ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

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CHAIRMAN
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COMMISSIONER
SANDRA D. KENNEDY
COMMISSIONER
PAUL NEWMAN
COMMISSIONER
BRENDA BURNS
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF RIO RICO UTILITIES, INC., AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANTS AND PROPERTY AND FOR INCREASES IN ITS WATER AND WASTEWATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. WS-02676A-12-0196

NOTICE OF FILING

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

RESPECTFULLY SUBMITTED this 31st day of December, 2012.

Michelle L. Wood
Counsel

AN ORIGINAL AND THIRTEEN COPIES of the foregoing filed this 31st day of December, 2012 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/ mailed this 31st day of December, 2012 to:

Lyn Farmer
Chief Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Janice Alward, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Steven Olea, Director
Utilities Division
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

Jay L. Shapiro
Fennemore Craig, P.C.
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012

Greg Sorensen
Liberty Utilities
12725 W. Indian School Road
Suite D-101
Avondale, Arizona 85392

By Cheryl Fraulob
Cheryl Fraulob

RIO RICO UTILITIES, INC.

DOCKET NO. WS-02676A-12-0196

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON

SUSTAINABLE WATER LOSS IMPROVEMENT PROGRAM

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 31, 2012

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EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of Rio Rico Utilities, Inc.'s application for a permanent rate increase for its Water and Wastewater Divisions, filed on May 31, 2012, RUCO recommends that the Arizona Corporation Commission reject Rio Rico Utilities, Inc.'s request for a Sustainable Water Loss Improvement Program.

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 with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present RUCO's position on Rio Rico Utilities, Inc.'s ("RRUI" or "Company") request for a Sustainable Water Loss Improvement Program ("SWIP"). The Company's SWIP request was part of RRUI's application for a permanent increase in rates ("Application") for the Company's Water and Wastewater Divisions. RRUI filed its Application with the Arizona Corporation Commission ("ACC" or "Commission") on May 31, 2012 using a test year ending on February 29, 2012 ("Test Year"). RRUI has elected not to perform a Reconstruction Cost New Less Depreciation ("RCND") study and is requesting that the Company's original cost rate base ("OCRB") be treated as the Company's fair value rate base ("FVRB") for ratemaking purposes.

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

A. Yes. RUCO witness Timothy J. Coley will provide direct testimony presenting RUCO's recommendations on required revenue and rate design. As I noted above, I have 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. As I stated above, my direct testimony will address RRUI's request for a SWIP, which I will refer to in this testimony as an "Enhanced SWIP" for reasons that will be explained in my direct testimony.

Q. What is RUCO's recommendation on RRUI's Enhanced SWIP request?

A. RUCO recommends that the Commission reject RRUI's Enhanced SWIP request for the reasons that I will discuss in my direct testimony.

SUSTAINABLE WATER LOSS IMPROVEMENT PROGRAM

Q. Have you reviewed the direct testimony of RRUI witnesses Christopher D. Krygier that addresses RRUI's request for an Enhanced SWIP?

A. Yes.

Q. Briefly describe RRUI's Enhanced SWIP request.

A. According to Mr. Krygier's testimony, RRUI is seeking Commission approval of a surcharge that would allow the Company to recover both deferred depreciation expense and deferred post-in-service allowance for funds used during construction ("AFUDC") on certain plant additions placed into service between general rate case proceedings.

Q. How would RRUI's Enhanced SWIP request work?

A. Under RRUI's proposal, the Commission would create two separate regulatory assets. The first regulatory asset would be the monthly amounts of depreciation expense that are calculated on eligible plant assets that are placed into service between general rate case proceedings. The second regulatory asset would be the total monthly amounts of accrued AFUDC that are also calculated on the same eligible plant assets. The costs described above would be booked into separate deferral accounts and then recovered from RRUI's ratepayers through a surcharge mechanism that would be implemented at a later date.

Q. How did RRUI develop the Company-proposed Enhanced SWIP?

A. The Company-proposed Enhanced SWIP is a mechanism based loosely on a SWIP mechanism proposed by ACC Staff in the pending Arizona Water Company's ("AWC") Eastern Group rate case.[1] However, the Enhanced SWIP proposed by RUI in this rate case is different from the SWIP recommended by ACC Staff in the AWC Eastern Group rate case.[2] In the AWC Eastern Group rate case, Staff recommended a SWIP as an alternative to an AWC-proposed Distribution System Improvement Charge ("DSIC") which Staff and RUCO both opposed. The SWIP was intended to address high water loss problems and would only apply to specific AWC systems.[3] Also, under Staff's recommended SWIP (Exhibit 1), only twenty-four months of recorded depreciation expense and AFUDC deferrals on transmission and distribution main improvements could be

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

[2] Throughout my testimony, for ease of reference, I will refer to the SWIP mechanism recommended by ACC Staff in the AWC Eastern Group rate case as the "SWIP" and the mechanism proposed by RRUI in this rate case as the "Enhanced SWIP."

[3] Pages 35 and 36 of the direct Testimony of ACC Staff Witness Jeffrey M. Michlik filed on March 13, 2012

recovered through the SWIP surcharge. The transmission and distribution main improvements would be subject to a full regulatory review for compliance with traditional ratemaking conditions (e.g. prudency, the used and useful standard and excess capacity) in a general rate case proceeding that is subsequent to the in-service date of the plant improvements. Under Staff's recommended SWIP, the Commission approved level of deferred costs would be recovered through a surcharge over a ten-year period, however AWC would have to demonstrate that the plant improvements are contributing to a reduction in water loss.

Q. Compare the Enhanced SWIP in this proceeding to the Staff-proposed SWIP in the AWC Eastern Group proceeding.

A. RRUI is requesting that it be permitted to apply for capped annual increases in the Enhanced SWIP surcharge mechanism, beginning twelve months after new rates go into effect, as opposed to having eligible plant additions subject to a full regulatory review for compliance with traditional ratemaking conditions in a general rate case proceeding subsequent to the in-service date of the plant improvements. Under the Enhanced SWIP, Staff would review SWIP-eligible additions in a vacuum that does not take other important ratemaking elements into consideration. Although the Company believes that Staff could schedule evidentiary hearings if needed, RUCO believes that such a scenario would only put additional burdens on Staff analysts, the ACC's Legal Division and the

ACC Hearing Division, not to mention the additional legal expense that RRUI would incur – and expect to recover from ratepayers.

The Enhanced SWIP doubles the SWIP deferral period to 48 months from 24 months. Furthermore, the Enhanced SWIP calls the deferral a "regulatory asset." RRUI is also proposing a number of other modifications in the Company's Enhanced SWIP that differs from the SWIP.

Q. Please describe the additional modifications that RRUI is proposing to the Staff's SWIP.

A. The Enhanced SWIP proposed by RRUI, would expand the types of plant assets that could be recovered through the mechanism. Whereas the SWIP is applicable only to transmission and distribution main replacements, the Enhanced SWIP would be applicable to assets added in NARUC accounts 309 - Supply Mains, 33 1 – Transmission & Distribution Mains, 333 – Services, and 334 – Meters. Further, while the SWIP was intended to address relevant plant replacements to reduce water loss, the Enhanced SWIP allows a surcharge for certain plant replacements regardless of water loss that could produce customer benefits demonstrated by any of the following: reduced non-revenue water, reduced operating expenses, reduced service interruptions.

Further, the Company does not propose any method that would flow recognized savings achieved from new plant through to ratepayers between general rate Case proceedings. In short, any savings associated with the new plant (such as lower energy costs, reduced water loss, reduced labor costs, etc.), would not be recognized in the Enhanced SWIP. This results in an inaccurate surcharge that does not take into consideration the cost savings associated with the new plant and provides undue revenue to the utility.

Q. Does the Enhanced SWIP alter the amortization period of costs associated with SWIP-eligible plant additions?

A. Yes. Unlike the SWIP which provides for the amortization of the allowed (i.e. net of any disallowances) combined depreciation and cost of money (i.e. AFUDC) deferrals over a ten year period (in order to provide a ten year incentive to reduce water loss), the Enhanced SWIP would provide for amortization of the allowed combined depreciation and cost of money deferrals over one year.

Q. Did Staff intend for SWIP surcharge increases to be implemented on a regular annual basis between general rate case proceedings?

A. No

Q. Is RRUI seeking the implementation of Enhanced SWIP surcharge increases on a regular annual basis between general rate case proceedings?

A. Yes. According to Mr. Krygier's direct testimony, RRUI would file documentation on or before January 31 of each year, on all of the costs recorded to the regulatory asset deferrals and calculate, based on the Company's known customer count information, the amount of the surcharge to be added to customer bills. If the documentation is approved by the Commission Staff, the monthly charge would be implemented in accordance with the Enhanced SWIP Tariff. RRUI is proposing annual increases will be capped as follows:

Year 1 - 3%

Year 2 - 3%

Year 3 - 4%

Year 4 or Later - 5%

Under the Enhanced SWIP, RRUI would, within 60 days of Staff approving RRUI's annual SWIP surcharge adjustment, hold a customer meeting to educate customers on the SWIP mechanism.

Q. Did RUCO offer written testimony in the AWC Eastern Group case that opposed ACC Staff's SWIP recommendation?

A. No. RUCO did not address ACC Staff's SWIP recommendation in its written testimony. However during the AWC Eastern Group evidentiary hearing, RUCO's Chief Legal Counsel did cross examine ACC Staff witnesses Jeffery M. Michlik and Gordon L. Fox on the differences between the DSIC surcharge being proposed by AWC, and the SWIP being recommended by ACC Staff. During RUCO's Chief Legal Counsel's cross examination, Mr. Fox acknowledged under oath that while consumers may be indifferent to paying for the SWIP in today's dollars or tomorrow's dollars, the ACC Staff recommended SWIP would cost more than the DSIC being proposed by AWC as evidenced by the following transcript excerpt:

Q. Finally, Mr. Fox, I wanted to ask you, in a general sense, has Staff crunched the numbers to see whether a surcharge would cost more on a given amount of plant using the SWIP versus the DSIC to the ratepayer?

A. Well, it's not a matter of crunching the numbers. It's just a conceptual difference. So the dollars under the SWIP are greater than the dollars under the DSIC because there's application of an AFUDC for the time difference between when the company collects those dollars.

So although the dollars are more, the economic -- if you assume that consumers look at the same discount rate as the AFUDC rate, to the consumer, they don't really care whether they pay the dollars today or pay the dollars tomorrow.

Q. I think that's consistent with our preliminary calculations, that the SWIP would cost more than the DSIC. Let me see if I have any further questions to ask you. Staff recommends an efficiency adjustment in their proposed DSIC as an alternative if the Commission goes that way. Is there a corresponding efficiency adjustment in the SWIP recommendation?

