "Applicants," "Global Utilities," or "Company") which were filed with the Arizona Corporation Commission ("ACC" or "Commission") on July 9, 2012.

The Global Utilities have chosen the operating period ended December 31, 2011 for the test year ("Test Year") in this proceeding. The Company has elected not to conduct a reconstruction cost new less depreciation study ("RCND") for the purpose of establishing a fair value rate base, and to use the Applicant's original cost rate base as their fair value rate base for the purpose of establishing a fair value rate of return on its invested capital.

....

Q. Briefly describe the Applicants.

A. The Applicants are all wholly owned subsidiaries of Global Water Resources, Inc. ("GWRI") which in turn is owned by Global Water Resources Corp. ('GWRC" or "Parent") a publicly traded Canadian firm which is listed on the Toronto Stock Exchange (stock ticker symbol GWR).

Q. Is this your first case involving the Company?

A. No. I testified in the Company's prior rate case during 2009 which included all of the Applicants in this filing with the exception of WUNS.

Q. What areas will you address in your direct testimony?

A. I will address the cost of capital issues associated with the case.

Q. Will RUCO also offer direct testimony on the rate base, operating income and rate design issues in this proceeding?

A. Yes. The rate base and operating income issues associated with the case will be addressed by RUCO witness Robert B. Mease. Mr. Mease will also provide testimony on rate design.

Q. Please explain your role in RUCO's analysis of the Company's Applications.

A. I reviewed the Company's Applications 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 costs of short-term and long-term debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, the Company's Applications, and from market-based research that I conducted during my analysis.

Q. Please identify the exhibits that you are sponsoring.

A. I am sponsoring Exhibit 1, Attachments A through D and 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 seven sections. First, the introduction I have just presented and second, a summary of my testimony and recommendations 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 costs short-term and of long-term debt for the Applicants. The fifth section of my direct testimony is devoted to a discussion of my recommended capital structures for the Applicants. Sixth I will discuss my recommended weighted average costs of capital for the Applicants. In the Seventh and final section, I will comment on the Company's cost of capital testimony. Attachments A through D and Sche dules 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:

<u>Cost of Common Equity</u> – I am recommending that the Commission adopt an 8.50 percent cost of common equity. This 8.50 percent figure falls within the range of results obtained in my cost of equity analysis, and is 294 basis points lower than the 11.44 percent cost of common equity capital proposed by the Company in its Applications.

Costs of Debt – I am recommending that the Commission adopt the Company-proposed following costs of short-term and long-term debt:

	Short-term	Long-term
Palo Verde	0.00%	6.36%
Santa Cruz	0.00%	6.58%
VWCT	5.95%	5.69%
WUGT	6.22%	6.33%
Willow Valley	5.17%	4.68%
VWCGB	6.78%	6.24%
WUNS	0.00%	0.00%

Capital Structures – I am recommending that the Commission adopt the Company-proposed capital structures of the Applicants as follows:

	S-T Debt	L-T Debt	Equity
Palo Verde	0.00%	51.73%	48.27%
Santa Cruz	0.00%	54.50%	45.50%
VWCT	1.17%	20.17%	78.66%
WUGT	0.82%	13.18%	86.00%
Willow Valley	0.89%	11.65%	87.46%
VWCGB	0.49%	4.61%	94.90%
WUNS	0.00%	0.00%	100.00%

Weighted Average Costs of Capital – I am recommending that the Commission adopt the following weighted average costs of capital ("WACC") which are the weighted costs of RUCO's recommended costs of short-term debt and long-term debt and cost of common equity:

	WACC
Palo Verde	7.39%
Santa Cruz	7.46%
VWCT	7.91%
WUGT	8.19%
Willow Valley	8.03%
VWCGB	8.39%
WUNS	8.50%

I am also recommending that my WACC for WUGT and WUNS be adopted as operating margins due to the fact that both systems have negative rate bases.

Q. Why do you believe that your recommended WACC are appropriate rates of return for the Applicants to earn on their invested capital?

A. The various WACC figures that I am recommending meet 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 the Global Utilities, are provided with the opportunity to earn an appropriate rate of return if their management

exercises good judgment and manages 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 the Global Utilities?

A. I am recommending a cost of equity of 8.50 percent. My recommended 8.50 percent cost of equity falls within the range of results derived from my DCF and CAPM analyses, which utilized a sample of publicly traded water providers and a sample of natural gas local distribution companies ("LDCs"). The results of my DCF and CAPM analyses are summarized on page 2 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 $g = b \times r$.

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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.[1]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book 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

[1] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

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.

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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[2] 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.[3] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

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

[2] [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

[3] [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

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,[4] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	1 - [(BV) / (MP)]
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

...

[4] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the expected growth rate in shares outstanding times 1 minus 1 divided by the market-to-book ratio in the equation [1 - (1 / (M / B))] .

A. In cases when a company is trading at a market price that is greater than its book value, multiplying the expected growth rate in shares outstanding by the equation [1 - (1 / (M / B))] increases the external growth rate and reflects investors' growth rate expectations associated with the issuance of new shares.

Q. Did the Commission adopt your cost of capital estimate in the prior Global Utilities rate case proceeding?

A. Yes. The Commission adopted my recommended cost of common equity in the 2009 Global Water rate case proceeding.[5] Decision No. 71878, dated September 14, 2010 stated the following:

[5] Docket Number W-02445A-09-0077

> "We find that the evidence presented by RUCO as a basis for its cost of equity recommendation constitutes substantial evidence in support of its cost of equity recommendation. We further find that the evidence presented by the Company as a basis for its cost of equity recommendation contrary to RUCO's assertion, constitutes evidence that is no less substantial in support of its recommendation and of Staff's acceptance thereof. The methodologies on which each of the parties relied in making their cost of equity recommendations are clearly set forth in the hearing exhibits. Based on a consideration of all the evidence presented in this proceeding, we find a cost of common equity of 9.0 percent to be reasonable in this case. This level of return on equity reasonably and fairly balances the needs of Applicants and their ratepayers, is reflective of current market conditions, and results in the setting of just and reasonable rates."

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 seven publicly traded water companies and a natural gas proxy group consisting of nine natural gas local distribution companies ("LDCs") 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 in this case where shares of are closely held and not publicly-traded on a stock exchange. Because of this situation, I used the aforementioned proxy that includes four publicly-traded water companies and nine LDCs.

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 seven water companies used in the proxy are publicly traded on the both the New York Stock Exchange ("NYSE") and the NASDAQ.[6] All of the 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 April 19, 2013 update of the water utility industry and evaluations of the water companies used in my proxy).

[6] "NASDAQ" originally stood for "National Association of Securities Dealers Automated Quotations". Today it is the second-largest stock exchange in the world, after the New York Stock Exchange ("NYSE").

Q. Are these the same water utilities that you have used in prior rate case proceedings?

A. I have used six of the seven water utilities in prior rate case proceedings. In this case, I am including Connecticut Water Service, Inc., (NASDAQ stock ticker symbol "CTWS") which was added to Value Line's Large Cap Edition in January 2013.

Q. What other water utilities comprise your water company proxy group?

A. In addition to Connecticut Water Service, Inc., my water company proxy group includes American Water Works Company, Inc. ("AWK"), American States Water Company (stock ticker symbol "AWR"), California Water Service Group ("CWT"), Middlesex Water Company ("MSEX"), SJW Corporation ("SJW"), and Aqua America, Inc. ("WTR"). Each of these water companies face the same types of risk that AWC faces. For the sake of brevity, I will refer to each of the companies in my samples by their appropriate stock ticker symbols henceforth.

Q. Briefly describe the areas served by the companies in your water company sample proxy.

A. AWK operates in over 30 U.S. states and Canada. AWR 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. As described earlier in my testimony, CTWS provides service to 400,000 people in over 55 towns in Connecticut and Maine. MSEX serves customers in New Jersey, Delaware and Pennsylvania. SJW serves approximately 226,000 customers in the San Jose area and approximately 8,700 customers in a region located between Austin and San Antonio, Texas. WTR is a holding company for a large number of water and wastewater utilities operating in nine different states including Pennsylvania, Ohio, New Jersey, Illinois, Maine, North Carolina, Texas, Florida and Kentucky.

Q. What criteria did you use in selecting the natural gas LDCs included in your proxy for the Company?

A. As are the water companies that I just described, each of the natural gas LDCs used in the proxy are publicly traded on a major stock exchange (all nine trade on the NYSE) and are followed by Value Line. Each of the nine LDCs 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.

Q. What companies are included your natural gas proxy?

A. The nine natural gas LDCs 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"), 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").

Q. Are these the same LDCs that you have used in prior rate case proceedings?

A. Yes, I have used these same LDCs in prior cases including two of the most recent water company proceedings that I have testified in before the Commission.[7]

Q. Briefly describe the regions of the U.S. served by the nine natural gas LDCs that make up your sample proxy.

A. The nine LDCs listed above provide natural gas service to customers in the Middle Atlantic region (i.e. NJR 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

[7] Arizona Water Company Eastern Group Rate Case, Docket No. W-01445A-11-0310 and Pima Utility Company Docket Numbers W-02199A-11-0329 and SW-02199A-11-0330.

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, 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. Are these the same water and natural gas companies that the Company used in its application?

A. For the most part, yes. The Company's consultant, Mathew J. Rowell, relied on a sample comprised of eight water providers which excluded American Water Works Company, Inc. but included York Water Company and Artesian Resources Corp.

Q. Why didn't you include York Water Company and Artesian Resources Corp. in your sample of water providers?

A. Both York Water Company and Artesian Resources Corp. are only followed in Value Line's Small and Mid-Cap Edition which does not provide the five-year projections on growth and earnings that I rely on in making my cost of common equity estimates.

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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 2008 to 2012 for both the water companies and for the LDCs. Schedule WAR-5 also includes Value Line's projected 2013, 2014 and 2016-18 values for the retention ratio, equity return, book value per share growth rate, and number of shares outstanding for the both the water utilities and the LDCs in my sample.

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 WTR as an example. The first dividend growth component that I evaluated was the internal growth rate. I used the "b x r" formula (described earlier on pages 11 and 12 of my direct testimony) to multiply WTR's earned return on common equity by its earnings retention ratio for each year in the 2008 to 2012 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 2, WTR had sustainable internal growth that averaged 3.59 percent during the 2008 to 2012 observation period. The company experienced a decline in growth from 2.80 percent in 2008, to 2.69 percent in 2009. Internal growth then climbed to 4.24 percent during the final year of the observation period. Value Line's analysts expect growth for WTR to decline in the coming years. Internal growth is expected to increase to 5.78 percent in 2013 before falling to 4.31 percent by the end of 2018. After weighing Value Line's earnings and book value estimates, I believe that internal growth of 5.00 percent is reasonable for WTR. (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 number of shares outstanding for WTR increased from 135.37 million in 2008, to 140.35 million in 2012. Value Line is forecasting higher future share growth. According to Value Line's analysts, outstanding shares should increase from 140.50 million in 2013 to 143.00 million by the end of the 2016-18 time period. Based on Value Line's expectations, I believe that a 0.30% rate of share growth is appropriate (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for WTR is 5.19 percent (5.00 percent internal growth + 0.19 percent external growth) 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 4.95 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 your proxy of natural gas LDCs?

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 for my natural gas sample is 5.28 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 4.95 percent growth estimate falls below Zacks' average long-term EPS projection of 5.10 percent for the water companies in my sample and Value Line's growth projection of 5.81 percent (which is an average of

EPS, DPS and BVPS). My 4.95 percent estimate is 104 basis points higher than the 3.91 percent average of Value Line's historical growth results and 6 basis points higher than the 4.89 percent average of the growth data published by both Value Line and Zacks. My 4.95 percent growth estimate is also 21 basis points higher than Value Line's 4.74 percent 5-year compound historical average of EPS, DPS and BVPS. On balance, I would say my 4.95 percent growth estimate, derived from Value Line data, is not out of line with the growth projections that are available to the investing public.

Q. How do your average growth rate estimates on natural gas LDCs compare to the growth rate data published by Value Line and other analysts?

A. As can be seen on Schedule WAR-6, my 5.28 percent growth estimate for the natural gas LDCs is 67 to 80 basis points higher than the average 4.48 percent average of long-term EPS consensus projection published by Zacks, and the 4.61 percent Value Line projected estimate (which is an average of EPS, DPS and BVPS). The 5.28 percent estimate that I have calculated is 50 basis points lower than the 4.78 percent average of the 5-year historic EPS, DPS and BVPS means of Value Line and is also 62 basis points higher than the combined 4.66 percent Value Line and Zacks averages displayed in Schedule WAR-6. In fact, my 5.28 percent growth estimate exceeds Value Line's 4.12 percent 5-year compound historical

average of EPS, DPS and BVPS by 116 basis points. In the case of the LDCs I would say that my 5.28 percent estimate is more optimistic than the growth projections for natural gas LDCs being 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 LDCs I used the estimated annual dividends, for the next twelve-month period, that appeared in Value Line's April 19, 2013 Ratings and Reports water utility industry update and Value Line's June 7, 2012 Ratings and Reports natural gas utility update. I then divided those figures by the eight-week average daily adjusted closing price per share of the appropriate utility's common stock. The eight-week observation period ran from April 15, 2013 to June 7, 2013. The average dividend yields were 2.97 percent and 3.56 percent for the water companies and natural gas LDCs, respectively.

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 7.92 percent for the water utilities and 8.84 percent for the

natural gas LDCs which is 332 to 424 basis points higher than the current 4.60 percent yield on a safer Baa/BBB-rated utility bond (Attachment D).

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[8], the Timken Professor Emeritus of Finance at Stanford University, who shared the 1990 Nobel Prize in Economics for research that eventually resulted in the CAPM model. CAPM is used to analyze the relationships between rates of return on various assets and risk as measured by beta.[9] 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

[8] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[9] 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.

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 is that the expected return on a given investment is the sum of a risk-free rate of return plus a market risk premium that is proportional to the systematic (non-diversifiable risk) associated with that investment. In mathematical terms, the formula is as follows:

$$k = r_f + [\, ß\, (r_m - r_f)\,]$$

where:

k	=	the expected return of a given security,
r_f	=	risk-free rate of return,
ß	=	beta coefficient, a statistical measurement of a security's systematic risk,
r_m	=	average market return (e.g. S&P 500), and
$r_m - r_f$	=	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 (Attachment D) will reveal that those with longer maturity dates do have slightly higher yields. Treasury yields are comprised of two separate components,[10] a real rate of interest (believed to be approximately 2.00 percent) and an inflationary expectation. When the real rate of interest is subtracted from the total treasury yield, all that remains is the inflationary expectation. Because increased inflation represents a potential capital loss, or risk, to investors, a higher inflationary expectation by itself represents a degree of risk to an investor. Another way of looking at this is from an opportunity cost 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

[10] As a general rule of thumb, there are three components that make up a given interest rate or rate of return on a security: the real rate of interest, an inflationary expectation, and a risk premium. The approximate risk premium of a given security can be determined by simply subtracting a 91-day T-Bill rate from the yield on the security.

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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 30-year U.S. Treasury instrument. The yields were published in Value Line's Selection and Opinion publication dated April 26, 2013 through June 7, 2013 (Attachment D). This resulted in a risk-free (r_f) rate of return of 3.06 percent.

Q. Why did you use the yield on a 30-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. Because utilities in Arizona generally file for rates every three to five years, the yield on a 5-year U.S. Treasury Instrument more closely matches the investment period or, in the case of regulated utilities, the period that new rates will be in effect. In prior rate cases I have relied on the yields of the 5-year Treasury instrument, however for the sake of argument in this case, I have used the higher yield of the longer term 30-year Treasury bond. As I will discuss later in my testimony, the yields of long-term U.S. Treasury instruments are at historic lows as a result of recent actions being undertaken by the U.S. Federal Reserve to stimulate the U.S. economy.

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 2012 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 long-term government bonds for the same eighty-four year period. The market risk premium (r_m - r_f) that results by using the geometric mean of these inputs is 3.70 percent (9.80% - 6.10% = 3.70%). The market risk premium that results by using the arithmetic mean calculation is 5.40 percent (11.80% - 6.40% = 5.40%).

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 April 19, 2013 for the water companies and June 7, 2013 for the natural gas LDCs. 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 0.60 to 0.85 with an average beta of 0.70. The beta coefficients for the LDCs included in my natural gas sample ranged from 0.60 to 0.75 with an average beta of 0.67.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.65 percent for the water companies and 5.52 percent for the natural gas LDCs. My calculation using an arithmetic mean results in an average expected return of 6.84 percent for the water companies and 6.66 percent for the natural gas LDCs.

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)	7.92%
DCF (Natural Gas Sample)	8.84%
CAPM (Water Sample)	5.65% – 6.84%
CAPM (Natural Gas)	5.52% – 6.66%

Based on these results, my best estimate of an unadjusted range for a cost of common equity for the Company is 5.52 percent to 8.84 percent. My final recommended cost of common equity figure is 8.50 percent which falls above the mid-point of 7.18 in the range of estimates shown above (Schedule WAR-1, Page 3) and 390 basis points higher than the current 4.60 percent yield on a safer Baa/BBB-rated utility bond. My final estimate also falls within the range of projected returns on book common equity that Value Line is projecting for both the water and natural gas utility industries (Attachment A & B).

As I will discuss in more detail in the next section of my testimony, my final estimate also takes into consideration current interest rates (as the cost of equity moves in the same direction as interest rates) and the current state

of the national economy. My final estimate also takes into consideration the U.S. Federal Reserve's decisions not to raise interest rates as long as the level of unemployment remains above 6.50 percent and on inflation, holding to within a half percentage point of the Fed's 2.00 percent target.[12] I also took into consideration information on Arizona's economy and current rate of unemployment in making my final cost of equity estimate.

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 11.44 percent cost of equity capital reflected in the Company's Application is 294 basis points higher than the 8.50 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

[12] U.S. Federal Reserve press release dated January 30, 2013: http://www.federalreserve.gov/newsevents/press/monetary/20130130a.htm

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 describe your analysis of the current economic environment.

A. My analysis begins with a review of the economic events that have occurred between 1990 and the present in order to provide a background on how we got to where we are now. It also describes how the Board of Governors of the Federal Reserve System ("Federal Reserve" or "Fed") and its Federal Open Market Committee ("FOMC") used its interest rate-setting authority to stimulate the economy by cutting interest rates during recessionary periods and by raising interest rates to control inflation during times of robust economic growth. 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, then chaired by noted economist Alan Greenspan, lowered its benchmark

federal funds rate[13] in an effort to further loosen monetary constraints - an action that resulted in lower interest rates.

During this same period, the nation's major money center banks followed the Federal Reserve's lead and began lowering their interest rates as well. By the end of the fourth quarter of 1993, the prime rate (the rate charged 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.

[13] This is the interest rate charged by banks with excess reserves at a Federal Reserve district bank to banks needing overnight loans to meet reserve requirements. The federal funds rate is the most sensitive indicator of the direction of interest rates, since it is set daily by the market, unlike the prime rate and the discount rate, which are periodically changed by banks and by the Federal Reserve Board, respectively.

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. Over the next ten years, the FOMC continued to stimulate the economy and keep inflation in check by raising and lowering the federal funds rate.

Q. How did the U.S. economy fare between 2001 and 2007?

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. Disappointing economic data releases, since the beginning of

2001, preceded the September 11, 2001 terrorist attacks on the World Trade Center and the Pentagon which are now regarded as a defining point during this economic slump. From January 2001 to June 2003 the Federal Reserve cut interest rates a total of thirteen times in order to stimulate growth. 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 during a period in which the economic picture turned considerably brighter as both Inflation and unemployment fell, wages increased and the overall economy, despite continued problems in housing, grew briskly.[14]

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

[14] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

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. Once again, the Fed managed to engineer a soft landing.

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 beginning of what is now being referred to as the Great Recession; the FOMC decided not to increase or decrease the federal funds rate for the ninth straight time and left its target rate unchanged at 5.25 percent.[15] 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

[15] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007

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 its open market operations) into the credit markets.[16] 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, [17] 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.

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

[16] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007

[17] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007

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).[18] 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

[18] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008

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 administration's 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[19]. 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.

Q. Has the Fed taken any further action to stimulate the economy besides cutting rates?

Yes. At the close of the FOMC's September 2011 meeting the Fed announced its decision to implement a plan that resembled a 1961 Federal Reserve program known as "Operation Twist".[20] Under this plan, the Fed would sell $400 billion in Treasury securities that mature within

[19] 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

[20] Hilsenrath, Jon and Luca Di Leo "Fed Launches New Stimulus" The Wall Street Journal, September 22, 2011

three years. The proceeds from these sales would then be reinvested into securities that mature in six to 30 years. This action would significantly alter the balance of the Fed's holdings toward long-term securities. In addition to selling off its shorter term Treasury holdings, the proceeds from the Fed's maturing mortgage-backed securities would be reinvested in other mortgage backed securities. Since 2010, the Fed had been reinvesting that money into Treasury bonds, shrinking its mortgage portfolio. The overall goal of the Fed's plan was to reduce long-term interest rates in the hope of boosting investment and spending and provide a shot in the arm to the beleaguered housing sector of the economy. On December 12, 2012, the Federal Open Market Committee voted to order a fourth round of quantitative easing, referred to as QE4, which authorized the purchase of up to $40 billion worth of agency mortgage-backed securities per month, and $45 billion worth of longer-term Treasury securities. The goal in buying the $85 billion in securities per month is to drive up the cost of available instruments in the market (by reducing the existing supply) which has the effect of decreasing their effective yields.

...

Q. What is the investment community's current view of the Fed's low interest rate policy?

A. A recent opinion piece by Mitch Zacks of Zacks Investment Management, published on June 16, 2013, provides some interesting insight into this question:

> "Right now the market is intensely focused on trying to determine when the Federal Reserve's quantitative easing program will end. Market participants realize that the Federal Reserve has stated they will continue with their program until unemployment falls to an acceptable level, which would hopefully coincide with a pick-up in the economy.
>
> To recap, the Federal Reserve cut the Fed funds rate to zero in order to stimulate the economy in the wake of the financial crisis of '08. The economy recovered, but did so at a relatively lackluster pace, so the chance of a double dip recession in the wake of European unrest was real. As a result, the Federal Reserve wanted to continue to take stimulus actions. However, they were unable to reduce interest rates any further – they could not cut rates below zero.
>
> In order to continue to stimulate the economy, the Federal Reserve decided to start actively buying treasury bonds and mortgage backed securities to keep long-term rates relatively low. The Fed was trying to stimulate the economy by causing riskier assets to appreciate, making individuals wealthier, and therefore causing them to spend more money. Additionally, by buying mortgage backed securities and causing longer-term rates to fall, the assets that banks hold on their balance sheets would increase in value. This would effectively help increase the capitalization of banks, and hopefully increase bank lending.
>
> Fast forward a few years and we see that the Fed's plan has resulted in asset prices going up and longer-term interest rates, such as mortgage rates, being held down. The stimulus activity effectively put a tax on individuals who held cash reserves. Interestingly enough, the stimulus appears to be working. It has caused consumer spending to increase and an upward movement in home prices. The concern the market now has is whether the economy will be strong enough in the absence of the quantitative easing to continue to grow."

Q. What is the current rate of inflation in the U.S.?

A. As can be seen on Schedule WAR-8, the current rate of inflation, as measured by the consumer price index, is at 1.10 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[21]

Q. Does the Fed have any immediate plans to raise interest rates in anticipation of higher inflation?

A. No. At the FOMC meeting held on June 18 and 19, 2013, the Fed made no changes to the Fed Funds rate. An article published in the Wall Street Journal on June 19, 2013 reported that Chairman Bernanke stated at the end of the meeting that the Fed could start winding down its $85 billion-a-month QE4 bond-buying program later this year and end it altogether by mid-2014 if growth picks up as the Fed projects, unemployment comes down, and inflation moves closer to the central bank's 2.00 percent target. Chairman Bernanke went on to say that if those expectations bear out, the Fed could stop buying bonds altogether by the middle of next year, when officials project unemployment to be around 7.00 percent.

...

[21] http://www.bls.gov/news.release/cpi.nr0.htm

Q. Has the Fed's quantitative easing actions resulted in lower yields on long-term Treasury instruments?

A. Yes. Despite a recent rise in the yields of longer-term instruments (Attachment C), mainly due to uncertainty over when the Fed will reverse its policy of quantitative easing, the yields on various treasury and utility instruments are currently at historic lows.

As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year 2000 and, as just noted, U.S. Treasury instruments, are for the most part, still at historically low levels. As can be seen on the first page of Attachment C, the previously mentioned federal discount rate (the rate charged to the Fed's member banks), has remained steady at 0.75 percent since June of 2012.[22]

As of June 14, 2013, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have decreased 3 to 6 basis points from their June 2012 levels. Longer term yields including the 5-year, 10-year and 30-year have increased somewhat from levels that existed a year ago, but still remain at historically low levels. The same is true for the 30-year Zero rate. The prime rate has remained constant at 3.25 percent

[22] Hilsenrath, Jon and Victoria McGrane, "Federal Reserve Eyes End of Bond Buying, Spooking Markets" The Wall Street Journal, June 19, 2013

over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[23], 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.

Q. What are the current yields on utility bonds?

A. Referring again to Attachment C, as of June 14, 2013, 25/30-year A-rated utility bonds were yielding 4.19 percent and 25/30-year Baa/BBB-rated utility bonds were yielding 4.60 percent. As with the intermediate and long-term Treasuries noted above, the yields on both utility bonds have increased somewhat over the last several weeks but still remain at historic lows.

Q. What is the current outlook for the economy?

A. The current outlook on the economy is for an improving picture in the second half of 2013. Value line's analysts offered this perspective on the economy in the June 14, 2013 edition of Value Line's Selection and Opinion publication:

[23] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005

> "**The economy is limping to the first half finish line.** To wit, after a modest recovery in the first quarter, with the U.S. gross domestic product rising by 2.4%, growth appears to be slipping again, with personal income, consumer spending, manufacturing, and the international trade figures denoting enough overall sluggishness to produce growth of no more than 1%-2% in the fast-ending period"

Value Line's analysts went on to say:

> **"However, we expect a selective pickup in business activity after midyear.** In part, this presumptive improvement probably will reflect the lesser impact of the sequestrations (or government spending cuts), as well as gains in non-manufacturing and home prices. Such a combination is likely to lead to more liberalized spending by consumers. In that more constructive setting, growth could edge back above 2% over the closing six months of this year."

Value Line's analysts further stated:

> **"Meanwhile, the focus is on the Federal Reserve,** as it may well be until the start of earnings reporting season, which is still about a month away. The worry is that the Fed might soon start slowing down the pace of bond buying, on the belief that the economy is now better able to stand on its own. We think such concerns are premature, and sense that it may be a while before the central bank opts to materially ease off on the stimulus pedal."

Q. What is the current outlook for water utilities such as the Applicants?

A. In the April 19, 2013 quarterly update (Attachment A) on the Water Utility Industry, Value Line analyst James A. Flood had this to say:

> "Despite some of the reservations that we have noted about the industry, overall, it is currently in decent shape. Though issuance of new shares dilutes earnings, we are glad to see companies selling new equity when the market is near its all-time high. This was the case recently with Connecticut Water, California Water Service Group, and SJW. And while the industry's prospects are not bad for 2013 and 2014, it is the pull to 2016-2018 that has us concerned. Also, despite the recent underperformance if certain water utility shares, almost all have advanced so far that they have below-average long-term total return potential."

Q. How has Arizona faired in terms of the overall economy and home foreclosures?

A. Arizona was one of the states hit hardest during the Great Recession and has lagged during the current recovery.[24] During the period between 2006 and 2009, statewide construction spending fell by 40.00 percent. According to information provided by Irvine, California-based RealtyTrac, Arizona was ranked third in the nation behind California and Nevada in terms of home foreclosures with the largest number of foreclosures occurring in Maricopa, Pinal and Pima Counties. As of this writing RealtyTrac is ranking Arizona as having the ninth highest foreclosure rate in the country.[25]

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on June 20, 2013, and displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics,[26] the seasonally adjusted unemployment rate for Arizona dropped from 8.40% in May 2012, to 7.80% in May 2013. At the time that this information was compiled,

[24] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011.

[25] RealtyTrac Staff: U.S. Foreclosure Activity Increases 2 Percent in May Boosted by 11 Percent Rise in Bank Repossessions, June 11, 2013.

[26] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/ .

Arizona's rate of unemployment was slightly higher than the current seasonally adjusted U.S. unemployment rate[27] of 7.6 percent.

According to the June 20, 2013 Arizona Department of Administration's Office of Employment and Population Statistics report, the May 2013 rates of unemployment for the counties that are served by Global Utilities were as follows:

Selected County Unemployment Rates - May 2013

Maricopa	6.10%
Mohave	8.90%
Pinal	7.70%

Q. After weighing the economic information that you've just discussed, do you believe that the 8.50 percent cost of equity capital that you have estimated is reasonable for the Company?

A. I believe that my recommended 8.50 percent cost of equity capital, which is 390 basis points higher than the current 4.60 percent yield on a Baa/BBB-rated utility bond and the 172 basis points higher than the Applicants highest weighted average cost of debt, will provide the Company with a reasonable rate of return on invested capital when data on interest rates (that are low by historical standards), the current state of the economy, current rates of unemployment (both nationally, in Arizona, and in the counties served by the Applicants), and the Fed's decision to

[27] U.S. Department of Labor, Bureau of Labor Statistics http://www.bls.gov/cps/

keep interest rates at their current levels until unemployment reaches 6.50 percent[28] 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.

COST OF DEBT

Q. Have you reviewed the Applicants' testimony on the Company-proposed costs of short and long-term debt?

A. Yes.

Q. What costs of short and long-term debt are you recommending for AWC?

A. I am recommending that the Commission adopt the Company-proposed costs of short and long-term debt as follows:

	Short-term	Long-term
Palo Verde	0.00%	6.36%
Santa Cruz	0.00%	6.58%
Valencia - Town	5.95%	5.69%
WUGT	6.22%	6.33%
Valencia - Greater Buckeye	6.78%	6.24%
Willow Valley	5.17%	4.68%
WUNS	0.00%	0.00%

[28] Federal Reserve Press Release issued on June 19, 2013.

CAPITAL STRUCTURE

Q. Have you reviewed the Company's testimony regarding the Applicants' proposed capital structures?

A. Yes.

Q. Please describe the Applicants' proposed capital structures.

A. The Applicants' are proposing the following:

	Short-term	Long-term
Palo Verde	0.00%	6.36%
Santa Cruz	0.00%	6.58%
VWCT	5.95%	5.69%
WUGT	6.22%	6.33%
Willow Valley	5.17%	4.68%
VWCGB	6.78%	6.24%
WUNS	0.00%	0.00%

Q. Are the Applicants' capital structures in line with industry averages?

A. No. Five of the seven Applicants – VWCT, WUGT, Willow Valley, VWCGB and WUNS – have capital structures that are heavier in equity than the capital structures of the water utilities in my sample and would be perceived by investors as having lower financial risk. As can be seen in Schedule WAR-9, the capital structures for my sample of water utilities averaged 54.00 percent for debt and 46.00 percent for equity (45.80

percent common equity + 0.2 percent preferred equity). Only Palo Verde and Santa Cruz had capital structures that were similar to the average capital structure of my sample water utilities. On the other hand, both Palo Verde and Santa Cruz have somewhat lower amounts of equity than do the capital structures of the LDCs in my sample. The capital structures for the LDC utilities averaged 44.80 percent for debt and 50.5 percent for equity (55.00 percent common equity + 0.1 percent preferred equity).

Q. What capital structures are you recommending for the Applicants?

A. I am recommending that the Commission adopt the Company-proposed capital structures described above. In the case of WUGT and WUNS, which have negative rate bases, I am recommending that the Company-proposed capital structures be adopted only for the purpose of calculating an operating margin.

Q. Have you made a downward adjustment to your recommended cost of equity that takes into consideration the fact that five of the seven Applicants have capital structures that are heavier in equity than the average capital structure of your sample water and natural gas companies?

A. No. I have not made a specific downward adjustment. However I believe that my recommended 8.50 percent cost of common equity, which falls within the range of estimates produced by my water and natural gas

sample DCF models is adequate to cover any perceived financial or business risks faced by the Applicants.

WEIGHTED AVERAGE COST OF CAPITAL

Q. How do the Applicants' proposed weighted average costs of capital compare with RUCO's recommendations?

A. The Applicants' and RUCO's recommended WACC's are as follows:

	WACC
Palo Verde	7.39%
Santa Cruz	7.46%
VWCT	7.91%
WUGT	8.19%
Willow Valley	8.03%
VWCGB	8.39%
WUNS	8.50%

As I explained earlier in my testimony, I am recommending that the WACC's calculated for WUGT and WUNS be adopted as operating margins given the fact that both systems have negative rate bases.

COMMENTS ON GLOBAL UTILITIES' COST OF EQUITY CAPITAL TESTIMONY

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The Company's cost of capital witness, Matthew J. Rowell, is recommending a cost of common equity of 11.44 percent. His 11.44 percent cost of equity capital is 294 basis points higher than the 8.50 percent cost of equity capital that I am recommending.

Q. What methods did Mr. Rowell use to arrive at his proposed cost of common equity for the Applicants?

A. Mr. Rowel utilized two versions of the DCF, three versions of the CAPM and a comparable earnings methodology which I have not employed. Mr. Rowell relies on the same single stage DCF model that I have used and a multi-stage version of the DCF model. His CAPM analysis relies on three different sets of risk free asset inputs and his comparable earnings analysis is based on the returns on book common equity of his sample utilities.

...

Q. What is the main reason for the difference between your recommended cost of equity and the Company-proposed cost of equity?

A. The main reason for the 294 basis point difference between my cost of equity recommendation and the Company-proposed cost of equity is Mr. Rowell's heavy reliance on the results of his comparable earnings analysis. Mr. Rowell gives a 2/3rds weighting to his comparable earnings results of 10.47 percent and a 1/3rd weighting to the 9.77 percent average of the results obtained from his DCF and CAPM models to arrive at a 10.24 percent weighted average. He then adds a 120 basis point Arizona risk premium to his 10.24 percent average to arrive at his proposed 11.44 percent cost of equity.

Q. Do you agree with Mr. Rowell's heavy reliance on his comparable earnings analysis?

A. No. Quite simply, returns on book common equity are not a company's cost of capital. The return on book common equity is the annual net income of a company (which appears on its income statement) divided by the shareholder equity recorded on the accounting books of the company (which appears on its balance sheet). The cost of equity capital on the other hand, is the return investors expect to earn in the marketplace for a particular risk-class of assets. If the market value of a company's stock is more than its book value (as are all of the company's included in my

sample based on their market to book ratios displayed as "M ÷ B" in Schedule WAR-4), the market return will be lower because the net income is being divided by a larger number (i.e. the market price of the company's stock) than the lower shareholder equity figure that appears on the books of the company. The return that investors expect to receive in the marketplace is the company's cost of equity because that is the return that the company has to offer in order to attract equity capital. By definition a company's cost of equity capital has to be lower than its return on book common equity or it would not be profitable. Given this rationale, Mr. Rowell's comparable earnings estimate carries far less weight than he assigns to it in my opinion.

Q. Are there other problems with Mr. Rowell's reliance on comparable earnings?

A. Yes. It represents circular logic from the standpoint that the authorized rates of return awarded by regulatory agencies, such as the ACC, to the utilities in his sample were most likely based on the same financial models, such as the DCF and the CAPM, which he seems to hold in low regard. I would have to say that Mr. Rowell, like a number of other utility consultants these days, is in a state of denial. By that I mean that they simply refuse to face the fact that the results from models such as the DCF and the CAPM are reflective of the current economic environment of low interest rates which I described earlier in my testimony.

DCF Comparison

Q. Briefly compare the results of Mr. Rowell's DCF analysis with the results your DCF analysis.

A. Mr. Rowell's single stage DCF model produced an average return of 9.06 percent for the natural gas and water companies in his sample compared to my average of 8.38 percent.

Q. Please compare the dividend yield results that you obtained from your DCF analysis and the results that Mr. Rowell obtained from his DCF analysis using the constant growth model?

A. Mr. Rowell relied on an average dividend yield of 3.81 percent obtained by dividing the expected dividends of his sample companies by the average spot price of his sample companies' stock on June 21, 2012 as opposed to the eight week average stock price which I relied on. His 3.81 percent average dividend yield is 54 basis points higher than my average dividend yield of 3.27 percent.

Q. What was the difference between Mr. Rowell's spot price average stock price and your eight week average stock price?

A. Mr. Rowell's average stock price was $29.81 as opposed to my average share price of $38.50 – a difference of $8.69. Clearly both the water stocks and the natural gas companies in our samples have increased in value during the year since Mr. Rowell conducted his analysis. The more

recent higher prices that I relied on would produce lower dividend yields in the DCF model thus resulting in a lower expected return.

Q. Does your comparison of the difference in average adjusted stock prices reveal anything else?

A. Yes. I believe that it demonstrates that both water and natural gas stocks are in demand by investors. Their dividend yields, which are attractive when compared to the lower yields on Treasury instruments, and the perceived safety of the investment, would also explain the increase in price. This being the case, as I have stated in prior proceedings, water companies such as the Global Utilities do not need higher rates of return to attract investors at this point in time.

Q. How does Mr. Rowell's DCF growth estimate (g) compare with your growth estimates for water utilities?

A. Mr. Rowell's analysis produced an average growth estimate of 5.25 percent as opposed to my average growth estimate of 5.11 percent for both the water companies and LDCs that were included in our samples.

Q. Can you explain the differences in your methods for obtaining your respective growth estimates?

A. Yes. Mr. Rowell's higher 5.52 percent growth rate was obtained by averaging only the 5-year earnings per share projections of analysts from

Value Line, Reuters, Zacks, CNN Money and Yahoo Finance. As I explained earlier in my direct testimony, I obtained my growth estimates by evaluating a larger number of metrics which included Value Line growth projections for both internal and external growth (based on retained earnings, returns on book common equity projections and shares outstanding for 2013 through 2018), and on future growth in earnings, dividends and book value per share (Schedule WAR 5 pages 1 through 5 and Attachments A and B) and then comparing them to current Zacks earnings per share estimates and Value Line estimates of earnings per share, dividends per share and book value per share for the companies included in my water and gas samples (Schedule WAR-6).

CAPM Comparison

Q. What were the results of Mr. Rowell's CAPM analysis and your CAPM analysis?

A. Mr. Rowell's analysis produced an average expected return of 10.51 percent as opposed to my expected returns that range from 5.52 percent to 6.84 percent.

Q. Compare the way that Mr. Rowell and you arrived at your expected rates of return using the CAPM.

A. For the risk free asset Mr. Rowell relied on much higher historic returns on long-term and medium-term U.S. Government bonds and bills, ranging

from 5.10 percent to 10.20 percent, as opposed to relying on the lower current yields of the same types of instruments.

Q. What are your concerns with Mr. Rowell's use of historic returns on medium and long-term U.S. Treasury instruments for a risk-free rate of return?

A. Mr. Rowell's reliance on historic returns result in much higher returns than the actual current yields of similar U.S. government instruments. I believe that the best indicators of future returns are the most recent yields on U.S. treasury instruments. Furthermore, Mr. Rowell's method totally ignores the fact that the Federal Reserve intends to keep interest rates at their current low levels until unemployment falls to 6.50 percent which most likely will not occur until the end of 2014.

Q. How dos Mr. Rowell's average beta used in his CAPM model compare with the average beta that you used in yours?

A. Despite the different companies included in our samples, Mr. Rowell's average beta of 0.688 falls between my average betas of 0.70 and 0.67 for my water company sample and LDC sample, respectively.

...

Q. How does Mr. Rowell's average market risk premium compare to your range of market risk premiums?

A. Mr. Rowell's average market risk premium of 3.80 percent fell within my range of 3.70 percent and 5.40 percent.

Q. Do you believe that the Applicants require a 120 basis point adjustment because they are regulated in Arizona?

A. No. Contrary to Mr. Rowell's position on returns granted in Arizona, I do not believe that such an adjustment is needed. In fact I would say that, if anything, the return on equity granted to the Global Utilities in the prior rate case proceeding was forward looking when you consider the range of estimates that my analysis has produced in this case.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Rowell or any other witness for the Applicants constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your testimony on the cost of capital issues in this case?

A. Yes, it does.

Appendix 1

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:

Chief of Accounting and Rates
Residential Utility Consumer Office
October 2011 – Present

Public Utilities Analyst V
Residential Utility Consumer Office
April 2001 – Present

Senior Rate Analyst
Accounting & Rates - Financial Analysis Unit
Arizona Corporation Commission, Utilities Division
July 1999 – April 2001

Senior Rate Analyst
Residential Utility Consumer Office
December 1997 – July 1999

Utilities Auditor II and III
Accounting & Rates – Revenue Requirements Analysis Unit
Arizona Corporation Commission, Utilities Division
October 1994 – November 1997

Tax Examiner Technician I / Revenue Auditor II
Arizona Department of Revenue
Transaction Privilege / Corporate Income Tax Audit Units
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-09-0257	Rate Increase
Arizona-American Water Company	W-01303A-09-0343	Rate Increase
Bella Vista Water Company	W-02465A-09-0411 et al.	Rate Increase
Chaparral City Water Company	W-02113A-10-0309	Reorganization
Qwest Communications International	T-04190A-10-0194 et al.	Merger
CenturyLink, Inc.	T-04190A-10-0194 et al.	Merger
Southwest Gas Corporation	G-01551A-10-0458	Rate Increase
Arizona-American Water Company	W-01303A-10-0448	Rate Increase
Arizona-American Water Company	W-01303A-11-0101	Reorganization
Arizona-American Water Company	W-01303A-09-0343	Deconsolidation
Goodman Water Company	W-02500A-10-0382	Rate Increase
Arizona Water Company	W-01445A-10-0517	Rate Increase
Bermuda Water Company, Inc.	W-01812A-10-0521	Rate Increase
UNS Gas, Inc.	G-04204A-11-0158	Rate Increase
Arizona Public Service Company	E-01345A-11-0224	Rate Increase
Arizona Water Company	W-01445A-11-0310	Rate Increase
Pima Utility Company	W-02199A-11-0329 et al.	Rate Increase
Tucson Electric Power Company	E-01933A-12-0291	Rate Increase
Rio Rico Utilities, Inc.	WS-02676A-12-0196	Rate Increase

RESUME OF RATE CASE AND REGULATORY PARTICIPATION (Cont.)