A. No.

Q. Why not?

A. The SWIP recognizes the recovery in a rate case, so there's no loss of -- any loss of -- or difference in operating expenses that result with a DSIC that are unknown between the rate cases, that event doesn't occur when you have a SWIP.

Q. And that's because you're looking at all the rate case elements during the general rate case proceeding, correct?

A. That's correct. There's no single-issue ratemaking there.

MR. POZEFSKY: Okay. Thank you, Mr. Fox.

Q. Has the Commission issued a final decision approving either a DSIC or SWIP surcharge for the AWC Eastern Group?

A. No. The Commission has not yet issued a final decision on the AWC Eastern Group rate case.

Q. What is RUCO's recommendation regarding the Enhanced SWIP?

A. RUCO recommends that the Commission reject the Enhanced SWIP in favor of the traditional ratemaking process. To support its recommendation, RUCO lists four reasons. First, RRUI is seeking recovery of routine plant improvements outside of a rate case that would normally be recovered in a general rate case proceeding. Second, the SWIP is a one-sided mechanism which works only in the interest of the shareholder. While it allows accelerated cost recovery for new plant with post in service AFUDC, it fails to consider reduced operations and maintenance expense ("O&M") savings attributable to the new plant. Third, unlike the current federal standard for arsenic levels in water, there are no federal or state requirements mandating the types of routine plant additions that RRUI seeks recovery for through the Company-proposed SWIP. Fourth, RRUI has not proven that it would not be able to ensure safe and reliable water service or achieve cost recovery absent the SWIP. Therefore, there is no need for the Commission to adopt a special surcharge for such routine additions.

Q. With regard to RUCO's first reason for rejecting the Enhanced SWIP, are the types of infrastructure improvements that would be recovered through the SWIP extraordinary in nature?

A. No. The types of infrastructure improvements for which RRUI seeks cost recovery through the Company's Enhanced SWIP 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. The 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. The Commission 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 such as in a prior rate case proceeding involving Arizona-American Water Company (now EPCOR Water Arizona Inc.).[4]

Q. Please discuss RUCO's second reason for opposing the Enhanced SWIP.

A. RUCO believes that the Enhanced SWIP is a one-sided mechanism which works only in the interest of the shareholder. While it allows accelerated

[4] Decision No. 72047, dated January 6, 2011

cost recovery for new plant with post in service AFUDC, it fails to consider other ratemaking elements such as reduced operations and maintenance expense ("O&M") that is attributable to the new plant.

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 reduce a utility's operating expenses which are recovered 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 repairing aging plant items after normal hours. Under the Enhanced SWIP, RRUI's shareholders would enjoy the benefit of receiving a return on and a return of its investment (i.e. AFUDC) in new plant through a surcharge established between general rate case proceedings. Unfortunately, ratepayers would receive no benefit from any cost savings that are related to the plant additions that they will be paying for through the Enhanced SWIP. Cost savings resulting from new plant additions recovered through the Company-proposed SWIP would be pocketed by RRUI's shareholders between general rate case proceedings.

…

Q. With regard to RUCO's third reason for rejecting the Company-proposed SWIP, are there any federal or state regulations that require the Commission to approve a mechanism that is similar to the Arsenic Cost Recovery Mechanism?

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 an extraordinary mechanism similar to the Arsenic Cost Recovery Mechanism ("ACRM")[5] for the recovery of aging plant between general rate cases. RUCO believes that adjustor mechanisms are extraordinary rate recovery devices that are permitted in certain narrow circumstances. In RUCO's view, the routine replacement of aging infrastructure, that would be recovered through the Enhanced SWIP, 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. In this case RRUI cites excessive water loss as one reason for its rationale for the Enhanced SWIP. RUCO believes that excessive water loss is something that the Company should keep in check as a matter of routine cost management in order to achieve its authorized rate of return. The Company's failure to perform ordinary maintenance is not a reason for the institution of a SWIP.

[5] 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.

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

A. RUCO believes that RRUI 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 an Enhanced SWIP surcharge is necessary for RRUI to meet the Company's obligation to provide safe and reliable water service. RRUI does not contend that the denial of an Enhanced SWIP would change its ability to meet the Company's statutory and regulatory commitments and RRUI does not allege that it is financially unable to make necessary and prudent infrastructure replacements without the Enhanced SWIP.

Q. Does RUCO have any legal concerns regarding the implementation of surcharge mechanisms such as a SWIP or DSIC that you've been discussing in your direct testimony?

A. While I am not an attorney and would not want to express a legal opinion on surcharge mechanisms such as a SWIP or DSIC, I believe a good discussion of the constitutionality of such mechanisms can be found in ACC Staff's Reply/Closing Brief on the AWC Eastern Group proceeding, which I have included in my direct testimony as Exhibit 2.

...

Q. Does the National Association of State Consumer Advocates ("NASUCA") endorse mechanisms similar to the Enhanced SWIP?

A. No. NASUCA issued a resolution in 1999 (Attachment A) that opposes the adoption and implementation of mechanisms such as the Enhanced SWIP. 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 Enhanced SWIP surcharge?

A. Yes. Ken Costello, a Principal with the National Regulatory Research Institute ("NRRI"), published a survey report on cost trackers (similar to the Enhanced SWIP) in September 2009. 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 profits 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, that utilities have little incentive to control."[6]

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 Commonwealth of Pennsylvania, offered testimony before the Pennsylvania House Consumer Affairs Committee regarding a House Bill that would have approved a DSIC mechanism, similar to the Enhanced SWIP, 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 Collection System Improvement Charge, being sought by Pennsylvania-American Water Company:

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

> "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 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. Has the Commission rejected such mechanisms in prior cases?

A. Yes. As I noted earlier in my direct testimony, the Commission adopted the recommendations of Staff and RUCO and rejected a similar cost recovery mechanism identified as an Infrastructure Improvement Surcharge ("IIS") in a prior Arizona-American Water Company (now EPCOR Water Arizona, Inc.) rate case proceeding. 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 estimated by RRUI justify the adoption of the Enhanced SWIP?

A. No. While an argument could be made that the Enhanced SWIP would result in gradual rate increases that would be more palatable to both ACC Commissioners and to ratepayers, if the Commission were to adopt the Enhanced SWIP, ratepayers could be looking at rate increases every year between general rate cases. An annual rate increase 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 the Enhanced SWIP 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 RRUI's 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 the Enhanced SWIP.

Q. Is there any way to mitigate the problems with the Enhanced SWIP 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[7] on a surcharge mechanism similar to the DSIC mechanism proposed in the AWC Eastern Group case 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 here. Mr. Dismukes recommendation makes good sense from the standpoint that O&M expense drops 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

[7] Dismukes, David E., Ph.D., Direct Testimony on Behalf of the Maryland Office of People's Counsel, Case no. 9267, filed July 27, 2011

being proposed by RRUI 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 Enhanced SWIP surcharges go into effect, would produce fairer rates in RUCO's view.

Q. Did the Maryland Public Service Commission approve the utility's infrastructure replacement surcharge?

A. No. In its final decision[8] on the matter, the Maryland Public Service Commission stated that "although the Commission does agree with WGL [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. Can RUCO cite any other studies that dispute the benefits of adjustor mechanisms such as a SWIP or DSIC 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

[8] Maryland Public Service Commission Order No. 84475 issued on November 14, 2011

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. Does your silence on any of the issues, matters or findings addressed in the testimony of the Company's 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 the Enhanced SWIP request in RRUI's 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

Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101-1923
(717) 783-5048 - Office
(717) 783-7152 - Fax
Email: spopowsky@paoca.org
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"

<u>the net change in</u>

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

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

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

<u>(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.</u>

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

<u>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.</u>

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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, including 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 underspending 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

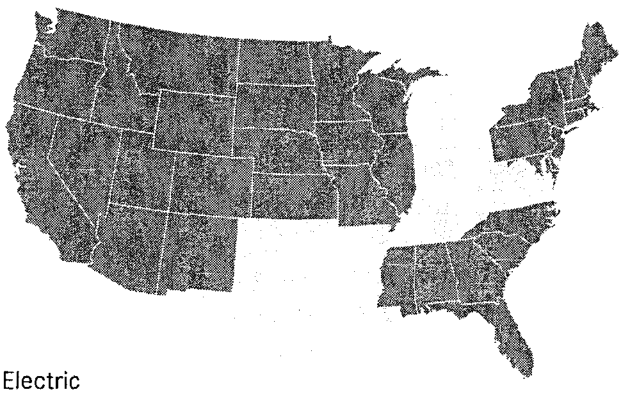
In the past, surcharges were only permitted in limited circumstances for costs that were substantial, volatile and uncontrollable, and that could harm the utilities' financial health. Examples of such traditional surcharges include fuel and purchased power adjustment mechanisms for electric utilities 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 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:

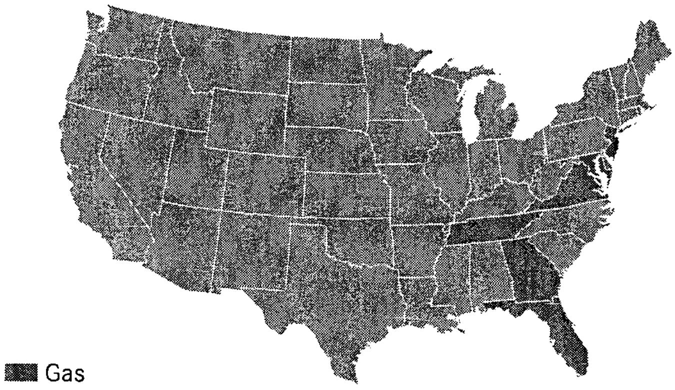
EXHIBIT 3

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

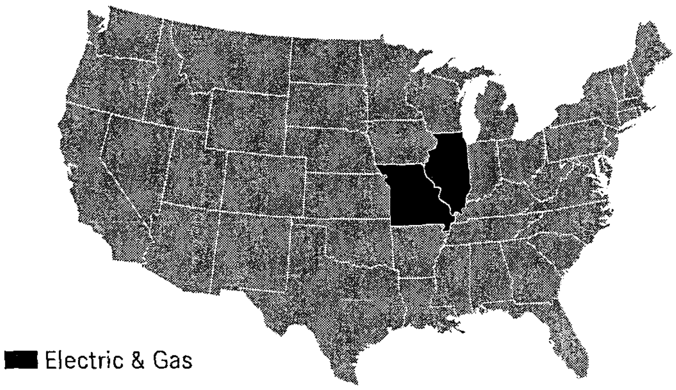
DESCRIPTION	FL	GA	MD	NJ	TN	VA
Conservation	•					
Environmental/Green House Gas Initiative		•		•		
Franchise Fees		•		•	•	
Pipeline Replacement/Utility Infrastructure Enhancement		•		•		
Revenue Normalization			•		•	•
Social Responsibility/Societal Benefits		•		•[1]		
Transitional Energy Facility Adj.				•		
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