Utility Company	Docket No.	Type of Proceeding
Far West Water & Sewer, Inc.	WS-03478A-12-0307	Rate Increase
Arizona Water Company	W-01445A-12-0348	Rate Increase
UNS Electric, Inc.	E-04204A-12-0504	Rate Increase

ATTACHMENT A

Equities in the Water Utility Industry may have finally peaked. Over the past nine months or so, investors have been pouring funds into this small industry and driving up prices. In our last report in January, the industry soared to a rank of 4 out of the 98 different stock groups in the *The Value Line Investment Survey.* This outperformance was highly unusual, considering it was accomplished in a rising market. Utilities are historically a defensive play that draw the interest of conservative, income-oriented investors, as well as contrarians who believe that the market is nearing a peak. The industry rank has since slipped to a still respectable 29. However, we wouldn't be surprised to see a further decline in the months ahead as the spread between yields on water utilities and the average stock have tightened, making them less attractive.

On the operational front, most water utilities are coming off a decent 2012. Moreover, we think that 2013 and 2014 won't be too bad, either. That said, we still have many concerns about the industry going forward. Much of the water infrastructure in the U.S. is aging and will require massive amounts of funds for repairs and modernization. No utility will be able to generate sufficient cash internally to cover these outlays. Hence, new issuances of debt and equity will be required to finance the difference. Moreover, plenty of rate cases will have to be filed to recover these investments, leaving utilities at the mercy of state regulators, whose final decisions can be politically motivated. On the whole, the regulatory climate has improved throughout the country, but that doesn't mean it can't change.

A Small Fragmented Market

There are only seven companies in our Water Utility Industry. That's because most cities have established their own entities that provide water to citizens as a municipal service. This is in contrast to electric utilities. Due to the capital-intensive nature of the power business, cities and states let investor-owned companies provide electricity at a price that is ultimately approved by them.

There has been much speculation that many cash-strapped municipalities may consider privatizing their water systems because they do not have the large sums of money needed to update and repair their existing facilities. Such a trend would probably be a plus for the existing investor-owned water utilities as they have the required expertise needed to operate these systems. The two utilities that dominate the industry in terms of market capitalization, *American Water Works* and *Aqua America*, would be the obvious beneficiaries. Still, we don't look for much privatization over the next few years.

America's Water Systems Are In Terrible Shape

In their quadrennial report on the status of the infrastructure in the U.S., the American Society of Civil Engineers (ASCE) found that the water/wastewater sector is perhaps the most underfunded part of the infrastructure system. According to ASCE, water systems are about 70% underfunded. Concurring with this opinion is the American Water Works Association (AWWA), which believes that America will have to spend $1 trillion over the next 25 years to get the system up to par.

INDUSTRY TIMELINESS: 29 (of 98)

Where Will the Money Come From?

Whether investor-owned or municipal, no water system has the funds on hand required to meet these projected costs. (We should point out that the higher the estimated funding needed, the more work for the engineers of ASCE.) There are two important factors that investors should focus on when examining a water utility. One, how much capital spending will be required by the company relative to its size, and, two, how will that firm come up with the capital. An increase in shares will dilute current earnings, and the higher interest costs resulting from the added debt can eat away at profits.

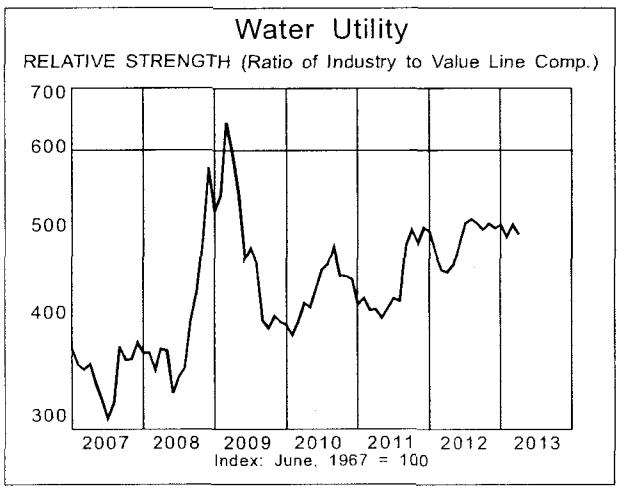
Regulators Will Play a Major Role

Upgrading their facilities and finding the funds to do so, is only the first hurdle that water utilities face. Second, and just as important, is the ability to recover their investment. And, to a large extent, this factor is out of their control. Directors on the state utility commissions are usually appointed by the governor. Since this is an elective office, politicians from both parties are very aware that water users (i.e., citizens that vote) do not like having their water bills raised. So, a utility is always at risk of spending and operating prudently, and then being denied the right to recover costs by a state utility commission. Therefore, we advise all investors when reading each utility page, to note the analyst's view on the regulatory climate in each state. What's more, this risk will always be with regulated utilities until politicians can get elected on campaign platforms that are pro-utility, a seemingly unlikely scenario.

Conclusion

Despite some of the reservations that we have noted about the industry, overall, it is currently in decent shape. Though issuance of new shares dilutes earnings, we are glad to see companies selling new equity when the market is near its all-time high. This was the case recently with *Connecticut Water, California Water Service Group*, and *SJW*. And while the industry's prospects are not bad for 2013 and 2014, it is the pull to 2016-2018 that has us concerned. Also, despite the recent underperformance of certain water utility shares, almost all have advanced so far that they have below-average long-term total return potential.

James A. Flood



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AMERICAN WATER NYSE-AWK

RECENT PRICE	41.64	P/E RATIO	18.9 (Trailing: 20.1; Median: NMF)	RELATIVE P/E RATIO	1.13	DIV'D YLD	2.5%	VALUE LINE

TIMELINESS 4 Lowered 3/29/13
SAFETY 3 New 7/25/08
TECHNICAL 3 Raised 4/19/13
BETA .65 (1.00 = Market)

	2008	2009	2010	2011	2012	2013
High:	23.7	23.0	25.8	32.8	39.4	41.9
Low:	16.5	16.2	19.4	25.2	31.3	37.0

Target Price Range 2016 | 2017 | 2018

2016-18 PROJECTIONS

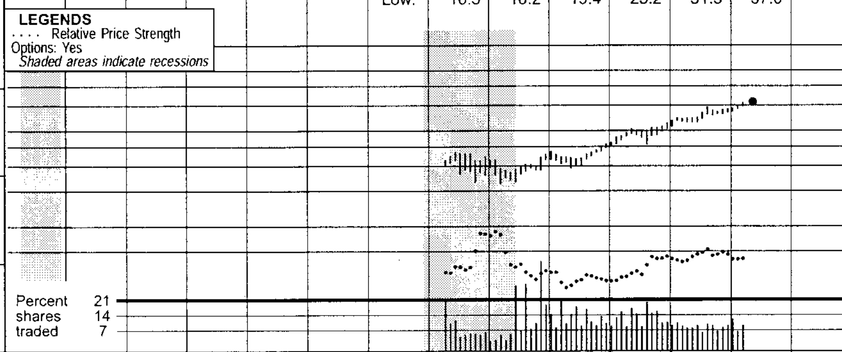
	Price	Gain	Ann'l Total Return
High	60	(+45%)	12%
Low	40	(-5%)	2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	1	0	5	0	0	4	0	0
to Sell	2	0	0	6	0	0	4	0	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	176	173	188
to Sell	162	171	175
Hld's(000)	140028	143865	146609



% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	25.2	15.7
3 yr.	109.4	43.2
5 yr.	—	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006E	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
--	--	--	--	--	--	--	--	--	13.08	13.84	14.61	13.98	15.49	15.18	16.25	*17.40*	*18.35*	Revenues per sh	*20.00*
--	--	--	--	--	--	--	--	--	.65	d.47	2.87	2.89	3.56	3.73	*4.15*	*4.30*	*4.50*	"Cash Flow" per sh	*5.20*
--	--	--	--	--	--	--	--	--	d.97	d2.14	1.10	1.25	1.53	1.72	2.11	*2.25*	*2.40*	Earnings per sh A	*2.85*
--	--	--	--	--	--	--	--	--	--	--	.40	.82	.86	.90	.96	*1.04*	*1.12*	Div'd Decl'd per sh B■	*1.40*
--	--	--	--	--	--	--	--	--	4.31	4.74	6.31	4.50	4.38	5.27	5.25	*5.35*	*5.40*	Cap'l Spending per sh	*5.25*
--	--	--	--	--	--	--	--	--	23.86	28.39	25.64	22.91	23.59	24.11	25.10	*26.40*	*27.50*	Book Value per sh D	*30.00*
--	--	--	--	--	--	--	--	--	160.00	160.00	160.00	174.63	175.00	175.66	176.99	*178.00*	*179.00*	Common Shs Outst'g g C	*190.00*
--	--	--	--	--	--	--	--	--	--	--	18.9	15.6	14.6	16.8	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
--	--	--	--	--	--	--	--	--	--	--	1.14	1.04	.93	1.05	1.07	*Value Line*		Relative P/E Ratio	*1.20*
--	--	--	--	--	--	--	--	--	--	--	1.9%	4.2%	3.8%	3.1%	2.7%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 12/31/12
Total Debt $5576.4 mil. **Due in 5 Yrs** $1034.0 mil.
LT Debt $5190.5 mil. **LT Interest** $301.0 mil.
(Total interest coverage: 4.4x) (54% of Cap'l)

Leases, Uncapitalized: Annual rentals $28.1 mill.
Pension Assets $1157.7 mill **Oblig.** $1621.2 mill.
Pfd Stock $18.9 mill. **Pfd Div'd** $.7 mill

Common Stock 177,409,722 shs. as of 2/21/13

MARKET CAP: $7.4 billion (Large Cap)

2003	2004	2005	2006E	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
--	--	--	2093.1	2214.2	2336.9	2440.7	2710.7	2666.2	2876.9	*3100*	*3300*	Revenues ($mill)	*3800*
--	--	--	d155.8	d342.3	187.2	209.9	267.8	304.9	375.0	*400*	*430*	Net Profit ($mill)	*540*
--	--	--	--	--	37.4%	37.9%	40.4%	39.5%	*40.7%*	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
--	--	--	--	--	--	--	--	12.5%	6.2%	*8.0%*	*10.0%*	AFUDC % to Net Profit	*12.0%*
--	--	--	56.1%	50.9%	53.1%	56.9%	56.8%	55.7%	53.8%	*54.0%*	*54.0%*	Long-Term Debt Ratio	*53.5%*
--	--	--	43.9%	49.1%	46.9%	43.1%	43.2%	44.2%	46.0%	*46.0%*	*46.0%*	Common Equity Ratio	*46.5%*
--	--	--	8692.8	9245.7	8750.2	9289.0	9561.3	9580.3	9652.7	*10300*	*10800*	Total Capital ($mill)	*12000*
--	--	--	8720.6	9318.0	9991.8	10524	11059	11021	11739	*12300*	*12800*	Net Plant ($mill)	*14000*
--	--	--	NMF	NMF	3.7%	3.8%	4.4%	4.8%	5.5%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
--	--	--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.5%*
--	--	--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	8.4%	*8.5%*	*8.5%*	Return on Com Equity	*9.5%*
--	--	--	NMF	NMF	3.0%	1.8%	2.8%	3.5%	4.6%	*4.5%*	*4.5%*	Retained to Com Eq	*4.5%*
--	--	--	--	--	34%	65%	56%	52%	45%	*46%*	*47%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	13.1	14.2	24.4
Other	521.2	1383.5	475.0
Current Assets	534.3	1397.7	499.4
Accts Payable	199.2	243.7	279.6
Debt Due	274.5	543.9	385.9
Other	300.8	701.5	329.3
Current Liab.	774.5	1489.1	994.8
Fix. Chg. Cov.	237%	256%	*300%*

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '16-'18
Revenues	--	2.5%	*4.5%*
"Cash Flow"	--	39.5%	*6.5%*
Earnings	--	--	*9.5%*
Dividends	--	--	*7.5%*
Book Value	--	-0.5%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	588.1	671.2	786.9	664.5	2710.7
2011	596.7	668.8	760.9	639.8	2666.2
2012	618.7	745.6	831.8	680.8	2876.9
2013	*650*	*800*	*900*	*750*	*3100*
2014	*700*	*850*	*975*	*775*	*3300*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	.18	.42	.71	.23	1.53
2011	.23	.42	.73	.32	1.72
2012	.28	.66	.87	.30	2.11
2013	*.30*	*.65*	*.95*	*.35*	*2.25*
2014	*.35*	*.70*	*1.00*	*.35*	*2.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.20	.20	.21	.21	.82
2010	.21	.21	.22	.22	.86
2011	.22	.23	.23	.23	.91
2012	.23	.23	.25	.25	.96
2013	.25				

BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to over 14 million people in over 30 states and Canada. Its nonregulated business assists municipalities and military bases with the maintenance and upkeep as well. Regulated operations made up 89.1% of 2012 revenues. New Jersey is its biggest market accounting for 22.2% of revenues. Has roughly 7,000 employees. Depreciation rate, 2.6% in '12. BlackRock, Inc., owns 10.3% of the common stock outstanding. Off. & dir. own less than 1% (3/13 Proxy). President & CEO; Jeffry Sterba. Chairman; George Mackenzie. Address: 1025 Laurel Oak Road, Voorhees, NJ 08043. Telephone: 856-346-8200. Internet: www.amwater.com.

American Water Works' successful cost containment helps it in more ways than one. The company has been busy paring expenses over the past few years. Indeed, expense ratios have declined from 42% in 2011 to 40.7% last year, and should fall below 40% by 2015. In addition to the benefit to the bottom line, leaner operations create goodwill with regulators. They also make it harder for them to make restrictive rulings on requests for needed rate hikes. Investors should note that a utility's relationship with regulators is of the utmost importance and cannot be over emphasized.

Capital expenditures will likely be large in the years ahead. In reference to the huge sums that American Water has and will continue to spend on upgrading and repairing its water system, its chairman recently stated that "we are in the infrastructure business." We estimate that the company will have to spend roughly $1 billion annually over the next five years.

The company's balance sheet will probably remain overleveraged. Internal cash generation will fall far short of funding all of American Water's capital budget. Currently, we believe the company has too much debt, and that now is a propitious time to issue new equity (even if it is somewhat dilutive), because its shares are near their all-time highs and are up 150% from 2009's low. American Water's management believes that its stock is undervalued, however, so a large stock offering seems unlikely.

American Water's earnings and dividend growth prospects are good for a water utility. With the help of its aforementioned leaner cost structure, we estimate that the company's bottom line will grow by a healthy 9%-10% annual rate through 2016-2018. Larger contributions from the higher-margined, nonregulated businesses will be part of the reason for the good showing.

We think American Water's positive attributes are reflected in its current stock price. These shares have been on a tear, outperforming the market averages over the past one-, three-, and five-year periods, an unusual feat for a regulated utility in a rising market. Thus, we advise investors to avoid this untimely equity.

James A. Flood *April 19, 2013*

(A) Diluted earnings. Excludes nonrecurring losses: '08, $4.62; '09, $2.63; '11, $0.07. Discontinued operations: '06, (4¢); '11, 3¢, '12, (10¢). Next earnings report due late May. Quarterly earnings may not sum due to rounding. (B) Dividends paid in March, June, September, and December. ■ Div. reinvestment available. (C) In millions. (D) Includes intangibles. In 2012: $1.207 billion, $6.82/share. (E) Pro forma numbers for '06 & '07.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	15

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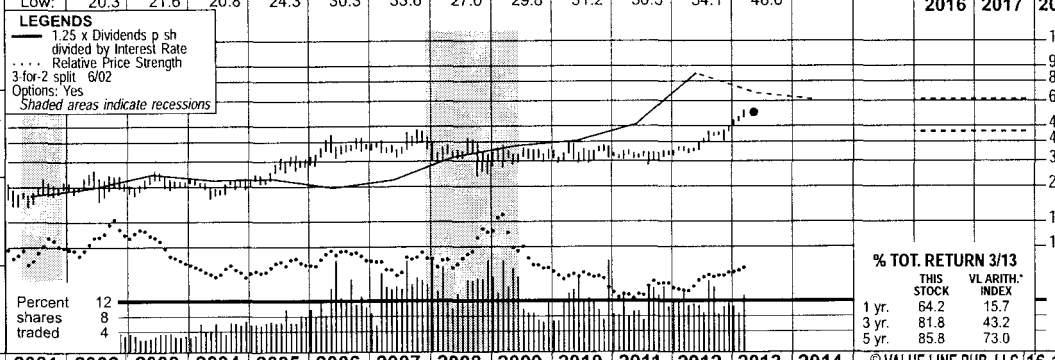
AMER. STATES WATER NYSE-AWR

RECENT PRICE 56.22 | P/E RATIO 20.2 (Trailing: 19.9 Median: 22.0) | RELATIVE P/E RATIO 1.21 | DIV'D YLD 2.5% | VALUE LINE

TIMELINESS 2 Raised 11/23/12
SAFETY 2 Raised 7/20/12
TECHNICAL 4 Lowered 2/22/13
BETA .70 (1.00 = Market)

High:	29.0	29.0	26.8	34.6	43.8	46.1	42.0	38.8	39.6	36.4	48.1	57.8
Low:	20.3	21.6	20.8	24.3	30.3	33.6	27.0	29.8	31.2	30.5	34.1	48.0

Target Price Range 2016 | 2017 | 2018



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+15%)	6%
Low	45	(-20%)	-2%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	1	0
Options	4	2	0	16	0	0	1	1	1
to Sell	4	2	0	17	0	0	2	3	1

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	83	79	77
to Sell	50	65	64
Hld's(000)	11968	11747	12033

% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	64.2	15.7
3 yr.	81.8	43.2
5 yr.	85.8	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
11.44	11.02	12.91	12.17	13.06	13.78	13.98	13.61	14.06	15.76	17.49	18.42	19.48	21.41	22.24	24.24	*24.40*	*24.85*	Revenues per sh	*25.60*
1.85	2.04	2.26	2.20	2.53	2.54	2.08	2.23	2.64	2.89	3.31	3.37	3.40	4.23	4.26	4.96	*5.15*	*5.60*	"Cash Flow" per sh	*6.25*
1.04	1.08	1.19	1.28	1.35	1.34	.78	1.05	1.32	1.33	1.62	1.55	1.62	2.22	2.24	2.82	*2.70*	*2.85*	Earnings per sh A	*3.00*
.83	.84	.85	.86	.87	.87	.88	.89	.90	.91	.96	1.00	1.01	1.04	1.10	1.27	*1.45*	*1.55*	Div'd Decl'd per sh B■	*1.70*
2.58	3.11	4.30	3.03	3.18	2.68	3.76	5.03	4.24	3.91	2.89	4.45	4.18	4.24	4.26	3.54	*4.40*	*4.35*	Cap'l Spending per sh	*4.20*
11.24	11.48	11.82	12.74	13.22	14.05	13.97	15.01	15.72	16.64	17.53	17.95	19.39	20.26	21.68	23.61	*23.70*	*23.95*	Book Value per sh	*24.25*
13.44	13.44	13.44	15.12	15.12	15.18	15.21	16.75	16.80	17.05	17.23	17.30	18.53	18.63	18.85	19.26	*19.25*	*19.50*	Common Shs Outst'g C	*21.50*
14.5	15.5	17.1	15.9	16.7	18.3	31.9	23.2	21.9	27.7	24.0	22.6	21.2	15.7	15.4	14.3	*Bold figures are*		Avg Ann'l P/E Ratio	*18.5*
.84	.81	.97	1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.36	1.41	1.00	.97	.92	*Value Line*		Relative P/E Ratio	*1.15*
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%	3.0%	3.2%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*3.1%*

CAPITAL STRUCTURE as of 12/31/12
Total Debt $335.8 mill. **Due in 5 Yrs** $10.6 mill.
LT Debt $332.5 mill. **LT Interest** $8.0 mill.
(LT interest earned: 5.2x: total interest coverage: 4.9x) (42% of Cap'l)
Leases, Uncapitalized: Annual rentals $3.0 mill.

Pension Assets-12/12 $107.6 mill. **Oblig.** $163.2 mill.

Pfd Stock None.
Common Stock 19,263,011 shs. as of 2/26/13
MARKET CAP: $1.1 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
212.7	228.0	236.2	268.6	301.4	318.7	361.0	398.9	419.3	466.9	*470*	*485*	Revenues ($mill)	*550*
11.9	16.5	22.5	23.1	28.0	26.8	29.5	41.4	42.0	54.1	*55.0*	*58.0*	Net Profit ($mill)	*65.0*
43.5%	37.4%	47.0%	40.5%	42.6%	37.8%	38.9%	43.2%	41.7%	39.9%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
--	--	--	12.2%	8.5%	6.9%	3.2%	5.8%	2.0%	2.5%	*2.5%*	*2.5%*	AFUDC % to Net Profit	*2.5%*
52.0%	47.7%	50.4%	48.6%	46.9%	46.2%	45.9%	44.3%	45.4%	42.2%	*43.0%*	*43.0%*	Long-Term Debt Ratio	*42.0%*
48.0%	52.3%	49.6%	51.4%	53.1%	53.8%	54.1%	55.7%	54.6%	57.8%	*57.0%*	*57.0%*	Common Equity Ratio	*58.0%*
442.3	480.4	532.5	551.6	569.4	577.0	665.0	677.4	749.1	787.0	*800*	*820*	Total Capital ($mill)	*900*
602.3	664.2	713.2	750.6	776.4	825.3	866.4	855.0	896.5	917.8	*940*	*985*	Net Plant ($mill)	*1060*
4.6%	5.2%	5.4%	6.0%	6.7%	6.4%	5.9%	7.6%	7.1%	8.3%	*7.5%*	*7.5%*	Return on Total Cap'l	*7.0%*
5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	11.9%	*12.0%*	*12.5%*	Return on Shr. Equity	*12.5%*
5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	11.9%	*12.0%*	*12.5%*	Return on Com Equity	*12.5%*
NMF	1.0%	2.8%	2.7%	3.9%	3.1%	3.2%	5.8%	5.3%	6.6%	*6.0%*	*6.0%*	Retained to Com Eq	*5.5%*
113%	84%	67%	67%	58%	64%	61%	47%	49%	45%	*51%*	*52%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	4.2	1.3	23.5
Other	200.8	164.3	160.5
Current Assets	205.0	165.6	184.0
Accts Payable	36.2	37.9	40.6
Debt Due	61.3	.3	3.3
Other	81.3	66.2	49.8
Current Liab.	178.8	104.4	93.7
Fix. Chg. Cov.	428%	401%	442%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	5.5%	7.5%	*3.5%*
"Cash Flow"	6.5%	9.0%	*4.5%*
Earnings	6.5%	11.5%	*8.0%*
Dividends	3.0%	4.5%	*8.0%*
Book Value	5.0%	5.5%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	88.4	95.5	111.3	103.7	398.9
2011	94.3	109.8	119.9	95.3	419.3
2012	107.6	114.3	133.5	111.5	466.9
2013	*105*	*120*	*135*	*110*	*470*
2014	*110*	*125*	*140*	*110*	*485*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	.45	.47	.62	.68	2.22
2011	.37	.68	.83	.36	2.24
2012	.53	.79	.97	.53	2.82
2013	*.50*	*.75*	*1.00*	*.45*	*2.70*
2014	*.55*	*.75*	*1.10*	*.45*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.250	.250	.250	.260	1.01
2010	.260	.260	.260	.260	1.04
2011	.260	.280	.280	.280	1.10
2012	.280	.280	.355	.355	1.27
2013	.355				

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. Sold Chaparral City Water of Arizona (6/11). Has 728 employees. Officers & directors own 2.9% of common stock (4/12 Proxy). Chairman: Lloyd Ross. President & CEO: Robert J. Sprowls. Inc: CA. Addr: 630 East Foothill Boulevard, San Dimas, CA 91773. Tel: 909-394-3600. Internet: www.aswater.com.

American States Water's bottom line will likely backtrack a bit in 2013. The company is coming off an impressive 2012, which saw share net increase 26% year over year. The strong performance was attributable to its American States Utility Services (ASUS) subsidiary that falls under its Contracted Services segment. Replacement and maintenance projects at Fort Bragg in North Carolina and Fort Bliss in Texas drove the majority of the bottom-line gains in this division. We believe that activity on military bases will slow down, given sequestration cuts and management's conservative tone for new military projects. We are maintaining our 2013 top- and bottom-line estimates until AWR reports its first-quarter results.

Golden State Water Company's (GSWC) water rate case should be finalized soon. The proposed settlement with the Division of Ratepayer Advocates (DRA) would generate $14.5 million in additional gross margin starting in 2013. Rates in 2014 and 2015 would be increased between 2% and 3%, until the next rate filing in 2015. A final decision is expected to be approved by the California Public Utilities Commission (CPUC) within the next 30 to 60 days. GSWC also filed its electric rate case for rates from 2013 through 2016. If approved, the rate increases are projected to generate roughly $1.3 million in additional annual revenues.

Capital investments will pick up over the next couple of years. The annual capex budget is projected to be $85 million over the next three years. These investments represent a step up from the roughly $70 million averaged over the past couple of years.

The balance sheet continues to improve. The company generated $27 million in free cash flow for 2012 compared to negative cash flow recorded over the prior couple of years. Improvements in liquidity and capitalization ratios should help AWR weather the sequester cuts.

This timely stock should have some appeal to momentum and income investors. Though we would suggest that value hunters wait for a better entry point, as these shares have appreciated substantially year to date.

Michael Collins *April 19, 2013*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 14¢; '05, 25¢; '06, 6¢; '08, (27¢); '10, (45¢) '11, 20¢. Next earnings report due early May. Quarterly egs. may not add due to rounding.
(B) Dividends historically paid in early March, June, September, and December. ■ Div'd reinvestment plan available
(C) In millions, adjusted for split.

Company's Financial Strength	A
Stock's Price Stability	90
Price Growth Persistence	65
Earnings Predictability	90

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CALIFORNIA WATER NYSE-CWT

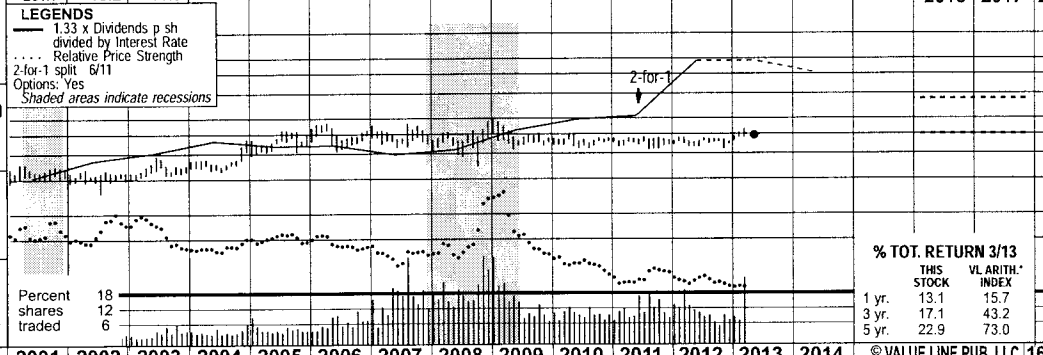
RECENT PRICE	19.75	P/E RATIO	21.5 (Trailing: 19.4 / Median: 21.0)	RELATIVE P/E RATIO	1.29	DIV'D YLD	3.2%	VALUE LINE

TIMELINESS 3 Raised 8/3/12
SAFETY 3 Lowered 7/27/07
TECHNICAL 3 Raised 3/15/13
BETA .65 (1.00 = Market)

High:	13.4	15.7	19.0	21.1	22.9	22.7	23.3	24.1	19.8	19.4	19.3	21.2
Low:	10.2	11.8	13.0	15.6	16.4	17.1	13.8	16.7	16.9	16.7	16.8	18.4

Target Price Range
2016 | 2017 | 2018

LEGENDS
— 1.33 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 6/11
Options: Yes
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	30	(+50%)	13%
Low	20	(Nil)	4%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	2	0	0	1	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	1	0	0	0	0	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	54	63	54
to Sell	53	46	63
Hld's(000)	21505	22150	22078

% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	15.7
3 yr.	17.1	43.2
5 yr.	22.9	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
7.74	7.38	7.98	8.08	8.13	8.67	8.18	8.59	8.72	8.10	8.88	9.90	10.82	11.05	12.00	13.36	**12.55**	**14.15**	Revenues per sh	**16.00**
1.46	1.30	1.37	1.26	1.10	1.32	1.26	1.42	1.52	1.36	1.56	1.86	1.93	1.93	2.07	2.25	**2.05**	**2.25**	"Cash Flow" per sh	**2.75**
.92	.73	.77	.66	.47	.63	.61	.73	.74	.67	.75	.95	.98	.91	.86	1.02	**.85**	**1.10**	Earnings per sh A	**1.35**
.53	.54	.54	.55	.56	.56	.56	.57	.57	.58	.58	.59	.59	.60	.62	.63	**.64**	**.68**	Div'd Decl'd per sh B ■	**.90**
1.30	1.37	1.72	1.23	2.04	2.91	2.19	1.87	2.01	2.14	1.84	2.41	2.66	2.97	2.83	3.05	**2.65**	**2.90**	Cap'l Spending per sh	**3.00**
6.50	6.69	6.71	6.45	6.48	6.56	7.22	7.83	7.90	9.07	9.25	9.72	10.13	10.45	10.76	11.30	**13.40**	**13.85**	Book Value per sh C	**15.00**
25.24	25.24	25.87	30.29	30.36	30.36	33.86	36.73	36.78	41.31	41.33	41.45	41.53	41.67	41.82	41.91	**47.75**	**48.00**	Common Shs Outst'g D	**50.0**
12.6	17.8	17.8	19.6	27.1	19.8	22.1	20.1	24.9	29.2	26.1	19.8	19.7	20.3	21.3	17.9	*Bold figures are*		Avg Ann'l P/E Ratio	**19.0**
.73	.93	1.01	1.27	1.39	1.08	1.26	1.06	1.33	1.58	1.39	1.19	1.31	1.29	1.34	1.10	*Value Line*		Relative P/E Ratio	**1.25**
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%	3.2%	3.4%	3.5%	*estimates*		Avg Ann'l Div'd Yield	**3.6%**

CAPITAL STRUCTURE as of 12/31/12
Total Debt $571.1 mill. **Due in 5 Yrs** $65.3 mill.

LT Debt $434.5 mill. **LT Interest** $29.5 mill.
(LT interest earned: 6.7x; total int. cov.: 6.0x)
(52% of Cap'l)

Pension Assets-12/12 $202.9 mill.
Oblig. $402.9 mill.

Pfd Stock None

Common Stock 41,908,218 shs.
as of 2/11/13

MARKET CAP: $825 million (Small Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
277.1	315.6	320.7	334.7	367.1	410.3	449.4	460.4	501.8	560.0	**600**	**650**	Revenues ($mill) E	**800**
19.4	26.0	27.2	25.6	31.2	39.8	40.6	37.7	36.1	42.7	**40.0**	**53.0**	Net Profit ($mill)	**67.0**
39.9%	39.6%	42.4%	37.4%	39.9%	37.7%	40.3%	39.5%	40.5%	**30.5%**	**34.0%**	**39.0%**	Income Tax Rate	**39.0%**
10.3%	3.2%	3.3%	10.6%	8.3%	8.6%	7.6%	4.2%	7.6%	8.0%	**8.0%**	**8.5%**	AFUDC % to Net Profit	**10.0%**
50.2%	48.6%	48.3%	43.5%	42.9%	41.6%	47.1%	52.4%	51.7%	52.1%	**42.0%**	**46.5%**	Long-Term Debt Ratio	**50.0%**
49.1%	50.8%	51.1%	55.9%	56.6%	58.4%	52.9%	47.6%	48.3%	47.8%	**58.0%**	**53.5%**	Common Equity Ratio	**50.0%**
498.4	565.9	568.1	670.1	674.9	690.4	794.9	914.7	931.5	908.2	**1050**	**1125**	Total Capital ($mill)	**1400**
759.5	800.3	862.7	941.5	1010.2	1112.4	1198.1	1294.3	1381.1	1457.1	**1510**	**1575**	Net Plant ($mill)	**1825**
5.6%	6.1%	6.3%	5.2%	5.9%	7.1%	6.5%	5.5%	5.5%	**6.5%**	**5.5%**	**6.0%**	Return on Total Cap'l	**6.5%**
7.8%	8.9%	9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	9.0%	**7.0%**	**8.0%**	Return on Shr. Equity	**9.5%**
7.9%	9.0%	9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	9.0%	**7.0%**	**8.0%**	Return on Com Equity	**9.5%**
.7%	2.1%	2.1%	1.0%	1.8%	3.8%	3.8%	3.0%	2.3%	3.6%	**1.5%**	**3.0%**	Retained to Com Eq	**3.0%**
91%	77%	78%	86%	77%	61%	60%	66%	71%	62%	**75%**	**62%**	All Div'ds to Net Prof	**67%**

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	42.3	27.2	38.8
Other	83.9	86.7	107.8
Current Assets	126.2	113.9	146.6
Accts Payable	39.5	48.9	46.8
Debt Due	26.1	53.7	136.3
Other	41.7	49.3	59.7
Current Liab.	107.3	151.9	242.8
Fix. Chg. Cov.	340%	278%	230%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '16-'18
Revenues	3.5%	6.0%	5.0%
"Cash Flow"	4.5%	6.5%	5.0%
Earnings	4.0%	5.0%	5.5%
Dividends	1.0%	1.0%	6.0%
Book Value	5.0%	5.0%	5.5%

Cal-endar	QUARTERLY REVENUES ($ mill.)E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	90.3	118.3	146.3	105.5	460.4
2011	98.1	131.4	169.3	103.0	501.8
2012	116.7	143.6	178.1	121.6	560.0
2013	**125**	**155**	**190**	**130**	**600**
2014	**135**	**165**	**210**	**140**	**650**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.05	.25	.49	.12	.91
2011	.03	.29	.50	.04	.86
2012	.03	.31	.56	.12	1.02
2013	**.04**	**.26**	**.50**	**.05**	**.85**
2014	**.05**	**.30**	**.60**	**.15**	**1.10**

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.148	.148	.148	.148	.59
2010	.149	.149	.149	.149	.60
2011	.154	.154	.154	.154	.62
2012	.1575	.1575	.1575	.1575	.63
2013	.16				

BUSINESS: California Water Service Group provides regulated and nonregulated water service to roughly 471,900 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, '12: residential, 66%; business, 18%; public authorities, 4%; industrial, 4%; other 8%. '12 reported depreciation rate: 2.8%. Has 1,131 employees. President, Chairman, and Chief Executive Officer: Peter C. Nelson. Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwatergroup.com.

California Water Service Group recently had a major stock offering. In late March, the utility sold five million new shares. The underwriters were also given an option to sell an additional three-quarters of a million shares over a period of 30 days.

We're lowering our annual share-net estimate for the company as a result. Assuming all the available stock is placed with investors, California Water's outstanding equity will increase by nearly 14%. Deduct another $0.06-a-share capital adjustment expense that will be incurred, and we estimate that earnings per share will decline 17%, to $0.85.

A pending regulatory decision will have a significant impact on next year's bottom line. In mid-2012, the firm filed a request with California regulators seeking a 19.4% rate increase for 2014. Without a meaningful hike, the utility's earnings prospects will be severely impaired. We are tentatively forecasting a reasonable outcome, which should enable California Water's earnings to bounce back somewhat, to $1.10 a share.

Additional external financing will be required to meet future capital expenditures. Even with the recent stock offering, California Water won't be able to fund the outlays required to repair its aging infrastructure over the next 3- to 5-year period. The company will most likely have to turn to the debt markets in the near future. This should result in the equity-to-total capital ratio (which has recently spiked) declining to 50%.

California Water's near-term dividend growth prospects are subpar for a water utility. With most of its cash designated for upgrading its system, the company doesn't have the funds needed to increase its dividend by much. Indeed, for the second consecutive year, the payout was hiked by a paltry 1.6%, compared to about 4.5% for the industry.

All told, we think investors can find more attractive selections elsewhere. Though this neutrally ranked equity carries a yield that is higher than the *Value Line* average, the combination of below-average total returns through 2016-2018 and regulatory risk, makes it hard for us to recommend this stock.

James A. Flood *April 19, 2013*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (4¢); '01, 2¢; '02, 4¢; '11, 4¢. Next earnings report due mid-May.
(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.
(C) Incl. intangible assets. In '12: $18.8 mill., $0.44/sh.
(D) In millions, adjusted for splits.
(E) Excludes non-reg. rev.

Company's Financial Strength	B+
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

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CONNECTICUT WATER NDQ-CTWS

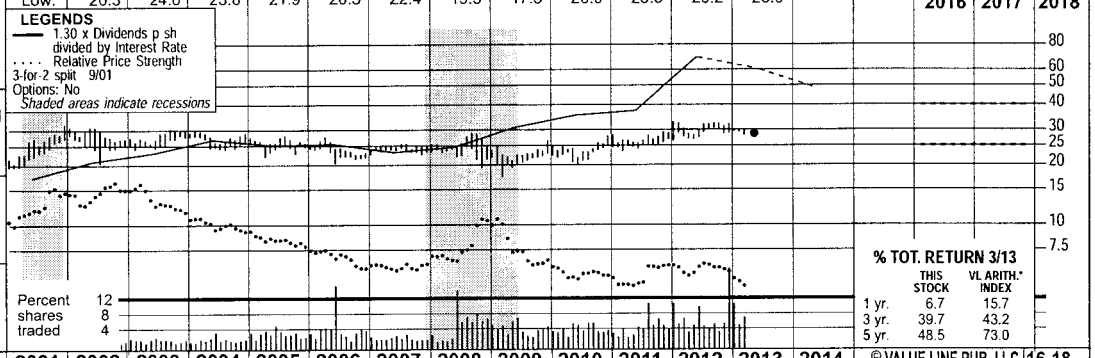
RECENT PRICE **28.67** | P/E RATIO **21.1** (Trailing: 18.9 / Median: 23.0) | RELATIVE P/E RATIO **1.26** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 4 Lowered 3/29/13
SAFETY 3 New 1/18/13
TECHNICAL 4 Lowered 4/5/13
BETA .75 (1.00 = Market)

High:	31.1	30.4	29.8	28.2	27.7	25.6	29.0	26.4	27.9	29.1	32.8	30.3
Low:	20.3	24.0	23.8	21.9	20.3	22.4	19.3	17.3	20.0	23.3	26.2	28.0

Target Price Range
2016 | 2017 | 2018

LEGENDS
— 1.30 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 9/01
Options: No
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+40%)	11%
Low	25	(-15%)	Nil

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	2	0
Options	0	0	0	3	0	0	0	0	0
to Sell	0	0	0	3	0	0	0	0	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	38	29	48
to Sell	29	22	16
Hld's(000)	3095	3102	4069

Percent shares traded 12 8 4

% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	6.7	15.7
3 yr.	39.7	43.2
5 yr.	48.5	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
5.67	5.58	5.87	5.70	5.93	5.77	5.91	6.04	5.81	5.68	7.05	7.24	6.93	7.65	7.93	7.63	*8.35*	*8.90*	Revenues per sh	*11.25*
1.51	1.59	1.65	1.73	1.78	1.78	1.89	1.91	1.62	1.52	1.90	1.95	1.93	2.04	2.11	*2.10*	*2.35*	*2.55*	"Cash Flow" per sh	*2.75*
1.00	1.02	1.03	1.09	1.13	1.12	1.15	1.16	.88	.81	1.05	1.11	1.19	1.13	1.13	1.53	*1.40*	*1.55*	Earnings per sh A	*1.70*
.77	.78	.79	.79	.80	.81	.83	.84	.85	.86	.87	.88	.90	.92	.94	.96	*..98*	*1.00*	Div'd Decl'd per sh B■	*1.10*
1.99	1.12	1.42	1.43	1.86	1.98	1.49	1.58	1.96	1.96	2.24	2.44	3.28	3.06	2.61	2.34	*2.75*	*2.85*	Cap'l Spending per sh	*2.90*
8.26	8.52	8.61	8.92	9.25	10.06	10.46	10.94	11.52	11.60	11.95	12.23	12.67	13.05	13.50	16.89	*17.25*	*17.80*	Book Value per sh D	*20.40*
6.79	6.80	7.26	7.28	7.65	7.94	7.97	8.04	8.17	8.27	8.38	8.46	8.57	8.68	8.76	10.97	*11.00*	*11.25*	Common Shs Outst'g C	*12.00*
12.9	15.5	18.2	18.2	21.5	24.3	23.5	22.9	28.6	29.0	23.0	22.2	18.4	20.7	23.0	19.4	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.74	.81	1.04	1.18	1.10	1.33	1.34	1.21	1.52	1.57	1.22	1.34	1.23	1.32	1.44	1.24	*Value Line*		Relative P/E Ratio	*1.35*
6.0%	4.9%	4.2%	4.0%	3.3%	3.0%	3.0%	3.1%	3.4%	3.6%	3.6%	3.6%	4.1%	3.9%	3.6%	3.6%	*estimates*		Avg Ann'l Div'd Yield	*3.4%*

CAPITAL STRUCTURE as of 12/31/12
Total Debt $181.5 mill. **Due in 5 Yrs** $1.3 mill.
LT Debt $178.5 mill. **LT Interest** $7.6 mill.
(Total interest coverage: 8.8x)
(48% of Cap'l)
Leases, Uncapitalized: Annual rentals $.2 mill.
Pension Assets $45.4 mill.
Oblig. $66.5 mill.

Pfd Stock $0.8 mill. **Pfd Divd** NMF

Common Stock 10,970,895 shs.

MARKET CAP: $325 million (Small Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
47.1	48.5	47.5	46.9	59.0	61.3	59.4	66.4	69.4	83.8	*92.0*	*100*	Revenues ($mill)	*135*
9.2	9.4	7.2	6.7	8.8	9.4	10.2	9.8	9.9	13.6	*15.5*	*17.5*	Net Profit ($mill)	*20.5*
17.9%	22.9%	--	23.5%	32.4%	27.2%	19.5%	35.2%	41.3%	*32.0%*	*32.0%*	*33.0%*	Income Tax Rate	*35%*
--	--	--	--	--	1.7%	--	--	1.8%	1.8%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*3.0%*
43.5%	42.8%	44.9%	44.4%	47.8%	46.9%	50.6%	49.5%	53.2%	49.0%	*49.5%*	*49.5%*	Long-Term Debt Ratio	*48.5%*
55.9%	56.7%	54.6%	55.1%	51.8%	52.7%	49.1%	50.2%	46.5%	50.9%	*50.5%*	*50.5%*	Common Equity Ratio	*51.5%*
148.9	155.1	172.3	174.1	193.2	196.5	221.3	225.6	254.2	364.6	*375*	*390*	Total Capital ($mill)	*475*
238.9	246.1	247.7	268.1	284.3	302.3	325.2	344.2	362.4	447.9	*470*	*490*	Net Plant ($mill)	*550*
7.5%	7.0%	5.0%	4.9%	5.5%	5.9%	5.5%	5.4%	4.9%	*4.8%*	*5.0%*	*5.5%*	Return on Total Cap'l	*5.5%*
10.9%	10.6%	7.5%	6.9%	8.7%	9.0%	9.3%	8.6%	8.3%	7.3%	*8.0%*	*9.0%*	Return on Shr. Equity	*8.5%*
11.0%	10.6%	7.6%	7.0%	8.7%	9.1%	9.4%	8.7%	8.3%	7.3%	*8.0%*	*9.0%*	Return on Com Equity	*8.5%*
3.2%	3.1%	.3%	NMF	1.6%	1.9%	2.3%	1.6%	1.4%	2.7%	*2.5%*	*3.0%*	Retained to Com Eq	*3.0%*
71%	71%	95%	105%	82%	79%	76%	81%	83%	63%	*70%*	*65%*	All Div'ds to Net Prof	*65%*

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	1.0	1.0	13.2
Accounts Receivable	10.1	14.9	11.5
Other	9.3	3.0	11.7
Current Assets	20.4	18.9	36.4
Accts Payable	6.6	7.2	10.0
Debt Due	--	--	3.0
Other	28.5	23.2	2.9
Current Liab.	35.1	30.4	15.9
Fix. Chg. Cov.	400%	419%	*200%*

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '16-'18
Revenues	2.5%	5.0%	*6.0%*
"Cash Flow"	1.5%	4.0%	*4.5%*
Earnings	0.5%	4.0%	*6.0%*
Dividends	1.5%	1.5%	*2.5%*
Book Value	4.0%	3.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	13.8	15.9	21.0	15.7	66.4
2011	16.0	17.4	20.6	15.4	69.4
2012	18.5	21.3	24.5	19.5	83.8
2013	*21.0*	*23.0*	*26.0*	*22.0*	*92.0*
2014	*22.0*	*24.0*	*30.0*	*24.0*	*100*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	.12	.27	.54	.20	1.13
2011	.26	.37	.39	.11	1.13
2012	.22	.47	.67	.16	1.53
2013	*.20*	*.40*	*.60*	*.20*	*1.40*
2014	*.25*	*.45*	*.65*	*.20*	*1.55*

Cal-endar	QUARTERLY DIVIDENDS PAID B Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.222	.222	.228	.228	.90
2010	.228	.228	.233	.233	.922
2011	.233	.233	.238	.238	.942
2012	.238	.238	.243	.243	.962
2013	.243				

BUSINESS: Connecticut Water Service, Inc. is a non-operating holding company, whose income is derived from earnings of its wholly-owned subsidiary companies (regulated water utilities). It largest subsidiary, Connecticut Water, accounted for about 85% of the holding company's net income in 2012, and provides water services to 400,000 people in 55 towns throughout Connecticut and Maine. Acquired The Maine Water Co., 1/12; Biddeford and Saco Water, 12/12. Inc.: CT. Has about 260 employees. Chairman/President/CEO: Eric W. Thornburg. Officers and directors own 2.2% of the common stock; BlackRock, Inc. 6.7%; The Vanguard Group, 5.3%. Address: 93 West Main Street, Clinton, CT 06413. Telephone: (860) 669-8636. Web: www.ctwater.com.

Connecticut Water Service's earnings per share will most likely decline in 2013. Due almost entirely to the large issuance of new equity in December, the amount of the company's outstanding stock rose by almost 25% last year. Though the company will probably perform well on an operational basis, we think its share net will fall by 12%, to $1.40.

We expect 2014 to be better. The utility filed a request for higher rates in 2012. After a recent delay, it seems like the much-needed rate relief will go into effect in January of next year. A reasonable ruling, along with some improvement on the cost front, should enable Connecticut's share net to rebound by 15%, to $1.55.

Connecticut Water's balance sheet has become much larger and healthier. The firm's total capital expanded by a whopping 43% in 2012, thanks in part to the acquisition of two Maine-based water utilities. And while the new equity will be dilutive, it did shore up the utility's finances, which had been deteriorating. In fact, the equity-to-total capital ratio rose by more than four percentage points.

The company's recent expansion diversifies its regulatory risk. Before 2012's purchases, Connecticut Water's fate was solely in the hands of regulators in the Nutmeg state. Unfortunately, for CTWS, the state hasn't always been sympathetic to utilities. Despite some signs of improvement, however, the established rate of return that it allowed utilities to earn on equity was almost a full percentage point below that of the national average. And, while Maine can't be described as pro-business, based on past decisions, the state appears to have a more constructive utility policy.

Investors should hold off making commitments to this untimely stock, for now. In our January report three months ago, we opined that despite some of the company's positives, the equity was more than fully valued. And even though it has underperfomed the market averages by more than 10% over that time span, we believe that there are other utilities in the *Value Line* universe that offer better total return potential over the pull to 2016-2018.

James A. Flood *April 19, 2013*

(A) Diluted earnings. Next earnings report due mid-May.
(B) Dividends historically paid in mid-March, June, September, and December. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for split.
(D) Includes intangibles. In '12: $31.7 million/$2.89 a share.

Company's Financial Strength	B+
Stock's Price Stability	90
Price Growth Persistence	35
Earnings Predictability	85

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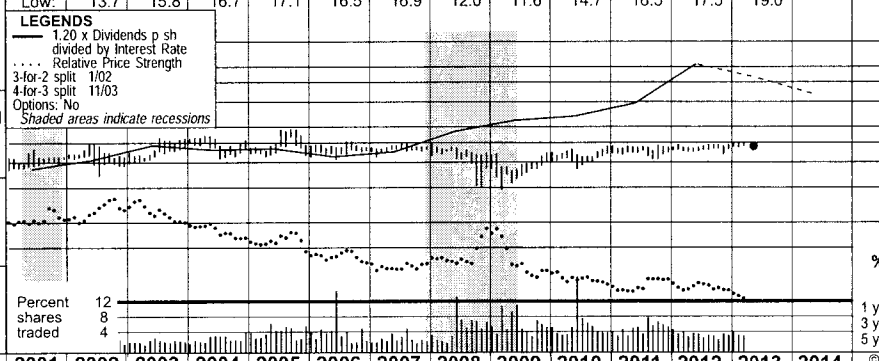
MIDDLESEX WATER NDQ-MSEX

RECENT PRICE 19.24 | P/E RATIO 20.3 (Trailing: 21.4 Median: 22.0) | RELATIVE P/E RATIO 1.22 | DIV'D YLD 3.9% | VALUE LINE

TIMELINESS 2 Lowered 3/29/13
SAFETY 2 New 10/21/11
TECHNICAL 3 Raised 6/29/12
BETA .70 (1.00 = Market)

High:	20.0	21.2	21.8	23.5	20.5	20.2	19.8	17.9	19.3	19.4	19.6	20.1
Low:	13.7	15.8	16.7	17.1	16.5	16.9	12.0	11.6	14.7	16.5	17.5	19.0

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 1/02
4-for-3 split 11/03
Options: No
Shaded areas indicate recessions



Target Price Range 2016 | 2017 | 2018

2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+30%)	10%
Low	20	(+5%)	5%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	1	1	1	1	1	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	1	0	0	0	0	0	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	32	37	38
to Sell	30	22	28
Hld's(000)	6653	6713	6696

Percent shares traded 12 8 4

% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	7.5	15.7
3 yr.	29.0	43.2
5 yr.	32.3	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
4.72	4.39	5.35	5.39	5.87	5.98	6.12	6.25	6.44	6.16	6.50	6.79	6.75	6.60	6.50	6.98	*7.20*	*7.70*	Revenues per sh	*9.10*
1.02	1.02	1.19	.99	1.18	1.20	1.15	1.28	1.33	1.33	1.49	1.53	1.40	1.55	1.46	1.56	*1.65*	*1.85*	"Cash Flow" per sh	*2.30*
.67	.71	.76	.51	.66	.73	.61	.73	.71	.82	.87	.89	.72	.96	.84	.90	*.95*	*1.00*	Earnings per sh A	*1.15*
.57	.58	.60	.61	.62	.63	.65	.66	.67	.68	.69	.70	.71	.72	.73	.74	*.75*	*.76*	Div'd Decl'd per sh B■	*.80*
1.20	2.68	2.33	1.32	1.25	1.59	1.87	2.54	2.18	2.31	1.66	2.12	1.49	1.90	1.50	1.36	*1.50*	*1.65*	Cap'l Spending per sh	*2.00*
6.00	6.80	6.95	6.98	7.11	7.39	7.60	8.02	8.26	9.52	10.05	10.03	10.33	11.13	11.27	11.48	*11.75*	*12.10*	Book Value per sh	*12.90*
8.54	9.82	10.00	10.11	10.17	10.36	10.48	11.36	11.58	13.17	13.25	13.40	13.52	15.57	15.70	15.82	*16.00*	*16.25*	Common Shs Outst'g C	*17.00*
13.4	15.2	17.6	28.7	24.6	23.5	30.0	26.4	27.4	22.7	21.6	19.8	21.0	17.8	21.7	20.8	*Bold figures are*		Avg Ann'l P/E Ratio	*20.0*
.77	.79	1.00	1.87	1.26	1.28	1.71	1.39	1.46	1.23	1.15	1.19	1.40	1.13	1.36	1.33	*Value Line*		Relative P/E Ratio	*1.35*
6.3%	5.4%	4.4%	4.2%	3.8%	3.7%	3.5%	3.4%	3.5%	3.7%	3.7%	4.0%	4.7%	4.2%	4.0%	4.0%	*estimates*		Avg Ann'l Div'd Yield	*3.6%*

CAPITAL STRUCTURE as of 12/31/12
Total Debt $142.6 mill. **Due in 5 Yrs** $32.5 mill.
LT Debt $131.5 mill. **LT Interest** $7.0 mill.
(LT interest coverage: 4.1x)
(42% of Cap'l)

Pension Assets-12/11 $37.9 mill.
Oblig. $62.8 mill.
Pfd Stock $3.4 mill. **Pfd Div'd:** $.2 mill.

Common Stock 15,815,595 shs.
as of 3/5/12

MARKET CAP: $300 million (Small Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
64.1	71.0	74.6	81.1	86.1	91.0	91.2	102.7	102.1	110.4	*115*	*125*	Revenues ($mill)	*155*
6.6	8.4	8.5	10.0	11.8	12.2	10.0	14.3	13.4	14.4	*15.5*	*17.0*	Net Profit ($mill)	*20.0*
32.8%	31.1%	27.6%	33.4%	32.6%	33.2%	34.1%	32.1%	32.7%	33.9%	*34.0%*	*34.0%*	Income Tax Rate	*34.0%*
--	--	--	--	--	--	--	6.8%	6.1%	3.4%	*4.5%*	*4.5%*	AFUDC % to Net Profit	*5.0%*
53.8%	53.8%	55.3%	49.5%	49.0%	45.6%	46.6%	43.1%	42.3%	41.5%	*43.0%*	*43.0%*	Long-Term Debt Ratio	*43.0%*
44.0%	42.5%	41.3%	47.5%	49.6%	51.8%	52.1%	55.8%	56.6%	57.4%	*57.0%*	*57.0%*	Common Equity Ratio	*57.0%*
181.1	214.5	231.7	264.0	268.8	259.4	267.9	310.5	312.5	316.5	*330*	*345*	Total Capital ($mill)	*400*
230.9	262.9	288.0	317.1	333.9	366.3	376.5	405.9	422.2	435.2	*440*	*450*	Net Plant ($mill)	*510*
5.0%	5.1%	5.0%	5.1%	5.6%	5.8%	5.0%	5.7%	5.2%	5.4%	*4.5%*	*5.0%*	Return on Total Cap'l	*5.5%*
7.9%	8.5%	8.2%	7.5%	8.6%	8.6%	7.0%	8.1%	7.5%	7.8%	*8.0%*	*8.5%*	Return on Shr. Equity	*9.0%*
8.0%	9.0%	8.6%	7.8%	8.7%	8.9%	7.0%	8.2%	7.5%	7.8%	*8.0%*	*8.5%*	Return on Com Equity	*9.0%*
NMF	.9%	.6%	1.3%	1.8%	2.0%	.1%	2.1%	1.0%	1.4%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
106%	90%	94%	84%	79%	78%	98%	75%	87%	83%	*80%*	*73%*	All Div'ds to Net Prof	*68%*

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	2.5	3.1	3.0
Other	20.3	19.8	21.6
Current Assets	22.8	22.9	24.6
Accts Payable	6.4	5.7	3.8
Debt Due	4.4	4.6	11.1
Other	29.9	36.4	41.0
Current Liab.	40.7	46.7	55.9
Fix. Chg. Cov.	400%	380%	410%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	1.5%	1.0%	*5.5%*
"Cash Flow"	3.0%	2.0%	*7.0%*
Earnings	3.5%	2.5%	*4.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	4.5%	4.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	21.6	26.5	29.6	25.0	102.7
2011	24.0	26.1	28.7	23.3	102.1
2012	23.5	27.4	32.3	27.1	110.4
2013	*28.0*	*28.0*	*32.0*	*27.0*	*115*
2014	*30.0*	*29.0*	*36.0*	*30.0*	*125*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	.11	.31	.37	.17	.96
2011	.17	.23	.32	.12	.84
2012	.11	.23	.38	.17	.90
2013	*.15*	*.28*	*.35*	*.17*	*.95*
2014	*.17*	*.28*	*.37*	*.18*	*1.00*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.178	.178	.178	.180	.71
2010	.180	.180	.180	.183	.72
2011	.183	.183	.183	.185	.73
2012	.185	.185	.185	.1875	.74
2013	.1875				

BUSINESS: Middlesex Water Company engages in the ownership and operation of regulated water utility systems in New Jersey, Delaware, and Pennsylvania. It also operates water and wastewater systems under contract on behalf of municipal and private clients in NJ and DE. Its Middlesex System provides water services to 60,000 retail customers, primarily in Middlesex County, New Jersey. In 2012, the Middlesex System accounted for 65% of total revenues. At 12/31/12, the company had 279 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers/directors own 3.1% of the common stock; BlackRock, 6.3%; The Vanguard Group, 5.7% (4/13 proxy). Address: 1500 Ronson Road, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: www.middlesexwater.com.

The profit outlook now looks a little less ebullient for Middlesex Water. We have trimmed our share-earnings target by a nickel, primarily due to the tepid economic environment in New Jersey. Though this market has shown some promising signs, New Jersey still has an above-average unemployment rate and trails only Florida in terms of the number of foreclosures to new residential mortgages. While the company's operations were not materially hurt by Superstorm Sandy, the lingering effects of the storm ought to further complicate matters for many homeowners and businesses.

Weakness in the commercial and industrial markets will stifle growth. Recently, Middlesex lost two contracts worth a combined $4.5 million in revenue. The borough of Sayreville, New Jersey, one of its wholesale customers, decided not to renew its service effective August of 2013. Additionally, the company lost a contract with its largest retail water customer, Hess. The oil & gas operator shut down a refining facility in Port Chester, New Jersey at the end of February. This contract was worth $2.6 million in revenue and may be a precursor of a larger drop in water consumption by commercial and industrial users in the Garden State.

Rate hikes in 2012 ought to provide some relief to top line. The company received rate increases last year of $8.1 million and $3.9 million for its Middlesex system and Tidewater business. These notable increases, coupled with additional hikes in the Pinelands market, should help offset some of the softness in the commercial and industrial sectors.

Capital investment will be key to longer-term growth. The company expects to invest $73 million over the next three years. The vast majority of these investments are targeted toward its Distribution systems. The RENEW initiative will help cut costs by improving the overall distribution process for its customers.

The issue has a Timeliness rank of 2 (Above Average). These shares are appealing to income and momentum investors. However, the longer-term investor should stay on the sidelines, given the stock's rich valuation and below-average 3- to 5-year capital appreciation potential.

Michael Collins *April 19, 2013*

(A) Diluted earnings. May not sum due to rounding. Next earnings report due early May.
(B) Dividends historically paid in mid-Feb., May, Aug., and November. ■ Div'd reinvestment plan available.
(C) In millions, adjusted for splits.
(D) Intangible assets in 2012: $9.2 million, $0.58 a share.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	80

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SJW CORP. NYSE-SJW

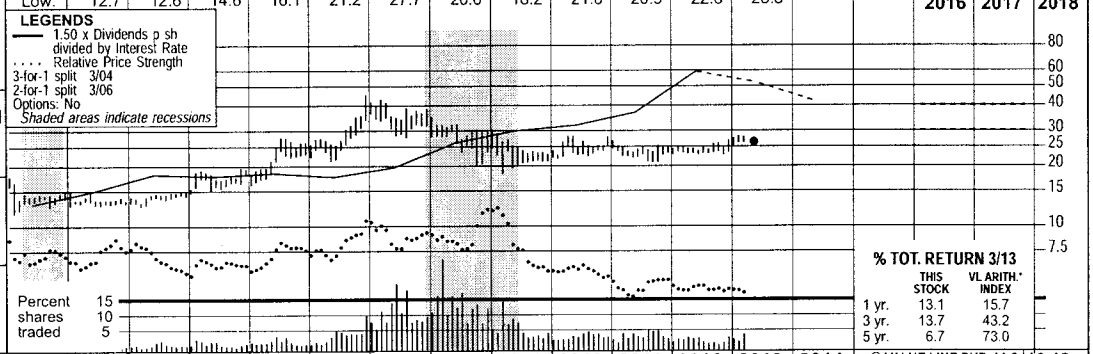
RECENT PRICE	26.38	P/E RATIO	20.6 (Trailing: 22.4 / Median: 23.0)	RELATIVE P/E RATIO	1.23	DIV'D YLD	2.8%	VALUE LINE

TIMELINESS 2 Raised 1/11/13
SAFETY 3 New 4/22/11
TECHNICAL 3 Raised 2/22/13
BETA .85 (1.00 = Market)

High:	15.1	15.0	19.6	27.8	45.3	43.0	35.1	30.4	28.2	26.8	26.9	28.1
Low:	12.7	12.6	14.6	16.1	21.2	27.7	20.0	18.2	21.6	20.9	22.6	25.3

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-1 split 3/04
2-for-1 split 3/06
Options: No
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+50%)	14%
Low	30	(+15%)	7%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	1	0	1	0	0	4	0	0
Options	0	0	0	0	0	0	0	1	0
to Sell	0	0	0	0	0	0	0	1	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	34	31	34
to Sell	31	31	30
Hld's(000)	8955	8844	9043

Percent shares traded 15 10 5

% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	15.7
3 yr.	13.7	43.2
5 yr.	6.7	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
5.79	5.58	6.40	6.74	7.45	7.97	8.20	9.14	9.86	10.35	11.25	12.12	11.68	11.62	12.85	13.99	*14.25*	*14.75*	Revenues per sh	*16.30*
1.27	1.26	1.43	1.23	1.49	1.55	1.75	1.89	2.21	2.38	2.30	2.44	2.21	2.38	2.80	2.94	*3.30*	*3.50*	"Cash Flow" per sh	*3.65*
.80	.76	.87	.58	.77	.78	.91	.87	1.12	1.19	1.04	1.08	.81	.84	1.11	1.18	*1.30*	*1.40*	Earnings per sh A	*1.60*
.38	.39	.40	.41	.43	.46	.49	.51	.53	.57	.61	.65	.66	.68	.69	.71	*.73*	*.75*	Div'd Decl'd per sh B■	*.90*
1.27	1.81	1.77	1.89	2.63	2.06	3.41	2.31	2.83	3.87	6.62	3.79	3.17	5.65	3.75	5.70	*5.25*	*5.20*	Cap'l Spending per sh	*4.85*
7.02	7.53	7.88	7.90	8.17	8.40	9.11	10.11	10.72	12.48	12.90	13.99	13.66	13.75	14.20	14.68	*15.60*	*16.40*	Book Value per sh	*19.15*
19.02	19.01	18.27	18.27	18.27	18.27	18.27	18.27	18.27	18.28	18.36	18.18	18.50	18.55	18.59	18.70	*20.00*	*21.00*	Common Shs Outst'g C	*23.00*
11.2	13.1	15.5	33.1	18.5	17.3	15.4	19.6	19.7	23.5	33.4	26.2	28.7	29.1	21.2	20.4	*Bold figures are*		Avg Ann'l P/E Ratio	*22.0*
.65	.68	.88	2.15	.95	.94	.88	1.04	1.05	1.27	1.77	1.58	1.91	1.85	1.33	1.31	*Value Line*		Relative P/E Ratio	*1.45*
4.3%	3.9%	3.0%	2.1%	3.0%	3.4%	3.5%	3.0%	2.4%	2.0%	1.7%	2.3%	2.8%	2.8%	2.9%	3.0%	*estimates*		Avg Ann'l Div'd Yield	*2.6%*

CAPITAL STRUCTURE as of 12/31/12
Total Debt $356.3 mill. **Due in 5 Yrs** $21.2 mill.
LT Debt $335.6 mill. **LT Interest** $18.6 mill.
(Total interest coverage: 4.6x) (55% of Cap'l)

Leases, Uncapitalized: Annual rentals $4.7 mill.

Pension Assets $75.5 mill. **Oblig.** $141.0 mill.

Pfd Stock None.

Common Stock 18,694,785 shs.

MARKET CAP: $500 million (Small Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
149.7	166.9	180.1	189.2	206.6	220.3	216.1	215.6	239.0	261.6	*285*	*310*	Revenues ($mill)	*375*
16.7	16.0	20.7	22.2	19.3	20.2	15.2	15.8	20.9	22.3	*26.0*	*29.0*	Net Profit ($mill)	*37.0*
36.2%	42.1%	41.6%	40.8%	39.4%	39.5%	40.4%	38.8%	41.1%	41.1%	*41.0%*	*40.0%*	Income Tax Rate	*40.0%*
1.6%	2.1%	1.6%	2.1%	2.7%	2.3%	2.0%	--	2.0%	2.0%	*3.0%*	*4.0%*	AFUDC % to Net Profit	*5.0%*
45.6%	43.7%	42.6%	41.8%	47.7%	46.0%	49.4%	53.7%	56.6%	55.0%	*54.5%*	*54.0%*	Long-Term Debt Ratio	*51.0%*
54.4%	56.3%	57.4%	58.2%	52.3%	54.0%	50.6%	46.3%	43.4%	45.0%	*45.5%*	*46.0%*	Common Equity Ratio	*49.0%*
306.0	328.3	341.2	391.8	453.2	470.9	499.6	550.7	607.9	610.2	*685*	*745*	Total Capital ($mill)	*900*
428.5	456.8	484.8	541.7	645.5	684.2	718.5	785.5	756.2	831.6	*890*	*950*	Net Plant ($mill)	*1150*
6.9%	6.5%	7.6%	7.0%	5.7%	5.8%	4.4%	4.3%	4.9%	5.2%	*5.0%*	*5.0%*	Return on Total Cap'l	*6.0%*
10.0%	8.7%	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	*8.5%*	*8.5%*	Return on Shr. Equity	*8.5%*
10.0%	8.7%	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	8.1%	*8.5%*	*8.5%*	Return on Com Equity	*8.5%*
4.7%	3.6%	5.6%	5.2%	3.5%	3.3%	1.2%	1.2%	3.1%	3.2%	*3.5%*	*4.0%*	Retained to Com Eq	*3.5%*
53%	58%	47%	46%	57%	59%	80%	80%	61%	60%	*56%*	*54%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	1.7	26.7	2.5
Other	36.3	42.2	40.4
Current Assets	38.0	68.9	42.9
Accts Payable	5.5	7.4	8.5
Debt Due	5.1	0.8	20.7
Other	18.6	20.1	19.9
Current Liab.	29.2	28.3	49.1
Fix. Chg. Cov.	262%	276%	247%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '16-'18
Revenues	6.0%	4.5%	*4.0%*
"Cash Flow"	6.0%	2.5%	*5.0%*
Earnings	2.0%	-3.0%	*7.5%*
Dividends	5.0%	5.0%	*4.5%*
Book Value	5.5%	4.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	40.4	54.1	70.3	50.8	215.6
2011	43.7	59.0	73.9	62.4	239.0
2012	51.2	65.6	82.4	62.4	261.6
2013	*55.0*	*70.0*	*90.0*	*70.0*	*285*
2014	*60.0*	*75.0*	*100*	*75.0*	*310*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2010	.05	.24	.44	.11	.84
2011	.03	.29	.44	.35	1.11
2012	.06	.28	.53	..31	1.18
2013	*.07*	*.32*	*.58*	*.33*	*1.30*
2014	*.10*	*.35*	*.60*	*.35*	*1.40*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.165	.165	.165	.165	.66
2010	.17	.17	.17	.17	.68
2011	.173	.173	.173	.173	.69
2012	.1775	.1775	.1775	.1775	.71
2013	.1825				

BUSINESS: SJW Corporation engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 227,000 connections that serve a population of approximately one million people in the San Jose area and 8,700 connections that serve approximately 36,000 residents in a service area in the region between San Antonio and Austin, Texas. The company offers nonregulated water-related services, including water system operations, cash remittances, and maintenance contract services. SJW also owns and operates commercial real estate investments. Has about 375 employees. Chrm.: Charles J. Toeniskoetter. Inc.: CA. Address: 110 W. Taylor Street, San Jose, CA 95110. Tel.: (408) 279-7800. Int: www.sjwater.com.

SJW is selling more stock. When the new offering is completed in late April, we expect the company will have sold 1.5 million new shares at a price of $26.50 each. This new issuance will increase the amount of equity outstanding by a hefty 8%.

We think the company's share net should see a nice rise in 2013. Early last year, SJW filed a rate case with state regulators seeking to raise fees by 21.5% in 2013, 4.9% in 2014, and 12.6% in 2016, respectively. No decision has been reached yet, but the utility was allowed to implement higher rates in January on an interim basis. So, even with the increase in shares outstanding, we think this additional revenue can increase SJW's earnings per share 10% this year, to $1.30.

Our earnings estimates for SJW are tentative as they are based upon reasonable regulatory ruling. Predicting the actions of a state regulatory commission is, to say the least, not an exact science. Faced with considerable political pressure to keep water rates low, we are still not forecasting a negative decision because certain of SJW main expenses did experience large increases in 2012. For example, the costs of purchasing water on the open market, which is SJW's largest expense, rose by almost 22%.

SJW's long-term capital expenditures will be substantial. With much of its existing infrastructure aging and in need of repair, the utility will probably have to spend more than $100 million annually over the next 3- to 5-year period. Internally generated cash won't come close to financing these outlays. Thus, the company will have to depend heavily on the outside markets. The resulting higher interest expense from the new debt issued will erode profits while more new equity offerings will dilute share earnings.

These timely shares are not for everyone. While the stock may do well in the short term as a result of the interim rate relief, its recent performance has discounted most of the positives, leaving it with below-average total return potential through 2016-2018. Moreover, a harsh ruling by regulators on SJW's pending rate cases could seriously impede the company's growth prospects.

James A. Flood *April 19, 2013*

(A) Diluted earnings. Excludes nonrecurring losses : '03, $1.97; '04, $3.78; '05, $1.09; '06, $16.36; '08, $1.22; '10, 46¢. Next earnings report due late May. Quarterly egs. 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 stock splits.

Company's Financial Strength	B+
Stock's Price Stability	80
Price Growth Persistence	60
Earnings Predictability	80

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AQUA AMERICA NYSE-WTR

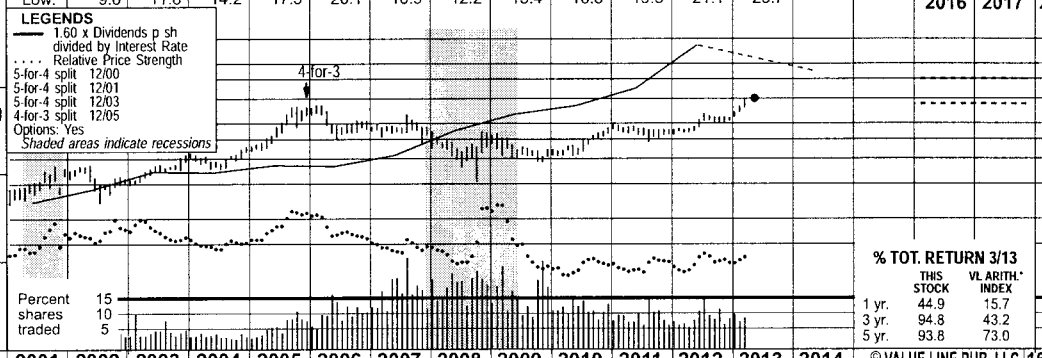
RECENT PRICE **32.12** | P/E RATIO **25.1** (Trailing: 29.2 / Median: 24.0) | RELATIVE P/E RATIO **1.50** | DIV'D YLD **2.2%** | VALUE LINE

TIMELINESS 2 Raised 10/5/12
SAFETY 2 Raised 4/20/12
TECHNICAL 3 Raised 4/12/13
BETA .60 (1.00 = Market)

High:	15.0	16.8	18.5	29.2	29.8	26.6	22.0	21.5	23.0	23.8	26.9	32.3
Low:	9.6	11.8	14.2	17.5	20.1	18.9	12.2	15.4	16.5	19.3	21.1	25.7

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.60 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
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 areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	8%
Low	30	(-5%)	1%

Insider Decisions

	M	J	J	A	S	O	N	D	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	1	0	0	0	0	1	3
to Sell	3	1	0	0	0	0	0	0	2

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	112	117	118
to Sell	108	108	117
Hld's(000)	60392	64465	67182

% TOT. RETURN 3/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	44.9	15.7
3 yr.	94.8	43.2
5 yr.	93.8	73.0

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
2.02	2.09	2.41	2.46	2.70	2.85	2.97	3.48	3.85	4.03	4.52	4.63	4.91	5.26	5.13	5.40	*5.70*	*5.90*	Revenues per sh	*6.40*
.56	.61	.72	.76	.86	.94	.96	1.09	1.21	1.26	1.37	1.42	1.61	1.78	1.81	1.89	*2.00*	*2.10*	"Cash Flow" per sh	*2.35*
.34	.40	.42	.47	.51	.54	.57	.64	.71	.70	.71	.73	.77	.90	1.04	1.09	*1.35*	*1.45*	Earnings per sh A	*1.60*
.24	.26	.27	.28	.30	.32	.35	.37	.40	.44	.48	.51	.55	.59	.63	.67	*.70*	*.84*	Div'd Decl'd per sh B■	*1.00*
.58	.82	.90	1.16	1.09	1.20	1.32	1.54	1.84	2.05	1.79	1.98	2.08	2.37	2.38	2.48	*2.65*	*2.65*	Cap'l Spending per sh	*2.65*
2.84	3.21	3.42	3.85	4.15	4.36	5.34	5.89	6.30	6.96	7.32	7.82	8.12	8.51	9.01	9.87	*11.20*	*12.25*	Book Value per sh	*13.30*
67.47	72.20	106.80	111.82	113.97	113.19	123.45	127.18	128.97	132.33	133.40	135.37	136.49	137.97	138.88	140.35	*140.50*	*141.00*	Common Shs Outst'g C	*143.00*
17.8	22.5	21.2	18.2	23.6	23.6	24.5	25.1	31.8	34.7	32.0	24.9	23.1	21.1	21.3	21.9	*Bold figures are*		Avg Ann'l P/E Ratio	*21.0*
1.03	1.17	1.21	1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.50	1.54	1.34	1.34	1.40	*Value Line*		Relative P/E Ratio	*1.40*
3.9%	2.9%	3.0%	3.3%	2.5%	2.5%	2.5%	2.3%	1.8%	1.8%	2.1%	2.8%	3.1%	3.1%	2.8%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*2.9%*

CAPITAL STRUCTURE as of 12/31/12
Total Debt $1669.2 mill. **Due in 5 Yrs** $368.3 mill.
LT Debt $1543.9 mill. **LT Interest** $60.0 mill.
(LT interest earned: 5.0x; total interest coverage: 4.1x) (53% of Cap'l)

Pension Assets-12/12 $190.1 mill. **Oblig.** $303.1 mill.

Pfd Stock None
Common Stock 140,347,743 shares as of 2/14/13
MARKET CAP: $4.5 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
367.2	442.0	496.8	533.5	602.5	627.0	670.5	726.1	712.0	757.8	*800*	*835*	Revenues ($mill)	*915*
67.3	80.0	91.2	92.0	95.0	97.9	104.4	124.0	144.8	153.1	*190*	*205*	Net Profit ($mill)	*220*
39.3%	39.4%	38.4%	39.6%	38.9%	39.7%	39.4%	39.2%	32.9%	39.0%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
--	--	--	--	--	--	--	--	2.9%	3.1%	*3.0%*	*3.0%*	AFUDC % to Net Profit	*2.0%*
51.4%	50.0%	52.0%	51.6%	55.4%	54.1%	55.6%	56.6%	52.7%	52.7%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
48.6%	50.0%	48.0%	48.4%	44.6%	45.9%	44.4%	43.4%	47.3%	47.3%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1355.7	1497.3	1690.4	1904.4	2191.4	2306.6	2495.5	2706.2	2646.8	2929.7	*3150*	*3450*	Total Capital ($mill)	*3800*
1824.3	2069.8	2280.0	2506.0	2792.8	2997.4	3227.3	3469.3	3612.9	3936.2	*4150*	*4350*	Net Plant ($mill)	*4600*
6.4%	6.7%	6.9%	6.4%	5.9%	5.7%	5.6%	5.9%	6.9%	6.6%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.0%*
10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	*12.0%*	*12.0%*	Return on Shr. Equity	*11.5%*
10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.6%	11.0%	*12.0%*	*12.0%*	Return on Com Equity	*11.5%*
4.2%	4.6%	4.9%	3.7%	3.2%	2.8%	2.7%	3.7%	4.6%	4.3%	*6.0%*	*6.0%*	Retained to Com Eq	*4.0%*
59%	57%	56%	63%	67%	70%	72%	65%	60%	61%	*52%*	*58%*	All Div'ds to Net Prof	*65%*

CURRENT POSITION ($MILL.)	2010	2011	12/31/12
Cash Assets	5.9	8.2	5.5
Receivables	85.9	81.1	92.9
Inventory (AvgCst)	9.2	11.2	11.8
Other	44.4	220.0	150.7
Current Assets	145.4	320.5	260.9
Accts Payable	45.3	68.3	55.5
Debt Due	28.5	80.4	125.4
Other	149.9	277.0	93.3
Current Liab.	223.7	425.7	274.2
Fix. Chg. Cov.	290%	367%	398%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	8.0%	7.5%	*3.5%*
"Cash Flow"	8.5%	8.0%	*4.5%*
Earnings	6.5%	4.5%	*8.0%*
Dividends	7.5%	8.0%	*8.0%*
Book Value	9.0%	7.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	160.5	178.5	207.8	179.3	726.1
2011	163.6	178.3	197.3	172.7	712.0
2012	164.0	191.7	214.6	187.5	757.8
2013	*180*	*210*	*215*	*195*	*800*
2014	*190*	*220*	*225*	*200*	*835*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	.16	.22	.32	.20	.90
2011	.22	.27	.30	.25	1.03
2012	.20	.30	.36	.25	1.09
2013	*.25*	*.35*	*.43*	*.32*	*1.35*
2014	*.28*	*.37*	*.47*	*.33*	*1.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.135	.135	.135	.145	.55
2010	.145	.145	.145	.155	.59
2011	.155	.155	.155	.165	.63
2012	.165	.165	.165	.175	.67
2013	.175				

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 '12: residential, 60.5%; commercial, 16.1%; industrial & other, 23.4%. Officers and directors own 1.4% of the common stock (4/13 Proxy). Chairman & Chief Executive Officer: Nicholas DeBenedictis. Incorporated: Pennsylvania. Address: 762 West Lancaster Avenue, Bryn Mawr, Pennsylvania 19010. Telephone: 610-525-1400. Internet: www.aquaamerica.com.

Aqua America ought to grow at a decent clip in 2013. The company should be able to capitalize on increased natural gas drilling that should strengthen over the long haul. WTR has some nice momentum after posting a record share net in 2012. The better-than-expected bottom-line figure was attributable to improved operational performance and solid growth in its regulated and unregulated units. It should be noted the GAAP share earnings included a tax benefit of $0.22. The benefit resulted from WTR revising its tax method of accounting for certain qualifying utility system repairs in its Pennsylvania operations (switched to expensing asset improvement costs that were previously being capitalized). That benefit included a "catchup clause" that allowed Aqua to reduce their tax bill from projects prior to 2012. We view the "catchup clause" as a one-time event and excluded it from our 2012 earnings presentation. However, the remaining tax benefit will be amortized over the next ten years and will be included in our projections going forward.

We are raising our 2013 share-net target from $1.15 to $1.35. We are also introducing 2014 estimates and expect revenue and share earnings to come in at $835 million and $1.45, respectively.

The balance sheet is looking healthier. WTR's cost-cutting plans, organic growth, and new tax method should continue to help generate solid free cash flow. A dividend hike may be possible, given that its current 50% payout ratio is below its historical average. Acquisitions may also be possible in markets with strong upside like Texas and Ohio.

Increased natural gas activity should provide a boost to profitability. The colder-than-expected winter has lifted prices to the $4.00 level of late. The Marcellus water pipeline venture finished its second phase and water has already begun pumping to drilling operators. Phase III of the project finished in March and will provide Shell with a majority of its water. Management also hinted there could be a Phase IV if market conditions permit.

These timely shares have risen 28% year to date. Thus, the stock may only be suitable for the income- and momentum-investor at this time.

Michael Collins *April 19, 2013*

(A) Diluted egs. Excl. nonrec. gains (losses): '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢; '12, 22¢. Excl. gain from disc. operations: '12, 9¢. May not sum due to rounding. Next earnings report due late April.
(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	100
Price Growth Persistence	65
Earnings Predictability	100

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ATTACHMENT B

Stocks in the Natural Gas Utility Industry have risen nicely in value of late. We attribute that movement partly to better-performing financial markets, as some central banks have indicated that they will maintain an expansionary monetary policy to help stimulate economic growth. Other catalysts include recent domestic data showing consumer confidence on the rise and the real estate sector gathering strength. Notably, when market corrections occur, the stocks in this category tend to be better off than those in a number of other industries. That's partly because their generous levels of dividend income provide a measure of stability.

The United States Economy

For the opening quarter of 2013, Gross Domestic Product (GDP) grew 2.4%, quite a turnaround from the fourth-quarter tally of just 0.4% (following an upward revision). Contributing factors included a rise in personal consumption expenditures, a smaller decrease in federal government spending, and an upturn in exports. Still, the first-quarter result was a bit lower than the better-than-3% gain generally forecasted, as there was a cooling off in industrial production and retail spending levels later during that period. For the second quarter, we believe that economic growth will average between just 1% and 2%, reflecting, among other things, uneven services sector gains, further sluggishness in industrial production, plus ongoing economic difficulties in Europe. In this not-so-spectacular operating environment, customers have been focusing on energy conservation, which, of course, acts as a restraint on the revenues of the companies included in the Natural Gas Utility Industry.

Rate Cases

Rate cases are a very important factor for natural gas utilities. Federal authorities establish wholesale service tariffs, and state regulators determine retail distribution rates. Adequate returns on common equity are necessary to keep these businesses viable. Higher rates are sought to pay for the cost of expansion, storm damage, and/or to cover the expenses of maintaining reliable service. To promote good relationships with customers and regulators, managements endeavor to keep operating and service costs as low as possible. At times, however, political pressure can compel authorities to limit rates of return, to the detriment of utility companies. But mostly, regulators attempt to strike an equitable balance between the interests of shareholders and customers.

Effect of Low Gas Prices On The Industry

Contrary to what some believe, a low gas price environment is generally good for regulated utility operations. That's partly because it may lead to reduced prices for customers, which could lessen bad-debt expense. Moreover, there is an increased possibility that homeowners will switch from alternative fuel sources, such as oil or propane, to natural gas. Even so, the companies in our category also possess nonregulated businesses, including energy marketing and trading, which tend to underperform when gas prices are in a slump.

INDUSTRY TIMELINESS: 35 (of 97)

Oklahoma Tornado

In late May, a powerful tornado, with winds exceeding 200 miles per hour, tore through a central Oklahoma city, demolishing thousands of homes and numerous other buildings, along a 17-mile path. Preliminary estimates indicate that the total damage could be roughly $2 billion.

Natural gas distribution pipelines are located mostly underground, providing a good measure of protection against adverse weather conditions. Nonetheless, these assets can be damaged by uprooted trees and shifted foundations. In addition, fallen tree limbs and other debris can crush meters and associated piping near homes and other buildings. It appears that companies in the group with operations in the affected area held up reasonably well, though.