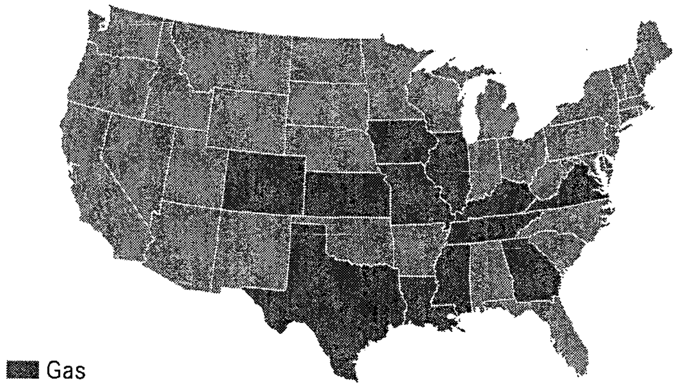
	ILLINOIS		MISSOURI	
DESCRIPTION	Electric	Gas	Electric	Gas
Coal Tar Cleanup[1]		•		
Energy Efficiency Costs	•	•		
Environmental Costs	•	•		
Excess Franchise Fees	•	•		
Government Compliance Costs	•	•		
Hazardous Materials (Asbestos)	•			
Infrastructure Maintenance	•			
Infrastructure Replacement				•
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

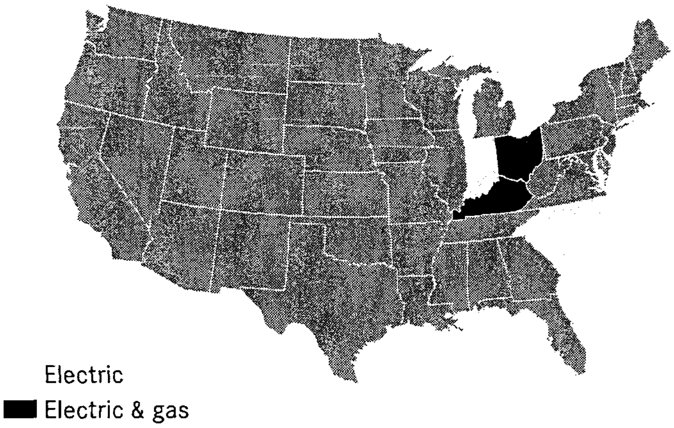
DESCRIPTION	CO	GA	IA	IL	KS	KY	LA	MO	MS	TN	MID TX	WEST TX	VA
Ad Valorem					•								
Automated Metering Incentive	•												
Demand Side Management	•					•							
Energy Efficiency			•								•	•	
Environmental										•			
Franchise Fee	•	•											
Low Income				•									
Municipal Fee											•		
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.

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

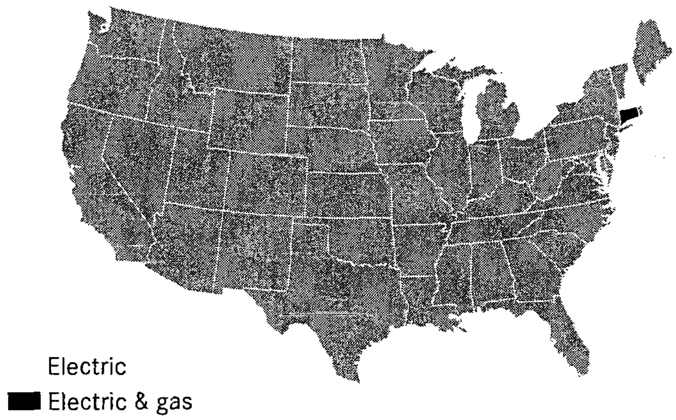
	KY		IN	NC	OH		SC
DESCRIPTION	ELEC	GAS	ELEC	ELEC	ELEC	GAS	ELEC
Accelerated Main Replacement						•	
Annually Adjusted Component					•		
Clean Coal Operating Cost Revenue Adjustment			•				
Demand Side Management	•	•	•	•			
Economic Competitiveness					•		
Emmission Allowances			•				
Energy Efficiency				•	•		•
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.



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)

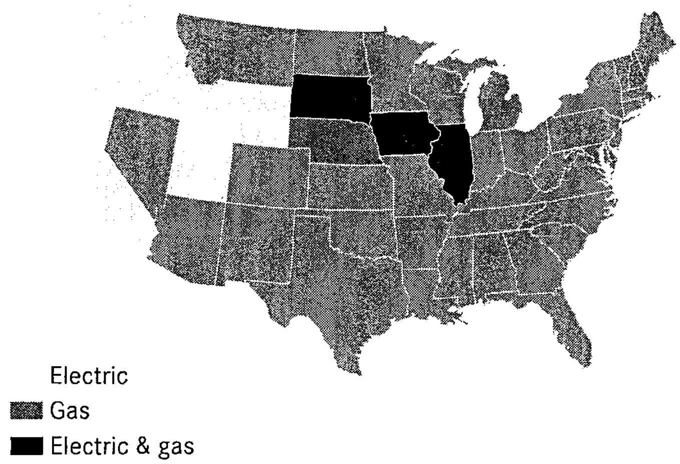
MidAmerican Energy Holdings Company ("MEHC") is a holding company that owns subsidiaries principally engaged in energy businesses (collectively with its subsidiaries, the "Company"). MEHC is a consolidated subsidiary of Berkshire Hathaway Inc. ("Berkshire Hathaway").

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:



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:

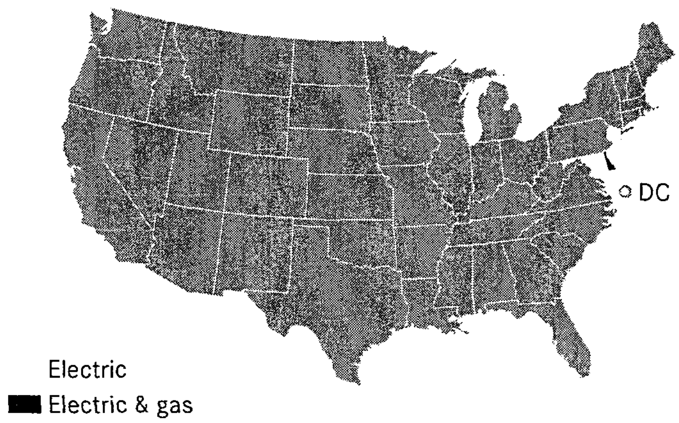
EXHIBIT 9

	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:

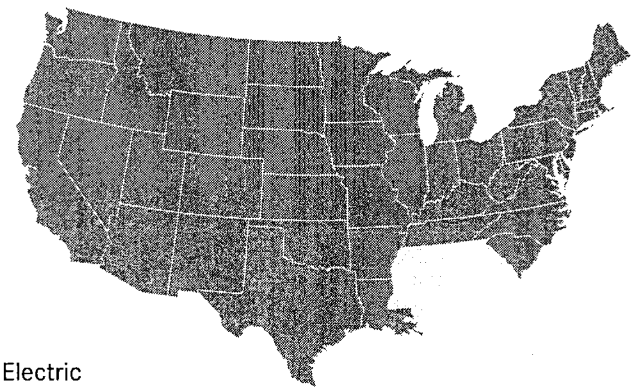
EXHIBIT 10

	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]

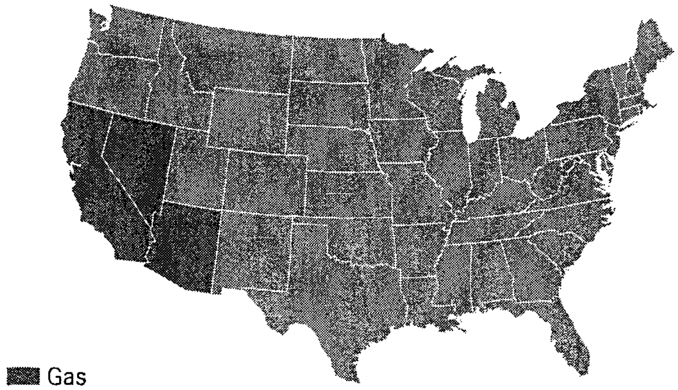


Exhibit 12 a comparison of revenues and costs recovered though surcharges in SWG's jurisdictions:

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]

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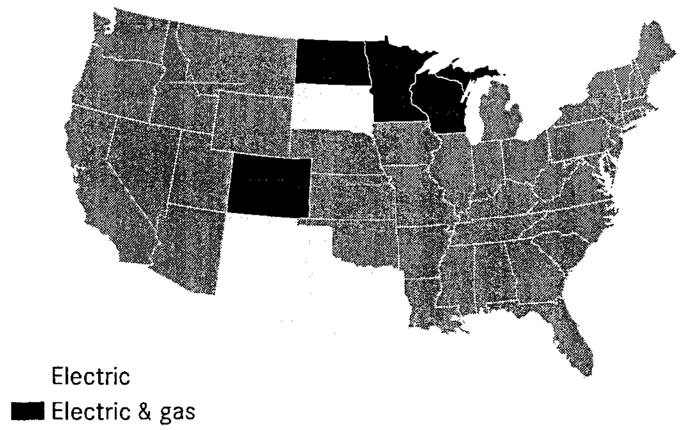
- Submit a proposed customer outreach/education plan to Staff for review and approval, to outline how SWG intends to explain decoupling to customers.[36]

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:



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 $0.075/kWh	$50 Fixed Charge $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

Ralph Smith is a senior regulatory consultant with Larkin & Associates, PLLC. His professional credentials include being a Certified Financial Planner™ Professional, a licensed certified public accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. He received a Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979; a Master of Science in Taxation, Walsh College, Michigan, 1981. His Master's thesis dealt with investment tax credit and property tax on various assets. He also graduated, cum laude, with a Juris Doctor from Wayne State University Law School, Detroit, Michigan, 1986, and received an American Jurisprudence Award for academic excellence. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving water and sewer, telephone, electric, and gas utilities.

Over the past 31 years, Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors, including AARP, on several occasions.

Tina Miller is a regulatory analyst with Larkin & Associates, PLLC. She graduated from Eastern Michigan University (Ypsilanti, Michigan) with a Bachelor of Business Administration in Accounting in December 1996. Ms. Miller prepares discovery requests, produces spreadsheets and models, assists with the review and analysis of regulatory filings, and performs regulatory and accounting research.