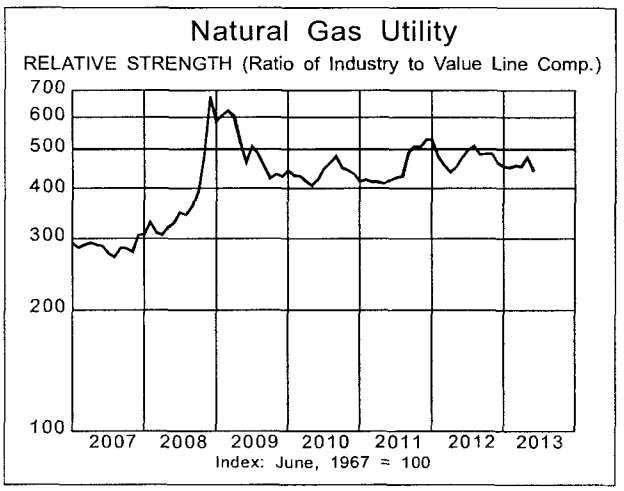
Dividends

The primary attraction of utility equities is their generous levels of dividend income. At the time of this writing, the average yield for the 11 companies in our group was about 3.4%, considerably higher than the *Value Line* median of 2.1%. Standouts include *AGL Resources*, *Northwest Natural Gas*, *Laclede Group*, and *WGL Holdings*. When the financial markets are turbulent, which seems to be more common these days, healthy dividend yields tend to act as an anchor, so to speak, in this category.

Conclusion

Stocks in the Natural Gas Utility Industry are most appropriate for income-oriented investors with a conservative bent (given that a number of these issues are ranked favorably for Safety and earn high marks for Price Stability). It should be noted, however, that companies with larger nonregulated operations may offer a higher potential for returns, though profits could be more volatile than for companies with a greater emphasis on the more stable utility segment. As always, our readers are advised to carefully examine the following reports before making a commitment.

Frederick L. Harris, III



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AGL RESOURCES NYSE-GAS

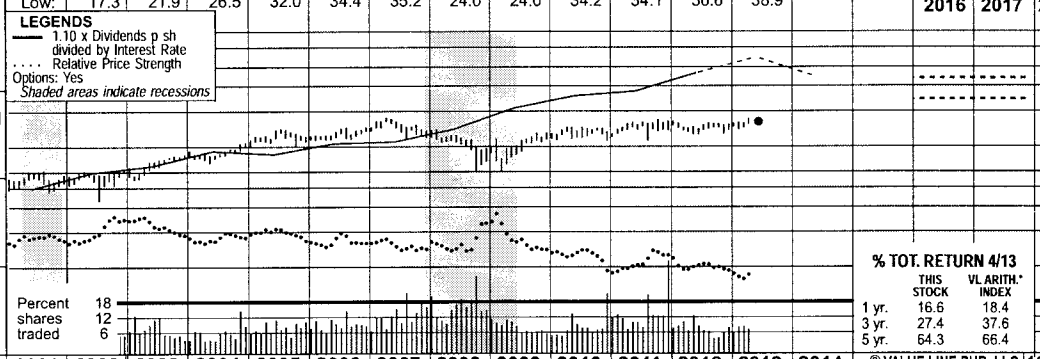
RECENT PRICE **42.55** | P/E RATIO **16.7** (Trailing: 17.0 / Median: 13.0) | RELATIVE P/E RATIO **0.96** | DIV'D YLD **4.4%** | VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 1 Raised 9/9/11
TECHNICAL 3 Raised 6/7/13
BETA .75 (1.00 = Market)

High:	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9	44.8
Low:	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6	38.9

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+65%)	16%
Low	55	(+30%)	10%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	2	0	0	0	0	0	1	0
to Sell	0	2	0	0	0	0	0	2	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	136	150	150
to Sell	151	140	141
Hld's(000)	69954	70430	71771

Percent shares traded 18 12 6

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.6	18.4
3 yr.	27.4	37.6
5 yr.	64.3	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	19.97	33.27	*35.50*	*37.65*	Revenues per sh A	*44.85*
2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.06	5.82	*6.10*	*6.65*	"Cash Flow" per sh	*8.40*
1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	2.32	*2.55*	*2.90*	Earnings per sh A B	*4.10*
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	1.90	1.74	*1.88*	*1.92*	Div'ds Decl'd per sh CF■	*2.04*
2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.65	6.63	*5.15*	*5.60*	Cap'l Spending per sh	*6.45*
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	23.24	28.33	28.76	*32.80*	*33.75*	Book Value per sh D	*36.05*
56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.10	117.88	*117.00*	*117.00*	Common Shs Outst'g E	*117.00*
14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	18.8	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	1.18	.82	*Value Line*		Relative P/E Ratio	*1.00*
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%	4.7%	4.8%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $5071 mill. **Due in 5 Yrs** $2370 mill.
LT Debt $3324 mill. **LT Interest** $184 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $214.9 mill.
Pension Assets-12/12 $845.0 mill. **Oblig.** $968.0 mill.

Pfd Stock None

Common Stock 118,180,688 shs. **as of 4/24/13**

MARKET CAP: $5.0 billion (Large Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	3922.0	*4155*	*4405*	Revenues ($mill) A	*5250*
132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	271.0	*300*	*340*	Net Profit ($mill)	*480*
35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	39.8%	*38.0%*	*36.5%*	Income Tax Rate	*32.5%*
13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	6.9%	*7.0%*	*7.7%*	Net Profit Margin	*9.2%*
50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	51.8%	49.5%	*48.0%*	*48.5%*	Long-Term Debt Ratio	*51.5%*
49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.2%	50.5%	*52.0%*	*51.5%*	Common Equity Ratio	*48.5%*
1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	6879.0	6716.0	*7365*	*7685*	Total Capital ($mill)	*8670*
2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	8347.0	*8850*	*9380*	Net Plant ($mill)	*11170*
8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.1%	5.4%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	8.0%	*8.0%*	*8.5%*	Return on Shr. Equity	*11.5%*
14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	8.0%	*8.0%*	*8.5%*	Return on Com Equity	*6.0%*
6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	2.0%	*2.0%*	*2.0%*	Retained to Com Eq	*6.0%*
53%	49%	52%	52%	58%	60%	57%	57%	86%	75%	*74%*	*66%*	All Div'ds to Net Prof	*50%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	69	131	149
Other	2677	2537	2212
Current Assets	2746	2668	2361
Accts Payable	294	334	314
Debt Due	1928	2214	1747
Other	862	790	999
Current Liab.	3084	3338	3060
Fix. Chg. Cov.	325%	330%	650%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	5.0%	-3.0%	*8.0%*
"Cash Flow"	4.5%	1.5%	*10.0%*
Earnings	8.0%	1.5%	*9.0%*
Dividends	5.0%	6.5%	*2.0%*
Book Value	8.0%	5.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	1003	359	346	665	2373
2011	878	375	295	790	2338
2012	1404	686	614	1218	3922
2013	1709	*650*	*560*	*1236*	*4155*
2014	*1805*	*695*	*595*	*1310*	*4405*

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.12	.28	.08	.84	2.32
2013	1.31	*.25*	*.15*	*.84*	*2.55*
2014	*1.75*	*.25*	*.15*	*.75*	*2.90*

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45	.45	.55	1.90
2012	.36	.46	.46	.46	1.74
2013	.47	.47			

BUSINESS: AGL Resources Inc. is a public utility holding company. Distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, Virginia Natural Gas, Florida City Gas and Elkton Gas. Acquired Nicor in 2011. The utilities have more than 4.4 million customers in Georgia, Virginia, Tennessee, New Jersey, Florida, and Illinois. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. BlackRock Inc. owns 7.0% of common stock; officers/directors, less than 1.0% (3/13 Proxy). President & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources' first-quarter results showed marked improvement over a year ago. Net income rose to $154 million (up 18%), and earnings per share were $1.31, a 17% increase. Total revenues rebounded from a year ago on the back of a cooler first quarter, which tended to be more in line with historical temperatures. A year ago, earnings were dragged down by Nicor merger-related expenses, which are no longer a factor. The company has outstanding rates cases and possible positive legislative actions, including a New Jersey update infrastructure replacement program, a Georgia expanded infrastructure case, and an Illinois depreciation rate change. These actions will likely be ruled upon by year's end, and positive results could boost earnings. The company also signed an agreement with UPS to deliver 500,000 gallons of liquid natural gas monthly in Tennessee over a 10-year contract, which should boost margins even further.

The company is building up its cash position through debt issuances and divestitures. Senior notes totalling $500 million were issued at a 4.4% coupon over 30 years. The interest rate is low compared to historical averages and should be highly beneficial to earnings when rates start to rise. It also sold off its Compass Energy subsidiary. The sale brought in $12 million, which will be upped by an additional $3 million-$8 million, based upon financial performance. This should add $0.05 a share to second-quarter earnings. Overall, the balance sheet continues to be strong, but total share count continues to creep higher.

The Timeliness rank of AGL Resources' shares is 3 (Average). However, this issue has some appealing characteristics, such as the highest total-return potential in the sector. Though price growth from its high perch may be somewhat limited, GAS shares remain a good choice for conservative and income-based investors, as the yield is also the highest in Natural Gas Utilities segment. That said, we have low expectations for future dividend increases at this point. Conservative investors should also notice the stock's high marks for Price Stability and Safety.

John E. Seibert III *June 7, 2013*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late July.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2012: $1933 million, $17.91/share.
(E) In millions. (F) Excluding special dividends from the Nicor merger.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	70

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ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
43.02	17.8 (Trailing: 17.7 / Median: 14.0)	1.02	3.3%

VALUE LINE

TIMELINESS 2 Raised 5/24/13
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Raised 5/3/13
BETA .70 (1.00 = Market)

High:	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3	45.1
Low:	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4	34.9

Target Price Range
2016 | 2017 | 2018

2016-18 PROJECTIONS

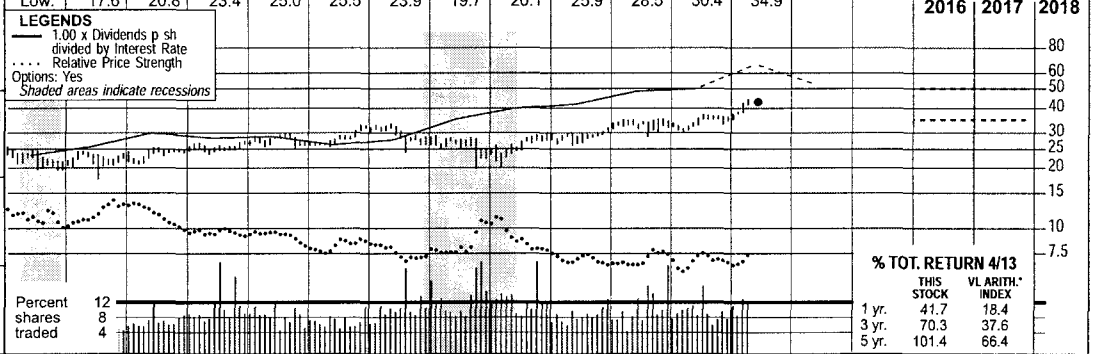
	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	35	(-20%)	-1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	1	0	0	0
to Sell	0	2	0	0	0	1	0	0	3

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	112	107	118
to Sell	131	115	115
Hld's(000)	51653	52881	53879



% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	41.7	18.4
3 yr.	70.3	37.6
5 yr.	101.4	66.4

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.

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	38.10	*38.35*	*39.15*	Revenues per sh A	*56.30*
3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	4.76	*5.20*	*5.45*	"Cash Flow" per sh	*6.05*
1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	*2.45*	*2.60*	Earnings per sh A B	*3.00*
1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	*1.40*	*1.42*	Div'ds Decl'd per sh C■	*1.50*
3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	8.12	*8.55*	*8.70*	Cap'l Spending per sh	*9.00*
16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	26.14	*29.70*	*31.30*	Book Value per sh	*34.65*
51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	90.24	*91.00*	*92.00*	Common Shs Outst'g D	*103.00*
13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.76	.84	.86	.73	.84	.82	.83	.84	.90	1.01	*Value Line*		Relative P/E Ratio	*.95*
5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*
2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	*3490*	*3600*	Revenues ($mill) A	*5800*
79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	192.2	*225*	*240*	Net Profit ($mill)	*310*
37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	*35.0%*	*35.0%*	Income Tax Rate	*38.0%*
2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	*6.4%*	*6.7%*	Net Profit Margin	*5.3%*
50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	45.3%	*49.0%*	*49.0%*	Long-Term Debt Ratio	*49.0%*
49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	54.7%	*51.0%*	*51.0%*	Common Equity Ratio	*51.0%*
1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	4315.5	*5300*	*5650*	Total Capital ($mill)	*7000*
1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	5475.6	*5825*	*6200*	Net Plant ($mill)	*8000*
6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	5.8%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	*8.5%*	*8.5%*	Return on Shr. Equity	*8.5%*
9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	8.1%	*8.5%*	*8.5%*	Return on Com Equity	*8.5%*
2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	2.8%	*3.5%*	*4.0%*	Retained to Com Eq	*4.5%*
70%	77%	73%	63%	65%	65%	68%	62%	62%	65%	*57%*	*54%*	All Div'ds to Net Prof	*50%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $2688.5 mill. **Due in 5 Yrs** $1320.0 mill.
LT Debt $2455.5 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.6 mill.
Pfd Stock None
Pension Assets-9/12 $343.1 mill. **Oblig.** $480.0 mill.
Common Stock 90,549,038 shs. as of 4/26/13
MARKET CAP: $3.9 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	131.4	64.2	65.5
Other	879.6	763.8	936.9
Current Assets	1011.0	828.0	1002.4
Accts Payable	291.2	215.2	316.4
Debt Due	208.8	571.1	233.0
Other	367.6	489.7	377.4
Current Liab.	867.6	1276.0	926.8
Fix. Chg. Cov.	432%	448%	445%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	5.0%	-7.0%	*3.5%*
"Cash Flow"	4.0%	3.0%	*4.5%*
Earnings	5.0%	3.0%	*5.5%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	6.5%	4.0%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1133.3	1581.5	843.6	789.2	4347.6
2012	1084.0	1225.5	576.4	552.6	3438.5
2013	1034.2	1309.0	*581*	*565.8*	*3490*
2014	*1050*	*1350*	*610*	*590*	*3600*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	.04	.01	2.26
2012	.68	1.12	.31	--	2.10
2013	.85	1.23	*.34*	*.03*	*2.45*
2014	*.82*	*1.37*	*.35*	*.06*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34	.34	.345	1.37
2012	.345	.345	.345	.35	1.39
2013	.35	.35			

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to more than three million customers through six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Gas sales breakdown for 2012: 65%, residential; 28%, commercial; 3%, industrial; and 4% other. 2012 depreciation rate 3.3%. Has around 4,760 employees. Officers and directors own 1.2% of common stock (12/12 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Incorporated: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

Atmos Energy generated solid profits during the first half of fiscal 2013 (ends September 30th), relative to the year-earlier tally. The bread-and-butter natural gas distribution unit benefited from a drop in operating expenses, including legal and depreciation costs. Notably, during that period, Atmos was able to complete 10 rate-case proceedings, which ought to result in a $66.4 million rise in annual operating income. (The majority of the increase is for the Mid-Tex division.) Meanwhile, the regulated transmission and storage operation enjoyed higher revenues from a Gas Reliability Infrastructure Program filing that became effective in April, 2012. At this juncture, it seems that Atmos' fiscal 2013 share net will climb about 16%, to $2.45. Assuming additional expansion of operating margins, the bottom line stands to advance another 6%, to $2.60 a share, next year.

Non-core operations have been divested. One of them was the natural gas distribution segment in Georgia, representing around 64,000 customers, to an affiliate of Algonquin Power & Utilities Corp. for about $155 million. That follows the sale of the natural gas distribution business in Missouri, Iowa, and Illinois (serving roughly 84,000 customers) to an affiliate of Algonquin Power & Utilities Corp. for $129 million. Management has used the proceeds from those deals to support growth initiatives in such key states as Texas and Louisiana.

The stock offers a healthy amount of current dividend income, which is well covered by earnings. Too, our 2016-2018 projections indicate that further, albeit moderate, increases in the payout will probably take place. Other positives include a 2 (Above Average) Safety rank and excellent score for Price Stability.

The shares have climbed to their highest levels since our last report in March. We attribute that movement partially to Atmos' solid profits during fiscal 2013. Consequently, the equity is ranked to outperform the year-ahead market. But it appears that the good news is already reflected in the recent quotation, dampening long-term capital appreciation potential.

Frederick L. Harris, III *June 7, 2013*

(A) Fiscal year ends Sept. 30th. (B) Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 27¢; '13, 8¢. Next egs. rpt. due early Aug. (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

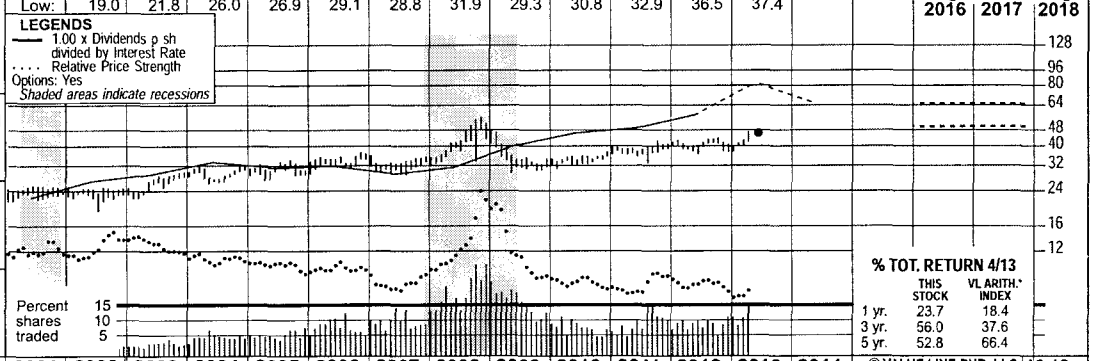
RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
46.46	15.7	(Trailing: 16.4 / Median: 14.0)	0.90	3.7%	VALUE LINE

TIMELINESS 3 Lowered 9/23/11
SAFETY 2 Raised 6/20/03
TECHNICAL 3 Raised 5/3/13
BETA .60 (1.00 = Market)

High:	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0	47.1
Low:	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5	37.4

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+40%)	12%
Low	50	(+10%)	6%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	1	2
to Sell	0	0	0	0	0	0	0	1	2

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	62	56	68
to Sell	64	75	52
Hld's(000)	10921	11121	11283

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.7	18.4
3 yr.	56.0	37.6
5 yr.	52.8	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
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	77.83	71.48	49.76	*50.40*	*50.90*	Revenues per sh A	*58.80*
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	4.11	4.62	4.58	*4.65*	*4.85*	"Cash Flow" per sh	*5.90*
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	2.43	2.86	2.79	*2.85*	*3.00*	Earnings per sh A B	*3.75*
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	1.66	*1.74*	*1.76*	Div'ds Decl'd per sh C■	*1.82*
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	2.56	3.02	4.71	*5.00*	*2.90*	Cap'l Spending per sh	*3.00*
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	24.02	25.56	26.60	*26.65*	*27.30*	Book Value per sh D	*28.65*
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	22.29	22.43	22.62	*23.0*	*23.0*	Common Shs Outst'g E	*23.5*
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	13.7	13.0	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	*15.5*
.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.82	.97	*Value Line*		Relative P/E Ratio	*1.05*
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%	4.7%	4.3%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $464.4 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $464.4 mill. **LT Interest** $24.0 mill.
(Total interest coverage: 4.4x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/11 $248.0 mill. **Oblig.** $384.2 mill.

Pfd Stock None
Common Stock 22,671,392 shs.
as of 4/26/13

MARKET CAP: $1.1 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	*1150*	*1175*	Revenues ($mill) A	*1400*
34.6	36.1	40.1	50.5	49.8	57.6	64.3	54.0	63.8	63.1	*65.0*	*70.0*	Net Profit ($mill)	*90.0*
35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	32.0%	*31.0%*	*30.0%*	Income Tax Rate	*28.0%*
3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	*5.6%*	*5.9%*	Net Profit Margin	*6.4%*
50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.0%	*42.0%*	*43.5%*	Long-Term Debt Ratio	*48.0%*
49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	64.0%	*58.0%*	*56.5%*	Common Equity Ratio	*52.0%*
605.0	737.4	707.9	798.9	784.5	876.1	906.3	899.9	937.7	941.0	*1050*	*1115*	Total Capital ($mill)	*1325*
621.2	646.9	679.5	763.8	793.8	823.2	855.9	884.1	928.7	1019.3	*1025*	*1175*	Net Plant ($mill)	*1120*
7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	6.5%	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	*10.5%*	*11.0%*	Return on Shr. Equity	*13.0%*
11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	*10.5%*	*11.0%*	Return on Com Equity	*13.0%*
3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	*4.1%*	*4.5%*	Retained to Com Eq	*6.8%*
74%	73%	72%	59%	63%	56%	53%	64%	56%	60%	*61%*	*59%*	All Div'ds to Net Prof	*48%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	43.3	27.5	146.9
Other	325.8	315.5	313.0
Current Assets	369.1	343.0	459.9
Accts Payable	96.6	89.5	108.6
Debt Due	46.0	25.0	- -
Other	89.3	137.6	98.7
Current Liab.	231.9	252.1	207.3
Fix. Chg. Cov.	463%	442%	438%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	5.0%	-5.5%	*-2.0%*
"Cash Flow"	5.0%	4.5%	*5.0%*
Earnings	7.0%	4.0%	*5.5%*
Dividends	2.0%	3.0%	*2.0%*
Book Value	5.5%	6.5%	*2.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	491.2	635.3	324.5	284.0	1735.0
2011	444.2	543.8	344.3	271.0	1603.3
2012	410.9	358.2	186.9	169.5	1125.5
2013	307.0	397.6	*210*	*235.4*	*1150*
2014	*375*	*405*	*215*	*180*	*1175*

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	1.03	1.26	.21	d.07	2.43
2011	1.05	1.25	.69	d.13	2.86
2012	1.12	1.32	.38	d.03	2.79
2013	1.14	1.34	*.40*	*d.03*	*2.85*
2014	*1.25*	*1.45*	*.40*	*d.10*	*3.00*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.385	.385	.385	.385	1.54
2010	.395	.395	.395	.395	1.58
2011	.405	.405	.405	.405	1.62
2012	.415	.415	.415	.415	1.66
2013	.425	.425			

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 628,000 customers. Purchased SM&P Utility Resources, 1/02; divested, 3/08. Utility therms sold and transported in fiscal 2012: 1.0 bill. Revenue mix for regulated operations: residential, 64; commercial and industrial, 21%; transportation, 2%; other, 13%. Has around 1,640 employees. Officers and directors own approximately 7% of common shares (1/13 proxy). Chairman: William E. Nasser; CEO: Suzanne Sitherwood. Incorporated: Missouri. Address: 720 Olive Street, St. Louis, Missouri 63101. Telephone: 314-342-0500. Internet: www.thelacledegroup.com.

The Laclede Group reported good fiscal second-quarter earnings. Revenues came in at $397.6 million, while per share earnings were a robust $1.34, which includes merger-related expenses. Profits were helped by lower pension costs and a cooler winter. Revenues were also boosted by higher infrastructure spending, which is passed through to customers as part of the infrastructure system replacement surcharge (ISRS). The company's outstanding rate case, which potentially could drive revenues even higher through enhanced ISRS rates, could boost earnings as early as the second half of 2013, though the timing of an outcome is somewhat uncertain.

The Missouri Gas Purchase appears to be on track. The financing behind the bridge loan, which will go toward paying the $1.035 billion cost, is fully syndicated, and all parties are waiting on regulatory approval. Indeed, the governing body's approval in Massachusetts will be necessary for the selloff of the New England Gas Co. to Algonquin Power. After the deal is complete, management expects to leverage the capital structure to return to a more normal one-to-one debt to equity ratio. The company has announced an equity sale, and we will update our estimates as more information becomes available.

The Laclede Group is maintaining a high level of capital expenditures. Management expects the spending to total around $115 million for fiscal 2013, which is largely recoverable under ISRS. The company is still working on building its natural gas vehicle fueling station at Lambert Airport in St. Louis, and could have other stations in the pipeline. Though capital expenditures are high, cash flow has improved year over year, thus far.

The Timeliness rank of Laclede Group stock is 3 (Average). These shares are expected to market perform over the next six to 12 months. The stock has performed well (up 15%) since our last report, and the dividend yield remains good for a natural gas utility. The total return potential is also above average for the sector. This issue should appeal to both conservative and income investors, but waiting for a dip may be the best course of action, as this stock is up considerably for a utility.

John E. Seibert III *June 7, 2013*

(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 July. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '12: $456.0 mill., $20.41/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	50
Earnings Predictability	85

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NEW JERSEY RES. NYSE-NJR

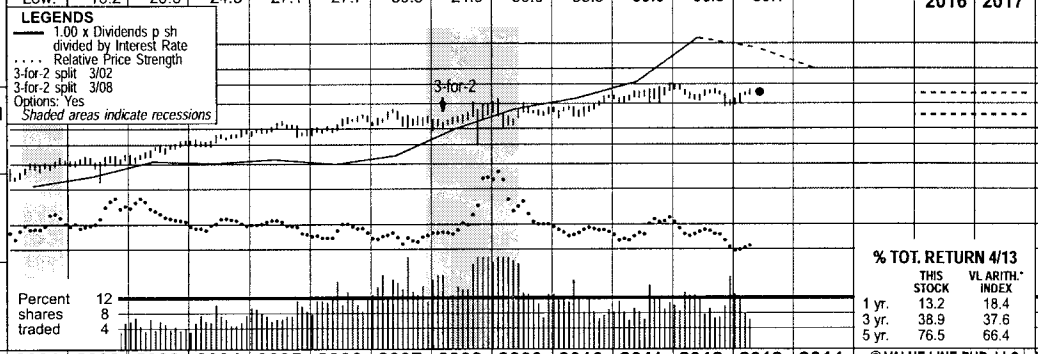
RECENT PRICE **45.56** | P/E RATIO **17.4** (Trailing: 19.6 / Median: 16.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **3.5%** | VALUE LINE

TIMELINESS 3 Raised 5/10/13
SAFETY 1 Raised 9/15/06
TECHNICAL 3 Lowered 2/1/13
BETA .65 (1.00 = Market)

High:	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	44.1	50.5	50.3	47.6
Low:	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	33.5	39.6	38.5	39.1

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 3/02
3-for-2 split 3/08
Options: Yes
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(Nil)	3%
Low	35	(-25%)	-2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	1	0	0	0
to Sell	0	0	0	0	0	0	0	3	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	68	73	84
to Sell	80	75	68
Hld's(000)	23904	23780	24376

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.2	18.4
3 yr.	38.9	37.6
5 yr.	76.5	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
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	64.10	72.60	54.16	*66.25*	*68.25*	Revenues per sh A	*74.55*
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	3.26	3.40	3.74	*3.55*	*3.75*	"Cash Flow" per sh	*4.00*
.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	2.46	2.58	2.71	*2.60*	*2.70*	Earnings per sh B	*2.95*
.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	1.36	1.44	1.54	*1.60*	*1.60*	Div'ds Decl'd per sh C■	*1.72*
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	2.10	2.26	2.00	*2.00*	*2.00*	Cap'l Spending per sh	*2.00*
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	17.62	18.73	18.15	*18.70*	*19.85*	Book Value per sh D	*23.50*
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	41.17	41.45	41.53	*40.00*	*40.00*	Common Shs Outst'g E	*40.00*
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	15.0	16.8	16.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.08	*Value Line*		Relative P/E Ratio	*.95*
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%	3.7%	3.3%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $824.4 mill. **Due in 5 Yrs** $214.3 mill.
LT Debt $527.7 mill. **LT Interest** $19.6 mill.
Incl. $65.8 mill. capitalized leases.
(LT interest earned: 7.5x; total interest coverage: 7.5x)
Pension Assets-9/12 $207.8 mill. **Oblig.** $332.2 mill.
Pfd Stock None
Common Stock 41,776,523 shs. as of 4/30/13
MARKET CAP: $1.9 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	*2650*	*2730*	Revenues ($mill) A	*2980*
65.4	71.6	74.4	78.5	65.3	113.9	101.0	101.8	106.5	112.8	*105*	*110*	Net Profit ($mill)	*120*
39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	8.6%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	5.0%	*4.0%*	*4.0%*	Net Profit Margin	*4.0%*
38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	*40.0%*	*38.5%*	Long-Term Debt Ratio	*34.5%*
61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	*60.0%*	*61.5%*	Common Equity Ratio	*65.5%*
676.8	783.8	755.3	954.0	1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	*1245*	*1295*	Total Capital ($mill)	*1440*
852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	*1515*	*1545*	Net Plant ($mill)	*1640*
10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	9.4%	*9.5%*	*9.5%*	Return on Total Cap'l	*9.0%*
15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.9%	*14.0%*	*14.0%*	Return on Shr. Equity	*12.5%*
15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	13.9%	*14.0%*	*14.0%*	Return on Com Equity	*12.5%*
7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	6.2%	*5.5%*	*5.5%*	Retained to Com Eq	*5.5%*
51%	49%	50%	50%	64%	40%	50%	52%	55%	56%	*61%*	*59%*	All Div'ds to Net Prof	*58%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	7.4	4.5	6.0
Other	725.0	642.8	756.6
Current Assets	732.4	647.3	762.6
Accts Payable	66.0	265.8	340.3
Debt Due	166.9	287.6	296.7
Other	470.5	99.7	99.5
Current Liab.	703.4	653.1	736.5
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	4.5%	-3.5%	*2.5%*
"Cash Flow"	5.0%	6.0%	*2.5%*
Earnings	7.0%	8.5%	*2.0%*
Dividends	6.5%	8.5%	*3.0%*
Book Value	8.0%	6.5%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	609.6	918.4	479.8	631.5	2639.3
2011	713.2	977.0	648.1	670.9	3009.2
2012	642.4	612.9	425.1	568.5	2248.9
2013	736.0	960.9	*470*	*483.1*	*2650*
2014	*755*	*980*	*490*	*505*	*2730*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	.66	1.55	.28	d.03	2.46
2011	.71	1.62	.23	.02	2.58
2012	1.09	1.79	.10	d.27	2.71
2013	.85	1.64	*.25*	*d.14*	*2.60*
2014	*.87*	*1.86*	*.17*	*d.20*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.31	.31	.31	.31	1.24
2010	.34	.34	.34	.34	1.36
2011	.36	.36	.36	.36	1.44
2012	.38	.38	.38	.80	1.94
2013	--	.40	.40		

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 500,070 customers at 9/30/12 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2012 volume: 161 bill. cu. ft. (6% interruptible, 31% residential and commercial and electric utility, 63% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2012 dep. rate: 2.3%. Has 927 empls. Off./dir. own about 1.1% of common (12/12 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 a mixed bag of financial results for the March interim. Indeed, the company's top line advanced approximately 57% on a year-over-year basis, to roughly $961 million. The bulk of this gain can be attributed to 3,697 new customer accounts at the New Jersey Natural Gas division. Those accounts were added in the first half of this fiscal year. Meanwhile, most of NJR's operating segments logged higher contributions to net financial earnings. The only two segments to register weaker contributions were the NJR Clean Energy Ventures and NJR Home Services units. Unfortunately, when combined with rising operating expenses, NJR's second-quarter bottom line declined about 8.5%, to $1.64. This was slightly lower than we had previously anticipated. However, we do expect the results to improve in the second half of the year. Consequently,

We have left our 2013 earnings estimate unchanged at $2.60 a share. Management has recently raised its guidance for new customer accounts at its New Jersey Natural Gas regulated utility division, which makes up the lion's share of overall operations. That segment was expected to add 12,500-14,500 new customers during 2013 and 2014 combined. However, at this point, it has raised the range to 13,000 to 15,000. Additionally, we look for the NJR Energy Services, NJR Clean Energy Ventures, and NJR Energy Holdings to be nicely complementary.

The overall financial position is in good shape. Indeed, the company's cash position has improved almost 33% during the first six months of this year, leaving its reserves at almost $6.0 million. Meantime, the long-term debt load continues to remain constant and represents a modest and easily serviceable portion of the capital structure.

Shares of New Jersey Resources have modest appeal for conservative investors. NJR offers a dividend yield that is in line with the median for the industry. Prospects are solid for good dividend growth, as well. Meanwhile, our Timeliness Ranking System suggests this equity will mirror the broader market averages in the year ahead. And total return potential is limited through 2016-2018.

Bryan J. Fong *June 7, 2013*

(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 July.
(C) Dividends historically paid in early Jan., April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2012: $441.3 million, $10.63/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	50

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N.W. NAT'L GAS NYSE-NWN

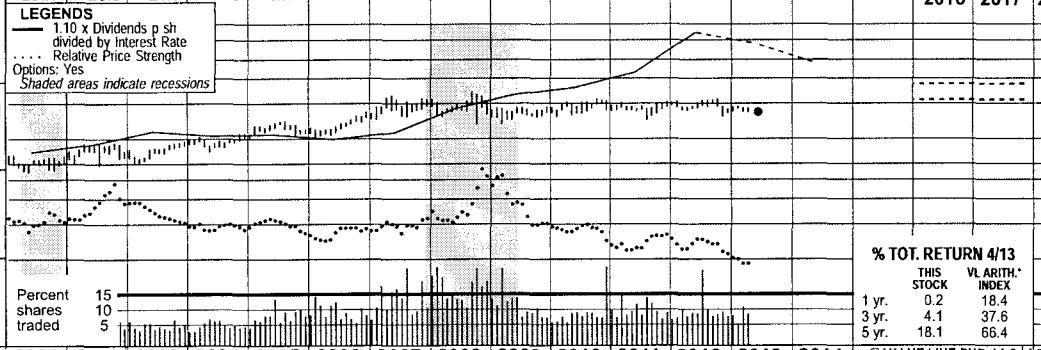
RECENT PRICE	43.56	P/E RATIO	18.9 (Trailing: 20.6 / Median: 17.0)	RELATIVE P/E RATIO	1.09	DIV'D YLD	4.2%	VALUE LINE

TIMELINESS 4 Lowered 5/10/13
SAFETY 1 Raised 3/18/05
TECHNICAL 3 Raised 5/10/13
BETA .60 (1.00 = Market)

High:	30.7	31.3	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8	46.6
Low:	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0	43.0

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	11%
Low	50	(+15%)	7%

Insider Decisions

	J	A	S	O	N	D	J	F	M
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	3	0	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	70	72	72
to Sell	51	54	58
Hld's(000)	16429	15820	16052

Percent shares traded 15 10 5

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	0.2	18.4
3 yr.	4.1	37.6
5 yr.	18.1	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	27.14	*27.60*	*28.15*	Revenues per sh	*29.65*
3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	4.94	*4.30*	*4.55*	"Cash Flow" per sh	*5.45*
1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	2.22	*2.30*	*2.50*	Earnings per sh A	*3.30*
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	1.75	1.79	*1.83*	*1.87*	Div'ds Decl'd per sh B■	*2.00*
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	9.35	3.76	4.91	*6.10*	*6.35*	Cap'l Spending per sh	*7.00*
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	26.08	26.70	27.23	*28.00*	*29.15*	Book Value per sh D	*31.70*
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	26.58	26.76	26.92	*27.00*	*27.00*	Common Shs Outst'g C	*28.00*
14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	21.1	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.19	1.35	*Value Line*		Relative P/E Ratio	*1.15*
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%	3.6%	3.9%	3.8%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $822.5 mill. **Due in 5 Yrs** $200 mill.
LT Debt $691.7 mill. **LT Interest** $45.0 mill.

(Total interest coverage: 3.3x)

Pension Assets-12/12 $249.6 mill. **Oblig.** $435.9 mill.

Pfd Stock None

Common Stock 26,948,572 shares as of 4/26/13

MARKET CAP $1.2 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	730.6	*745*	*760*	Revenues ($mill)	*830*
46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	59.9	*63.0*	*67.5*	Net Profit ($mill)	*93.0*
33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	42.4%	*37.5%*	*36.0%*	Income Tax Rate	*31.0%*
7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	8.2%	*8.4%*	*8.9%*	Net Profit Margin	*11.1%*
49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	48.5%	*48.5%*	*48.5%*	Long-Term Debt Ratio	*48.0%*
50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	51.5%	*51.5%*	*51.5%*	Common Equity Ratio	*52.0%*
1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	1424.7	*1470*	*1530*	Total Capital ($mill)	*1710*
1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	1973.6	*2055*	*2135*	Net Plant ($mill)	*2400*
5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	5.7%	*4.5%*	*5.5%*	Return on Total Cap'l	*5.5%*
9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*10.5%*
9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	8.2%	*8.5%*	*8.5%*	Return on Com Equity	*10.5%*
2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	1.6%	*1.5%*	*2.0%*	Retained to Com Eq	*4.5%*
72%	69%	63%	59%	52%	59%	56%	61%	73%	80%	*80%*	*75%*	All Div'ds to Net Prof	*60%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	5.8	8.9	8.3
Other	342.9	274.8	239.9
Current Assets	348.7	283.7	248.2
Accts Payable	86.3	85.6	77.0
Debt Due	181.6	190.3	130.8
Other	146.6	92.5	94.3
Current Liab.	414.5	368.4	302.1
Fix. Chg. Cov.	334%	329%	667%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	2.0%	-4.0%	*Nil*
"Cash Flow"	3.0%	1.0%	*1.5%*
Earnings	3.5%	0.5%	*5.0%*
Dividends	3.5%	4.5%	*2.5%*
Book Value	4.0%	4.0%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	161.2	93.3	271.2	848.8
2012	317.5	106.6	89.8	229.5	730.6
2013	227.9	*125*	*85*	*307.1*	*745*
2014	*305*	*130*	*85*	*240*	*760*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.08	d.31	1.09	2.39
2012	1.51	.05	d.39	1.05	2.22
2013	1.40	*.10*	*d.30*	*1.05*	*2.30*
2014	*1.55*	*.15*	*d.30*	*1.10*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435	.435	.445	1.75
2012	.445	.445	.445	.455	1.79
2013	.455	.455			

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 681,000 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, 59%; commercial, 29%; industrial, gas transportation, and other, 12%. Employs 1,092. BlackRock Inc. owns 8.2% of shares; officers and directors, 1.8% (4/13 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 Gas started the year on a good note. Earnings were $1.40 a share. Though this is a decrease from 2012 first-quarter earnings, two rules were approved in the fourth quarter in a decoupling rates case, that will cause much less seasonality in earnings. The rules should help second- and third-quarter results. Higher natural gas gross margins, lower bad-debt expenses, and an improved Portland housing market all helped the bottom line. Management thinks margins should strengthen in the second and third quarters, based on the new rules, and reaffirmed its annual earnings target of $2.15-$2.35 a share. Currently, the base-rate case changes are causing earnings volatility, but we expect greater clarity after second-quarter results are reported. 2012 fourth-quarter earnings were in line with our estimates.

The company has many outstanding rates cases, which could affect the second half of the year. One is a new utility tariff, which would allow the company to provide consumers with compressed natural gas, mainly for fleet use. The prepaid pension case rate is still being decided, as is a system integrity program. All of these cases would be beneficial to long-term earnings, but likely won't contributre to results in the short term. The improved housing and natural gas vehicle trends may provide a tailwind to long-term earnings growth.

The balance sheet continues to be strong. Northwest Natural Gas has an "A" rating for Financial Strength and shareholder equity continues to grow. Cash flow will likely be spent on the dividend, which is steadily growing. Though payout growth is expected to lag the industry, the yield remains solid. That said, the rising share count could eventually be a drag on earnings per share and dividend growth.

Northwest Natural Gas shares have a Timeliness rank of 4 (Below Average). The shares are expected to lag the broader market, but do enjoy the highest Price Stability rating. Also, capital appreciation potential is below average. This stock remains a solid choice for an income-seeking investor, but has little appeal to all others.

John E. Seibert III *June 7, 2013*

(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 in early August.
(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.
(D) Includes intangibles. In 2012: $387.9 million, $14.41/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	90

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PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
34.11	19.8	(Trailing: 19.1 Median: 18.0)	1.14	3.6%	VALUE LINE

TIMELINESS 3 Raised 6/22/12
SAFETY 2 New 7/27/90
TECHNICAL 2 Raised 5/31/13
BETA .65 (1.00 = Market)

High:	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6	35.5
Low:	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.5	30.9

Target Price Range 2016 | 2017 | 2018

2016-18 PROJECTIONS

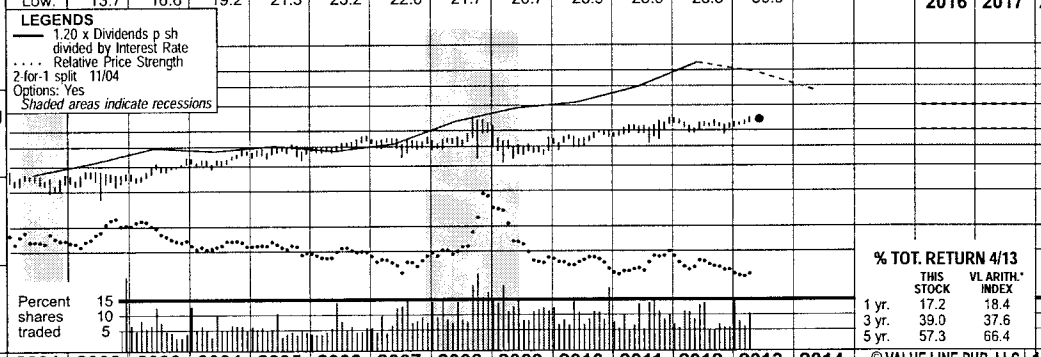
	Price	Gain	Ann'l Total Return
High	40	(+15%)	8%
Low	30	(-10%)	1%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	0	1	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	1	0	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	84	85	85
to Sell	74	68	78
Hld's(000)	33222	32681	33873



% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	17.2	18.4
3 yr.	39.0	37.6
5 yr.	57.3	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
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	21.48	19.83	15.54	*16.00*	*16.80*	Revenues per sh A	*18.35*
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	2.91	2.99	3.09	*3.10*	*3.15*	"Cash Flow" per sh	*3.35*
.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	1.66	*1.70*	*1.75*	Earnings per sh AB	*1.90*
.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	1.19	*1.23*	*1.27*	Div'ds Decl'd per sh C■	*1.39*
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	2.75	3.37	7.33	*7.25*	*7.25*	Cap'l Spending per sh	*7.25*
6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	14.21	*15.65*	*16.10*	Book Value per sh D	*17.60*
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	72.28	72.32	72.25	*76.00*	*76.00*	Common Shs Outst'g E	*76.00*
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	17.1	18.9	19.2	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	1.22	*Value Line*		Relative P/E Ratio	*1.20*
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%	4.2%	3.9%	4.7%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 1/31/13
Total Debt $1505.0 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $875.0 mill. **LT Interest** $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/12 $296.5 mill. **Oblig.** $333.7 mill.