Dawn Bisdorf is a research associate with Larkin & Associates, PLLC. Ms. Bisdorf holds an Associate's degree in Accounting from Schoolcraft College and a Bachelor of Arts in Social Science from Madonna University, both of which are located in Livonia, Michigan. Ms. Bisdorf assists on regulatory projects by preparing analyses under the direction of the senior professionals, locating testimony and orders online, performing research, proofing schedules and testimony, and keeping files organized, as needed.

Jill Zhao is a regulatory analyst with Larkin & Associates, PLLC. She graduated from Eastern Michigan University (Ypsilanti, Michigan) with a Master of Science in Accounting in 2009. Ms. Zhao prepares discovery requests, produces spreadsheets and models, assists with the review and analysis of regulatory filings, and performs regulatory and accounting research.

Input for this report was also provided by Hugh Larkin, Jr., senior partner of Larkin & Associates; Helmuth W. Schultz, III, and Donna Ramas, senior regulatory analysts; Mark Dady and John Defever, regulatory analysts, and Kerry Niemiec, administrator.

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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EXHIBIT 1

BEFORE THE ARIZONA CORPORATION COMMISSION

GARY PIERCE
Chairman
BOB STUMP
Commissioner
SANDRA D. KENNEDY
Commissioner
PAUL NEWMAN
Commissioner
BRENDA BURNS
Commissioner

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY, AND FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	)	DOCKET NO. W-01445A-11-0310

DIRECT

TESTIMONY

OF

JEFFREY M. MICHLIK

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MARCH 13, 2012

Q. What is Staff's overall view of the DSIC?

A. A DSIC is a type of adjustor mechanism that alters the balance of regulatory lags to favor the Company and away from ratepayers. In general, Staff supports limiting the use of such an adjustor mechanism to an extraordinary circumstance. The Company's planned use of this surcharge is for routine expenditures, and the Company has not demonstrated extraordinary circumstances to justify a surcharge between rate cases. Staff anticipates that implementation of a DSIC would place a substantial imposition on Commission resources. However, Staff recognizes that implementation of a DSIC has many potential benefits to the Company and its ratepayers that may offset any disruption to the balance of regulatory lags and imposition on regulatory resources. Staff concludes that implementation of a DSIC-like mechanism deserves further consideration; however, details of the specific DSIC proposed by the Company and the consequences to the Company, ratepayers and Commission resources of its implementation are insufficiently resolved at this time.

Q. What does Staff recommend?

A. Staff recommends denial of the Company proposal to implement a DSIC in this case; however, Staff recommends an alternative mechanism method that provides many of the benefits of the DSIC and less demand on regulatory resources.

Q. What is Staff recommending as an alternative to the DSIC?

A. Staff's alternative mechanism – Sustainable Water Loss Improvement Program ("SWIP") is focused on addressing the Company's high water loss in the Superstition water system (specifically the Miami sub-system) and the Cochise water system, (specifically the Bisbee sub-system), and it consists of the following:

1. Applicable only to the Miami and Bisbee sub-systems;
2. Applicable only to transmission and distribution main replacements;
3. Allows deferral of depreciation expense on qualified plant replacements for up to 24 months[5] after the in-service date;
4. Allows recording and deferring a cost of money using its Allowance For Funds Used During Construction rate on qualified plant replacements for up to 24 months[6] after the in-service date;
5. Depreciation and cost of money deferrals will be subject to full regulatory review for compliance with traditional ratemaking conditions (e.g., prudency, used and useful and excess capacity) in the Company's rate case subsequent to the in-service date of the associated plant;
6. Depreciation and cost of money deferrals will be subject to the following specific SWIP conditions:
    a) Maintenance of appropriate supporting records to correlate depreciation and cost of money deferrals with the associated plant;
    b) Demonstration during its relevant rate case(s) (see condition No. 7) that the plant replacements contributed to a reduction in water loss; and
    c) Whole or partial disallowances for deficiencies in "a" or "b"
7. Amortization of the allowed (i.e., net of any disallowances) combined depreciation and cost of money deferrals over 10 years. The purpose of this provision is to provide a continuous, 10-year incentive for the Company to reduce its water loss. Thus, the Company must continue to meet conditions "6a" and "6b" in each rate case over the 10-year amortization period to continue recovering the deferral amortizations.

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[5] Terminates before 24 months if rates become effective that include the qualified plant in rate base in the 24-month period.
[6] Terminates before 24 months if rates become effective that include the qualified plant in rate base in the 24-month period.

EXHIBIT 2

ORIGINAL

BEFORE THE ARIZONA CORPORATION

RECEIVED

COMMISSIONERS
GARY PIERCE - Chairman
BOB STUMP
SANDRA D. KENNEDY
PAUL NEWMAN
BRENDA BURNS

2012 JUL 11 P 3:55

AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS EASTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	DOCKET NO. W-01445A-11-0310

Arizona Corporation Commission
DOCKETED
JUL 11 2012
DOCKETED BY TM

STAFF'S REPLY/CLOSING BRIEF

JULY 11, 2012

Bridget A. Humphrey, Attorney
Wesley C. Van Cleve, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, AZ 85007
(602) 542-3402

AWC also opposes requiring refunds of surcharges in the event water loss is not reduced. What would satisfy the water loss reduction has not been established. However, Staff's assessment thereof would likely take into consideration that a reduction in one section of a system might partially offset incremental losses in another resulting in a net increase in water loss. Should the Company be granted this rare opportunity to effectively increase rates between rate cases, it should be able to assure that the purpose for which the DSIC is required is accomplished. Further, even though recovery of infrastructure costs through the DSIC may be denied if there is no reduction in water loss, the Company would be able to seek recovery of those costs within the context of subsequent rate increase.

Staff continues to support its position in its Opening Brief regarding the conditions to be included in any DSIC. Despite the further clarifications of the mechanics of the DSIC in AWC's brief, some elements require further clarification. First, Staff would be required to review and respond only to the initial filing; remaining filings would be adopted if Staff did not oppose or make other recommendations. However, all annual surcharges would be subject to true-up in the next rate case, where a prudency review would be conducted. Any refunds due to any over-collection due to improperly computed DSICs would not be limited to calculation or accounting-type errors but would include substantive bases such as prudency.

Second, a DSIC would not automatically continue in perpetuity. At each future rate case, a determination would be made as to whether the DSIC was still appropriate. If the DSIC does continue, the surcharge would be reset to zero.

E. The DSIC, as Proposed, Violates the Arizona Constitution.

A DSIC-type mechanism has not been addressed judicially in Arizona. However, based upon existing case law, Staff does not believe that a DSIC, per se, would violate the Arizona Constitution so long as its methodology meets the constitutional mandate.[111] Staff is concerned that the DISC as proposed by AWC does not meet that mandate. As AWC states in its Brief, Arizona's Supreme Court has noted, in *U.S. West vs. Arizona Corporation Commission*[112] (U.S.West II), it is judicial

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[111] *Arizona Corp. Comm'n v. Arizona Pub. Serv. Co.,* 113 Ariz. 368, 555 P.2d 326 (1976); Arizona Cmt'y Action Ass'n, 123 Ariz. 228, 599 P.2d 184 (1979).

[112] *U.S. West Communications, Inc. v. Arizona Corp. Comm'n,* 201 Ariz. 242, 245-46, 34 P.2d 351, 354-55 2001).

interpretation of Arizona's Constitution that requires that the finding of fair value be used in a formula wherein a rate of return is applied to that fair value to determine rates.[113] As such, the requirement could be judicially modified, which the Court did in that case. That modification does not apply to this matter, however.

U.S. West II was the result of a lawsuit filed by a local non-competitive telephone service provider against the Commission in which U.S. West challenged the Commission's method of setting rates for competitive local exchange carriers (CLECs). The Commission had not determined fair value before setting rates for the reason that the CLECs operated in a competitive rather than monopolistic environment. The Supreme Court determined that the Arizona Constitution made mandatory that the Commission determine fair value for the purpose of setting rates. As it was the judiciary which interpreted that mandate to determine the fair value and calculate a reasonable rate of return thereon, the judiciary could re-evaluate it as well.

In doing so, the Court affirmed that the Constitution mandated the finding of fair value and that "when a monopoly exists, the rate of return method is proper."[114] It is only when the rate case concerns a competitive utility that the rate of reform method is inappropriate.[115] In this case, AWC has monopoly status. Therefore, the rate of return methodology still applies.

At the same time, Arizona case law acknowledges that the Commission has a great deal of discretion in setting rates, and can utilize a variety of methodologies as long as the method used complies with the Constitutional mandate.[116] The Commission can consider matters subsequent to the historic test year,[117] including construction projects contracted for and commenced during the test year[118] and construction work in progress but not yet in service,[119] subject to the constitutional mandate. The Commission may also engage in rate-making without first determining fair value rate base under circumstances limited to interim rates and automatic adjustment clauses.[120] In addition,

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[113] *Id.*
[114] *Id.*, 201 Ariz. at 246, 34 P.2d at 355.
[115] *Id.*
[116] *Arizona Pub. Serv. Co.*, 113 Ariz. at 371, 555 P.2d at 329.
[117] *Id.*
[118] *Id.*
[119] *Arizona Cmt'y Action Ass'n*, 123 Ariz. at 230, 599 P.2d at 186.
[120] *Residential Util. Consumer Office v. Arizona Corp. Comm'n*, 199 Ariz. 588, 20 P.2d 1169 (App. 2011).

with the adoption of new federal drinking water standards for arsenic, which would cause water utilities to construct and operate new arsenic treatment facilities, the Commission approved an Arsenic Cost Recovery Mechanism to enable water utilities to meet its requirements.[121] Such mechanisms are in place throughout Arizona and none has been constitutionally challenged. All of these indicate that a DSIC can be adopted, subject to the constitutional mandate.

In *Arizona Community Action Association v. Arizona Corporation Commission,*[122] where the Court allowed the inclusion of plant under construction, it rejected the utility's methodology used to determine the increase. To the extent that an increase was based solely on the company's common equity falling below a certain level, and given that the company had the ability to influence the return on equity, this methodology would be beneficial only to shareholders and was not constitutional.[123] In *Scates v. Arizona Corp Commission,* the Court determined that the Commission did not have the authority to increase rates without first considering the impact of the overall rate of return on rate base.[124]

The proposed DSIC in this case is neither an interim rate nor an adjustor mechanism. An interim rate is a rate which is authorized pending the establishment of a permanent rate.[125] Interim rates may only be ordered where an emergency exists, the utility posts a bond to assure payment of refunds and where it is followed by a rate case in which fair value will be determined, usually within a specified period of time.[126] While a bond could be required to satisfy that requirement in this case, the other two criteria are not met. There has been no assertion that an emergency exists in this case, nor does it. The deterioration of infrastructure is a slow process and complete or major failures in the system are not imminent; there is no immediate threat to the Company's ability to provide services to the ratepayors. Nor is this a temporary order pending a rate hearing. This is the rate hearing.