Pfd Stock None

Common Stock 72,520,220 shs. as of 3/4/13

MARKET CAP: $2.5 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	1122.8	*1225*	*1275*	Revenues ($mill) A	*1395*
74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	119.8	*130*	*135*	Net Profit ($mill)	*145*
34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	29.7%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	10.7%	*10.6%*	*10.5%*	Net Profit Margin	*10.5%*
42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	48.7%	*45.5%*	*47.5%*	Long-Term Debt Ratio	*48.5%*
57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	51.3%	*54.5%*	*52.5%*	Common Equity Ratio	*51.5%*
1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	2002.0	*2200*	*2325*	Total Capital ($mill)	*2590*
1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	3105.1	*3200*	*3300*	Net Plant ($mill)	*3600*
8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	7.0%	*8.0%*	*7.5%*	Return on Total Cap'l	*7.5%*
11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.7%	*11.0%*	*11.0%*	Return on Shr. Equity	*11.0%*
11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	11.7%	*11.0%*	*11.0%*	Return on Com Equity	*11.0%*
3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	3.3%	*3.0%*	*3.0%*	Retained to Com Eq	*3.0%*
74%	66%	68%	74%	70%	69%	64%	72%	73%	72%	*72%*	*72%*	All Div'ds to Net Prof	*72%*

CURRENT POSITION ($MILL.)	2011	2012	1/31/13
Cash Assets	6.8	2.0	10.6
Other	279.2	303.6	445.1
Current Assets	286.0	305.6	455.7
Accts Payable	129.7	142.0	150.7
Debt Due	331.0	365.0	630.0
Other	73.4	85.6	105.9
Current Liab.	534.1	592.6	886.6
Fix. Chg. Cov.	323%	325%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	3.0%	-4.5%	-.5%
"Cash Flow"	5.0%	3.5%	2.0%
Earnings	5.0%	3.5%	3.0%
Dividends	5.0%	5.5%	3.0%
Book Value	5.0%	3.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.0	392.6	197.3	192.0	1433.9
2012	471.8	308.4	161.2	181.4	1122.8
2013	515.9	*330*	*180*	*199.1*	*1225*
2014	*530*	*345*	*190*	*210*	*1275*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	.66	d.12	d.13	1.57
2012	1.05	.70	d.06	d.03	1.66
2013	1.18	*.70*	*d.09*	*d.09*	*1.70*
2014	*1.20*	*.71*	*d.08*	*d.08*	*1.75*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29	.29	.29	1.15
2012	.29	.30	.30	.60	1.49
2013	--	.31			

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 976,253 customers in North Carolina, South Carolina, and Tennessee. 2012 revenue mix: residential (48%), commercial (27%), industrial (9%), other (16%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 48.7% of revenues. '12 deprec. rate: 2.9%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,752 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.5% (1/13 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas is off to a solid start this year. Indeed, the company's top line increased approximately 9.5% due to customer growth and a boost in volume deliveries in the residential, commercial, and industrial markets as a result of colder weather patterns. Additional benefits stemmed from increased transportation services in the power generation markets and higher ancillary sales. On the margin front, a rise in cost of goods sold was partially offset by a decline in operating expenses. The bottom line also benefited from a rise in other income and a drop in utility interest charges. Combined, these factors caused the January-period earnings to advance 12.5%, to $1.18 a share. This was in line with our previous estimate. Therefore,

We have left our fiscal 2013 share-net estimate unchanged at $1.70. This falls toward the lower end of the company's guidance range of $1.67-$1.77, which management recently reiterated. Additionally, it would represent an earnings advance of about 2.5%. This should be supported by continued customer additions, as well as capital projects that are slated to come on line later this year (see below).

The balance sheet is in good shape at the moment. The company's cash reserves have increased more than fivefold, so far this year, to roughly $10.6 million. Meanwhile, management has also trimmed the long-term debt load by about 10%. That figure represents a relatively modest portion of Piedmont's capital structure. What's more, the board recently approved a hike in the quarterly dividend of about 3.5% on a sequential basis, to $0.31 a share.

An active pipeline of capital projects augurs well for prospects. Piedmont has $550 million to $600 million earmarked for expansion programs. Of that, $250 million is set for system integrity upgrades. Also, the Sutton power generation delivery project is on schedule to be in service in June.

At the moment, these good-quality shares appear to be fairly valued. However, they may appeal to conservative, income-seeking accounts, thanks to their above-average dividend yield, top mark for Price Stability, and solid Safety rank.

Bryan J. Fong *June 7, 2013*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due mid June. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October. 2013 Q1 dividend paid in Q4 of 2012. ■ Div'd reinvest. plan available; 5% discount. (D) Includes deferred charges. In 2012: $597.2 million, $8.27/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

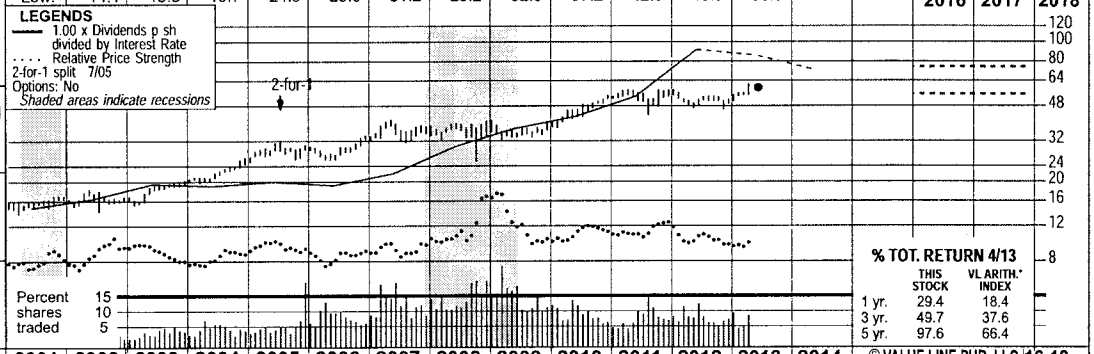
RECENT PRICE **59.21** | P/E RATIO **18.8** (Trailing: 20.3 / Median: 16.0) | RELATIVE P/E RATIO **1.08** | DIV'D YLD **3.1%** | VALUE LINE

TIMELINESS 3 Lowered 11/23/12
SAFETY 2 Lowered 1/4/91
TECHNICAL 3 Raised 5/3/13
BETA .65 (1.00 = Market)

High:	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	54.2	58.0	58.0	61.8
Low:	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2	42.8	45.8	50.5

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	75	(+25%)	9%
Low	55	(-5%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	3	1	0	0	1
Options	0	0	0	0	0	0	0	0	0
to Sell	0	3	2	1	2	1	1	1	6

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	78	78	69
to Sell	55	59	53
Hld's(000)	18018	18468	18794

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	29.4	18.4
3 yr.	49.7	37.6
5 yr.	97.6	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
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	30.97	27.42	22.31	*23.40*	*25.35*	Revenues per sh	*33.35*
1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.72	4.21	4.46	4.69	*4.75*	*5.35*	"Cash Flow" per sh	*6.65*
.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.38	2.70	2.90	3.03	*3.15*	*3.35*	Earnings per sh A	*4.60*
.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	1.36	1.50	1.65	*1.80*	*1.95*	Div'ds Decl'd per sh B ■	*2.45*
2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	3.67	5.59	6.39	8.02	*5.55*	*5.95*	Cap'l Spending per sh	*7.80*
6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.24	19.08	20.66	23.26	*25.40*	*26.10*	Book Value per sh C	*30.55*
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	29.87	30.21	31.65	*32.50*	*33.50*	Common Shs Outst'g D	*36.00*
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	16.8	18.4	16.9	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.15	1.08	*Value Line*		Relative P/E Ratio	*.95*
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%	3.0%	2.8%	3.2%	*estimates*		Avg Ann'l Div'd Yield	*3.8%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $874.8 mill. **Due in 5 Yrs** $429.1 mill.
LT Debt $601.4 mill. **LT Interest** $15.0 mill.
(Total interest coverage: 5.6x)

Pension Assets-12/12 $150.2 mill. **Oblig.** $224.4 mill.

Pfd Stock None

Common Stock 31,960,311 common shs. as of 5/1/13

MARKET CAP: $1.9 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
696.8	819.1	921.0	931.4	956.4	962.0	845.4	925.1	828.6	706.3	*760*	*850*	Revenues ($mill)	*1200*
34.6	43.0	48.6	72.0	61.8	67.7	71.3	81.0	87.0	93.3	*105*	*125*	Net Profit ($mill)	*170*
40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	10.8%	*20.0%*	*25.0%*	Income Tax Rate	*30.0%*
5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	13.2%	*13.8%*	*14.7%*	Net Profit Margin	*14.2%*
50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	45.0%	*43.0%*	*42.5%*	Long-Term Debt Ratio	*42.0%*
49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	55.0%	*57.0%*	*57.5%*	Common Equity Ratio	*58.0%*
608.4	675.0	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	1337.6	*1450*	*1525*	Total Capital ($mill)	*1900*
748.3	799.9	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	1578.0	*1650*	*1725*	Net Plant ($mill)	*2000*
7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	7.4%	*8.0%*	*8.5%*	Return on Total Cap'l	*9.5%*
11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	*12.5%*	*14.5%*	Return on Shr. Equity	*15.5%*
11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	12.7%	*12.5%*	*14.5%*	Return on Com Equity	*15.5%*
5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	5.8%	*5.5%*	*7.0%*	Retained to Com Eq	*7.5%*
57%	52%	50%	37%	48%	49%	51%	50%	52%	55%	*56%*	*52%*	All Div'ds to Net Prof	*52%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	7.5	4.6	1.3
Other	333.1	390.2	440.3
Current Assets	340.6	394.8	441.6
Accts Payable	153.7	193.3	217.5
Debt Due	323.6	363.9	273.4
Other	110.7	94.6	106.1
Current Liab.	588.0	651.8	597.0
Fix. Chg. Cov.	505%	579%	486%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	.5%	-3.5%	*3.5%*
"Cash Flow"	8.5%	7.5%	*7.0%*
Earnings	9.5%	6.5%	*8.0%*
Dividends	7.5%	10.0%	*8.5%*
Book Value	10.0%	7.0%	*6.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	329.3	151.6	160.7	283.5	925.1
2011	331.9	160.5	137.6	198.6	828.6
2012	274.8	121.9	112.0	197.6	706.3
2013	255.6	*130*	*130*	*244.4*	*760*
2014	*280*	*150*	*150*	*270*	*850*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	1.49	.24	.10	.87	2.70
2011	1.63	.20	.01	1.05	2.89
2012	1.65	.28	.13	.98	3.03
2013	1.52	*.35*	*.20*	*1.08*	*3.15*
2014	*1.60*	*.38*	*.22*	*1.15*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	--	.298	.298	.628	1.22
2010	--	.330	.330	.695	1.36
2011	--	.365	.365	.768	1.50
2012	--	.403	.403	.845	1.65
2013	--	.443			

BUSINESS: South Jersey Industries, Inc. is a holding company. Its subsidiary, South Jersey Gas Co., distributes natural gas to 347,725 customers in New Jersey's southern counties, which covers about 2,500 square miles and includes Atlantic City. Gas revenue mix '12: residential, 37%; commercial, 18%; cogeneration and electric generation, 21%; industrial, 24%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 700 employees. Off./dir. control 1.0% of common shares; BlackRock Inc., 7.6% (3/13 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Telephone: 609-561-9000. Internet: www.sjindustries.com.

South Jersey Industries reported unimpressive performance for the first quarter. Revenues and share earnings both declined, on a year-over-year basis. The company's utility operations posted a modest bottom-line advance. Results here benefited from residential customer growth, but a seasonal increase in the reserve for doubtful accounts related to abnormally cold weather in March provided an offset. On the nonutility side, both the Retail Energy and the Wholesale Energy businesses experienced weakness.

South Jersey Gas should post healthy results going forward. The utility has over 359,000 customers in southern New Jersey (including Atlantic City). Natural gas remains the fuel of choice here, and the utility ought to further benefit from customer interest in converting from other sources of fuel. Moreover, spending on infrastructure projects under the Capital Investment Recovery Tracker Program should improve service quality and allow the utility to earn a good return on these investments. SJG received approval from the New Jersey Board of Public Utilities earlier in the year for a new four-year accelerated infrastructure investment program that permits investment of up to $141.2 million during this time frame.

The nonutility operations may well improve somewhat. The Retail Energy business should gain from new projects coming online. Demand for renewable and gas-fired energy projects remains strong. Elsewhere, the Wholesale Energy business will likely continue to face challenges, due to difficult market conditions. However, business development initiatives related to Marcellus Shale marketing and producer services should pay off. Also, the repricing or restructure of storage leases ought to afford significant benefits to ongoing wholesale marketing operations.

We project steady growth in earnings and dividends from the company in the coming years. Moreover, South Jersey earns good marks for Safety, Price Stability, and Earnings Predictability. This issue may offer some appeal for conservative investors. That said, total return potential does appear somewhat limited from the recent quotation, following a run-up in the share price.

Michael Napoli, CFA *June 7, 2013*

(A) Based on GAAP egs. through 2006, economic egs. thereafter. GAAP EPS: '07, $2.10; '08, $2.58; '09, $1.94; '10, $2.22; '11, $2.97; '12, $2.97. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31; '09, ($0.44); '10, ($0.47); '11, $0.08; '12, ($0.06). Earnings may not sum due to rounding. Next egs. report due in August. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2012: $352.7 mill., $11.14 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	90

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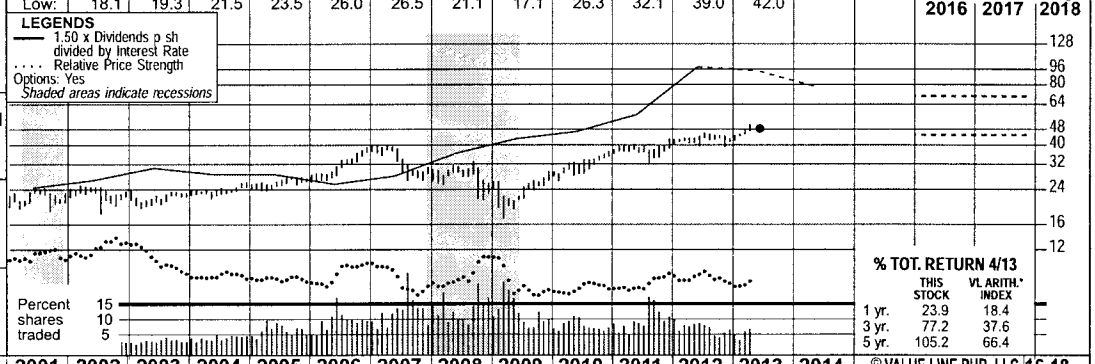
SOUTHWEST GAS NYSE-SWX

RECENT PRICE 48.42 | P/E RATIO 16.4 (Trailing: 16.7 Median: 16.0) | RELATIVE P/E RATIO 0.94 | DIV'D YLD 2.8% | VALUE LINE

TIMELINESS 3 Lowered 11/16/12
SAFETY 3 Lowered 1/4/91
TECHNICAL 3 Raised 3/1/13
BETA .75 (1.00 = Market)

High:	25.3	23.6	26.2	28.1	39.4	39.9	33.3	29.5	37.3	43.2	46.1	51.5
Low:	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	26.3	32.1	39.0	42.0

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range 2016 | 2017 | 2018

2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	12%
Low	45	(-5%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	1	0	1	1	0	0	0
Options	0	0	1	0	0	1	0	0	7
to Sell	0	0	1	0	0	4	1	0	7

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	85	75	78
to Sell	70	79	68
Hld's(000)	34847	35008	34487

Percent shares traded 15 10 5

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.9	18.4
3 yr.	77.2	37.6
5 yr.	105.2	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
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	40.18	41.07	41.77	*42.00*	*43.25*	Revenues per sh	*50.00*
3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	7.73	*7.85*	*8.15*	"Cash Flow" per sh	*9.40*
.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	2.27	2.43	2.86	*2.95*	*3.10*	Earnings per sh A	*3.75*
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	1.18	*1.32*	*1.40*	Div'ds Decl'd per sh B■†	*1.60*
6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	8.57	*6.40*	*7.30*	Cap'l Spending per sh	*9.60*
14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	28.39	*30.85*	*32.30*	Book Value per sh	*36.00*
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	45.56	45.96	46.15	*47.00*	*48.00*	Common Shs Outst'g C	*50.00*
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	14.0	15.7	15.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.98	.95	*Value Line*		Relative P/E Ratio	*1.00*
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%	3.2%	2.8%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $1256.0 mill. **Due in 5 Yrs** $198.2 mill.
LT Debt $1250.8 mill. **LT Interest** $70.0 mill.
(Total interest coverage: 3.2x) (49% of Cap'l)
Leases, Uncapitalized Annual rentals $7.0 mill.
Pension Assets-12/12 $645.0 mill.
Oblig. $962.5 mill.

Pfd Stock None

Common Stock 46,328,592 shs.
as of 5/1/13

MARKET CAP: $2.2 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	1927.8	*1975*	*2075*	Revenues ($mill)	*2500*
38.5	58.9	48.1	80.5	83.2	61.0	87.5	103.9	112.3	133.3	*140*	*150*	Net Profit ($mill)	*190*
30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	36.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	6.9%	*7.1%*	*7.2%*	Net Profit Margin	*7.6%*
66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	49.2%	*47.5%*	*47.5%*	Long-Term Debt Ratio	*48.5%*
34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	50.8%	*52.5%*	*52.5%*	Common Equity Ratio	*51.5%*
1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	2579	*2750*	*2950*	Total Capital ($mill)	*3500*
2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	3343.8	*3400*	*3500*	Net Plant ($mill)	*3750*
4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	6.5%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	10.2%	*9.5%*	*9.5%*	Return on Com Equity	*10.5%*
1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	6.0%	*5.5%*	*5.5%*	Retained to Com Eq	*6.0%*
72%	49%	65%	42%	44%	63%	48%	43%	43%	41%	*44%*	*45%*	All Div'ds to Net Prof	*43%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	21.9	25.5	33.1
Other	439.7	432.9	337.1
Current Assets	461.6	458.4	370.2
Accts Payable	186.8	155.7	120.3
Debt Due	322.6	50.1	5.2
Other	338.2	329.3	290.4
Current Liab.	847.6	535.1	415.9
Fix. Chg. Cov.	359%	399%	412%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '16-'18
Revenues	1.5%	-1.5%	3.5%
"Cash Flow"	3.5%	3.0%	5.0%
Earnings	6.0%	6.5%	7.0%
Dividends	2.0%	4.0%	7.0%
Book Value	4.5%	5.0%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	668.8	385.8	307.7	468.1	1830.4
2011	628.4	388.5	352.6	517.7	1887.2
2012	657.6	409.8	371.8	488.6	1927.8
2013	613.5	*425*	*390*	*546.5*	*1975*
2014	*660*	*440*	*410*	*565*	*2075*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2010	1.42	d.02	d.11	.98	2.27
2011	1.48	.09	d.34	1.19	2.43
2012	1.70	d.08	d.09	1.34	2.86
2013	1.73	*.08*	*d.15*	*1.29*	*2.95*
2014	*1.80*	*.10*	*d.15*	*1.35*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265	.265	.265	1.05
2012	.265	.295	.295	.295	1.15
2013	.295	.33			

BUSINESS: Southwest Gas Corporation is a regulated gas distributor serving approximately 1.9 million customers in sections of Arizona, Nevada, and California. Comprised of two business segments: natural gas operations and construction services. 2012 margin mix: residential and small commercial, 85%; large commercial and industrial, 4%; transportation, 11%. Total throughput: 2.1 billion therms. Sold PriMerit Bank, 7/96. Has 6,015 employees. Off. & Dir. own 1.5% of common stock; BlackRock Inc., 8.2%; GAMCO Investors, Inc., 7.5%; T. Rowe Price Associates, Inc., 6.7% (3/13 Proxy). Chairman: Michael J. Melarkey. 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 reported marginally improved share net for the first quarter. The top line declined somewhat for the period. But cost of gas sold and construction expenses declined nicely, and share net advanced modestly. Net income for the natural gas segment was roughly equivalent to the prior-year quarter, while construction services subsidiary NPL experienced a nice improvement.

Top-line performance may prove somewhat more favorable in the coming quarters. The utility operations will probably benefit from modest customer growth and higher rates (a $7 million annualized increase in Nevada should boost results). NPL should continue to experience healthy demand, considering the need to replace aging infrastructure. Moreover, efforts to control operating expenses ought to support the bottom line. Overall, we look for a relatively modest advance in revenues and share earnings for the company for full-year 2013.

Southwest Gas remains active on the regulatory front. It has filed a general rate case application with the California Public Utilities Commission requesting a total revenue increase of about $11.6 million. Hearings on the general rate case are expected for the third quarter, with new rates proposed to take effect in January, 2014. The company's focus on this matter is important, as it depends on such approved revenue increases to help it adjust to greater costs and as compensation for investment in infrastructure.

The stock is not without risk. The company will probably continue to incur greater operating costs as it expands. Moreover, insufficient, or lagging, rate relief could hurt performance at the core utility business.

This issue is ranked to track the broader market for the coming six to 12 months. This equity is not a standout for total return potential either, at this juncture. We do expect steady growth in earnings and dividends going forward. Moreover, Southwest Gas earns good marks for Price Stability and Earnings Predictability. However, all this appears to be partly reflected in the recent quotation. Moreover, the stock's dividend yield is below average for a utility.

Michael Napoli, CFA *June 7, 2013*

(A) Based on avg. shares outstand. thru. '97, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Earnings may not sum due to rounding. Next egs. report due early August. (B) Dividends historically paid early March, June, September, and December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	75

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WGL HOLDINGS NYSE-WGL

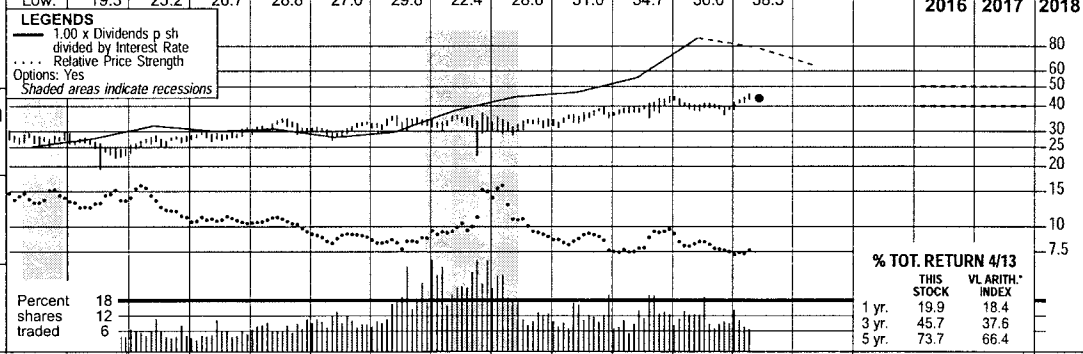
RECENT PRICE	43.75	P/E RATIO	16.9 (Trailing: 15.2 / Median: 15.0)	RELATIVE P/E RATIO	0.97	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS 3 Raised 4/19/13
SAFETY 1 Raised 4/2/93
TECHNICAL 3 Lowered 12/14/12
BETA .65 (1.00 = Market)

High:	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0	46.2
Low:	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0	38.3

Target Price Range 2016 | 2017 | 2018

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2016-18 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	7%
Low	40	(-10%)	2%

Insider Decisions

	J	A	S	O	N	D	J	F	M
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	3	0	0	1	0	0	2	0

Institutional Decisions

	2Q2012	3Q2012	4Q2012
to Buy	86	102	84
to Sell	83	67	87
Hld's(000)	31990	31678	31947

Percent shares traded 18 12 6

% TOT. RETURN 4/13

	THIS STOCK	VL ARITH.* INDEX
1 yr.	19.9	18.4
3 yr.	45.7	37.6
5 yr.	73.7	66.4

1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	© VALUE LINE PUB. LLC	16-18
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	53.60	53.75	47.09	*48.30*	*49.50*	Revenues per sh A	*54.10*
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	4.11	4.01	4.60	*4.45*	*4.55*	"Cash Flow" per sh	*4.85*
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	2.27	2.25	2.68	*2.55*	*2.65*	Earnings per sh B	*2.95*
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	1.50	1.55	1.59	*1.66*	*1.71*	Div'ds Decl'd per sh C■	*1.83*
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	2.57	3.94	5.85	*4.85*	*4.80*	Cap'l Spending per sh	*4.80*
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	22.82	23.49	24.75	*25.60*	*26.60*	Book Value per sh D	*29.80*
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	50.54	51.20	51.50	*51.75*	*52.00*	Common Shs Outst'g E	*52.00*
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	15.1	17.0	15.3	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.99	*Value Line*		Relative P/E Ratio	*1.00*
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%	4.4%	4.1%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 3/31/13
Total Debt $773.8 mill. **Due in 5 Yrs** $112.0 mill.
LT Debt $554.7 mill. **LT Interest** $36.4 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)
Pension Assets-9/12 $1,108.9 mill.
Oblig. $1,417.2 mill.
Preferred Stock $28.2 mill. **Pfd. Div'd** $1.3 mill.

Common Stock 51,705,892 shs.
as of 4/30/13

MARKET CAP: $2.3 billion (Mid Cap)

2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014		16-18
2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	*2500*	*2575*	Revenues ($mill) A	*2815*
112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	115.5	138.3	*130*	*140*	Net Profit ($mill)	*155*
38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	39.0%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	5.7%	*5.3%*	*5.4%*	Net Profit Margin	*5.5%*
43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	31.0%	*30.5%*	*30.0%*	Long-Term Debt Ratio	*28.0%*
54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	67.5%	*68.0%*	*70.0%*	Common Equity Ratio	*70.5%*
1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	*1945*	*2010*	Total Capital ($mill)	*2175*
1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	*2855*	*3060*	Net Plant ($mill)	*3765*
9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	10.9%	*10.0%*	*10.0%*	Return on Shr. Equity	*10.0%*
14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	11.0%	*10.0%*	*10.0%*	Return on Com Equity	*10.0%*
6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.3%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
56%	65%	62%	69%	66%	57%	57%	67%	64%	59%	*65%*	*64%*	All Div'ds to Net Prof	*61%*

CURRENT POSITION ($MILL.)	2011	2012	3/31/13
Cash Assets	4.3	10.3	9.7
Other	720.4	822.5	896.0
Current Assets	724.7	832.8	905.7
Accts Payable	279.4	270.4	298.7
Debt Due	116.5	247.7	219.1
Other	180.8	238.9	276.2
Current Liab.	576.7	757.0	794.0
Fix. Chg. Cov.	535%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '10-'12 to '16-'18
Revenues	6.0%	0.5%	*1.0%*
"Cash Flow"	3.5%	1.5%	*2.5%*
Earnings	4.0%	3.0%	*3.5%*
Dividends	2.0%	3.0%	*3.0%*
Book Value	4.0%	4.5%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	727.4	1056	459.7	465.1	2708.9
2011	795.9	1017	490.3	448.1	2751.5
2012	727.7	839.5	438.3	419.8	2425.3
2013	686.7	891.4	*475*	*446.9*	*2500*
2014	*705*	*910*	*495*	*465*	*2575*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	d.03	d.27	2.25
2012	1.13	1.58	.08	d.11	2.68
2013	1.14	1.75	*d.04*	*d.30*	*2.55*
2014	*1.18*	*1.77*	*d.02*	*d.28*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.36	.37	.37	.37	1.47
2010	.37	.378	.378	.378	1.50
2011	.378	.39	.39	.39	1.55
2012	.39	.40	.40	.40	1.59
2013	.40	.42			

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 (1,094,109 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. State Street Global owns 9.3% of common stock; Off./dir. less than 1% (1/13 proxy). Chmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted better-than-expected financial results for the March period. Indeed, the company's top line increased approximately 6%, on a year-over-year basis. This reflected nicely higher revenue contributions from the utility division, which were partially offset by a year-to-year decline in volumes at the nonutility segment. The regulated utility business benefited from an increase in average active customer meters; favorable effects of changes in natural gas consumption patterns due to shifts in the weather; and a reduction in customer delinquencies and charge-offs. Meanwhile, on the margin front, overall operating expenses declined 100 basis points as a percentage of the top line. All told, WGL's bottom line advanced almost 11%, to $1.75 a share. This was a fair amount higher that we had previously anticipated. Consequently,

We have raised our 2013 and 2014 earnings estimates by a dime and nickel, to $2.55 and $2.65 a share, respectively. This would still represent an annual decline of almost 5% for this year. On the plus side are good contributions at the regulated utility, retail energy marketing, and commercial energy system divisions. Offsetting factors stem from weakness at the wholesale energy solutions unit, as well as rising costs in other areas of WGL's business. Meanwhile, our call is slightly above the high end of management's recently raised guidance range of $2.42-$2.54 for the year.

A pending rate case augurs well for prospects. Early in the fiscal third quarter, the company filed a rate case with the Maryland Public Service Commission requesting a revenue increase of $30.7 million to compensate for rising costs associated with pipeline replacement and higher operating and maintenance expenses.

Alternative-energy projects are also a plus. Washington Gas Energy Services (WGES) is providing 100% wind energy to DC's Union Station. Also, WGES is providing power for a new community power project that allows communities to use thier collective buying power to shift to clean energy while reducing costs.

The yield on these shares is a bit above the group average, but total return potential is below average.

Bryan J. Fong *June 7, 2013*

(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 July. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available. (D) Includes deferred charges and intangibles. '12: $610.8 million, $11.93/sh. (E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

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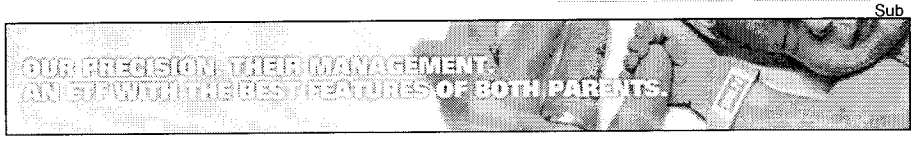

American Water Works Co Inc: (NYSE: AWK)

ZACKS RANK: 3-HOLD #3

$39.41 -0.16 (-0.40%) **Volume 865,341** Jun 21 02:40 PM ET

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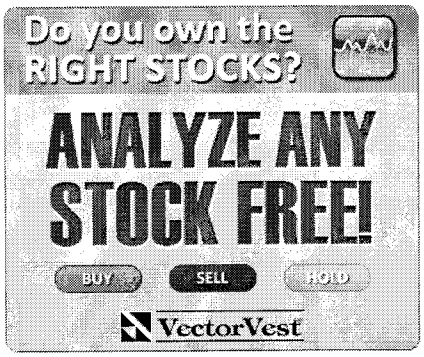
AMER WATER is the largest investor-owned U.S. water and wastewater utility company. With headquarters in Voorhees, N.J., the company employs nearly seven thousand dedicated professionals who provide drinking water, wastewater and other related services to approximately 15.6 million people in 32 states and Ontario, Canada.

GENERAL INFORMATION

AMER WATER WORK
1025 LAUREL OAK ROAD
VOORHEES, NJ 08043
Phone: 856-346-8200
Fax: 856-346-8360
Web: http://www.amwater.com
Email: NA

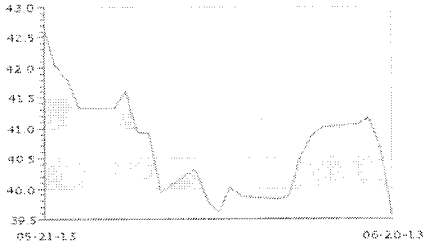
Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/08/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	39.57
52 Week High	43.09
52 Week Low	32.75
Beta	0.32
20 Day Moving Average	958,508.38
Target Price Consensus	45.78

[AWK] 30-Day Closing Prices



% Price Change

4 Week	-5.33
12 Week	-4.51
YTD	9.45

% Price Change Relative to S&P 500

4 Week	-1.62
12 Week	-5.65
YTD	-3.17

Share Information

Shares Outstanding (millions)	177.70
Market Capitalization (millions)	7,031.63
Short Ratio	0.88
Last Split Date	NA

Dividend Information

Dividend Yield	2.83%
Annual Dividend	$1.12
Payout Ratio	0.47
Change in Payout Ratio	-0.11
Last Dividend Payout / Amount	05/22/2013 / $0.28

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.62

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.00

Current Year EPS Consensus Estimate	2.21	30 Days Ago	1.00
Estimated Long-Term EPS Growth Rate	8.00	60 Days Ago	1.18
Next EPS Report Date	08/08/2013	90 Days Ago	1.18

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	17.88
Trailing 12 Months	18.49
PEG Ratio	2.23

EPS Growth

vs. Previous Year	10.34%
vs. Previous Quarter	6.67%

Sales Growth

vs. Previous Year	2.84%
vs. Previous Quarter	-6.58%

Price Ratios

Price/Book	1.56
Price/Cash Flow	9.25
Price / Sales	2.43

ROE

03-31-13	8.64
12-31-12	8.60
09-30-12	8.86

ROA

03-31-13	2.62
12-31-12	2.60
09-30-12	2.64

Current Ratio

03-31-13	0.51
12-31-12	0.50
09-30-12	0.64

Quick Ratio

03-31-13	0.48
12-31-12	0.47
09-30-12	0.61

Operating Margin

03-31-13	13.22
12-31-12	13.06
09-30-12	13.48

Net Margin

03-31-13	12.92
12-31-12	12.45
09-30-12	12.96

Pre-Tax Margin

03-31-13	21.95
12-31-12	21.94
09-30-12	22.53

Book Value

03-31-13	25.41
12-31-12	25.14
09-30-12	25.21

Inventory Turnover

03-31-13	43.43
12-31-12	43.64
09-30-12	42.95

Debt-to-Equity

03-31-13	1.15
12-31-12	1.17
09-30-12	1.17

Debt to Capital

03-31-13	53.57
12-31-12	53.96
09-30-12	53.91

Top 3 Stocks for 2013
www.TheStockReport.com
3 Stock Opportunities That Are Poised To Explode.

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American Sts Wtr Co: (NYSE: AWR)

ZACKS RANK: 2-BUY #2

$52.00 -1.05 (-1.98%) **Volume 158,904** Jun 21 02:40 PM ET

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American States is a public utility company engaged principally in the purchase, production, distribution and sale of water. The company also distributes 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
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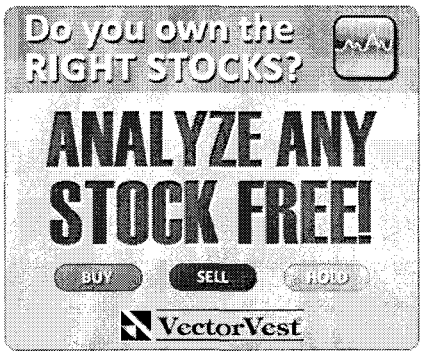
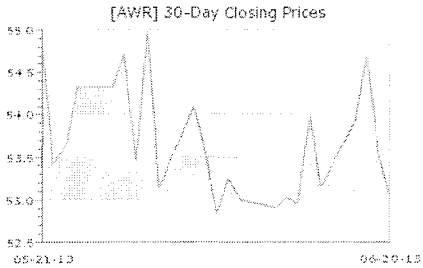
Email: investorinfo@aswater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/05/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	53.05
52 Week High	57.80
52 Week Low	37.46
Beta	0.33
20 Day Moving Average	167,825.55
Target Price Consensus	55.50



% Price Change

4 Week	-1.10
12 Week	-7.85
YTD	11.61

% Price Change Relative to S&P 500

4 Week	2.78
12 Week	-8.95
YTD	-2.88

Share Information

Shares Outstanding (millions)	19.28
Market Capitalization (mllions)	1,023.07
Short Ratio	2.71
Last Split Date	06/10/02

Dividend Information

Dividend Yield	2.68%
Annual Dividend	$1.42
Payout Ratio	0.48
Change in Payout Ratio	-0.08
Last Dividend Payout / Amount	05/13/2013 / $0.35

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.84

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.00

Current Year EPS Consensus Estimate	2.85	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	2.00	60 Days Ago	3.00
Next EPS Report Date	08/05/2013	90 Days Ago	3.00

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FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	18.61	vs. Previous Year	30.19%	vs. Previous Year	3.66%
Trailing 12 Months	17.80	vs. Previous Quarter	30.19%	vs. Previous Quarter	-0.89%
PEG Ratio	9.31				

Price Ratios		ROE		ROA	
Price/Book	2.21	03-31-13	12.83	03-31-13	4.50
Price/Cash Flow	10.47	12-31-12	12.41	12-31-12	4.27
Price / Sales	2.18	09-30-12	11.90	09-30-12	4.02

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	1.94	03-31-13	1.86	03-31-13	12.24
12-31-12	1.96	12-31-12	1.91	12-31-12	11.62
09-30-12	1.71	09-30-12	1.65	09-30-12	11.24

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	12.24	03-31-13	20.23	03-31-13	23.97
12-31-12	11.62	12-31-12	19.30	12-31-12	23.66
09-30-12	11.24	09-30-12	18.89	09-30-12	23.72

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	17.83	03-31-13	0.72	03-31-13	41.86
12-31-12	19.42	12-31-12	0.73	12-31-12	42.24
09-30-12	21.38	09-30-12	0.77	09-30-12	43.40

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California Wtr Svc Group: (NYSE: CWT)

$18.95 -0.32 (-1.66%) **Volume 296,620** Jun 21 02:43 PM ET

ZACKS RANK: 3-HOLD #3

Full Company Report

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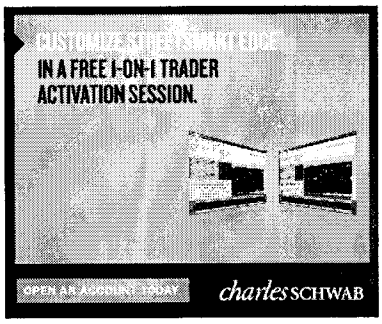
California Water Service Company's business, which is carried on through its operating subsidiaries, consists of the production, purchase, storage, purification, distribution and sale of water for domestic, industrial, public and irrigation uses, and for fire protection. It also provides water related 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 N FIRST ST C/O CALIFORNIA WATER SERVICE CO
SAN JOSE, CA 95112
Phone: 4083678200
Fax: 831-427-9185
Web: http://www.calwatergroup.com
Email: klichtenberg@calwater.com

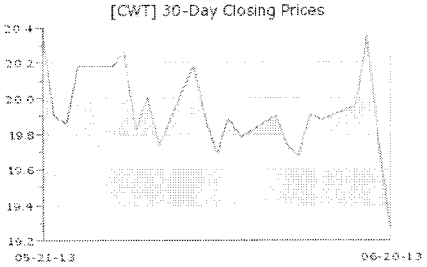
Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	07/24/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	19.27
52 Week High	21.22
52 Week Low	16.84
Beta	0.28
20 Day Moving Average	180,349.66
Target Price Consensus	21.50

[CWT] 30-Day Closing Prices



% Price Change

4 Week	-2.97
12 Week	-3.17
YTD	7.47

% Price Change Relative to S&P 500

4 Week	0.84
12 Week	-4.32
YTD	-5.02

Share Information

Shares Outstanding (millions)	47.73
Market Capitalization (millions)	919.74
Short Ratio	2.78
Last Split Date	06/13/11

Dividend Information

Dividend Yield	3.32%
Annual Dividend	$0.64
Payout Ratio	0.58
Change in Payout Ratio	-0.07
Last Dividend Payout / Amount	05/02/2013 / $0.16

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.28

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.71

Current Year EPS Consensus Estimate	0.86	30 Days Ago	2.71
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	2.73
Next EPS Report Date	07/24/2013	90 Days Ago	2.71

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	22.36
Trailing 12 Months	17.36
PEG Ratio	3.73

EPS Growth

vs. Previous Year	NA%
vs. Previous Quarter	-125.00%

Sales Growth

vs. Previous Year	-4.54%
vs. Previous Quarter	-8.30%

Price Ratios

Price/Book	1.58
Price/Cash Flow	7.63
Price / Sales	1.66

ROE

03-31-13	9.47
12-31-12	10.39
09-30-12	9.84

ROA

03-31-13	2.34
12-31-12	2.47
09-30-12	2.35

Current Ratio

03-31-13	0.90
12-31-12	0.60
09-30-12	0.79

Quick Ratio

03-31-13	0.88
12-31-12	0.58
09-30-12	0.76

Operating Margin

03-31-13	8.41
12-31-12	8.56
09-30-12	8.27

Net Margin

03-31-13	8.41
12-31-12	8.72
09-30-12	8.44

Pre-Tax Margin

03-31-13	12.22
12-31-12	12.55
09-30-12	13.11

Book Value

03-31-13	12.20
12-31-12	11.30
09-30-12	11.33

Inventory Turnover

03-31-13	36.36
12-31-12	37.33
09-30-12	39.18

Debt-to-Equity

03-31-13	0.76
12-31-12	0.92
09-30-12	1.01

Debt to Capital

03-31-13	43.14
12-31-12	47.84
09-30-12	50.24

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Conn Water Serv: (NASD: CTWS)

ZACKS RANK: 3-HOLD #3

$28.29 0.04 (0.14%) **Volume 76,577** Jun 21 01:58 PM ET

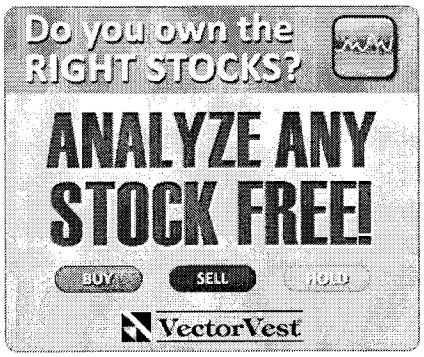
Full Company Report Get Full Company Report for: Enter Symbol GO

Connecticut Water Service, Inc., is a non-operating holding company whose income comes solely from its subsidiaries. The core business is water service to people throughout towns in Connecticut and Massachusetts.