Adjustor clauses are initially adopted as a part of a rate case and made part of the overall rate structure.[127] In that respect, the proposed DSIC meets these requirements. However, an adjustor

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[121] Garfield Dir. Test., Ex. A-1at 22.
[122] *Arizona Community Action Ass'n v Arizona Corp. Comm'n* 123 Ariz. 228, 599 P.2d 184(1979).
[123] *Id.* at 231, 599 P.2d at 187.
[124] *Id.*
[125] *Scates v. Arizona Corp Comm'n,* 118 Ariz. 531, 535, 578 P.2d 612, 616 (App. 1978).
[126] *Id.*
[127] *Residential Util. Consumer Office,* 199 Ariz. at 591, 20 P.2d at 1172; *Scates,* 118 Ariz. at 535, 578 P.2d at 616.

clause is designed to allow a utility to increase or decrease rates by passing on to customers increases or decreases in specific and easily segregated costs, such as the cost of fuel or purchased water.[128] Rather than changing the utility's overall rate of return, an adjustor mechanism allows the authorized rate of return to be maintained.[129] The DSIC in this case does far more than simply pass on increasing and decreasing costs to AWC. It allows surcharges based on the cost of new plant, effectively increasing the fair value rate base without any determination by the Commission of what that fair value is.

Although the DSIC is similar to an ACRM, there are distinctions which raise questions about its constitutionality. Both allow a utility to seek periodic rate increases outside of a rate case based on the cost of certain added plant specified in the rate case which authorized the mechanism.[130] Many of the procedures by which the annual increase will be sought are also similar, but are not the subject of constitutionality.

In contrast to the proposed DSIC, an ACRM has been fully developed and was only approved after about two years of study by the various interested parties.[131] An ACRM is more limited in scope than the DSIC: it is in place for one plant only and is limited to two instances in which a surcharge or increase can occur, step one occurring when the plant goes into service and step two at a later date to recover the additional capital expenditures.[132] In addition, when the ACRM is authorized, a specific date for filing a next rate case is set, at which time a true up would occur.[133] These latter two distinctions are most concerning.

Unlike an ACRM, a DSIC allows for more immediate recovery not of a single plant or item, but for on-going infrastructure structure replacement over at least a decade. This is somewhat ameliorated by AWC's agreement that the projects included in a DSIC would be limited to those non-revenue producing projects itemized in the DSIC Study docketed in the 2008 rate case and submitted

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[128] *Id.*
[129] *Id.*
[130] *Id.* at 1173; *Scates,* 118 Ariz. at 535, 578 P.2d at 616.
[131] Ex. A-41.
[132] Tr. at 1423.
[133] *Id.* at 1428-31.

with the Company's pre-filed testimony.[134] Whether this is sufficient to meet the constitutional mandate is unknown.

Also, as noted, the Company would not be required to file a rate case by any specific date under a DSIC. The Company asserts that the maximum annual cap and lifetime maximum cap would incentivize the Company to file a rate case without such a mandate.[135] While Staff agrees to an extent, the possibility remains that, even the though maximum cap is reached, the Company could simply leave the surcharge in place for an extended period of time without a true up for prudency occurring, possibly resulting in over-recovery of costs. Again, whether the Company's proposal for resolving this matter is sufficient cannot yet be determined.

The conditions proposed by Staff would further reduce any risk of violating the Arizona Constitution. For instance, while an ACRM is limited to a single project, it is not entirely clear that the DSIC would be similarly limited. Mr. Fox testified that he understood that a DSIC would be limited to a specific system, rather than to multiple systems,[136] but it is not clear whether the Company agrees. Limiting a DSIC to systems with water loss exceeding 10 per cent would clarify this. In addition, the clarification that a true-up at the next rate case would evaluate all surcharges subsequent to the decision herein, regardless of any annual or interim approvals by the Commission, would help assure the constitutionality of the DSIC.

V. RATE CONSOLIDATION AND RATE DESIGN.

A. Full Consolidation of the SaddleBrooke Ranch and Oracle Systems Would Result in Higher Rates for SaddleBrooke Ranch Customers and Should Be Denied at This Time.

The Company asserts that Staff's argument that consolidation would have adverse impacts on SaddleBrooke Ranch customers is incorrect and that Staff offered no testimony or specifics about any such adverse impacts.[137] Instead, argues the Company, the results of Staff's non-consolidation of SaddleBrooke Ranch would result in a revenue increase for that system of $126,586, or 108.10

[134] *Id.* at 1434.
[135] Harris Dir. Test., Ex. A-9, att. A.
[136] AWC's Cl. Br. at 20.
[137] Tr. at 1450.

RIO RICO UTILITIES, INC.

DOCKET NO. WS-2676A-12-0196

DIRECT TESTIMONY

OF

WILLIAM A. RIGSBY

ON

COST OF CAPITAL

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 31, 2012

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Based on the Residential Utility Consumer Office's ("RUCO") analysis of Rio Rico Utilities, Inc.'s application for a permanent rate increase, filed with the Arizona Corporation Commission ("ACC" or "Commission") on May 31, 2012, RUCO recommends the following:

Cost of Equity – RUCO recommends that the Commission adopt a 9.00 percent cost of common equity. This 9.00 percent figure is 26 basis points more than the high side of the range of results obtained in RUCO's cost of equity analysis, and is 170 basis points lower than the 10.70 percent cost of equity capital proposed by Rio Rico Utilities, Inc. in its application for a permanent rate increase.

Cost of Debt – RUCO recommends that the Commission adopt a 4.13 percent hypothetical cost of debt which is 157 basis points lower than the 5.70 percent being proposed by Rio Rico Utilities, Inc.

Capital Structure – RUCO recommends that the Commission adopt a capital structure comprised of 80.00 percent common equity and 20.00 percent debt which was agreed on in Rio Rico Utilities, Inc.'s prior rate case proceeding.

Weighted Average Cost of Capital – RUCO recommends that the Commission adopt RUCO's recommended 8.03 percent weighted average cost of capital ("WACC"), which is the weighted cost of RUCO's recommended costs of common equity and long-term debt, and is 167 basis points lower than the 9.70 percent WACC being proposed by Rio Rico Utilities, Inc.

RUCO disagrees with a number of inputs that Rio Rico Utilities, Inc.'s cost of capital consultant used in both the discounted cash flow ("DCF") model and the capital asset pricing model ("CAPM") which were used to develop Rio Rico Utilities, Inc.'s proposed cost of common equity estimate of 10.70 percent. This includes his use of forecasted yields on long-term U.S. Treasury instruments, his calculation of a market risk premium using a narrow range of economic data, and his assumptions regarding risk as it relates to company size.

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 cost of capital recommendations that are based on my analysis of Rio Rico Utilities, Inc.'s ("RRUI" or "Company") application for a permanent rate increase for the Company's Water and Wastewater Divisions. RRUI's rate application was filed with the Commission on May 31, 2012. The Company has chosen the operating period ending February 29, 2012 for the test year ("Test Year") in this proceeding. RRUI 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 Company's Water and Wastewater Division's original cost rate base as the fair value rate base for the purpose of establishing a fair value rate of return on its invested capital.

Q. Briefly describe RRUI.

A. RRUI is a Class B Arizona public service corporation that is organized as a C Corporation. The Company serves the community of Rio Rico which is located approximately 62 miles south of Tucson in Santa Cruz County. According to RRUI's Application, the Company's Water Division had 6,751 customers and 2,207 wastewater customers during the Test Year ending February 29, 2012. RRUI's current water rates and charges were established in Decision No. 72059, dated January 6, 2011 using a test year ending December 31, 2008. RRUI is a subsidiary of Liberty Utilities, whose ultimate parent is Algonquin Power Utility Corporation ("APUC" or "Parent Company"), a publicly traded member of the Toronto Stock Exchange.

Q. Is this your first case involving RRUI?

A. No. I testified on behalf of RUCO in RRUI's last two rate case proceedings before the Commission.

Q. What areas will you address in your direct testimony?

A. I will address the cost of capital issues associated with the case. I have also filed, under separate cover, direct testimony on the Sustainable Water Loss Improvement Program ("SWIP") issue in this case.

Q. Will RUCO also offer direct testimony on the rate base, operating income and rate design aspects of this proceeding?

A. Yes. RUCO witness Timothy J. Coley will provide direct testimony on rate base, operating income and rate design for the Company's Water and Wastewater Divisions.

Q. Please explain your role in RUCO's analysis of RRUI's Application.

A. I reviewed RRUI's Application and performed a cost of capital analysis to determine a fair rate of return on the Company's invested capital. In addition to my recommended capital structure, my direct testimony will present my recommended cost of common equity (the Company has no preferred stock) and my recommended hypothetical cost of debt. The recommendations contained in this testimony are based on information obtained from Company responses to data requests, RRUI's Application, and from market-based research that I conducted during my analysis. Because RRUI has no actual debt and is proposing a hypothetical capital structure, [1] for ratemaking purposes the Company's cost of capital will be determined on a consolidated basis (i.e. the same hypothetical capital structure for both RRUI's Water and Wastewater Divisions).

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

[1] At open meeting held December 14 and 15, 2010, RRUI committed to file a financing application with the Commission in 2011 to infuse 20 percent debt into the Company's capital structure with an actual cost of debt of 5.70 percent. Based on that commitment, the Company offered to use a hypothetical capital structure of 20 percent debt and 80 percent equity, with a cost of debt of 5.70 percent. To date, neither RRUI nor any other Arizona subsidiary of Liberty Utilities has filed a financing application.

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 hypothetical cost of long-term debt for RRUI. The fifth section of my direct testimony is devoted to a discussion of my recommended capital structure for the Company. Sixth, I will discuss my recommended weighted average cost of capital. In the seventh and final section, I will comment on the Company's cost of capital testimony. Exhibit 1, Attachments A through D and Schedules WAR-1 through WAR-9 will provide support for my cost of capital analysis.

Q. Please summarize the recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis, I am making the following recommendations:

Cost of Equity – I am recommending that the Commission adopt a 9.00 percent cost of equity. This 9.00 percent figure is 26 basis points more than the 8.74 percent high side of the range of results obtained in RUCO's cost of equity analysis, and is 170 basis points lower than the 10.70 percent cost of equity capital proposed by RRUI.