GENERAL INFORMATION

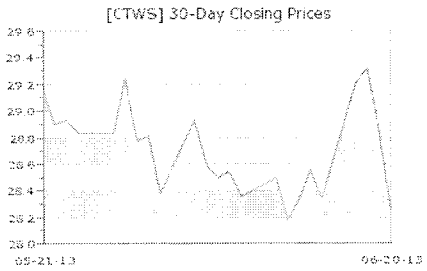
CONN WATER SVC
93 W MAIN ST
CLINTON, CT 06413
Phone: 8606698630
Fax: 860-669-9326
Web: http://www.ctwater.com
Email: info@ctwater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/08/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	3
Yesterday's Close	28.25
52 Week High	32.31
52 Week Low	27.31
Beta	0.48
20 Day Moving Average	31,071.05
Target Price Consensus	32.50



% Price Change

4 Week	-2.35
12 Week	-3.35
YTD	-3.22

% Price Change Relative to S&P 500

4 Week	1.48
12 Week	-4.51
YTD	-16.57

Share Information

Shares Outstanding (millions)	10.98
Market Capitalization (millions)	310.24
Short Ratio	5.82
Last Split Date	09/10/01

Dividend Information

Dividend Yield	3.43%
Annual Dividend	$0.97
Payout Ratio	0.66
Change in Payout Ratio	-0.10
Last Dividend Payout / Amount	05/30/2013 / $0.24

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.38
Current Year EPS Consensus Estimate	1.43

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.50
30 Days Ago	2.20

Estimated Long-Term EPS Growth Rate	4.00	60 Days Ago	2.20		
Next EPS Report Date	08/08/2013	90 Days Ago	2.06		

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	19.75	vs. Previous Year	33.33%	vs. Previous Year	6.39%
Trailing 12 Months	19.22	vs. Previous Quarter	50.00%	vs. Previous Quarter	1.02%
PEG Ratio	4.94				

Price Ratios		ROE		ROA	
Price/Book	1.67	03-31-13	8.86	03-31-13	2.41
Price/Cash Flow	13.15	12-31-12	9.17	12-31-12	2.26
Price / Sales	3.31	09-30-12	10.63	09-30-12	2.45

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	2.68	03-31-13	2.55	03-31-13	14.61
12-31-12	2.29	12-31-12	2.19	12-31-12	13.67
09-30-12	0.89	09-30-12	0.85	09-30-12	13.87

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	15.28	03-31-13	15.28	03-31-13	16.94
12-31-12	14.73	12-31-12	16.26	12-31-12	17.54
09-30-12	14.93	09-30-12	14.97	09-30-12	14.36

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	26.66	03-31-13	0.96	03-31-13	48.80
12-31-12	26.70	12-31-12	0.96	12-31-12	48.95
09-30-12	27.57	09-30-12	1.48	09-30-12	59.53

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Middlesex Water Co: (NASD: MSEX)

ZACKS RANK: 1-STRONG BUY #1

$19.27 -0.01 (-0.05%) **Volume 44,914** **Jun 21 02:30 PM ET**

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Middlesex Water Company treats, stores and distributes water for residential, commercial, industrial and fire prevention purposes.

GENERAL INFORMATION

MIDDLESEX WATER
1500 RONSON RD P O BOX 1500
ISELIN, NJ 08830
Phone: 7326341500
Fax: 732-750-5981
Web: http://www.middlesexwater.com
Email: bsohler@middlesexwater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/08/2013

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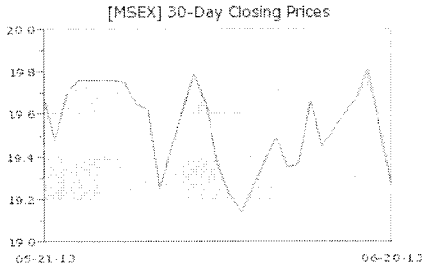
PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	19.28
52 Week High	20.06
52 Week Low	17.48
Beta	0.47
20 Day Moving Average	30,428.50
Target Price Consensus	21.00

[MSEX] 30-Day Closing Prices



% Price Change

4 Week	-2.13
12 Week	-1.23
YTD	-0.15

% Price Change Relative to S&P 500

4 Week	1.71
12 Week	-2.41
YTD	-12.82

Share Information

Shares Outstanding (millions)	15.82
Market Capitalization (millions)	305.01
Short Ratio	7.18
Last Split Date	11/17/03

Dividend Information

Dividend Yield	3.89%
Annual Dividend	$0.75
Payout Ratio	0.77
Change in Payout Ratio	-0.02
Last Dividend Payout / Amount	05/13/2013 / $0.19

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.31
Current Year EPS Consensus Estimate	1.00

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.00
30 Days Ago	2.00

Estimated Long-Term EPS Growth Rate	NA	60 Days Ago	2.00		
Next EPS Report Date	08/08/2013	90 Days Ago	2.33		

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FUNDAMENTAL RATIOS

P/E	
Current FY Estimate	19.28
Trailing 12 Months	19.88
PEG Ratio	NA

EPS Growth	
vs. Previous Year	72.73%
vs. Previous Quarter	11.76%

Sales Growth	
vs. Previous Year	14.83%
vs. Previous Quarter	-0.15%

Price Ratios	
Price/Book	1.67
Price/Cash Flow	11.85
Price / Sales	2.68

ROE	
03-31-13	8.66
12-31-12	8.00
09-30-12	7.67

ROA	
03-31-13	2.85
12-31-12	2.62
09-30-12	2.52

Current Ratio	
03-31-13	0.49
12-31-12	0.44
09-30-12	0.51

Quick Ratio	
03-31-13	0.45
12-31-12	0.41
09-30-12	0.48

Operating Margin	
03-31-13	13.75
12-31-12	12.99
09-30-12	12.82

Net Margin	
03-31-13	13.85
12-31-12	13.04
09-30-12	12.87

Pre-Tax Margin	
03-31-13	20.98
12-31-12	19.73
09-30-12	19.38

Book Value	
03-31-13	11.52
12-31-12	11.53
09-30-12	11.53

Inventory Turnover	
03-31-13	35.87
12-31-12	35.09
09-30-12	31.22

Debt-to-Equity	
03-31-13	0.72
12-31-12	0.72
09-30-12	0.73

Debt to Capital	
03-31-13	41.28
12-31-12	41.54
09-30-12	41.75

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Sjw Corp: (NYSE: SJW)

ZACKS RANK: 5-STRONG SELL #5

$24.88 -0.44 (-1.74%) **Volume 52,237** Jun 21 02:43 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

SJW CORP. is a holding company which operates through its wholly-owned subsidiaries, San Jose Water Co., SJW Land Co., and Western Precision, Inc. San Jose Water Co., is a public utility in the business of providing water service to a population of approximately 928,000 people. Their service area encompasses about 134 sq. miles in the metropolitan San Juan area. SJW Land Co. operates parking facilities located adjacent to the their headquarters and the San Jose area.

GENERAL INFORMATION

SJW CORP
110 W. TAYLOR STREET
SAN JOSE, CA 95110
Phone: 4082797800
Fax: 408-279-7917
Web: http://www.sjwater.com
Email: boardofdirectors@sjwater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	07/24/2013

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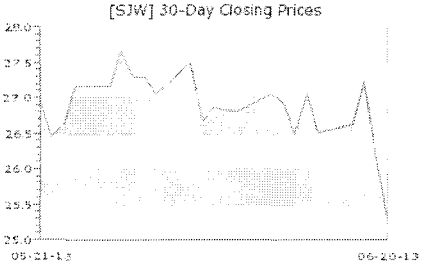
PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	25.32
52 Week High	28.11
52 Week Low	22.56
Beta	0.57
20 Day Moving Average	32,153.35
Target Price Consensus	29.67

[SJW] 30-Day Closing Prices



% Price Change

4 Week	-4.85
12 Week	-4.45
YTD	-1.77

% Price Change Relative to S&P 500

4 Week	-1.11
12 Week	-5.60
YTD	-12.62

Share Information

Shares Outstanding (millions)	20.02
Market Capitalization (millions)	506.91
Short Ratio	4.01
Last Split Date	03/17/06

Dividend Information

Dividend Yield	2.88%
Annual Dividend	$0.73
Payout Ratio	0.61
Change in Payout Ratio	-0.11
Last Dividend Payout / Amount	05/02/2013 / $0.18

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.26

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.67

Current Year EPS Consensus Estimate	1.25	30 Days Ago	1.67
Estimated Long-Term EPS Growth Rate	NA	60 Days Ago	1.63
Next EPS Report Date	07/24/2013	90 Days Ago	1.67

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	20.26	vs. Previous Year	16.67%	vs. Previous Year	-1.97%
Trailing 12 Months	21.28	vs. Previous Quarter	-77.42%	vs. Previous Quarter	-19.71%
PEG Ratio	NA				

Price Ratios		ROE		ROA	
Price/Book	1.73	03-31-13	8.31	03-31-13	2.09
Price/Cash Flow	8.30	12-31-12	8.32	12-31-12	2.10
Price / Sales	1.95	09-30-12	7.40	09-30-12	1.87

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	0.58	03-31-13	0.56	03-31-13	8.65
12-31-12	0.87	12-31-12	0.85	12-31-12	8.53
09-30-12	1.22	09-30-12	1.20	09-30-12	7.52

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	8.65	03-31-13	14.66	03-31-13	14.63
12-31-12	8.53	12-31-12	14.48	12-31-12	14.72
09-30-12	8.80	09-30-12	14.98	09-30-12	14.58

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	112.80	03-31-13	1.23	03-31-13	55.09
12-31-12	114.89	12-31-12	1.22	12-31-12	55.00
09-30-12	116.20	09-30-12	1.24	09-30-12	55.28

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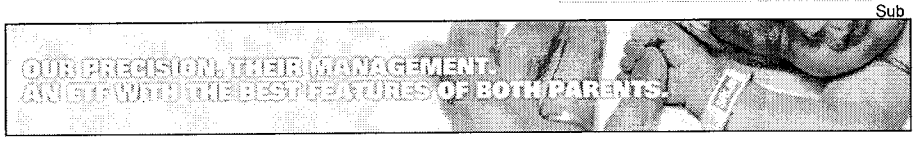

Aqua America Inc: (NYSE: WTR)

ZACKS RANK: 3-HOLD #3

$29.66 -0.52 (-1.72%) **Volume 1,281,009** Jun 21 02:51 PM ET

Full Company Report

Get Full Company Report for: Enter Symbol GO

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 AVE
BRYN MAWR, PA 19010-3489
Phone: 6105278000
Fax: 610-645-1061
Web: http://www.aquaamerica.com
Email: NA

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/05/2013

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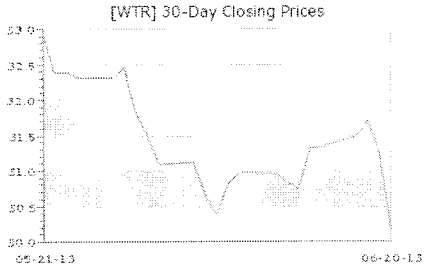
PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	30.18
52 Week High	33.28
52 Week Low	24.00
Beta	0.20
20 Day Moving Average	510,220.50
Target Price Consensus	33.17



% Price Change

4 Week	-6.82
12 Week	-4.01
YTD	22.82

% Price Change Relative to S&P 500

4 Week	-3.17
12 Week	-5.16
YTD	8.09

Share Information

Shares Outstanding (millions)	140.74
Market Capitalization (mllions)	4,247.59
Short Ratio	4.46
Last Split Date	12/02/05

Dividend Information

Dividend Yield	2.32%
Annual Dividend	$0.70
Payout Ratio	0.62
Change in Payout Ratio	NA
Last Dividend Payout / Amount	05/15/2013 / $0.17

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.37

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.58

Current Year EPS Consensus Estimate	1.41	30 Days Ago	2.58
Estimated Long-Term EPS Growth Rate	5.50	60 Days Ago	2.58
Next EPS Report Date	08/05/2013	90 Days Ago	2.50

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	21.39	vs. Previous Year	45.00%	vs. Previous Year	5.75%
Trailing 12 Months	28.47	vs. Previous Quarter	NA%	vs. Previous Quarter	-0.52%
PEG Ratio	3.87				

Price Ratios		ROE		ROA	
Price/Book	2.99	03-31-13	14.64	03-31-13	4.26
Price/Cash Flow	15.64	12-31-12	14.01	12-31-12	4.09
Price / Sales	5.49	09-30-12	11.59	09-30-12	3.39

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	0.71	03-31-13	0.67	03-31-13	25.65
12-31-12	0.95	12-31-12	0.91	12-31-12	24.20
09-30-12	0.73	09-30-12	0.69	09-30-12	19.71

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	26.52	03-31-13	32.94	03-31-13	10.11
12-31-12	25.73	12-31-12	33.12	12-31-12	9.90
09-30-12	21.70	09-30-12	31.82	09-30-12	9.41

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	23.15	03-31-13	1.03	03-31-13	50.80
12-31-12	23.36	12-31-12	1.11	12-31-12	52.70
09-30-12	22.95	09-30-12	1.16	09-30-12	53.61

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Agl Resources Inc: (NYSE: GAS)

ZACKS RANK: 3-HOLD #3

$42.23 0.37 (0.87%) **Volume 477,539** Jun 21 03:00 PM ET

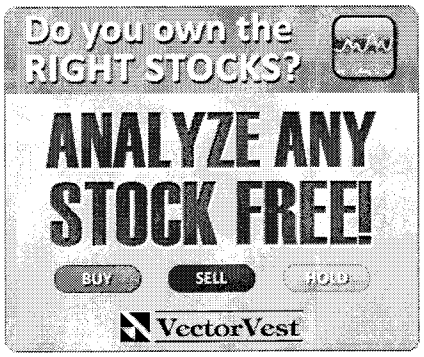
Full Company Report Get Full Company Report for: Enter Symbol GO

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

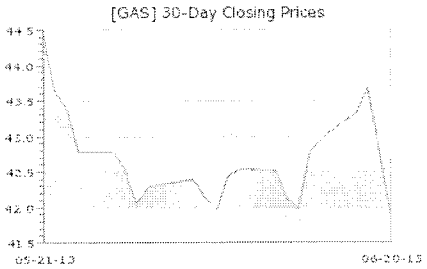
AGL RESOURCES
TEN PEACHTREE PLACE
ATLANTA, GA 30309
Phone: 4045844000
Fax: 404-584-3714
Web: http://www.aglresources.com
Email: scave@aglresources.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/07/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	41.86
52 Week High	44.85
52 Week Low	36.90
Beta	0.41
20 Day Moving Average	391,409.50
Target Price Consensus	43.00



% Price Change

4 Week	-3.50
12 Week	-0.21
YTD	7.01

% Price Change Relative to S&P 500

4 Week	0.28
12 Week	-1.41
YTD	-5.73

Share Information

Shares Outstanding (millions)	118.18
Market Capitalization (millions)	4,947.06
Short Ratio	4.05
Last Split Date	12/04/95

Dividend Information

Dividend Yield	4.49%
Annual Dividend	$1.88
Payout Ratio	0.72
Change in Payout Ratio	0.08
Last Dividend Payout / Amount	05/15/2013 / $0.47

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.28

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.14

Current Year EPS Consensus Estimate	2.59	30 Days Ago	3.14
Estimated Long-Term EPS Growth Rate	3.50	60 Days Ago	2.53
Next EPS Report Date	08/07/2013	90 Days Ago	2.57

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	16.15	vs. Previous Year	12.93%	vs. Previous Year	21.72%
Trailing 12 Months	16.04	vs. Previous Quarter	43.96%	vs. Previous Quarter	40.31%
PEG Ratio	4.57				

Price Ratios		ROE		ROA	
Price/Book	1.39	03-31-13	8.89	03-31-13	2.23
Price/Cash Flow	7.01	12-31-12	8.43	12-31-12	2.13
Price / Sales	1.17	09-30-12	7.63	09-30-12	1.92

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	0.77	03-31-13	0.64	03-31-13	7.26
12-31-12	0.80	12-31-12	0.59	12-31-12	7.36
09-30-12	0.77	09-30-12	0.49	09-30-12	7.42

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	6.98	03-31-13	11.57	03-31-13	30.03
12-31-12	6.91	12-31-12	11.47	12-31-12	29.16
09-30-12	5.90	09-30-12	10.48	09-30-12	28.92

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	4.91	03-31-13	0.94	03-31-13	48.42
12-31-12	4.34	12-31-12	0.97	12-31-12	49.20
09-30-12	3.77	09-30-12	0.98	09-30-12	49.49

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Atmos Energy Corp: (NYSE: ATO)

ZACKS RANK: 2-BUY #2

$38.71 -0.17 (-0.44%) **Volume 396,227** Jun 21 03:01 PM ET

Full Company Report

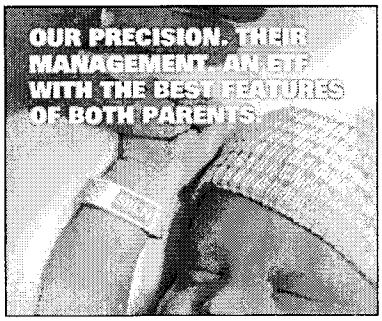
Get Full Company Report for: Enter Symbol GO

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
1800 THREE LINCOLN CTR 5430 LBJ FREEWAY
DALLAS, TX 75240
Phone: 9729349227
Fax: 972-855-3040
Web: http://www.atmosenergy.com
Email: NA

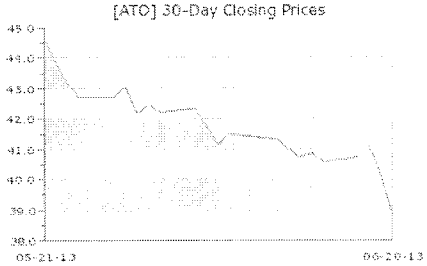
Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/2013
Next EPS Date	08/07/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	38.88
52 Week High	45.12
52 Week Low	32.94
Beta	0.45
20 Day Moving Average	421,751.84
Target Price Consensus	43.20

[ATO] 30-Day Closing Prices



% Price Change

4 Week	-9.83
12 Week	-8.92
YTD	14.10

% Price Change Relative to S&P 500

4 Week	-6.29
12 Week	-10.01
YTD	1.30

Share Information

Shares Outstanding (millions)	90.55
Market Capitalization (millions)	3,520.54
Short Ratio	4.11
Last Split Date	05/17/94

Dividend Information

Dividend Yield	3.60%
Annual Dividend	$1.40
Payout Ratio	0.57
Change in Payout Ratio	-0.06
Last Dividend Payout / Amount	05/16/2013 / $0.35

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.36
Current Year EPS Consensus Estimate	2.51
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	08/07/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00
60 Days Ago	2.86
90 Days Ago	2.57

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	15.49
Trailing 12 Months	15.87
PEG Ratio	2.58

EPS Growth

vs. Previous Year	-2.34%
vs. Previous Quarter	68.92%

Sales Growth

vs. Previous Year	6.81%
vs. Previous Quarter	26.58%

Price Ratios

Price/Book	1.38
Price/Cash Flow	7.49
Price / Sales	1.01

ROE

03-31-13	9.25
12-31-12	9.51
09-30-12	9.15

ROA

03-31-13	2.91
12-31-12	2.99
09-30-12	2.86

Current Ratio

03-31-13	1.08
12-31-12	0.71
09-30-12	0.65

Quick Ratio

03-31-13	0.87
12-31-12	0.54
09-30-12	0.45

Operating Margin

03-31-13	6.45
12-31-12	6.67
09-30-12	6.22

Net Margin

03-31-13	6.80
12-31-12	6.75
09-30-12	6.30

Pre-Tax Margin

03-31-13	9.39
12-31-12	9.26
09-30-12	8.45

Book Value

03-31-13	28.12
12-31-12	26.80
09-30-12	26.16

Inventory Turnover

03-31-13	10.68
12-31-12	10.10
09-30-12	9.85

Debt-to-Equity

03-31-13	0.97
12-31-12	0.81
09-30-12	0.83

Debt to Capital

03-31-13	49.12
12-31-12	44.66
09-30-12	45.33

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Laclede Group Inc: (NYSE: LG)

ZACKS RANK: 3-HOLD #3

$44.49 -0.03 (-0.06%) **Volume 232,395** **Jun 21 03:02 PM ET**

Full Company Report Get Full Company Report for: Enter Symbol GO

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 ST
ST LOUIS, MO 63101
Phone: 3143420500
Fax: 314-421-1979
Web: http://www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/2013
Next EPS Date	07/26/2013

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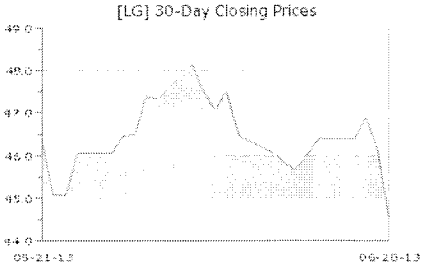
PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	44.52
52 Week High	48.50
52 Week Low	37.35
Beta	0.07
20 Day Moving Average	636,594.00
Target Price Consensus	46.00

[LG] 30-Day Closing Prices



% Price Change

4 Week	-1.20
12 Week	4.26
YTD	19.42

% Price Change Relative to S&P 500

4 Week	2.68
12 Week	3.02
YTD	5.38

Share Information

Shares Outstanding (millions)	31.34
Market Capitalization (millions)	1,395.44
Short Ratio	11.75
Last Split Date	03/08/94

Dividend Information

Dividend Yield	3.82%
Annual Dividend	$1.70
Payout Ratio	0.55
Change in Payout Ratio	-0.04
Last Dividend Payout / Amount	06/07/2013 / $0.43

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.22

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.50

Current Year EPS Consensus Estimate	2.72	30 Days Ago	3.00
Estimated Long-Term EPS Growth Rate	3.00	60 Days Ago	3.00
Next EPS Report Date	07/26/2013	90 Days Ago	3.00

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	16.36	vs. Previous Year	13.39%	vs. Previous Year	11.01%
Trailing 12 Months	14.31	vs. Previous Quarter	15.20%	vs. Previous Quarter	29.51%
PEG Ratio	5.45				

Price Ratios		ROE		ROA	
Price/Book	1.57	03-31-13	11.33	03-31-13	3.70
Price/Cash Flow	9.64	12-31-12	10.77	12-31-12	3.60
Price / Sales	1.32	09-30-12	10.36	09-30-12	3.45

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	2.22	03-31-13	2.00	03-31-13	6.60
12-31-12	1.45	12-31-12	1.08	12-31-12	6.45
09-30-12	1.36	09-30-12	0.94	09-30-12	5.57

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	5.99	03-31-13	8.31	03-31-13	28.35
12-31-12	6.17	12-31-12	8.55	12-31-12	27.56
09-30-12	5.57	09-30-12	7.90	09-30-12	26.73

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	8.65	03-31-13	0.73	03-31-13	42.05
12-31-12	7.66	12-31-12	0.59	12-31-12	36.99
09-30-12	8.28	09-30-12	0.56	09-30-12	36.07

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New Jersey Resources Corp: (NYSE: NJR)

ZACKS RANK: 3-HOLD #3

$42.04 0.12 (0.29%) **Volume 271,802** Jun 21 03:03 PM ET

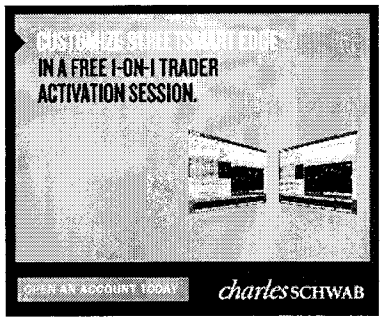
Full Company Report Get Full Company Report for: Enter Symbol GO

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

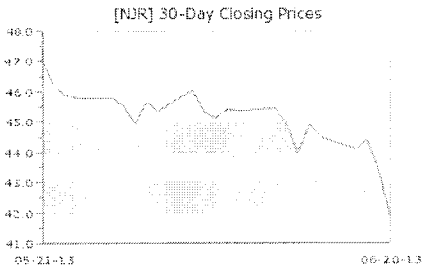
NJ RESOURCES
1415 WYCKOFF RD PO BOX 1468
WALL, NJ 07719
Phone: 9089381494
Fax: 732-938-3154
Web: http://www.njresources.com
Email: dpuma@njresources.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/2013
Next EPS Date	08/08/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	41.92
52 Week High	47.60
52 Week Low	38.51
Beta	0.21
20 Day Moving Average	137,358.05
Target Price Consensus	46.60



% Price Change

4 Week	-8.63
12 Week	-6.53
YTD	9.46

% Price Change Relative to S&P 500

4 Week	-5.05
12 Week	-7.65
YTD	-1.60

Share Information

Shares Outstanding (millions)	41.78
Market Capitalization (milions)	1,751.29
Short Ratio	15.47
Last Split Date	03/04/08

Dividend Information

Dividend Yield	3.82%
Annual Dividend	$1.60
Payout Ratio	0.69
Change in Payout Ratio	0.12
Last Dividend Payout / Amount	06/12/2013 / $0.40

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.22
Current Year EPS Consensus Estimate	2.64
Estimated Long-Term EPS Growth Rate	4.00
Next EPS Report Date	08/08/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.86
30 Days Ago	2.86
60 Days Ago	2.86
90 Days Ago	2.86

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	15.87
Trailing 12 Months	18.15
PEG Ratio	3.97

EPS Growth

vs. Previous Year	-8.94%
vs. Previous Quarter	91.76%

Sales Growth

vs. Previous Year	56.77%
vs. Previous Quarter	30.55%

Price Ratios

Price/Book	1.95
Price/Cash Flow	11.32
Price / Sales	0.65

ROE

03-31-13	11.39
12-31-12	12.16
09-30-12	13.49

ROA

03-31-13	3.43
12-31-12	3.71
09-30-12	4.10

Current Ratio

03-31-13	1.04
12-31-12	0.97
09-30-12	0.99

Quick Ratio

03-31-13	0.79
12-31-12	0.56
09-30-12	0.57

Operating Margin

03-31-13	3.61
12-31-12	4.38
09-30-12	5.00

Net Margin

03-31-13	3.22
12-31-12	4.09
09-30-12	4.13

Pre-Tax Margin

03-31-13	3.43
12-31-12	4.31
09-30-12	4.00

Book Value

03-31-13	21.47
12-31-12	20.70
09-30-12	19.57

Inventory Turnover

03-31-13	9.69
12-31-12	8.29
09-30-12	8.22

Debt-to-Equity

03-31-13	0.59
12-31-12	0.61
09-30-12	0.65

Debt to Capital

03-31-13	37.02
12-31-12	38.04
09-30-12	39.22

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Northwest Natural Gas: (NYSE: NWN)

ZACKS RANK: 3-HOLD #3

$41.86 -0.12 (-0.29%) **Volume 209,391** **Jun 21 03:03 PM ET**

Full Company Report Get Full Company Report for: Enter Symbol GO

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

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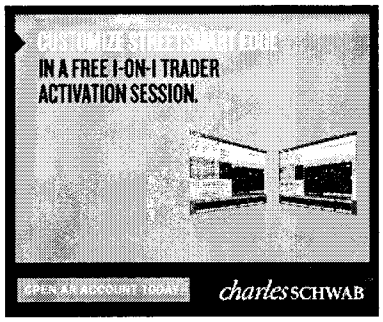
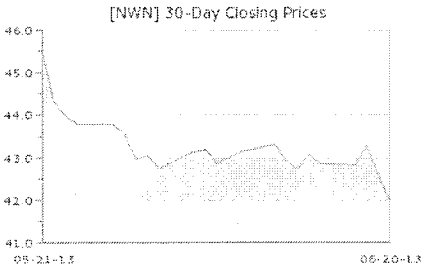
Email: bob.hess@nwnatural.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/09/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	3
Yesterday's Close	41.98
52 Week High	50.80
52 Week Low	41.01
Beta	0.22
20 Day Moving Average	107,862.95
Target Price Consensus	45.25



% Price Change

4 Week	-4.48
12 Week	-4.20
YTD	-3.73

% Price Change Relative to S&P 500

4 Week	-0.73
12 Week	-5.35
YTD	-15.05

Share Information

Shares Outstanding (millions)	26.95
Market Capitalization (millions)	1,131.32
Short Ratio	13.02
Last Split Date	09/09/96

Dividend Information

Dividend Yield	4.34%
Annual Dividend	$1.82
Payout Ratio	0.82
Change in Payout Ratio	0.17
Last Dividend Payout / Amount	04/26/2013 / $0.46

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.09
Current Year EPS Consensus Estimate	2.26
Estimated Long-Term EPS Growth Rate	3.80
Next EPS Report Date	08/09/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.38
30 Days Ago	3.38
60 Days Ago	3.50
90 Days Ago	3.50

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	18.58
Trailing 12 Months	19.00
PEG Ratio	4.85

EPS Growth

vs. Previous Year	-7.28%
vs. Previous Quarter	33.33%

Sales Growth

vs. Previous Year	-12.48%
vs. Previous Quarter	21.08%

Price Ratios

Price/Book	1.49
Price/Cash Flow	8.32
Price / Sales	1.61

ROE

03-31-13	8.09
12-31-12	8.54
09-30-12	8.71

ROA

03-31-13	2.18
12-31-12	2.30
09-30-12	2.35

Current Ratio

03-31-13	0.82
12-31-12	0.77
09-30-12	0.57

Quick Ratio

03-31-13	0.65
12-31-12	0.59
09-30-12	0.36

Operating Margin

03-31-13	8.47
12-31-12	8.42
09-30-12	8.08

Net Margin

03-31-13	8.08
12-31-12	8.05
09-30-12	7.73

Pre-Tax Margin

03-31-13	14.15
12-31-12	14.23
09-30-12	13.48

Book Value

03-31-13	28.11
12-31-12	27.28
09-30-12	26.74

Inventory Turnover

03-31-13	6.98
12-31-12	7.15
09-30-12	7.45

Debt-to-Equity

03-31-13	0.91
12-31-12	0.94
09-30-12	0.89

Debt to Capital

03-31-13	47.76
12-31-12	48.55
09-30-12	47.21

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- Financial Overview
- Income Statements
- Balance Sheet
- Cash flow Statements

Piedmont Natural Gas Co Inc: (NYSE: PNY)

ZACKS RANK: 3-HOLD #3

$32.98 0.13 (0.40%) **Volume 414,531** Jun 21 03:06 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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

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4720 PIEDMONT ROW DR
CHARLOTTE, NC 28233
Phone: 7043643120
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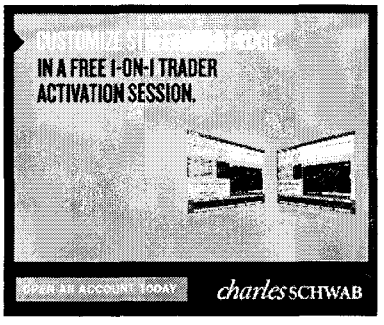
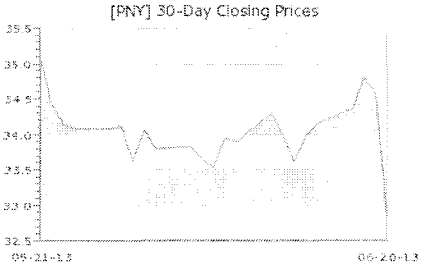
Web: http://www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	October
Last Reported Quarter	04/30/2013
Next EPS Date	09/06/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	32.85
52 Week High	35.53
52 Week Low	28.51
Beta	0.29
20 Day Moving Average	307,161.84
Target Price Consensus	33.29



% Price Change

4 Week	-3.75
12 Week	-0.09
YTD	10.38

% Price Change Relative to S&P 500

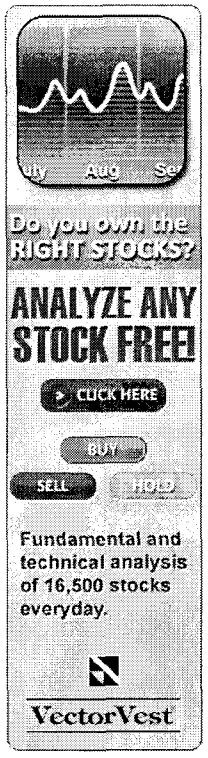
4 Week	0.03
12 Week	-1.29
YTD	-4.38

Share Information

Shares Outstanding (millions)	75.52
Market Capitalization (millions)	2,480.83
Short Ratio	12.09
Last Split Date	11/01/04

Dividend Information

Dividend Yield	3.77%
Annual Dividend	$1.24
Payout Ratio	0.68
Change in Payout Ratio	-0.03
Last Dividend Payout / Amount	03/21/2013 / $0.31



EPS INFORMATION

Current Quarter EPS Consensus Estimate	-0.08
Current Year EPS Consensus Estimate	1.73
Estimated Long-Term EPS Growth Rate	4.30
Next EPS Report Date	09/06/2013

CONSENSUS RECOMMENDATIONS

	Sub
Current (1=Strong Buy, 5=Strong Sell)	3.25
30 Days Ago	3.25
60 Days Ago	3.00
90 Days Ago	3.00

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	18.97	vs. Previous Year	5.71%	vs. Previous Year	29.50%
Trailing 12 Months	17.95	vs. Previous Quarter	-37.29%	vs. Previous Quarter	-22.58%
PEG Ratio	4.41				

Price Ratios		ROE		ROA	
Price/Book	2.02	04-30-13	12.28	04-30-13	3.51
Price/Cash Flow	10.35	01-31-13	12.23	01-31-13	3.50
Price / Sales	1.97	10-31-12	11.51	10-31-12	3.37

Current Ratio		Quick Ratio		Operating Margin	
04-30-13	0.47	04-30-13	0.39	04-30-13	10.74
01-31-13	0.51	01-31-13	0.42	01-31-13	11.10
10-31-12	0.52	10-31-12	0.39	10-31-12	10.67

Net Margin		Pre-Tax Margin		Book Value	
04-30-13	10.74	04-30-13	17.02	04-30-13	16.30
01-31-13	11.10	01-31-13	17.84	01-31-13	15.15
10-31-12	10.67	10-31-12	17.64	10-31-12	14.25

Inventory Turnover		Debt-to-Equity		Debt to Capital	
04-30-13	13.10	04-30-13	0.71	04-30-13	41.55
01-31-13	10.92	01-31-13	0.80	01-31-13	44.33
10-31-12	9.65	10-31-12	0.95	10-31-12	48.70

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South Jersey Industries Inc: (NYSE: SJI)

ZACKS RANK: 3-HOLD #3

$56.20 0.28 (0.50%) **Volume 128,338** Jun 21 03:06 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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
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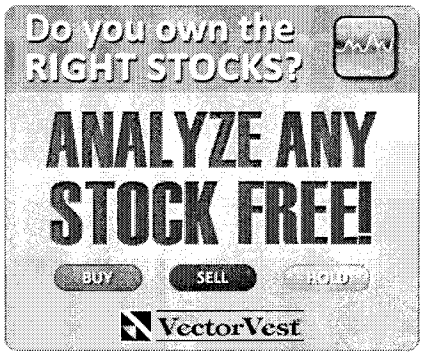
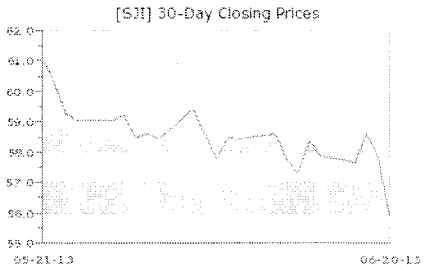
Phone: 609-561-9000
Fax: 609-561-8225
Web: http://www.sjindustries.com
Email: NA

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/06/2013



PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	55.92
52 Week High	61.78
52 Week Low	45.81
Beta	0.31
20 Day Moving Average	88,193.00
Target Price Consensus	65.00



% Price Change

4 Week	-5.64
12 Week	0.59
YTD	14.88

% Price Change Relative to S&P 500

4 Week	-1.93
12 Week	-0.61
YTD	0.77

Share Information

Shares Outstanding (millions)	31.96
Market Capitalization (milions)	1,787.20
Short Ratio	10.08
Last Split Date	07/01/05

Dividend Information

Dividend Yield	3.17%
Annual Dividend	$1.77
Payout Ratio	0.61
Change in Payout Ratio	0.08
Last Dividend Payout / Amount	06/06/2013 / $0.44

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.36

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.25

Current Year EPS Consensus Estimate	3.15	30 Days Ago	2.25
Estimated Long-Term EPS Growth Rate	6.00	60 Days Ago	1.50
Next EPS Report Date	08/06/2013	90 Days Ago	1.50

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	17.75	vs. Previous Year	-7.88%	vs. Previous Year	-6.99%
Trailing 12 Months	19.22	vs. Previous Quarter	55.10%	vs. Previous Quarter	29.40%
PEG Ratio	2.96				

Price Ratios		ROE		ROA	
Price/Book	2.28	03-31-13	12.73	03-31-13	3.67
Price/Cash Flow	11.78	12-31-12	13.46	12-31-12	3.88
Price / Sales	2.60	09-30-12	14.21	09-30-12	4.09

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	0.74	03-31-13	0.66	03-31-13	13.35
12-31-12	0.61	12-31-12	0.52	12-31-12	13.21
09-30-12	0.59	09-30-12	0.47	09-30-12	13.36

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	11.70	03-31-13	12.12	03-31-13	24.50
12-31-12	12.97	12-31-12	14.44	12-31-12	23.55
09-30-12	14.61	09-30-12	16.58	09-30-12	22.54

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	9.93	03-31-13	0.77	03-31-13	43.60
12-31-12	9.81	12-31-12	0.82	12-31-12	44.96
09-30-12	9.00	09-30-12	0.81	09-30-12	44.87

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Price and Consensus
12 month EPS
Price & EPS Surprise
Broker Recommendations
Fundamental Charts

RESEARCH
Full Company Report
Zacks Equity Research
Brokerage Digest Report
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Annual Report

FINANCIALS
Financial Overview
Income Statements
Balance Sheet
Cash flow Statements

Southwest Gas Corp: (NYSE: SWX)

ZACKS RANK: 4-SELL #4

$46.05 0.29 (0.63%) **Volume 186,371** Jun 21 03:07 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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 RD PO BOX 98510
LAS VEGAS, NV 89193-8510
Phone: 7028767237
Fax: 702-876-7037
Web: http://www.swgas.com
Email: NA

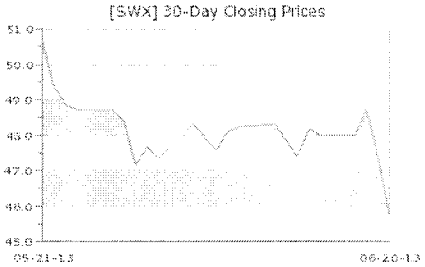
SRLN The first actively managed senior loan ETF. Offering income potential while positioning your fixed income portfolio for rising interest rates.

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	03/31/2013
Next EPS Date	08/06/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	45.76
52 Week High	51.52
52 Week Low	39.01
Beta	0.67
20 Day Moving Average	142,172.25
Target Price Consensus	49.00

[SWX] 30-Day Closing Prices



% Price Change

4 Week	-6.33
12 Week	-3.58
YTD	11.67

% Price Change Relative to S&P 500

4 Week	-2.65
12 Week	-4.74
YTD	-0.77

Share Information

Shares Outstanding (millions)	46.33
Market Capitalization (millions)	2,120.01
Short Ratio	5.96
Last Split Date	NA

Dividend Information

Dividend Yield	2.88%
Annual Dividend	$1.32
Payout Ratio	0.41
Change in Payout Ratio	-0.05
Last Dividend Payout / Amount	05/13/2013 / $0.33

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.07

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.43

Current Year EPS Consensus Estimate	2.90	30 Days Ago	2.75
Estimated Long-Term EPS Growth Rate	5.30	60 Days Ago	2.28
Next EPS Report Date	08/06/2013	90 Days Ago	2.38

FUNDAMENTAL RATIOS

P/E		EPS Growth		Sales Growth	
Current FY Estimate	15.78	vs. Previous Year	-2.94%	vs. Previous Year	-6.71%
Trailing 12 Months	15.73	vs. Previous Quarter	37.50%	vs. Previous Quarter	25.57%
PEG Ratio	3.01				

Price Ratios		ROE		ROA	
Price/Book	1.54	03-31-13	10.36	03-31-13	3.12
Price/Cash Flow	6.39	12-31-12	10.68	12-31-12	3.16
Price / Sales	1.13	09-30-12	10.82	09-30-12	3.18

Current Ratio		Quick Ratio		Operating Margin	
03-31-13	0.89	03-31-13	0.89	03-31-13	7.20
12-31-12	0.86	12-31-12	0.86	12-31-12	7.13
09-30-12	0.75	09-30-12	0.75	09-30-12	7.00

Net Margin		Pre-Tax Margin		Book Value	
03-31-13	7.18	03-31-13	11.23	03-31-13	29.78
12-31-12	6.92	12-31-12	10.78	12-31-12	28.36
09-30-12	6.45	09-30-12	9.99	09-30-12	27.42

Inventory Turnover		Debt-to-Equity		Debt to Capital	
03-31-13	NA	03-31-13	0.91	03-31-13	47.57
12-31-12	NA	12-31-12	0.97	12-31-12	49.22
09-30-12	NA	09-30-12	0.99	09-30-12	49.82

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At the center of everything we do is a strong commitment to independent research and sharing its profitable discoveries with investors. This dedication to giving investors a trading advantage led to the creation of our proven Zacks Rank stock-rating system. Since 1986 it has nearly tripled the S&P 500 with an average gain of +26% per year. These returns cover a period from 1986-2011 and were examined and attested by Baker Tilly, an independent accounting firm.