<u>Cost of Debt</u> – I am recommending that the Commission adopt a hypothetical 4.13 percent cost of debt which is 157 basis points lower than the hypothetical 5.70 percent cost of debt that the Company agreed to in RRUI's prior rate case proceeding. My recommended hypothetical 4.13 percent cost of debt is the current yield on a Baa/BBB-rated utility bond (Attachment D)

<u>Capital Structure</u> – I am recommending that the Commission adopt the hypothetical capital structure comprised of 80.00 percent equity and 20.00 percent debt that the Company agreed to in RRUI's prior rate case proceeding.

<u>Weighted Average Cost of Capital</u> – I am recommending that the Commission adopt my recommended 8.03 percent weighted average cost of capital ("WACC") which is the weighted cost of my recommended costs of common equity and debt, and is 167 basis points lower than the 9.70 percent WACC being proposed by RRUI.

Q. Why do you believe that your recommended 8.03 percent WACC is an appropriate rate of return for RRUI to earn on its invested capital?

A. The 8.03 percent WACC figure that I am recommending meets the criteria established in the landmark Supreme Court cases of <u>Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia</u> (262 U.S. 679, 1923) and <u>Federal Power Commission v. Hope Natural Gas Company</u> (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 <u>Hope</u> 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 <u>Bluefield</u> and <u>Hope</u> 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 <u>Bluefield</u> and <u>Hope</u> decisions *do allow*, is for a utility to be provided with the *opportunity* to earn a reasonable rate of return on its investment. That is to say that a utility, such as RRUI, is provided with the opportunity to earn an appropriate rate of return if the Company's management exercises good judgment and manages its assets and resources in a manner that is both prudent and economically efficient.

COST OF EQUITY CAPITAL

Q. What is your final recommended cost of equity capital for RRUI?

A. I am recommending a cost of equity of 9.00 percent. My recommended 9.00 percent cost of equity figure is 26 basis points more than the 8.74 percent high side of 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 $g = b \times r$.

Q. Would you please provide an example that will illustrate the relationship that earnings, the dividend payout ratio and book value have with dividend growth?

A. RUCO consultant Stephen Hill illustrated this relationship in a Citizens Utilities Company 1993 rate case by using a hypothetical utility.[2]

Table I

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.25	$11.70	4.00%
Equity Return	10%	10%	10%	10%	10%	N/A
Earnings/Sh.	$1.00	$1.04	$1.082	$1.125	$1.170	4.00%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.649	$0.675	$0.702	4.00%

Table I of Mr. Hill's illustration presents data for a five-year period on his hypothetical utility. In Year 1, the utility had a common equity or book value of $10.00 per share, an investor-expected equity return of ten

[2] Citizens Utilities Company, Arizona Gas Division, Docket No. E-1032-93-111, Prepared Testimony, dated December 10, 1993, p. 25.

percent, and a dividend payout ratio of sixty percent. This results in earnings per share of $1.00 ($10.00 book value x 10 percent equity return) and a dividend of $0.60 ($1.00 earnings/sh. x 0.60 payout ratio) during Year 1. Because forty percent (1 - 0. 60 payout ratio) of the utility's earnings are retained as opposed to being paid out to investors, book value increases to $10.40 in Year 2 of Mr. Hill's illustration. Table I presents the results of this continuing scenario over the remaining five-year period.

The results displayed in Table I demonstrate that under "steady-state" (i.e. constant) conditions, book value, earnings and dividends all grow at the same constant rate. The table further illustrates that the dividend growth rate, as discussed earlier, is a function of (1) the internally generated funds or earnings that are retained by a company to become new equity, and (2) the return that an investor earns on that new equity. The DCF dividend growth rate, expressed as g = b x r, is also referred to as the internal or sustainable growth rate.

Q. If earnings and dividends both grow at the same rate as book value, shouldn't that rate be the sole factor in determining the DCF growth rate?

A. No. Possible changes in the expected rate of return on either common equity or the dividend payout ratio make earnings and dividend growth by themselves unreliable. This can be seen in the continuation of Mr. Hill's illustration on a hypothetical utility.

Table II

	Year 1	Year 2	Year 3	Year 4	Year 5	Growth
Book Value	$10.00	$10.40	$10.82	$11.47	$12.158	5.00%
Equity Return	10%	10%	15%	15%	15%	10.67%
Earnings/Sh	$1.00	$1.04	$1.623	$1.720	$1.824	16.20%
Payout Ratio	0.60	0.60	0.60	0.60	0.60	N/A
Dividend/Sh	$0.60	$0.624	$0.974	$1.032	$1.094	16.20%

In the example displayed in Table II, a sustainable growth rate of four percent[3] exists in Year 1 and Year 2 (as in the prior example). In Year 3, Year 4 and Year 5, however, the sustainable growth rate increases to six percent.[4] If the hypothetical utility in Mr. Hill's illustration were expected to earn a fifteen-percent return on common equity on a continuing basis, then a six percent long-term rate of growth would be reasonable. However, the compound growth rate for earnings and dividends, displayed in the last column, is 16.20 percent. If this rate was to be used in the DCF model, the utility's return on common equity would be expected to increase by fifty percent every five years, [(15 percent ÷ 10 percent) – 1]. This is clearly an unrealistic expectation.

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3 [(Year 2 Earnings/Sh – Year 1 Earnings/Sh) ÷ Year 1 Earnings/Sh] = [($1.04 - $1.00) ÷ $1.00] = [$0.04 ÷ $1.00] = 4.00%

4 [(1 – Payout Ratio) x Rate of Return] = [(1 - 0.60) x 15.00%] = 0.40 x 15.00% = 6.00%

Although it is not illustrated in Mr. Hill's hypothetical example, a change in only the dividend payout ratio will eventually result in a utility paying out more in dividends than it earns. While it is not uncommon for a utility in the real world to have a dividend payout ratio that exceeds one hundred percent on occasion, it would be unrealistic to expect the practice to continue over a sustained long-term period of time.

Q. Other than the retention of internally generated funds, as illustrated in Mr. Hill's hypothetical example, are there any other sources of new equity capital that can influence an investor's growth expectations for a given company?

A. Yes, a company can raise new equity capital externally. The best example of external funding would be the sale of new shares of common stock. This would create additional equity for the issuer and is often the case with utilities that are either in the process of acquiring smaller systems or providing service to rapidly growing areas.

Q. How does external equity financing influence the growth expectations held by investors?

A. Rational investors will put their available funds into investments that will either meet or exceed their given cost of capital (i.e. the return earned on their investment). In the case of a utility, the book value of a company's stock usually mirrors the equity portion of its rate base (the utility's earning base). Because regulators allow utilities the opportunity to earn a reasonable rate of return on rate base, an investor would take into consideration the effect that a change in book value would have on the rate of return that he or she would expect the utility to earn. If an investor believes that a utility's book value (i.e. the utility's earning base) will increase, then he or she would expect the return on the utility's common stock to increase. If this positive trend in book value continues over an extended period of time, an investor would have a reasonable expectation for sustained long-term growth.

Q. Please provide an example of how external financing affects a utility's book value of equity.

A. As I explained earlier, one way that a utility can increase its equity is by selling new shares of common stock on the open market. If these new shares are purchased at prices that are higher than those shares sold previously, the utility's book value per share will increase in value. This would increase both the earnings base of the utility and the earnings expectations of investors. However, if new shares sold at a price below the pre-sale book value per share, the after-sale book value per share declines in value. If this downward trend continues over time, investors might view this as a decline in the utility's sustainable growth rate and will have lower expectations regarding growth. Using this same logic, if a new stock issue sells at a price per share that is the same as the pre-sale book value per share, there would be no impact on either the utility's earnings base or investor expectations.

Q. Please explain how the external component of the DCF growth rate is determined.

A. In his book, The Cost of Capital to a Public Utility,[5] Dr. Gordon (the individual responsible for the development of the DCF or constant growth model) identified a growth rate that includes both expected internal and external financing components. The mathematical expression for Dr. Gordon's growth rate is as follows:

$$g = (br) + (sv)$$

where:	g	=	DCF expected growth rate,
	b	=	the earnings retention ratio,
	r	=	the return on common equity,
	s	=	the fraction of new common stock sold that accrues to a current shareholder, and
	v	=	funds raised from the sale of stock as a fraction of existing equity.
and	v	=	1 - [(BV) ÷ (MP)]
where:	BV	=	book value per share of common stock, and
	MP	=	the market price per share of common stock.

[5] Gordon, M.J., The Cost of Capital to a Public Utility, East Lansing, MI: Michigan State University, 1974, pp. 30-33.

Q. Did you include the effect of external equity financing on long-term growth rate expectations in your analysis of expected dividend growth for the DCF model?

A. Yes. The external growth rate estimate (sv) is displayed on Page 1 of Schedule WAR-4, where it is added to the internal growth rate estimate (br) to arrive at a final sustainable growth rate estimate.

Q. Please explain why your calculation of external growth on page 2 of Schedule WAR-4, is the current market-to-book ratio averaged with 1.0 in the equation [(M ÷ B) + 1] ÷ 2.

A. The market price of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital (one of the desired effects of regulation). As a result of this situation, I used [(M ÷ B) + 1] ÷ 2 as opposed to the current market-to-book ratio by itself to represent investor's expectations that, in the future, a given utility will achieve a market-to-book ratio of 1.0.

Q. Has the Commission ever adopted a cost of capital estimate that included this assumption?

A. Yes. In a prior Southwest Gas Corporation rate case[6], the Commission adopted the recommendations of ACC Staff's cost of capital witness, Stephen Hill, who I noted earlier in my testimony. In that case, Mr. Hill

[6] Decision No. 68487, Dated February 23, 2006 (Docket No. G-01551A-04-0876)

used the same methods that I have used in arriving at the inputs for the DCF model. His final recommendation for Southwest Gas Corporation was largely based on the results of his DCF analysis, which incorporated the same valid market-to-book ratio assumption that I have used consistently in the DCF model as a cost of capital witness for RUCO.

Q. Can you cite a more recent case in which the Commission adopted a cost of capital estimate that included this assumption?

A. Yes. The Commission adopted a RUCO recommended cost of common equity which relied on the same assumption in a 2009 Global Water rate case proceeding.[7] Decision No. 71878, dated September 14, 2010 stated the following:

> "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 Staffs 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."

...

[7] Docket Number W-02445A-09-0077

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 six 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 <u>Hope</u> 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 six water companies used in the proxy are publicly traded on the both the New York Stock Exchange ("NYSE") and the NASDAQ.[8] 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 October 19, 2012 update of the water utility industry and evaluations of the water companies used in my proxy).