Visit performance for information about the performance numbers displayed above.

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FINANCIALS
Financial Overview
Income Statements
Balance Sheet
Cash flow Statements

Wgl Holdings Inc: (NYSE: WGL)

$42.10 0.32 (0.77%) **Volume 256,930** Jun 21 03:08 PM ET

ZACKS RANK: 2-BUY #2

Full Company Report

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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 AVE N.W.
WASHINGTON, DC 20080
Phone: 2026246011
Fax: 703-750-4828
Web: http://www.wglholdings.com
Email: robertdennis@washgas.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	03/31/2013
Next EPS Date	08/09/2013

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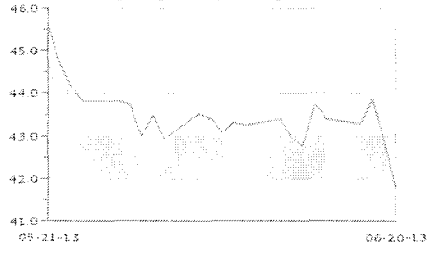
PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	41.78
52 Week High	46.22
52 Week Low	35.96
Beta	0.22
20 Day Moving Average	153,174.25
Target Price Consensus	43.20

[WGL] 30-Day Closing Prices



% Price Change

4 Week	-5.35
12 Week	-5.26
YTD	9.36

% Price Change Relative to S&P 500

4 Week	-1.63
12 Week	-6.39
YTD	-2.89

Share Information

Shares Outstanding (millions)	51.70
Market Capitalization (millions)	2,160.15
Short Ratio	6.00
Last Split Date	05/02/95

Dividend Information

Dividend Yield	4.02%
Annual Dividend	$1.68
Payout Ratio	0.56
Change in Payout Ratio	-0.06
Last Dividend Payout / Amount	04/08/2013 / $0.42

EPS INFORMATION

Current Quarter EPS Consensus Estimate	-0.05
Current Year EPS Consensus Estimate	2.50
Estimated Long-Term EPS Growth Rate	5.30
Next EPS Report Date	08/09/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.14
30 Days Ago	3.14
60 Days Ago	3.00
90 Days Ago	3.00

FUNDAMENTAL RATIOS

P/E

Current FY Estimate	16.72
Trailing 12 Months	14.56
PEG Ratio	3.18

EPS Growth

vs. Previous Year	10.76%
vs. Previous Quarter	53.51%

Sales Growth

vs. Previous Year	6.19%
vs. Previous Quarter	29.80%

Price Ratios

Price/Book	1.57
Price/Cash Flow	9.11
Price / Sales	0.89

ROE

03-31-13	11.37
12-31-12	10.84
09-30-12	10.95

ROA

03-31-13	3.57
12-31-12	3.39
09-30-12	3.42

Current Ratio

03-31-13	1.14
12-31-12	1.04
09-30-12	1.10

Quick Ratio

03-31-13	0.90
12-31-12	0.73
09-30-12	0.69

Operating Margin

03-31-13	6.10
12-31-12	5.85
09-30-12	5.73

Net Margin

03-31-13	6.50
12-31-12	6.00
09-30-12	5.82

Pre-Tax Margin

03-31-13	10.36
12-31-12	9.87
09-30-12	9.67

Book Value

03-31-13	26.59
12-31-12	25.24
09-30-12	24.62

Inventory Turnover

03-31-13	7.19
12-31-12	7.00
09-30-12	6.89

Debt-to-Equity

03-31-13	0.40
12-31-12	0.42
09-30-12	0.46

Debt to Capital

03-31-13	28.35
12-31-12	29.38
09-30-12	31.23

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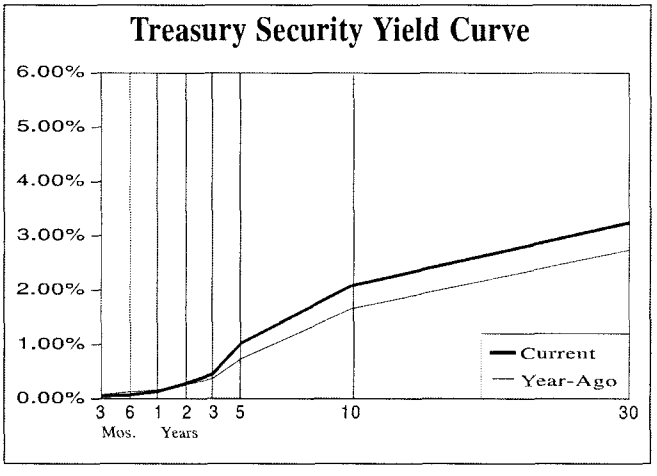
ATTACHMENT D

ATTACHMENT D

Selected Yields

	Recent (6/05/13)	3 Months Ago (3/06/13)	Year Ago (6/06/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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	0.20	0.30
3-month LIBOR	0.27	0.28	0.47
Bank CDs			
6-month	0.08	0.10	0.21
1-year	0.10	0.13	0.32
5-year	0.64	0.70	1.11
U.S. Treasury Securities			
3-month	0.05	0.09	0.08
6-month	0.07	0.11	0.13
1-year	0.13	0.15	0.17
5-year	1.02	0.81	0.73
10-year	2.08	1.95	1.66
10-year (inflation-protected)	-0.10	-0.64	-0.52
30-year	3.24	3.16	2.74
30-year Zero	3.49	3.42	2.95

	Recent (6/05/13)	3 Months Ago (3/06/13)	Year Ago (6/06/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.31	1.77	1.37
FHLMC 5.5% (Gold)	2.68	2.25	2.16
FNMA 5.5%	2.27	1.88	1.97
FNMA ARM	2.13	2.12	2.29
Corporate Bonds			
Financial (10-year) A	3.27	3.03	3.40
Industrial (25/30-year) A	4.26	4.08	4.05
Utility (25/30-year) A	4.19	4.07	3.98
Utility (25/30-year) Baa/BBB	4.60	4.42	4.38
Foreign Bonds (10-Year)			
Canada	2.05	1.85	1.81
Germany	1.51	1.46	1.34
Japan	0.85	0.65	0.85
United Kingdom	2.01	1.96	1.66
Preferred Stocks			
Utility A	5.55	5.40	5.30
Financial BBB	5.06	5.93	6.52
Financial Adjustable A	5.53	5.53	5.53



	Recent (6/05/13)	3 Months Ago (3/06/13)	Year Ago (6/06/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.84	3.74	3.77
25-Bond Index (Revs)	4.39	4.29	4.73
General Obligation Bonds (GOs)			
1-year Aaa	0.16	0.19	0.21
1-year A	0.88	0.78	0.93
5-year Aaa	1.01	0.80	0.78
5-year A	1.94	1.78	1.74
10-year Aaa	2.21	2.01	1.95
10-year A	3.21	2.89	2.98
25/30-year Aaa	3.36	3.13	3.47
25/30-year A	5.11	4.82	4.81
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.38	4.21	4.32
Electric AA	4.53	4.34	4.63
Housing AA	4.87	4.64	4.69
Hospital AA	4.62	4.45	4.54
Toll Road Aaa	4.56	4.37	4.38

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/29/13	5/15/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1897054	1823318	73736	1762549	1632938	1544745
Borrowed Reserves	410	422	-12	403	547	1866
Net Free/Borrowed Reserves	1896644	1822896	73748	1762146	1632390	1542879

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	5/20/13	5/13/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2533.8	2540.0	-6.2	8.0%	10.1%	12.0%
M2 (M1+savings+small time deposits)	10541.5	10553.4	-11.9	4.6%	5.2%	6.7%

Source: United States Federal Reserve Bank

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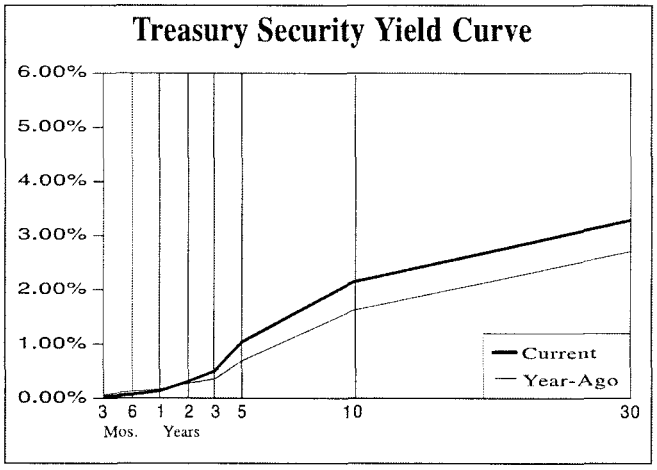
Selected Yields

	Recent (5/29/13)	3 Months Ago (2/27/13)	Year Ago (5/30/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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	0.21	0.31
3-month LIBOR	0.28	0.29	0.47
Bank CDs			
6-month	0.08	0.10	0.21
1-year	0.10	0.13	0.33
5-year	0.64	0.70	1.12
U.S. Treasury Securities			
3-month	0.03	0.10	0.07
6-month	0.07	0.13	0.13
1-year	0.13	0.15	0.17
5-year	1.04	0.76	0.69
10-year	2.14	1.88	1.62
10-year (inflation-protected)	-0.14	-0.63	-0.48
30-year	3.28	3.08	2.71
30-year Zero	3.51	3.37	2.93

	Recent (5/29/13)	3 Months Ago (2/27/13)	Year Ago (5/30/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.25	1.59	1.32
FHLMC 5.5% (Gold)	2.57	2.22	2.15
FNMA 5.5%	2.19	1.83	1.97
FNMA ARM	2.12	2.23	2.32
Corporate Bonds			
Financial (10-year) A	3.27	2.99	3.28
Industrial (25/30-year) A	4.28	4.03	3.98
Utility (25/30-year) A	4.19	4.03	3.91
Utility (25/30-year) Baa/BBB	4.51	4.40	4.39
Foreign Bonds (10-Year)			
Canada	2.07	1.87	1.80
Germany	1.53	1.45	1.27
Japan	0.93	0.67	0.85
United Kingdom	2.00	1.96	1.65
Preferred Stocks			
Utility A	5.74	5.37	5.32
Financial BBB	6.34	5.92	6.51
Financial Adjustable A	5.53	5.53	5.53



	Recent (5/29/13)	3 Months Ago (2/27/13)	Year Ago (5/30/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.70	3.74	3.81
25-Bond Index (Revs)	4.30	4.30	4.76
General Obligation Bonds (GOs)			
1-year Aaa	0.17	0.16	0.21
1-year A	0.82	0.74	0.92
5-year Aaa	0.91	0.87	0.80
5-year A	1.84	1.79	1.74
10-year Aaa	2.11	2.04	2.00
10-year A	3.11	2.90	3.03
25/30-year Aaa	3.28	3.13	3.51
25/30-year A	5.03	4.83	4.83
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.29	4.21	4.35
Electric AA	4.46	4.34	4.66
Housing AA	4.78	4.64	4.72
Hospital AA	4.55	4.47	4.56
Toll Road Aaa	4.51	4.37	4.42

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/15/13	5/1/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1823317	1751983	71334	1722318	1600204	1528214
Borrowed Reserves	422	407	15	412	599	2090
Net Free/Borrowed Reserves	1822895	1751576	71319	1721907	1599605	1526124

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	5/13/13	5/6/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2540.1	2540.3	-0.2	8.6%	10.2%	12.4%
M2 (M1+savings+small time deposits)	10553.4	10540.7	12.7	4.1%	5.2%	7.0%

Source: United States Federal Reserve Bank

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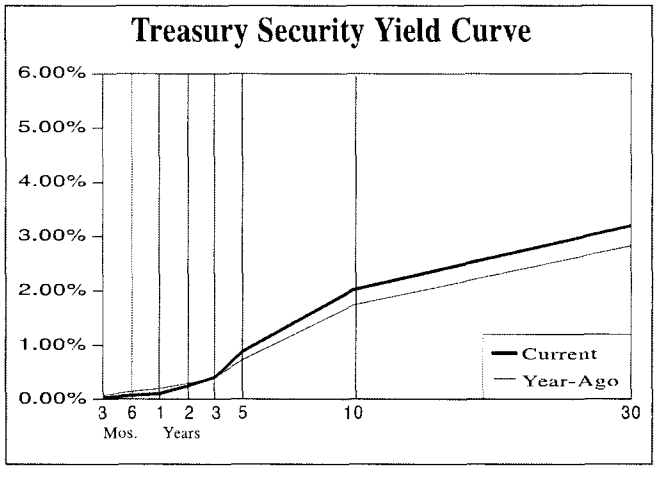
Selected Yields

	Recent (5/22/13)	3 Months Ago (2/20/13)	Year Ago (5/23/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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	0.20	0.31
3-month LIBOR	0.27	0.29	0.47
Bank CDs			
6-month	0.09	0.10	0.21
1-year	0.11	0.13	0.33
5-year	0.64	0.70	1.12
U.S. Treasury Securities			
3-month	0.03	0.12	0.08
6-month	0.07	0.13	0.14
1-year	0.10	0.15	0.19
5-year	0.89	0.84	0.73
10-year	2.02	1.99	1.74
10-year (inflation-protected)	-0.26	-0.68	-0.45
30-year	3.19	3.18	2.82
30-year Zero	3.47	3.47	3.03

	Recent (5/22/13)	3 Months Ago (2/20/13)	Year Ago (5/23/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.19	1.60	1.14
FHLMC 5.5% (Gold)	2.36	2.32	2.19
FNMA 5.5%	1.99	2.01	1.99
FNMA ARM	2.12	2.23	2.32
Corporate Bonds			
Financial (10-year) A	3.04	3.08	3.39
Industrial (25/30-year) A	4.20	4.12	4.03
Utility (25/30-year) A	4.12	4.12	3.98
Utility (25/30-year) Baa/BBB	4.52	4.45	4.50
Foreign Bonds (10-Year)			
Canada	1.97	2.02	1.88
Germany	1.43	1.65	1.38
Japan	0.89	0.75	0.87
United Kingdom	1.90	2.19	1.77
Preferred Stocks			
Utility A	5.59	5.51	5.32
Financial BBB	6.22	5.91	6.50
Financial Adjustable A	5.52	5.52	5.52



	Recent (5/22/13)	3 Months Ago (2/20/13)	Year Ago (5/23/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.61	3.72	3.75
25-Bond Index (Revs)	4.25	4.30	4.75
General Obligation Bonds (GOs)			
1-year Aaa	0.16	0.19	0.21
1-year A	0.81	0.79	0.91
5-year Aaa	0.86	0.85	0.80
5-year A	1.79	1.85	1.75
10-year Aaa	2.05	2.00	1.97
10-year A	3.05	2.93	3.03
25/30-year Aaa	3.24	3.15	3.51
25/30-year A	4.99	4.86	4.83
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.28	4.22	4.35
Electric AA	4.42	4.35	4.65
Housing AA	4.74	4.65	4.75
Hospital AA	4.56	4.47	4.56
Toll Road Aaa	4.41	4.37	4.42

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/15/13	5/1/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1823319	1751984	71335	1722319	1600204	1528214
Borrowed Reserves	422	407	15	412	599	2090
Net Free/Borrowed Reserves	1822897	1751577	71320	1721907	1599605	1526124

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	5/6/13	4/29/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2540.2	2523.1	17.1	9.8%	9.5%	12.7%
M2 (M1+savings+small time deposits)	10540.2	10535.0	5.2	4.2%	4.4%	6.9%

Source: United States Federal Reserve Bank

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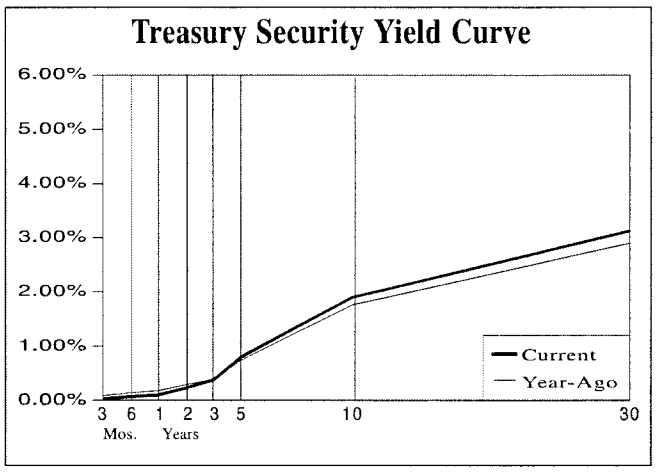
Selected Yields

	Recent (5/15/13)	3 Months Ago (2/13/13)	Year Ago (5/16/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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)	0.19	0.21	0.31
3-month LIBOR	0.27	0.29	0.47
Bank CDs			
6-month	0.09	0.10	0.22
1-year	0.11	0.13	0.33
5-year	0.64	0.70	1.12
U.S. Treasury Securities			
3-month	0.03	0.09	0.09
6-month	0.07	0.12	0.14
1-year	0.10	0.15	0.18
5-year	0.80	0.89	0.74
10-year	1.90	2.04	1.76
10-year (inflation-protected)	-0.40	-0.68	-0.38
30-year	3.12	3.22	2.90
30-year Zero	3.41	3.48	3.13

	Recent (5/15/13)	3 Months Ago (2/13/13)	Year Ago (5/16/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.08	1.85	1.13
FHLMC 5.5% (Gold)	2.22	2.16	2.09
FNMA 5.5%	1.87	1.90	1.87
FNMA ARM	2.12	2.23	2.32
Corporate Bonds			
Financial (10-year) A	2.96	3.23	3.36
Industrial (25/30-year) A	4.13	4.18	4.05
Utility (25/30-year) A	4.07	4.15	4.00
Utility (25/30-year) Baa/BBB	4.42	4.50	4.48
Foreign Bonds (10-Year)			
Canada	1.92	2.04	1.92
Germany	1.38	1.67	1.47
Japan	0.86	0.75	0.83
United Kingdom	1.92	2.21	1.88
Preferred Stocks			
Utility A	5.47	5.50	5.31
Financial BBB	6.22	5.92	6.69
Financial Adjustable A	5.51	5.51	5.52



	Recent (5/15/13)	3 Months Ago (2/13/13)	Year Ago (5/16/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.67	3.68	3.71
25-Bond Index (Revs)	4.22	4.29	4.73
General Obligation Bonds (GOs)			
1-year Aaa	0.17	0.20	0.21
1-year A	0.82	0.78	0.95
5-year Aaa	0.85	0.83	0.78
5-year A	1.78	1.83	1.78
10-year Aaa	1.99	1.99	1.92
10-year A	2.99	2.90	3.06
25/30-year Aaa	3.19	3.12	3.50
25/30-year A	4.94	4.83	4.95
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.21	4.30
Electric AA	4.37	4.31	4.60
Housing AA	4.69	4.68	4.70
Hospital AA	4.54	4.43	4.56
Toll Road Aaa	4.39	4.36	4.42

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/1/13	4/17/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1751987	1793542	-41555	1687300	1571604	1514671
Borrowed Reserves	407	397	10	428	666	2320
Net Free/Borrowed Reserves	1751580	1793145	-41565	1686872	1570938	1512351

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	4/29/13	4/22/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2523.1	2508.5	14.6	10.1%	8.4%	12.0%
M2 (M1+savings+small time deposits)	10535.0	10501.4	33.6	4.4%	4.8%	6.9%

Source: United States Federal Reserve Bank

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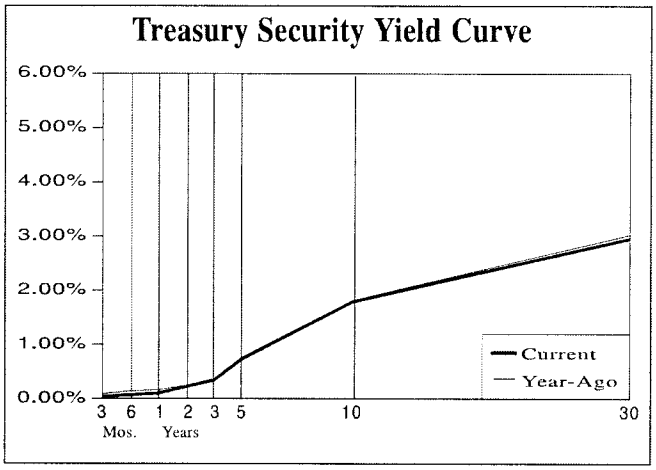
Selected Yields

	Recent (5/08/13)	3 Months Ago (2/06/13)	Year Ago (5/09/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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)	0.19	0.21	0.32
3-month LIBOR	0.28	0.29	0.47
Bank CDs			
6-month	0.09	0.10	0.22
1-year	0.11	0.13	0.33
5-year	0.64	0.70	1.13
U.S. Treasury Securities			
3-month	0.04	0.07	0.09
6-month	0.07	0.11	0.14
1-year	0.10	0.15	0.17
5-year	0.73	0.85	0.76
10-year	1.79	1.98	1.82
10-year (inflation-protected)	-0.52	-0.72	-0.34
30-year	2.96	3.18	3.03
30-year Zero	3.25	3.42	3.27

	Recent (5/08/13)	3 Months Ago (2/06/13)	Year Ago (5/09/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.04	1.83	1.09
FHLMC 5.5% (Gold)	2.13	2.06	2.08
FNMA 5.5%	1.86	1.83	1.86
FNMA ARM	2.12	2.23	2.39
Corporate Bonds			
Financial (10-year) A	2.83	3.18	3.34
Industrial (25/30-year) A	3.96	4.14	4.14
Utility (25/30-year) A	3.94	4.09	4.07
Utility (25/30-year) Baa/BBB	4.29	4.45	4.54
Foreign Bonds (10-Year)			
Canada	1.81	2.00	1.98
Germany	1.27	1.63	1.52
Japan	0.60	0.78	0.85
United Kingdom	1.77	2.10	1.90
Preferred Stocks			
Utility A	5.46	5.48	5.31
Financial BBB	6.20	5.90	6.18
Financial Adjustable A	5.51	5.51	5.51



	Recent (5/08/13)	3 Months Ago (2/06/13)	Year Ago (5/09/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.77	3.67	3.81
25-Bond Index (Revs)	4.19	4.29	4.77
General Obligation Bonds (GOs)			
1-year Aaa	0.16	0.22	0.18
1-year A	0.79	0.82	0.98
5-year Aaa	0.81	0.85	0.83
5-year A	1.73	1.85	1.84
10-year Aaa	1.93	2.02	1.96
10-year A	2.92	2.92	3.11
25/30-year Aaa	3.12	3.14	3.56
25/30-year A	4.86	4.85	5.03
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.21	4.22	4.28
Electric AA	4.34	4.33	4.60
Housing AA	4.67	4.68	4.77
Hospital AA	4.48	4.45	4.58
Toll Road Aaa	4.35	4.39	4.42

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	5/1/13	4/17/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1751987	1793542	-41555	1687300	1571604	1514671
Borrowed Reserves	407	397	10	428	666	2320
Net Free/Borrowed Reserves	1751580	1793145	-41565	1686872	1570938	1512351

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	4/22/13	4/15/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2508.5	2486.9	21.6	9.5%	8.7%	11.6%
M2 (M1+savings+small time deposits)	10501.0	10550.6	-49.6	3.4%	5.2%	7.0%

Source: United States Federal Reserve Bank

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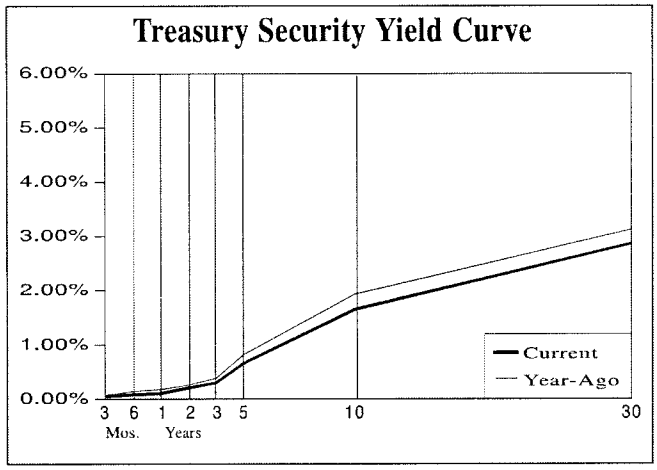
Selected Yields

	Recent (5/01/13)	3 Months Ago (1/30/13)	Year Ago (5/02/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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)	0.19	0.22	0.31
3-month LIBOR	0.27	0.30	0.47
Bank CDs			
6-month	0.09	0.10	0.22
1-year	0.11	0.13	0.33
5-year	0.64	0.70	1.13
U.S. Treasury Securities			
3-month	0.05	0.06	0.08
6-month	0.08	0.11	0.14
1-year	0.11	0.13	0.18
5-year	0.66	0.86	0.82
10-year	1.65	1.97	1.93
10-year (inflation-protected)	-0.67	-0.68	-0.35
30-year	2.86	3.16	3.12
30-year Zero	3.08	3.43	3.36

	Recent (5/01/13)	3 Months Ago (1/30/13)	Year Ago (5/02/12)
Mortgage-Backed Securities			
GNMA 5.5%	1.99	1.86	1.10
FHLMC 5.5% (Gold)	2.19	2.12	2.07
FNMA 5.5%	1.85	1.91	1.87
FNMA ARM	2.12	2.16	2.32
Corporate Bonds			
Financial (10-year) A	2.70	3.22	3.43
Industrial (25/30-year) A	3.80	4.12	4.22
Utility (25/30-year) A	3.78	4.10	4.15
Utility (25/30-year) Baa/BBB	4.15	4.45	4.63
Foreign Bonds (10-Year)			
Canada	1.68	2.00	2.02
Germany	1.20	1.71	1.61
Japan	0.59	0.77	0.89
United Kingdom	1.65	2.11	2.05
Preferred Stocks			
Utility A	5.53	5.40	5.42
Financial BBB	6.20	5.89	6.19
Financial Adjustable A	5.50	5.50	5.50



	Recent (5/01/13)	3 Months Ago (1/30/13)	Year Ago (5/02/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.90	3.54	3.86
25-Bond Index (Revs)	4.29	4.24	4.78
General Obligation Bonds (GOs)			
1-year Aaa	0.16	0.21	0.20
1-year A	0.77	0.79	1.03
5-year Aaa	0.78	0.81	0.86
5-year A	1.71	1.80	1.87
10-year Aaa	1.91	1.95	2.02
10-year A	2.91	2.87	3.17
25/30-year Aaa	3.10	3.11	3.62
25/30-year A	4.85	4.81	5.08
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.20	4.21	4.38
Electric AA	4.33	4.32	4.69
Housing AA	4.63	4.62	4.86
Hospital AA	4.45	4.42	4.60
Toll Road Aaa	4.31	4.38	4.44

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/17/13	4/3/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1793541	1726553	66988	1654429	1548156	1505709
Borrowed Reserves	397	391	6	451	746	2565
Net Free/Borrowed Reserves	1793144	1726162	66982	1653978	1547410	1503144

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	4/15/13	4/8/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2481.0	2457.9	23.1	6.4%	7.7%	10.8%
M2 (M1+savings+small time deposits)	10536.3	10491.9	44.4	3.0%	6.3%	7.2%

Source: United States Federal Reserve Bank

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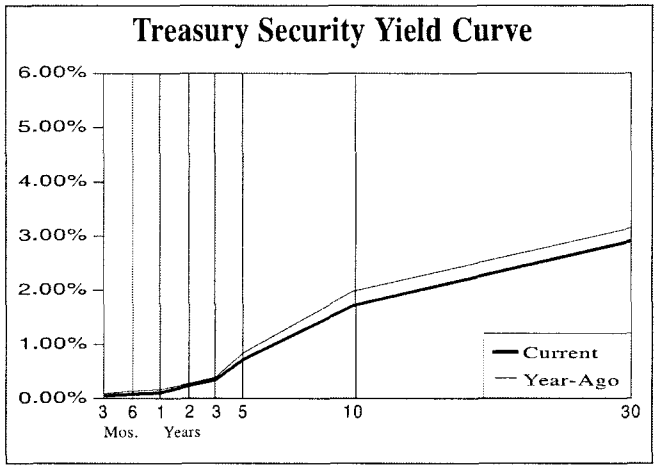
Selected Yields

	Recent (4/24/13)	3 Months Ago (1/23/13)	Year Ago (4/25/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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	0.23	0.36
3-month LIBOR	0.28	0.30	0.47
Bank CDs			
6-month	0.09	0.10	0.22
1-year	0.11	0.13	0.33
5-year	0.64	0.70	1.13
U.S. Treasury Securities			
3-month	0.05	0.07	0.09
6-month	0.08	0.10	0.14
1-year	0.11	0.13	0.17
5-year	0.72	0.74	0.84
10-year	1.72	1.81	1.98
10-year (inflation-protected)	-0.68	-0.75	-0.28
30-year	2.91	3.01	3.15
30-year Zero	3.15	3.26	3.39

	Recent (4/24/13)	3 Months Ago (1/23/13)	Year Ago (4/25/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.06	1.80	1.12
FHLMC 5.5% (Gold)	2.24	2.06	2.10
FNMA 5.5%	1.90	1.76	1.89
FNMA ARM	2.15	2.16	2.36
Corporate Bonds			
Financial (10-year) A	2.78	3.07	3.52
Industrial (25/30-year) A	3.88	3.97	4.27
Utility (25/30-year) A	3.85	3.94	4.17
Utility (25/30-year) Baa/BBB	4.18	4.32	4.65
Foreign Bonds (10-Year)			
Canada	1.72	1.88	2.11
Germany	1.24	1.54	1.74
Japan	0.59	0.74	0.92
United Kingdom	1.69	1.99	2.14
Preferred Stocks			
Utility A	5.41	5.40	5.67
Financial BBB	6.19	5.88	6.14
Financial Adjustable A	5.50	5.50	5.50



	Recent (4/24/13)	3 Months Ago (1/23/13)	Year Ago (4/25/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.89	3.53	3.90
25-Bond Index (Revs)	4.28	4.22	4.81
General Obligation Bonds (GOs)			
1-year Aaa	0.18	0.17	0.18
1-year A	0.77	0.75	1.02
5-year Aaa	0.78	0.78	0.87
5-year A	1.71	1.73	1.86
10-year Aaa	1.92	1.88	2.02
10-year A	2.92	2.82	3.17
25/30-year Aaa	3.13	3.09	3.63
25/30-year A	4.87	4.77	5.08
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.22	4.22	4.40
Electric AA	4.35	4.32	4.64
Housing AA	4.65	4.62	4.82
Hospital AA	4.49	4.41	4.60
Toll Road Aaa	4.36	4.35	4.44

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/17/13	4/3/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1793540	1726553	66987	1654429	1548156	1505709
Borrowed Reserves	397	391	6	451	746	2565
Net Free/Borrowed Reserves	1793143	1726162	66981	1653978	1547410	1503144

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	4/8/13	4/1/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2457.7	2452.8	4.8	3.8%	7.1%	10.3%
M2 (M1+savings+small time deposits)	10491.0	10517.3	-26.3	0.2%	5.6%	6.9%

Source: United States Federal Reserve Bank

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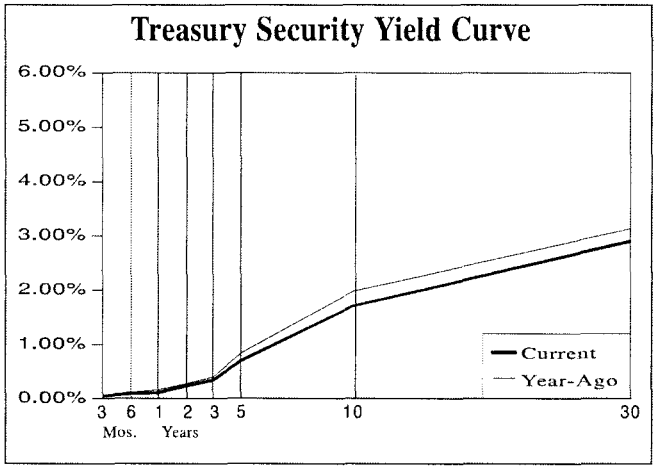
Selected Yields

	Recent (4/17/13)	3 Months Ago (1/16/13)	Year Ago (4/18/12)
TAXABLE			
Market Rates			
Discount Rate	0.75	0.75	0.75
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	0.23	0.32
3-month LIBOR	0.28	0.30	0.47
Bank CDs			
6-month	0.09	0.10	0.22
1-year	0.11	0.13	0.33
5-year	0.64	0.70	1.14
U.S. Treasury Securities			
3-month	0.05	0.07	0.07
6-month	0.09	0.10	0.12
1-year	0.11	0.14	0.16
5-year	0.70	0.76	0.84
10-year	1.71	1.85	1.98
10-year (inflation-protected)	-0.67	-0.73	-0.29
30-year	2.90	3.05	3.13
30-year Zero	3.13	3.25	3.36

	Recent (4/17/13)	3 Months Ago (1/16/13)	Year Ago (4/18/12)
Mortgage-Backed Securities			
GNMA 5.5%	2.14	1.77	1.08
FHLMC 5.5% (Gold)	2.23	1.98	2.14
FNMA 5.5%	1.93	1.75	1.94
FNMA ARM	2.15	2.23	2.36
Corporate Bonds			
Financial (10-year) A	2.79	3.05	3.48
Industrial (25/30-year) A	3.86	3.96	4.21
Utility (25/30-year) A	3.84	3.96	4.15
Utility (25/30-year) Baa/BBB	4.19	4.31	4.62
Foreign Bonds (10-Year)			
Canada	1.71	1.89	2.04
Germany	1.23	1.57	1.72
Japan	0.60	0.76	0.94
United Kingdom	1.68	2.00	2.13
Preferred Stocks			
Utility A	5.38	5.48	5.34
Financial BBB	6.18	5.91	6.44
Financial Adjustable A	5.49	5.49	5.49



	Recent (4/17/13)	3 Months Ago (1/16/13)	Year Ago (4/18/12)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.93	3.60	3.97
25-Bond Index (Revs)	4.30	4.26	4.85
General Obligation Bonds (GOs)			
1-year Aaa	0.17	0.19	0.21
1-year A	0.76	0.75	1.01
5-year Aaa	0.80	0.80	0.93
5-year A	1.74	1.76	1.91
10-year Aaa	1.95	1.89	2.11
10-year A	2.94	2.84	3.23
25/30-year Aaa	3.13	3.11	3.66
25/30-year A	4.88	4.79	5.10
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.22	4.45
Electric AA	4.37	4.32	4.67
Housing AA	4.67	4.63	4.87
Hospital AA	4.47	4.43	4.60
Toll Road Aaa	4.39	4.35	4.44

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	4/3/13	3/20/13	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1726553	1697294	29259	1607277	1517991	1494429
Borrowed Reserves	391	392	-1	479	836	2812
Net Free/Borrowed Reserves	1726162	1696902	29260	1606799	1517155	1491617

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	4/1/13	3/25/13	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2453.0	2443.5	9.5	2.2%	7.1%	10.3%
M2 (M1+savings+small time deposits)	10518.2	10450.4	67.8	1.6%	5.9%	7.1%

Source: United States Federal Reserve Bank

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GLOBAL UTILITIES
DOCKET NO. W-01212A-12-0309 ET AL
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GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
COST OF CAPITAL SUMMARY

WEIGHTED AVERAGE COST OF CAPITAL – GLOBAL WATER - PALO VERDE UTILITIES COMPANY

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	62,047,253	-	62,047,253	51.73%	6.36%	3.29%
3	COMMON EQUITY	57,892,796	-	57,892,796	48.27%	8.50%	4.10%
4	TOTAL CAPITALIZATION	$119,940,049	$ -	$ 119,940,049	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**7.39%**

WEIGHTED AVERAGE COST OF CAPITAL – GLOBAL WATER - SANTA CRUZ WATER COMPANY

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	50,745,824	-	50,745,824	54.50%	6.58%	3.59%
3	COMMON EQUITY	42,364,815	-	42,364,815	45.50%	8.50%	3.87%
4	TOTAL CAPITALIZATION	$ 93,110,639	$ -	$ 93,110,639	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**7.46%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): LINES 1 THROUGH 3 / LINE 4
COLUMN (E): LINES 1 AND 2, SCHEDULE WAR 1, PAGE 2 OF 3, LINE 3; TESTIMONY, WAR
COLUMN (F): LINES 1 THRU 3; COLUMN (D) X COLUMN (E)

WEIGHTED AVERAGE COST OF CAPITAL – GLOBAL WATER - VALENCIA WATER COMPANY, TOWN DIVISION

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ 188,558	$ -	$ 188,558	1.17%	5.95%	0.07%
2	LONG-TERM DEBT	3,248,406	-	3,248,406	20.17%	5.69%	1.15%
3	COMMON EQUITY	12,667,946	-	12,667,946	78.66%	8.50%	6.69%
4	TOTAL CAPITALIZATION	$ 16,104,910	$ -	$ 16,104,910	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**7.91%**

WEIGHTED AVERAGE COST OF CAPITAL – WATER UTILITY OF GREATER TONOPAH, INC.

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ 25,759	$ -	$ 25,759	0.82%	6.22%	0.05%
2	LONG-TERM DEBT	415,212	-	415,212	13.18%	6.33%	0.83%
3	COMMON EQUITY	2,708,518	-	2,708,518	86.00%	8.50%	7.31%
4	TOTAL CAPITALIZATION	$ 3,149,489	$ -	$ 3,149,489	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**8.19%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): LINES 1 THROUGH 3 / LINE 4
COLUMN (E): LINES 1 AND 2, SCHEDULE WAR 1, PAGE 2 OF 3, LINE 3; TESTIMONY, WAR
COLUMN (F): LINES 1 THRU 3; COLUMN (D) X COLUMN (E)

WEIGHTED AVERAGE COST OF CAPITAL – WILLOW VALLEY WATER COMPANY, INC.