Q. Are these the same water utilities that you have used in prior rate case proceedings?

A. I have used five of the six water utilities in prior rate case proceedings. In this case I am including American Water Works Company, Inc., (NYSE stock ticker symbol "AWK") the largest investor-owned water and wastewater utility in the U.S. American Water Works Company, Inc. has been followed by Value Line since July of 2008 after the New Jersey-based water provider was spun off from its German parent, RWE, AG and became a publicly traded entity. Value Line now has four years of operating numbers available on American Water Works Company, Inc. and so I've decided to include it in my sample of water utilities.

[8] "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. Please describe the other water utilities that comprise your water company proxy group.

A. My water company proxy group also includes American States Water Company (stock ticker symbol "AWR"), California Water Service Group ("CWT"), Middlesex Water Company (stock ticker symbol "MSEX", which is traded on the NASDAQ), SJW Corporation ("SJW"), and Aqua America, Inc. ("WTR"). Each of these water companies face the same types of risk that RRUI faces. For the sake of brevity, I will refer to each of 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, 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.[9]

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 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.

...

[9] 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.

Q. Are these the same water and natural gas companies that RRUI used in its application?

A. RRUI's cost of equity witness, Thomas J. Bourassa, used all of the same water companies included in my proxy with the exception of AWK, but did not rely on a sample of LDCs as I did. Mr. Bourassa also used one other water company in his cost of capital analysis which I excluded from mine.

Q. Which water company did you exclude from your sample?

A. I excluded Connecticut Water Service, Inc.

Q. Why did you exclude that particular water company?

A. Connecticut Water Service, Inc. is followed in Value Line's Small and Mid-Cap edition which does not provide the same type of forward-looking information (i.e. long-term estimates on return on common equity and share growth) that it provides on the six water companies that I used in my proxy.

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 2007 to 2011 for both the water companies and for the LDCs. Schedule WAR-5 also includes Value Line's projected 2012, 2013 and 2015-17 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 AWR's earned return on common equity by its earnings retention ratio for each year in the 2007 to 2011 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 3.36 percent during the 2007 to 2011 observation period. The company experienced a decline in growth from 3.14 percent in 2007, to 2.69 percent in 2009. Internal growth climbed to 3.65 percent during the final year of the observation period. Value Line's analysts expect this pattern to continue for the most part in the coming years. Internal growth is expected to climb steadily to 5.45 percent by the end of 2017. After weighing Value Line's earnings and book value estimates, I believe that internal growth of 5.25 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 133.40 million in 2007, to 138.87 million in 2011. Value Line is forecasting higher future share growth. According to Value Line's analysts, outstanding shares should increase from 139.90 million in 2012 to 142.90 million by the end of the 2015-17 time period. Based on Value Lines slightly higher expectations, I believe that a 0.60% rate of share growth is appropriate (Page 2 of Schedule WAR-4). My final dividend growth rate estimate for WTR is 5.74 percent (5.25 percent internal growth + 0.49 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 4.79 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 is 4.89 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 4.79 percent growth estimate falls below Zacks' average long-term EPS projection of 6.55 percent for the water companies in my sample and Value Line's growth projection of 4.97 percent (which is an average of EPS, DPS and BVPS). My 4.79 percent estimate is 29 basis points higher than the 4.50 percent average of Value Line's historical growth results and 19 basis points lower than the 4.98 percent average of the growth data published by Value Line and Zacks. My 4.79 percent growth estimate is also 133 basis points higher than Value Line's 3.46 percent 5-year compound historical average of EPS, DPS and BVPS. On balance, I would say my 4.79 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 4.89 percent growth estimate for the natural gas LDCs is 37 to 48 basis points higher than the average 4.52 percent average of long-term EPS consensus projection published by Zacks, and the 4.41 percent Value Line projected estimate (which is an average of EPS, DPS and BVPS). The 4.89 percent estimate that I have calculated is 26 basis points lower than the 5.15 percent average of the 5-year historic EPS, DPS and BVPS means of Value Line and is also 15 basis points higher than the combined 4.74 percent Value Line and Zacks averages displayed in Schedule WAR-6. In fact, my 4.89 percent growth estimate exceeds Value Line's 4.48 percent 5-year compound historical average of EPS, DPS and BVPS by 41 basis points. In the case of the LDCs I would say that my 4.89 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 October 19, 2012 Ratings and Reports water utility industry update and Value Line's December 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 October 9, 2012 to November 30, 2012. The average dividend yields were 3.21 percent and 3.85 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 page 3 of Schedule WAR-2, the cost of equity capital derived from my DCF analysis is 8.00 percent for the water utilities and 8.74 percent for the natural gas LDCs which is 387 to 461 basis points higher than the current 4.13 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[10], 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.[11] In this regard, CAPM can help an investor to determine how much risk is associated with a given investment so that he or she can decide if that investment meets their individual preferences. Finance theory has always held that as the risk associated with a given investment increases, so should the expected rate of return on that investment and vice versa. According to CAPM theory, risk can be classified into two specific forms: nonsystematic or diversifiable risk, and systematic or non-diversifiable risk. While nonsystematic risk can be virtually eliminated through diversification (i.e. by including stocks of various companies in various industries in a portfolio of securities), systematic risk, on the other hand, cannot be eliminated by diversification.

[10] William F. Sharpe, "A Simplified Model of Portfolio Analysis," Management Science, Vol. 9, No. 2 (January 1963), pp. 277-93.

[11] 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.

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,[12] 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 testimony, this compensation translates into higher rates of returns to the investor.

...

[12] 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.

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 October 12, 2012 through November 30, 2012 (Attachment D). This resulted in a risk-free (r_f) rate of return of 2.86 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. Since 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 currently falling 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 2011 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 4.10 percent (9.80% - 5.70% = 4.10%). The market risk premium that results by using the arithmetic mean calculation is 5.70 percent (11.80% - 6.10% = 5.70%).

Q. How did you select the beta coefficients that were used in your CAPM analysis?

A. The beta coefficients (ß), for the individual utilities used in both my proxies, were calculated by Value Line and were current as of October 19, 2012 for the water companies and December 7, 2012 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 0.69. The beta coefficients for the LDCs included in my natural gas sample ranged from 0.55 to 0.75 with an average beta of 0.66.

Q. What are the results of your CAPM analysis?

A. As shown on pages 1 and 2 of Schedule WAR-7, my CAPM calculation using a geometric mean to calculate the risk premium results in an average expected return of 5.69 percent for the water companies and 5.54 percent for the natural gas LDCs. My calculation using an arithmetic mean results in an average expected return of 6.80 percent for the water companies and 6.59 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)	8.00%
DCF (Natural Gas Sample)	8.74%
CAPM (Water Sample)	5.69% – 6.80%
CAPM (Natural Gas)	5.54% – 6.59%

Based on these results, my best estimate of an appropriate range for a cost of common equity for the Company is 5.54 percent to 8.74 percent. My final recommended cost of common equity figure is 9.00 percent which is 26 basis points above the high end of the range of estimates shown above (Schedule WAR-1, Page 3) and 487 basis points higher than the current 4.13 percent yield on a safer Baa/BBB-rated utility bond.

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), the current state of the national economy – which could be sliding back into recession. My final estimate also takes into consideration the U.S. Federal Reserve's recent decisions not to raise interest rates at least through mid-2015.[13] I also took into consideration information on Arizona's economy and current rate of unemployment in making my final cost of equity estimate. 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).

[13] U.S. Federal Reserve press release dated October 24, 2012: http://www.federalreserve.gov/newsevents/press/monetary/20121024a.htm

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The 10.70 percent cost of equity capital reflected in the Company's Application is 170 basis points higher than the 9.00 percent cost of equity capital that I am recommending.

Current Economic Environment

Q. Please explain why it is necessary to consider the current economic environment when performing a cost of equity capital analysis for a regulated utility.

A. Consideration of the economic environment is necessary because trends in interest rates, present and projected levels of inflation, and the overall state of the U.S. economy determine the rates of return that investors earn on their invested funds. Each of these factors represent potential risks that must be weighed when estimating the cost of equity capital for a regulated utility and are, most often, the same factors considered by individuals who are also investing in non-regulated entities.

Q. Please 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[14] 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

[14] 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.

1990 level of 10.01 percent. In addition, the Federal Reserve's discount rate on loans to its member banks had fallen to 3.00 percent and short-term interest rates had declined to levels that had not been seen since 1972.

Although GDP increased in 1992 and 1993, the Federal Reserve took steps to increase interest rates beginning in February of 1994, in order to keep inflation under control. By the end of 1995, the Federal discount rate had risen to 5.21 percent. Once again, the banking community followed the Federal Reserve's moves. The Fed's strategy, during this period, was to engineer a "soft landing." That is to say that the Federal Reserve wanted to foster a situation in which economic growth would be stabilized without incurring either a prolonged recession or runaway inflation.

Q. Did the Federal Reserve achieve its goals during this period?

A. Yes. The Fed's strategy of decreasing interest rates to stimulate the economy worked. The annual change in GDP began an upward trend in 1992. A change of 4.50 percent and 4.20 percent were recorded at the end of 1997 and 1998, respectively. Based on daily reports that were presented in the mainstream print and broadcast media during most of 1999, there appeared to be little doubt among both economists and the public at large that the U.S. was experiencing a period of robust economic growth highlighted by low rates of unemployment and inflation. Investors, who believed that technology stocks and Internet company start-ups (with little or no history of earnings) had high growth potential, purchased these types of issues with enthusiasm. These types of investors, who exhibited what former Chairman Greenspan described as "irrational exuberance," pushed stock prices and market indexes to all time highs from 1997 to 2000. 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.[15]

The FOMC's January 31, 2006 meeting marked the final appearance of Alan Greenspan, who had presided over the rate setting body for a total of eighteen years. On that same day, Greenspan's successor, Ben Bernanke, the former chairman of the President's Council of Economic Advisers, and a former Fed governor under Greenspan from 2002 to 2005, was confirmed by the U.S. Senate to be the new Federal Reserve chief. As expected by Fed watchers, Chairman Bernanke picked up where his predecessor left off and increased the federal funds rate by 25 basis points during each of the next three FOMC meetings for a total of seventeen consecutive rate increases since June 2004, and raising the federal funds rate to a level of 5.25 percent. The Fed's rate increase campaign finally came to a halt at the FOMC meeting held on August 8, 2006, when the FOMC decided not to raise rates. 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

[15] Henderson, Nell, "Bullish on Bernanke" The Washington Post, January 30, 2007.

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.[16] At the time of the Fed's decision, analysts speculated that a rate cut over the next several months was unlikely given the Fed's concern that inflation would fail to moderate. However, during this same period, evidence of an even slower economy and a possible recession was beginning to surface. Within days of the Fed's decision to stand pat on rates, a borrowing crisis rooted in a deterioration of the market for subprime mortgages, and securities linked to them, forced the Fed to inject $24 billion in funds (raised through its open market operations) into the credit markets.[17] 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

[16] Ip, Greg, "Markets Gyrate As Fed Straddles Inflation, Growth" The Wall Street Journal, August 8, 2007.

[17] Ip, Greg, "Fed Enters Market To Tamp Down Rate" The Wall Street Journal, August 9, 2007.

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,[18] 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 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.

[18] Ip, Greg, Robin Sidel and Randall Smith, "Fed Offers Banks Loans Amid Crises" The Wall Street Journal, August 9, 2007.

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).[19] As a result of the Fed's actions, the federal funds rate was reduced to a level of 2.00 percent. From April 30, 2008 through September 16, 2008, the Fed took no further action on its key interest rate. However, the days before and after the Fed's September 16, 2008 meeting saw longstanding Wall Street firms such as Lehman Brothers, Merrill Lynch and AIG failing as a result of their subprime holdings. By the end of the week, the Bush administration had announced plans to deal with the deteriorating financial condition which had now become a worldwide crisis. The administrations actions included former Treasury Secretary Henry Paulson's request to Congress for $700 billion to buy distressed assets as part of a plan to halt what has been described as the worst financial crisis since the 1930's[20]. Amidst this turmoil, the Fed made the decision to cut the federal funds rate by another

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[19] Ip, Greg, "Credit Worries Ease as Fed Cuts, Hints at More Relief" The Wall Street Journal, March 19, 2008.

[20] 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.

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?

A. Yes. At the close of the FOMC's September 2011 meeting the Fed announced its decision to implement a plan that resembles a 1961 Federal Reserve program known as "Operation Twist".[21] Under this plan, the Fed would sell $400 billion in Treasury securities that mature within 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

[21] Hilsenrath, Jon and Luca Di Leo "Fed Launches New Stimulus" The Wall Street Journal, September 22, 2011.

provide a shot in the arm to the beleaguered housing sector of the economy.

Q. Has there been any noticeable drop in long-term rates since the Fed announced its plan to purchase longer term Treasury instruments?

A. Yes. The yield on the 30-year Treasury bond has from fallen from 2.88 percent to 2.82 percent since the latter part of November 2011 (Attachment D).

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 2.20 percent according to information provided by the U.S. Department of Labor's Bureau of Labor Statistics.[22]

Q. Has the Fed raised interest rates in anticipation of higher inflation?

A. No. The FOMC has not raised interest rates to date. The Fed's plan to buy $600 billion of U.S. government bonds over an eight month period, known as quantitative easing stage two or QE2,[23] was completed during the summer of 2011. The attempt to drive down long-term interest rates

[22] http://www.bls.gov/news.release/cpi.nr0.htm .

[23] Hilsenrath, Jon, "Fed Fires $600 Billion Stimulus Shot" The Wall Street Journal, November 4, 2010.

and encourage more borrowing and growth by increasing the money supply has yet to stimulate the economy and fears of a recession persist.

At its October 24, 2012 meeting, the FOMC announced that it will continue purchasing additional agency mortgage-backed securities at a pace of $40 billion per month and continue, through the end of the year, its program to extend the average maturity of its holdings of Treasury securities. The FOMC also stated that it is maintaining its existing policy of reinvesting principal payments from its holdings of agency debt and agency mortgage-backed securities in agency mortgage-backed securities. According to the FOMC, these actions, which together will increase the Committee's holdings of longer-term securities by about $85 billion each month through the end of the year, should put downward pressure on longer-term interest rates, support mortgage markets, and help to make broader financial conditions more accommodative. The FOMC further stated that it had decided to keep the target range for the federal funds rate at 0 to 0.25 percent. The FOMC currently anticipates that exceptionally low levels for the federal funds rate are likely to be warranted at least through mid-2015.

Q. Putting this all into perspective, how have the Fed's actions since 2000 affected the yields on Treasury Instruments and benchmark interest rates?

A. As can be seen on Schedule WAR-8, current Treasury yields are considerably lower than corresponding yields that existed during the year 2000 and 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 November of 2011.

As of November 20, 2011, leading interest rates that include the 3-month, 6-month and 1-year treasury yields have only increased 7 to 8 basis points from their November 2011 levels. Longer term yields including the 5-year, 10-year and 30-year have all fallen from levels that existed a year ago. The same is true for the 30-year Zero rate. The prime rate has remained constant at 3.25 percent over the past year, as has the benchmark federal funds rate discussed above. A previous trend, described by former Chairman Greenspan as a "conundrum"[24], 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

[24] Wolk, Martin, "Greenspan wrestling with rate 'conundrum'," MSNBC, June 8, 2005.

lengthen) presently exists. The 30-year Treasury yield, used in my CAPM analysis, has decreased 6 basis points from 2.88 percent, in November 2011, to 2.82 percent as of November 20, 2012.

Q. What are the current yields on utility bonds?

A. Referring again to Attachment D, as of November 20, 2012, 25/30-year A-rated utility bonds were yielding 3.78 percent (28 basis points lower than a year ago) and 25/30-year Baa/BBB-rated utility bonds were yielding 4.13 percent (down 61 basis points from a year earlier).

Q. How has the current environment of low interest rates impacted the returns on utilities in general?

A. In the November 2, 2012 Value Line quarterly update on the Electric Utility (West) Industry, Value Line analyst Paul E. Debbas, CFA had this to say on the effects of interest rates on utilities:

> "Since 2008, interest rates have been low as a result of Federal Reserve policy. This has had various effects on utilities (and their stocks). Some of these effects are positive, some negative. The most noticeable effect on utilities is reflected in their stock prices. With interest rates on savings accounts, money market funds, and other income vehicles minuscule, many investors have chosen to turn to income stocks. Utilities are known for paying healthy dividends. Indeed, at 4.1%, this industry's average yield is well above the median yield of all dividend-paying equities under our coverage. Low interest rates also reduce utilities' borrowing costs—something that is important in such a capital-intensive sector. Interest savings from refinancing debt will eventually be passed on to customers once the utility receives a rate order. However, for debt held at the parent level or at a non-utility subsidiary, the company retains any interest reductions.

> Low interest rates also have some negative aspects for this industry. Allowed returns on equity have been trending down due to declining interest rates. Also, low interest rates increase a company's pension obligations because they are discounted at a lower rate. This can be reflected in higher pension expense. Finally, Hawaiian Electric Industries is unique in this group due to its ownership of American Savings Bank. Low interest rates are squeezing the interest-rate spreads for thrifts."

Q. What is the current outlook for the economy?

A. The current outlook on the economy includes fears that a slide into recession could occur if there is no resolution of the so called fiscal cliff situation (which involves the scheduled expiration of Bush Administration-era tax cuts and scheduled federal spending cuts) between the Executive Branch and Congress. Value line's analysts offered this perspective on the economy in the November 30, 2011 edition of Value Line's Selection and Opinion publication:

> "**We are starting to see Hurricane Sandy's impact on the final-quarter economy.** Of note, recent weeks have seen reports showing declines in retail spending, factory usage, and industrial production, with output in this last category estimated to have been reduced by nearly a percentage point by the storm. At the same time, jobless claims soared during the first part of November, due principally to disruptions from the hurricane."

Value Line's analysts went on to say:

> "**Other disappointments could be on the way.** For example, reports for November may well show the storm's effect on payroll growth, the jobless rate, car sales, manufacturing, and non-manufacturing. We feel any step back will be brief — but still painful. Then, there is the fiscal cliff of mandated tax hikes and spending cuts that is

> set to kick in on January 2nd, unless Congress and the White House can author a deal. The fiscal cliff already is hurting business and consumer confidence and may, along with the toll from the hurricane, hold gross domestic product growth to less than 1.5% in the fast-ending quarter."

Value Line's analysts also stated:

> "**Meanwhile, volatility is stepping up a notch on Wall Street,** which is understandable given the uncertain backdrop. Still, the fundamentals of a growing economy, low inflation, and a supportive Federal Reserve favor the bulls over the intermediate term. But first, investors may have to navigate through some choppy seas."

Q. How are water utilities such as RRUI faring in the current economic environment?

A. While, as always, there are concerns regarding long-term infrastructure requirements, Value Line analyst Andre J. Costanza stated in his October 19, 2012 quarterly water industry update (Attachment A) that water utilities are being viewed as safe havens during the current period of economic uncertainty. Mr. Costanza went on to state the following:

> "There have not been any major developments out of the Water Utility Industry of late. However, the group, as a whole, has soared into the upper rungs of The Value Line Investment Survey for Timeliness since our July review. It was ranked 54 out of 98 last time around.) Although providers posting the best company-specific results led the way in terms of price momentum, even those reporting far more-modest performances have done well relative to the broader market. Growing economic uneasiness overseas, coupled with stilltough domestic conditions, appear to have many investors looking to take shelter from the instability in the group's healthy dividends. Cloudiness regarding a global recovery is likely to continue painting a favorable backdrop for this space in the months ahead."

Q. How has Arizona fared 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.[25] 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 fifth highest foreclosure rate in the country. [26]

Q. What is the current unemployment situation in Arizona during this period of economic recovery?

A. According to information published on November 30, 2012, and displayed on the website of the Arizona Department of Administration's Office of Employment and Population Statistics,[27] the seasonally adjusted unemployment rate for Arizona dropped two tenths of a percentage point from 8.2% in September 2012, to 8.1% in October 2012. At the time that

[25] Beard, Betty, "Recession hit Arizona hardest" The Arizona Republic, March 6, 2011.

[26] Associated Press: Arizona foreclosures keep on dropping," Arizona Capital Times, November 15, 2012.

[27] Arizona Department of Administration's Office of Employment and Population Statistics http://www.workforce.az.gov/

this information was compiled, Arizona's rate of unemployment was higher than the U.S. unemployment rate of 7.9%.

More recent information on the national rate of unemployment, released by the U.S. Department of Labor on December 7, 2012, has pegged U.S. unemployment at 7.70 percent. According to the November 30, 2012 Arizona Department of Administration's Office of Employment and Population Statistics report, the October 2012 rate of unemployment for the Santa Cruz, where RRUI is located, was 18.30 percent.

Q. After weighing the economic information that you've just discussed, do you believe that the 9.00 percent cost of equity capital that you have estimated is reasonable for the Company?

A. I believe that my recommended 9.00 