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ 29,470	$ -	$ 29,470	0.89%	5.17%	0.05%
2	LONG-TERM DEBT	387,538	-	387,538	11.65%	4.68%	0.55%
3	COMMON EQUITY	2,908,686	-	2,908,686	87.46%	8.50%	7.43%
4	TOTAL CAPITALIZATION	$ 3,325,694	$ -	$ 3,325,694	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**8.03%**

WEIGHTED AVERAGE COST OF CAPITAL – VALENCIA WATER COMPANY, GREATER BUCKEYE DIVISION

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ 12,886	$ -	$ 12,886	0.49%	6.78%	0.03%
2	LONG-TERM DEBT	121,380	-	121,380	4.61%	6.24%	0.29%
3	COMMON EQUITY	2,499,277	-	2,499,277	94.90%	8.50%	8.07%
4	TOTAL CAPITALIZATION	$ 2,633,543	$ -	$ 2,633,543	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**8.39%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): LINES 1 THROUGH 3 / LINE 4
COLUMN (E): LINES 1 AND 2, SCHEDULE WAR 1, PAGE 2 OF 3, LINE 3; TESTIMONY, WAR
COLUMN (F): LINES 1 THRU 3; COLUMN (D) X COLUMN (E)

WEIGHTED AVERAGE COST OF CAPITAL – GLOBAL WATER - WATER UTILITY OF NORTHERN SCOTTSDALE

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) CAPITAL RATIO	(E) COST	(F) WEIGHTED COST
1	SHORT-TERM DEBT	$ -	$ -	$ -	0.00%	0.00%	0.00%
2	LONG-TERM DEBT	-	-	-	0.00%	0.00%	0.00%
3	COMMON EQUITY	(233,834)	-	(233,834)	100.00%	8.50%	8.50%
4	TOTAL CAPITALIZATION	$ (233,834)	$ -	$ (233,834)	100.00%		
5	**WEIGHTED AVERAGE COST OF CAPITAL**						**8.50%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-1, PAGE 1
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): LINES 1 THROUGH 3 / LINE 4
COLUMN (E): LINES 1 AND 2, SCHEDULE WAR 1, PAGE 2 OF 3, LINE 3; TESTIMONY, WAR
COLUMN (F): LINES 1 THRU 3; COLUMN (D) X COLUMN (E)

WEIGHTED AVERAGE COST OF LONG-TERM DEBT – GLOBAL WATER - PALO VERDE UTILITIES COMPANY

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	2006, DUE 12/01/2017	$ 4,041,872	$ -	$ 4,041,872	$ 220,282	6.51%	5.45%	0.36%
2	2006, DUE 12/01/2022	4,600,776	-	4,600,776	257,643	7.41%	5.60%	0.42%
3	2006, DUE 12/01/2032	17,300,102	-	17,300,102	994,756	27.88%	5.75%	1.60%
4	2007, DUE 12/01/2013	488,468	-	488,468	26,866	0.79%	5.50%	0.04%
5	2007, DUE 12/01/2037	22,712,932	-	22,712,932	1,487,697	36.61%	6.55%	2.40%
6	2008, DUE 12/01/2018	691,144	-	691,144	44,060	1.11%	6.37%	0.07%
7	2008, DUE 12/01/2038	12,211,959	-	12,211,959	915,897	19.68%	7.50%	1.48%
8	TOTAL CAPITALIZATION/INTEREST	$ 62,047,253	$ -	$ 62,047,253	$ 3,947,201	100.00%		
9	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.36%**

WEIGHTED AVERAGE COST OF LONG-TERM DEBT – GLOBAL WATER - SANTA CRUZ WATER COMPANY

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	2006, DUE 12/01/2017	$ 1,418,128	$ -	$ 1,418,128	$ 77,288	2.79%	5.45%	0.15%
2	2006, DUE 12/01/2022	1,614,224	-	1,614,224	90,397	3.18%	5.60%	0.18%
3	2006, DUE 12/01/2032	6,069,898	-	6,069,898	349,019	11.96%	5.75%	0.69%
4	2007, DUE 12/01/2013	631,532	-	631,532	34,734	1.24%	5.50%	0.07%
5	2007, DUE 12/01/2037	29,365,145	-	29,365,145	1,923,417	57.87%	6.55%	3.79%
6	2008, DUE 12/01/2018	623,856	-	623,856	39,771	1.23%	6.38%	0.08%
7	2008, DUE 12/01/2038	11,023,041	-	11,023,041	826,728	21.72%	7.50%	1.63%
8	TOTAL CAPITALIZATION/INTEREST	$ 50,745,824	$ -	$ 50,745,824	$ 3,341,354	100.00%		
9	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.58%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY SCHEDULE D-2
COLUMN (E): LINES 1 THROUGH 7 / LINE 8
COLUMN (F): LINES 1 THRU 3; COLUMN (D) / COLUMN (C)
COLUMN (G): LINES 1 THRU 7; COLUMN (E) X COLUMN (F)
COLUMN (G) LINE 9: SUM OF COLUMN G, LINES 1 THRU 7

WEIGHTED AVERAGE COST OF SHORT-TERM DEBT – GLOBAL WATER - VALENCIA WATER COMPANY, TOWN DIVISION

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 920024-99	$ 3,849	$ -	$ 3,849	$ 224	2.04%	5.82%	0.12%
2	WIFA 920102-06	126,712	-	126,712	8,553	67.20%	6.75%	4.54%
3	WIFA 92A170-10	57,997	-	57,997	2,436	30.76%	4.20%	1.29%
4	TOTAL CAPITALIZATION/INTEREST	$ 188,558	$ -	$ 188,558	$ 11,213	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**5.95%**

WEIGHTED AVERAGE COST OF LONG-TERM DEBT – GLOBAL WATER - VALENCIA WATER COMPANY, TOWN DIVISION

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 920024-99	$ 29,281	$ -	$ 29,281	$ 1,701	0.90%	5.81%	0.05%
2	WIFA 920102-06	1,878,688	-	1,878,688	126,811	57.83%	6.75%	3.90%
3	WIFA 92A170-10	1,340,437	-	1,340,437	56,298	41.26%	4.20%	1.73%
4	TOTAL CAPITALIZATION/INTEREST	$ 3,248,406	$ -	$ 3,248,406	$ 184,811	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**5.69%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY SCHEDULE D-2
COLUMN (E): LINES 1 THROUGH 3 / LINE 4
COLUMN (F): LINES 1 THRU 3; COLUMN (D) / COLUMN (C)
COLUMN (G): LINES 1 THRU 3; COLUMN (E) X COLUMN (F)
COLUMN (G) LINE 5: SUM OF COLUMN G, LINES 1 THRU 3

WEIGHTED AVERAGE COST OF SHORT-TERM DEBT – WATER UTILITY OF GREATER TONOPAH, INC.

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 920071-03	$ 4,925	$ -	$ 4,925	$ 215	19.12%	4.37%	0.84%
2	WIFA 920104-06	20,834	-	20,834	1,385	80.88%	6.65%	5.38%
3		-	-	-	-	0.00%	0.00%	0.00%
4	TOTAL CAPITALIZATION/INTEREST	$ 25,759	$ -	$ 25,759	$ 1,601	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.22%**

WEIGHTED AVERAGE COST OF LONG-TERM DEBT – WATER UTILITY OF GREATER TONOPAH, INC.

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 920071-03	$ 59,157	$ -	$ 59,157	$ 2,589	14.25%	4.38%	0.62%
2	WIFA 920104-06	356,055	-	356,055	23,678	85.75%	6.65%	5.70%
3		-	-	-	-	0.00%	0.00%	0.00%
4	TOTAL CAPITALIZATION/INTEREST	$ 415,212	$ -	$ 415,212	$ 26,267	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.33%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY SCHEDULE D-2
COLUMN (E): LINES 1 THROUGH 3 / LINE 4
COLUMN (F): LINES 1 THRU 3; COLUMN (D) / COLUMN (C)
COLUMN (G): LINES 1 THRU 3; COLUMN (E) X COLUMN (F)
COLUMN (G) LINE 5: SUM OF COLUMN G, LINES 1 THRU 3

WEIGHTED AVERAGE COST OF SHORT-TERM DEBT - WILLOW VALLEY WATER COMPANY

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 92A179-10	$ 9,656	$ -	$ 9,656	$ 406	32.77%	4.20%	1.38%
2	WIFA 920010-98	14,344	-	14,344	879	48.67%	6.13%	2.98%
3	WIFA 920078-03	5,470	-	5,470	239	18.56%	4.37%	0.81%
4	TOTAL CAPITALIZATION/INTEREST	$ 29,470	$ -	$ 29,470	$ 1,524	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**5.17%**

WEIGHTED AVERAGE COST OF LONG-TERM DEBT - WILLOW VALLEY WATER COMPANY

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 92A179-10	$ 232,347	$ -	$ 232,347	$ 9,759	59.95%	4.20%	2.52%
2	WIFA 920010-98	91,312	-	91,312	5,593	23.56%	6.13%	1.44%
3	WIFA 920078-03	63,879	-	63,879	2,795	16.48%	4.38%	0.72%
4	TOTAL CAPITALIZATION/INTEREST	$ 387,538	$ -	$ 387,538	$ 18,147	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**4.68%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY SCHEDULE D-2
COLUMN (E): LINES 1 THROUGH 3 / LINE 4
COLUMN (F): LINES 1 THRU 3; COLUMN (D) / COLUMN (C)
COLUMN (G): LINES 1 THRU 3; COLUMN (E) X COLUMN (F)
COLUMN (G) LINE 5: SUM OF COLUMN G, LINES 1 THRU 3

WEIGHTED AVERAGE COST OF SHORT-TERM DEBT – VALENCIA WATER COMPANY, GREATER BUCKEYE DIVISION

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 920072-03	$ 2,677	$ -	$ 2,677	$ 125	20.77%	4.67%	0.97%
2	WIFA 920103-06	5,108	-	5,108	340	39.64%	6.66%	2.64%
3	STEWART TITLE (GARCIA)	5,101	-	5,101	408	39.59%	8.00%	3.17%
4	TOTAL CAPITALIZATION/INTEREST	$ 12,886	$ -	$ 12,886	$ 873	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.78%**

WEIGHTED AVERAGE COST OF LONG-TERM DEBT – VALENCIA WATER COMPANY, GREATER BUCKEYE DIVISION

LINE NO.	DESCRIPTION	(A) COMPANY PROPOSED	(B) RUCO ADJUSTMENT	(C) RUCO ADJUSTED	(D) ANNUAL COST	(E) CAPITAL RATIO	(F) COST	(G) WEIGHTED COST
1	WIFA 920072-03	$ 33,356	$ -	$ 33,356	$ 1,564	27.48%	4.69%	1.29%
2	WIFA 920103-06	76,278	-	76,278	5,072	62.84%	6.65%	4.18%
3	STEWART TITLE (GARCIA)	11,746	-	11,746	940	9.68%	8.00%	0.77%
4	TOTAL CAPITALIZATION/INTEREST	$ 121,380	$ -	$ 121,380	$ 7,576	100.00%		
5	**WEIGHTED AVERAGE COST OF LONG-TERM DEBT**							**6.24%**

REFERENCES:
COLUMN (A): COMPANY SCHEDULE D-2
COLUMN (B): TESTIMONY WAR
COLUMN (C): COLUMN (A) + COLUMN (B)
COLUMN (D): COMPANY SCHEDULE D-2
COLUMN (E): LINES 1 THROUGH 3 / LINE 4
COLUMN (F): LINES 1 THRU 3; COLUMN (D) / COLUMN (C)
COLUMN (G): LINES 1 THRU 3; COLUMN (E) X COLUMN (F)
COLUMN (G) LINE 5: SUM OF COLUMN G, LINES 1 THRU 3

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	7.92%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.84%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**8.38%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.65%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.52%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.84%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.66%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**6.17%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.27%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	**8.50%**	TESTIMONY WAR

GLOBAL UTILITIES
DOCKET NO. W-01212A-12-0309 ET AL
DCF COST OF EQUITY CAPITAL

DOCKET NO. W-01212A-12-0309 ET AL
SCHEDULE WAR - 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) DIVIDEND YIELD	+	(B) GROWTH RATE (g)	=	(C) DCF COST OF EQUITY CAPITAL
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	2.71%	+	5.21%	=	7.91%
2	AWR	AMERICAN STATES WATER CO.	2.61%	+	6.16%	=	8.78%
3	CWT	CALIFORNIA WATER SERVICE GROUP	3.22%	+	5.28%	=	8.50%
4	CTWS	CONNECTICUT WATER SERVICE, INC.	3.41%	+	3.55%	=	6.96%
5	MSEX	MIDDLESEX WATER COMPANY	3.88%	+	3.01%	=	6.89%
6	SJW	SJW CORPORATION	2.78%	+	6.24%	=	9.02%
7	WTR	AQUA AMERICA, INC.	2.20%	+	5.19%	=	7.39%
8	**WATER COMPANY AVERAGE**						**7.92%**
9	GAS	AGL RESOURCES, INC.	4.37%	+	3.00%	=	7.38%
10	ATO	ATMOS ENERGY CORP.	3.23%	+	4.92%	=	8.15%
11	LG	LACLEDE GROUP, INC.	3.73%	+	6.92%	=	10.64%
12	NJR	NEW JERSEY RESOURCES CORPORATION	3.51%	+	5.51%	=	9.02%
13	NWN	NORTHWEST NATURAL GAS CO.	4.12%	+	4.29%	=	8.41%
14	PNY	PIEDMONT NATURAL GAS COMPANY	3.66%	+	3.54%	=	7.20%
15	SJI	SOUTH JERSEY INDUSTRIES, INC.	3.00%	+	8.85%	=	11.84%
16	SWX	SOUTHWEST GAS CORPORATION	2.68%	+	6.56%	=	9.24%
17	WGL	WGL HOLDINGS, INC.	3.78%	+	3.91%	=	7.69%
18	**NATURAL GAS LDC AVERAGE**						**8.84%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND YIELD CALCULATION

DOCKET NO. W-01212A-12-0309 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	AWK	AMERICAN WATER WORKS COMPANY, INC.	$1.12	/	$41.35	=	2.71%
2	AWR	AMERICAN STATES WATER CO.	1.42	/	54.30	=	2.61%
3	CWT	CALIFORNIA WATER SERVICE GROUP	0.64	/	19.88	=	3.22%
4	CTWS	CONNECTICUT WATER SERVICE, INC.	0.97	/	28.40	=	3.41%
5	MSEX	MIDDLESEX WATER COMPANY	0.75	/	19.32	=	3.88%
6	SJW	SJW CORPORATION	0.73	/	26.30	=	2.78%
7	WTR	AQUA AMERICA, INC.	0.70	/	31.89	=	2.20%
8	**WATER COMPANY AVERAGE**						**2.97%**
9	GAS	AGL RESOURCES, INC.	$1.88	/	$42.98	=	4.37%
10	ATO	ATMOS ENERGY CORP.	1.40	/	43.32	=	3.23%
11	LG	LACLEDE GROUP, INC.	1.70	/	45.61	=	3.73%
12	NJR	NEW JERSEY RESOURCES CORPORATION	1.60	/	45.59	=	3.51%
13	NWN	NORTHWEST NATURAL GAS CO.	1.82	/	44.17	=	4.12%
14	PNY	PIEDMONT NATURAL GAS COMPANY	1.24	/	33.85	=	3.66%
15	SJI	SOUTH JERSEY INDUSTRIES, INC.	1.77	/	59.12	=	3.00%
16	SWX	SOUTHWEST GAS CORPORATION	1.32	/	49.24	=	2.68%
17	WGL	WGL HOLDINGS, INC.	1.68	/	44.49	=	3.78%
18	**NATURAL GAS LDC AVERAGE**						**3.56%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 04/19/2013 (WATER COMPANIES) AND 06/07/2013 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF ADJUSTED CLOSING PRICES FROM 04/15/2013 TO 06/07/2013 STOCK QUOTES OBTAINED THROUGH YAHOO! FINANCE WEB SITE - HISTORICAL QUOTES (http://finance.yahoo.com).
COLUMN (C): COLUMN (A) DIVIDED BY COLUMN (B)

NOTE:
CLOSING STOCK PRICES ARE ADJUSTED FOR DIVIDENDS AND STOCK SPLITS.

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY	(A) INTERNAL GROWTH (br)	+	(B) EXTERNAL GROWTH (sv)	=	(C) DIVIDEND GROWTH (g)
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	4.70%	+	0.51%	=	5.21%
2	AWR	AMERICAN STATES WATER CO.	5.60%	+	0.56%	=	6.16%
3	CWT	CALIFORNIA WATER SERVICE GROUP	3.00%	+	2.28%	=	5.28%
4	CTWS	CONNECTICUT WATER SERVICE, INC.	3.00%	+	0.55%	=	3.55%
5	MSEX	MIDDLESEX WATER COMPANY	2.50%	+	0.51%	=	3.01%
6	SJW	SJW CORPORATION	3.80%	+	2.44%	=	6.24%
7	WTR	AQUA AMERICA, INC.	5.00%	+	0.19%	=	5.19%
8	**WATER COMPANY AVERAGE**						**4.95%**
9	GAS	AGL RESOURCES, INC.	3.00%	+	0.00%	=	3.00%
10	ATO	ATMOS ENERGY CORP.	4.10%	+	0.82%	=	4.92%
11	LG	LACLEDE GROUP, INC.	6.50%	+	0.42%	=	6.92%
12	NJR	NEW JERSEY RESOURCES CORPORATION	5.50%	+	0.01%	=	5.51%
13	NWN	NORTHWEST NATURAL GAS CO.	4.00%	+	0.29%	=	4.29%
14	PNY	PIEDMONT NATURAL GAS COMPANY	3.00%	+	0.54%	=	3.54%
15	SJI	SOUTH JERSEY INDUSTRIES, INC.	7.25%	+	1.60%	=	8.85%
16	SWX	SOUTHWEST GAS CORPORATION	6.00%	+	0.56%	=	6.56%
17	WGL	WGL HOLDINGS, INC.	3.70%	+	0.21%	=	3.91%
18	**NATURAL GAS LDC AVERAGE**						**5.28%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
DIVIDEND GROWTH RATE CALCULATION

LINE NO.	STOCK SYMBOL	COMPANY NAME	(A) SHARE GROWTH	x	[1 - (1 / M ÷ B)]	=	(C) EXTERNAL GROWTH (sv)
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	1.40%	x	[1 - (1 / 1.57)]	=	0.51%
2	AWR	AMERICAN STATES WATER CO.	1.00%	x	[1 - (1 / 2.29)]	=	0.56%
3	CWT	CALIFORNIA WATER SERVICE GROUP	7.00%	x	[1 - (1 / 1.48)]	=	2.28%
4	CTWS	CONNECTICUT WATER SERVICE, INC.	1.40%	x	[1 - (1 / 1.65)]	=	0.55%
5	MSEX	MIDDLESEX WATER COMPANY	1.30%	x	[1 - (1 / 1.64)]	=	0.51%
6	SJW	SJW CORPORATION	6.00%	x	[1 - (1 / 1.69)]	=	2.44%
7	WTR	AQUA AMERICA, INC.	0.30%	x	[1 - (1 / 2.85)]	=	0.19%
8	**WATER COMPANY AVERAGE**						**1.01%**
9	GAS	AGL RESOURCES, INC.	0.01%	x	[1 - (1 / 1.31)]	=	0.00%
10	ATO	ATMOS ENERGY CORP.	2.60%	x	[1 - (1 / 1.46)]	=	0.82%
11	LG	LACLEDE GROUP, INC.	1.00%	x	[1 - (1 / 1.71)]	=	0.42%
12	NJR	NEW JERSEY RESOURCES CORPORATION	0.01%	x	[1 - (1 / 2.44)]	=	0.01%
13	NWN	NORTHWEST NATURAL GAS CO.	0.80%	x	[1 - (1 / 1.58)]	=	0.29%
14	PNY	PIEDMONT NATURAL GAS COMPANY	1.00%	x	[1 - (1 / 2.16)]	=	0.54%
15	SJI	SOUTH JERSEY INDUSTRIES, INC.	2.80%	x	[1 - (1 / 2.33)]	=	1.60%
16	SWX	SOUTHWEST GAS CORPORATION	1.50%	x	[1 - (1 / 1.60)]	=	0.56%
17	WGL	WGL HOLDINGS, INC.	0.50%	x	[1 - (1 / 1.74)]	=	0.21%
18	**NATURAL GAS LDC AVERAGE**						**0.54%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/19/2013 (WATER COMPANIES) AND 06/07/2013 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
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	AWK	AMERICAN WATER WORKS COMPANY, INC.	2008	-		4.60%		-	25.64	160.00	
2			2009	0.3440		5.20%		1.79%	22.91	174.63	
3			2010	0.4379		6.50%		2.85%	23.59	175.00	
4			2011	0.4767		7.20%		3.43%	24.11	175.66	
5			2012	0.5450		8.40%		4.58%	25.10	176.99	
6			GROWTH 2008 - 2012					3.16%	-0.50%		2.56%
7			2013	0.5378		8.50%		4.57%		178.00	0.57%
8			2014	0.5333		8.50%		4.53%		179.00	0.57%
9			2016-18	0.5088		9.50%		4.83%	3.50%	190.00	1.43%
10											
11	AWR	AMERICAN STATES WATER CO.	2008	0.3548		8.60%		3.05%	17.95	17.30	
12			2009	0.3765		8.20%		3.09%	19.39	18.53	
13			2010	0.5315		11.00%		5.85%	20.26	18.63	
14			2011	0.5089		10.30%		5.24%	21.68	18.85	
15			2012	0.5496		11.90%		6.54%	23.61	19.26	
16			GROWTH 2008 - 2012					4.75%	5.50%		2.72%
17			2013	0.4630		12.00%		5.56%		19.25	-0.05%
18			2014	0.4561		12.50%		5.70%		19.50	0.62%
19			2016-18	0.4333		12.50%		5.42%	6.50%	21.50	2.22%
20											
21	CWT	CALIFORNIA WATER SERVICE GROUP	2008	0.3789		9.90%		3.75%	9.72	41.45	
22			2009	0.3980		9.60%		3.82%	10.13	41.53	
23			2010	0.3407		8.60%		2.93%	10.45	41.67	
24			2011	0.2791		8.00%		2.23%	10.76	41.82	
25			2012	0.3824		9.00%		3.44%	11.30	41.91	
26			GROWTH 2008 - 2012					3.24%	5.00%		0.28%
27			2013	0.2471		7.00%		1.73%		47.75	13.93%
28			2014	0.3818		8.00%		3.05%		48.00	7.02%
29			2016-18	0.3333		9.50%		3.17%	5.50%	50.00	3.59%
30											
31	CTWS	CONNECTICUT WATER SERVICE, INC.	2008	0.2072		9.10%		1.89%	12.23	8.46	
32			2009	0.2437		9.40%		2.29%	12.67	8.57	
33			2010	0.1858		8.70%		1.62%	13.05	8.68	
34			2011	0.1681		8.30%		1.40%	13.50	8.76	
35			2012	0.3725		7.30%		2.72%	16.89	10.97	
36			GROWTH 2008 - 2012					1.98%	3.00%		6.71%
37			2013	0.3000		8.00%		2.40%		11.00	0.27%
38			2014	0.3548		9.00%		3.19%		11.25	1.27%
39			2016-18	0.3529		8.50%		3.00%	6.50%	12.00	1.81%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/19/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2008 - 2012

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

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	MSEX	MIDDLESEX WATER COMPANY	2008	0.2135		8.90%		1.90%	10.03	13.40	
2			2009	0.0139		7.00%		0.10%	10.33	13.52	
3			2010	0.2500		8.20%		2.05%	11.13	15.57	
4			2011	0.1310		7.50%		0.98%	11.27	15.70	
5			2012	0.1778		7.80%		1.39%	11.48	15.82	
6			GROWTH 2008 - 2012					1.28%	4.00%		4.24%
7			2013	0.2105		8.00%		1.68%		16.00	1.14%
8			2014	0.2400		8.50%		2.04%		16.25	1.35%
9			2016-18	0.3043		9.00%		2.74%	2.00%	17.00	1.45%
10											
11	SJW	SJW CORPORATION	2008	0.3981		8.00%		3.19%	13.99	18.18	
12			2009	0.1852		6.00%		1.11%	13.66	18.50	
13			2010	0.1905		6.20%		1.18%	13.75	18.55	
14			2011	0.3784		7.90%		2.99%	14.20	18.59	
15			2012	0.3983		8.10%		3.23%	14.68	18.70	
16			GROWTH 2008 - 2012					2.34%	4.50%		0.71%
17			2013	0.4385		8.50%		3.73%		20.00	6.95%
18			2014	0.4643		8.50%		3.95%		21.00	5.97%
19			2016-18	0.4375		8.50%		3.72%	5.00%	23.00	4.23%
20											
21	WTR	AQUA AMERICA, INC.	2008	0.3014		9.30%		2.80%	7.82	135.37	
22			2009	0.2857		9.40%		2.69%	8.12	136.49	
23			2010	0.3444		10.60%		3.65%	8.51	137.97	
24			2011	0.3942		11.60%		4.57%	9.01	138.88	
25			2012	0.3853		11.00%		4.24%	9.87	140.35	
26			GROWTH 2008 - 2012					3.59%	7.00%		0.91%
27			2013	0.4815		12.00%		5.78%		140.50	0.11%
28			2014	0.4207		12.00%		5.05%		141.00	0.23%
29			2016-18	0.3750		11.50%		4.31%	6.50%	143.00	0.37%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/19/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16 & 26, SIMPLE AVERAGE GROWTH, 2008 - 2012

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
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	AGL RESOURCES, INC.	2008	0.3801		12.60%		4.79%	21.48	76.90	
2			2009	0.4028		12.50%		5.03%	22.95	77.54	
3			2010	0.4133		12.90%		5.33%	23.24	78.00	
4			2011	0.1038		5.20%		0.54%	28.33	117.10	
5			2012	0.2500		8.00%		2.00%	28.76	117.88	
6			GROWTH 2008 - 2012					3.54%	5.00%		11.27%
7			2013	0.2627		8.00%		2.10%		117.00	-0.75%
8			2014	0.3379		8.50%		2.87%		117.00	-0.37%
9			2016-18	0.5024		6.00%		3.01%	5.00%	117.00	-0.15%
10											
11	ATO	ATMOS ENERGY CORP.	2008	0.3500		8.80%		3.08%	22.60	90.81	
12			2009	0.3299		8.30%		2.74%	23.52	92.55	
13			2010	0.3796		9.20%		3.49%	24.16	90.16	
14			2011	0.3982		8.80%		3.50%	24.98	90.30	
15			2012	0.3429		8.10%		2.78%	26.14	90.24	
16			GROWTH 2008 - 2012					3.12%	4.00%		-0.16%
17			2013	0.4286		8.50%		3.64%		91.00	0.84%
18			2014	0.4538		8.50%		3.86%		92.00	0.97%
19			2016-18	0.5000		8.50%		4.25%	5.50%	103.00	2.68%
20											
21	LG	LACLEDE GROUP, INC.	2008	0.4356		11.80%		5.14%	22.12	21.99	
22			2009	0.4760		12.40%		5.90%	23.32	22.17	
23			2010	0.3539		10.10%		3.57%	24.02	22.29	
24			2011	0.4371		11.10%		4.85%	25.56	22.43	
25			2012	0.4050		10.60%		4.29%	26.60	22.62	
26			GROWTH 2008 - 2012					4.75%	6.50%		0.71%
27			2013	0.3895		10.50%		4.09%		23.00	1.68%
28			2014	0.4133		11.00%		4.55%		23.00	0.84%
29			2016-18	0.5147		13.00%		6.69%	2.00%	23.50	0.77%
30											
31	NJR	NEW JERSEY RESOURCES CORPORATION	2008	0.5889		15.70%		9.25%	17.28	42.06	
32			2009	0.4833		14.60%		7.06%	16.59	41.59	
33			2010	0.4472		14.00%		6.26%	17.62	41.17	
34			2011	0.4419		13.70%		6.05%	18.73	41.45	
35			2012	0.4317		13.90%		6.00%	18.15	41.53	
36			GROWTH 2008 - 2012					6.92%	6.50%		-0.32%
37			2013	0.3846		14.00%		5.38%		40.00	-3.68%
38			2014	0.4074		14.00%		5.70%		40.00	-1.86%
39			2016-18	0.4169		12.50%		5.21%	4.00%	40.00	-0.75%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/07/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2008 - 2012

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

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
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	NWN	NORTHWEST NATURAL GAS CO.	2008	0.4086		10.90%		4.45%	23.71	26.50	
2			2009	0.4346		11.40%		4.95%	24.88	26.53	
3			2010	0.3846		10.50%		4.04%	26.08	26.58	
4			2011	0.2678		8.90%		2.38%	26.70	26.76	
5			2012	0.1937		8.20%		1.59%	27.23	26.92	
6			GROWTH 2008 - 2012					3.48%	4.00%		0.39%
7			2013	0.2043		8.50%		1.74%		27.00	0.30%
8			2014	0.2520		8.50%		2.14%		27.00	0.15%
9			2016-18	0.3939		10.50%		4.14%	3.00%	28.00	0.79%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2008	0.3087		12.40%		3.83%	12.11	73.26	
12			2009	0.3593		13.20%		4.74%	12.67	73.27	
13			2010	0.2839		11.60%		3.29%	13.35	72.28	
14			2011	0.2675		11.40%		3.05%	13.79	72.32	
15			2012	0.2831		11.70%		3.31%	14.21	72.25	
16			GROWTH 2008 - 2012					3.65%	3.00%		-0.35%
17			2013	0.2765		11.00%		3.04%		76.00	5.19%
18			2014	0.2743		11.00%		3.02%		76.00	2.56%
19			2016-18	0.2684		11.00%		2.95%	4.00%	76.00	1.02%
20											
21	SJI	SOUTH JERSEY INDUSTRIES, INC.	2008	0.5110		13.10%		6.69%	17.33	29.73	
22			2009	0.4874		13.10%		6.38%	18.24	29.80	
23			2010	0.4963		14.20%		7.05%	19.08	29.87	
24			2011	0.4828		13.90%		6.71%	20.66	30.21	
25			2012	0.4554		12.70%		5.78%	23.26	31.65	
26			GROWTH 2008 - 2012					6.52%	7.00%		1.58%
27			2013	0.4286		12.50%		5.36%		32.50	2.69%
28			2014	0.4179		14.50%		6.06%		33.50	2.88%
29			2016-18	0.4674		15.50%		7.24%	6.50%	36.00	2.61%
30											
31	SWX	SOUTHWEST GAS CORPORATION	2008	0.3525		5.90%		2.08%	23.49	44.19	
32			2009	0.5103		7.90%		4.03%	24.44	45.09	
33			2010	0.5595		8.90%		4.98%	25.62	45.56	
34			2011	0.5638		9.20%		5.19%	26.66	45.96	
35			2012	0.5874		10.20%		5.99%	28.39	46.15	
36			GROWTH 2008 - 2012					4.45%	5.00%		1.09%
37			2013	0.5525		9.50%		5.25%		47.00	1.84%
38			2014	0.5484		9.50%		5.21%		48.00	1.98%
39			2016-18	0.5733		10.50%		6.02%	5.00%	50.00	1.62%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/07/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2008 - 2012

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

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	WGL	WGL HOLDINGS, INC.	2008	0.4221		11.60%		4.90%	20.99	49.92	
2			2009	0.4190		11.60%		4.86%	21.89	50.14	
3			2010	0.3392		9.90%		3.36%	22.82	50.54	
4			2011	0.3111		9.50%		2.96%	23.49	51.20	
5			2012	0.4067		11.00%		4.47%	24.75	51.50	
6			GROWTH 2008 - 2012					4.11%	4.50%		0.78%
7			2013	0.3490		10.00%		3.49%		51.75	0.49%
8			2014	0.3547		10.00%		3.55%		52.00	0.48%
9			2016-18	0.3797		10.00%		3.80%	4.00%	52.00	0.19%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 06/07/2013
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2008 - 2012

COLUMN (D): VALUE LINE INVESTMENT SURVEY
COLUMN (D): LINE 6, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

GLOBAL UTILITIES
TEST YEAR ENDED DECEMBER 31, 2011
GROWTH RATE COMPARISON

DOCKET NO. W-01212A-12-0309 ET AL
SCHEDULE WAR - 6

WATER COMPANY SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	DPS	BVPS	(D) VALUE LINE HISTORIC EPS	DPS	BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	DPS	BVPS
1	AWK	5.21%	8.00%	9.50%	7.50%	3.50%	-	-	-0.50%	5.60%	-	-	-0.53%
2	AWR	6.16%	2.00%	8.00%	8.00%	6.50%	11.50%	4.50%	5.50%	6.57%	16.14%	6.16%	7.09%
3	CWT	5.28%	6.00%	5.50%	6.00%	5.50%	5.00%	1.00%	5.00%	4.86%	1.79%	1.65%	3.84%
4	CTWS	3.55%	4.00%	6.00%	2.50%	6.50%	4.00%	1.50%	3.00%	3.93%	8.35%	2.20%	8.41%
5	MSEX	3.01%	-	4.00%	1.50%	2.00%	2.50%	1.50%	4.00%	2.58%	0.28%	1.40%	3.43%
6	SJW	6.24%	-	7.50%	4.50%	5.00%	-3.00%	5.00%	4.50%	3.92%	2.24%	2.23%	1.21%
7	WTR	5.19%	5.50%	8.00%	8.00%	6.50%	4.50%	8.00%	7.00%	6.79%	10.54%	7.06%	5.99%
8				6.93%	5.43%	5.07%	4.08%	3.58%	4.07%		6.56%	3.45%	4.21%
9	AVERAGES	4.95%	5.10%		5.81%			3.91%		4.89%		4.74%	

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	DPS	BVPS	(D) VALUE LINE HISTORIC EPS	DPS	BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	DPS	BVPS
1	GAS	3.00%	4.30%	9.00%	6.50%	5.00%	1.50%	6.50%	5.00%	5.40%	-3.81%	0.88%	7.57%
2	ATO	4.92%	4.30%	5.50%	1.50%	5.50%	3.00%	1.50%	4.00%	3.61%	1.23%	1.50%	3.70%
3	LG	6.92%	3.00%	5.50%	2.00%	2.00%	4.00%	3.00%	6.50%	3.71%	1.39%	2.74%	4.72%
4	NJR	5.51%	4.00%	2.00%	3.00%	4.00%	8.50%	8.50%	6.50%	5.21%	0.09%	8.53%	1.24%
5	NWN	4.29%	3.80%	5.00%	2.50%	3.00%	0.50%	4.50%	4.00%	3.33%	-3.59%	4.17%	3.52%
6	PNY	3.54%	4.30%	3.00%	3.00%	4.00%	3.50%	5.50%	3.00%	3.76%	2.74%	3.68%	4.08%
7	SJI	8.85%	6.00%	8.00%	8.50%	6.50%	6.50%	10.00%	7.00%	7.50%	7.49%	10.42%	7.63%
8	SWX	6.56%	5.30%	7.00%	7.00%	5.00%	6.50%	4.00%	5.00%	5.69%	19.77%	7.01%	4.85%
9	WGL	3.91%	5.30%	3.50%	3.00%	4.00%	3.00%	3.00%	4.50%	3.76%	2.37%	3.05%	4.21%
10				5.39%	4.11%	4.33%	4.11%	5.17%	5.06%		3.07%	4.66%	4.61%
11	AVERAGES	5.28%	4.48%		4.61%			4.78%		4.66%		4.12%	

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 04/19/2013 (WATER COMPANIES) AND 06/07/2013 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 04/19/2013 (WATER COMPANIES) AND 06/07/2013 (NATURAL GAS LDC's)
COLUMN (E): SIMPLE AVERAGE OF COLUMNS (B) THRU (D) LINES 1 THRU 3 (WATER) AND 1 THRU 9 (NATURAL GAS)
COLUMN (F): 5-YEAR ANNUAL GROWTH RATE CALCULATED WITH DATA COMPILED FROM VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 04/19/2013 (WATER COMPANIES) AND 06/07/2013 (NATURAL GAS LDC's)

BASED ON A GEOMETRIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+	[	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWK	k	=	3.06%	+	[	0.65	x	(	9.80%	-	6.10%	)]	=	5.46%
2	AWR	k	=	3.06%	+	[	0.70	x	(	9.80%	-	6.10%	)]	=	5.65%
3	CWT	k	=	3.06%	+	[	0.65	x	(	9.80%	-	6.10%	)]	=	5.46%
4	CTWS	k	=	3.06%	+	[	0.75	x	(	9.80%	-	6.10%	)]	=	5.83%
5	MSEX	k	=	3.06%	+	[	0.70	x	(	9.80%	-	6.10%	)]	=	5.65%
6	SJW	k	=	3.06%	+	[	0.85	x	(	9.80%	-	6.10%	)]	=	6.20%
7	WTR	k	=	3.06%	+	[	0.60	x	(	9.80%	-	6.10%	)]	=	5.28%
8	**WATER COMPANY AVERAGE**						0.70								**5.65%**
9	GAS	k	=	3.06%	+	[	0.75	x	(	9.80%	-	6.10%	)]	=	5.83%
10	ATO	k	=	3.06%	+	[	0.70	x	(	9.80%	-	6.10%	)]	=	5.65%
11	LG	k	=	3.06%	+	[	0.60	x	(	9.80%	-	6.10%	)]	=	5.28%
12	NJR	k	=	3.06%	+	[	0.65	x	(	9.80%	-	6.10%	)]	=	5.46%
13	NWN	k	=	3.06%	+	[	0.60	x	(	9.80%	-	6.10%	)]	=	5.28%
14	PNY	k	=	3.06%	+	[	0.65	x	(	9.80%	-	6.10%	)]	=	5.46%
15	SJI	k	=	3.06%	+	[	0.65	x	(	9.80%	-	6.10%	)]	=	5.46%
16	SWX	k	=	3.06%	+	[	0.75	x	(	9.80%	-	6.10%	)]	=	5.83%
17	WGL	k	=	3.06%	+	[	0.65	x	(	9.80%	-	6.10%	)]	=	5.46%
18	**NATURAL GAS LDC AVERAGE**						0.67								**5.52%**

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 30-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 03/01/2013 THROUGH 04/19/2013 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 - 2011 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2012 YEARBOOK.

BASED ON AN ARITHMETIC MEAN:

LINE NO.	STOCK SYMBOL	k	=	r_f	+	[	(A) ß	x	(	r_m	-	r_f	)]	=	(B) EXPECTED RETURN
1	AWK	k	=	3.06%	+	[	0.65	x	(	11.80%	-	6.40%	)]	=	6.57%
2	AWR	k	=	3.06%	+	[	0.70	x	(	11.80%	-	6.40%	)]	=	6.84%
3	CWT	k	=	3.06%	+	[	0.65	x	(	11.80%	-	6.40%	)]	=	6.57%
4	CTWS	k	=	3.06%	+	[	0.75	x	(	11.80%	-	6.40%	)]	=	7.11%
5	MSEX	k	=	3.06%	+	[	0.70	x	(	11.80%	-	6.40%	)]	=	6.84%
6	SJW	k	=	3.06%	+	[	0.85	x	(	11.80%	-	6.40%	)]	=	7.65%
7	WTR	k	=	3.06%	+	[	0.60	x	(	11.80%	-	6.40%	)]	=	6.30%
8	**WATER COMPANY AVERAGE**						0.70								**6.84%**
9	GAS	k	=	3.06%	+	[	0.75	x	(	11.80%	-	6.40%	)]	=	7.11%
10	ATO	k	=	3.06%	+	[	0.70	x	(	11.80%	-	6.40%	)]	=	6.84%
11	LG	k	=	3.06%	+	[	0.60	x	(	11.80%	-	6.40%	)]	=	6.30%
12	NJR	k	=	3.06%	+	[	0.65	x	(	11.80%	-	6.40%	)]	=	6.57%
13	NWN	k	=	3.06%	+	[	0.60	x	(	11.80%	-	6.40%	)]	=	6.30%
14	PNY	k	=	3.06%	+	[	0.65	x	(	11.80%	-	6.40%	)]	=	6.57%
15	SJI	k	=	3.06%	+	[	0.65	x	(	11.80%	-	6.40%	)]	=	6.57%
16	SWX	k	=	3.06%	+	[	0.75	x	(	11.80%	-	6.40%	)]	=	7.11%
17	WGL	k	=	3.06%	+	[	0.65	x	(	11.80%	-	6.40%	)]	=	6.57%
18	**NATURAL GAS LDC AVERAGE**						0.67								**6.66%**

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)
r_f = PROXY FOR THE RISK FREE RATE ON LONG-TERM TREASURIES (b)

COLUMN (B): EXPECTED RATE OF RETURN USING THE CAPM FORMULA

NOTES:

(a) AN 8-WEEK AVERAGE OF THE YIELD ON A 30-YEAR U.S. TREASURY INSTRUMENT THAT APPEARED IN VALUE LINE INVESTMENT SURVEY'S "SELECTION & OPINIONS" PUBLICATION FROM 04/26/2013 THROUGH 06/14/2013 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 - 2012 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME PERIOD. THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2013 YEARBOOK.

GLOBAL UTILITIES
DOCKET NO. W-01212A-12-0309 ET AL
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. W-01212A-12-0309 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%	2.90%	8.05%	5.86%	5.02%	4.36%	4.84%	6.07%	6.24%
19	2008	3.84%	-6.80%	5.09%	2.39%	1.92%	1.37%	4.28%	6.34%	6.64%
20	2009	-0.36%	5.00%	3.25%	0.50%	0.00% - 0.25%	0.15%	4.08%	5.84%	6.87%
21	2010	1.64%	2.80%	3.25%	0.72%	0.00% - 0.25%	0.13%	4.25%	5.50%	5.98%
22	2011	3.00%	1.70%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.93%	5.06%	5.58%
23	2012	1.70%	2.20%	3.25%	0.75%	0.00% - 0.25%	0.08%	2.92%	3.99%	4.42%
24	CURRENT	1.10%	2.40%	3.25%	0.75%	0.00% - 0.25%	0.05%	3.24%	4.19%	4.60%

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
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 06/143/2013
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 06/14/2013
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

AVERAGE CAPITAL STRUCTURES OF SAMPLE WATER COMPANIES (000's)

LINE NO.		AWK	PCT.	AWR	PCT.	CWT	PCT.	CTWS	PCT.	SJW	PCT.
1	DEBT	$ 5,339.9	55.6%	$ 340.6	45.5%	$ 479.2	52.4%	$ 178.5	49.0%	$ 343.8	56.6%
2											
3	PREFERRED STOCK	25.7	0.3%	0.0	0.0%	0.0	0.0%	0.7	0.2%	0.0	0.0%
4											
5	COMMON EQUITY	4,235.8	44.1%	408.6	54.5%	435.5	47.6%	185.3	50.8%	264.0	43.4%
6											
7	TOTALS	$ 9,601.4	100%	$ 749.2	100%	$ 914.7	100%	$ 364.5	100%	$ 607.8	100%
8											
9						WATER COMPANY					
10		MSEX	PCT.	WTR	PCT.	AVERAGE	PCT.				
11											
12	DEBT	$ 132.2	42.3%	$ 1,395.4	52.7%	$ 1,172.8	54.0%				
13											
14	PREFERRED STOCK	3.3	1.1%	0.0	0.0%	4.2	0.2%				
15											
16	COMMON EQUITY	177.0	56.6%	1,251.8	47.3%	994.0	45.8%				
17											
18	TOTALS	$ 312.5	100%	$ 2,647.2	100%	$ 2,171.0	100%				

AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES (000's)

LINE NO.		AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	NWN	PCT.
1											
2											
3	DEBT	$ 3,561.0	51.6%	$ 1,956.3	45.3%	$ 339.4	40.9%	$ 525.1	39.2%	$ 641.7	47.3%
4											
5	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
6											
7	COMMON EQUITY	3,339.0	48.4%	2,359.2	54.7%	491.3	59.1%	813.9	60.8%	714.5	52.7%
8											
9	TOTALS	$ 6,900.0	100%	$ 4,315.5	100%	$ 830.7	100%	$ 1,339.0	100%	$ 1,356.2	100%
10											
11										NATURAL GAS LDC	
12		PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.	AVERAGE	PCT.
13											
14	DEBT	$ 675.0	40.4%	$ 424.2	40.5%	$ 930.8	43.2%	$ 589.2	31.2%	$ 1,071.4	44.8%
15											
16	PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	28.2	1.5%	$ 3.1	0.1%
17											
18	COMMON EQUITY	996.9	59.6%	624.1	59.5%	1,225.0	56.8%	1,269.5	67.3%	1,314.8	55.0%
19											
20	TOTALS	$ 1,671.9	100%	$ 1,048.3	100%	$ 2,155.8	100%	$1,886.9	100%	$ 2,389.4	100%
21											
22		WATER & LDC									
23		AVERAGE	PCT.								
24											
25	DEBT	$ 1,122.1	49.3%								
26											
27	PREFERRED STOCK	1.6	0.1%								
28											
29	COMMON EQUITY	1,154.4	50.7%								
30											
31	TOTALS	$ 2,278.1	100%								

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS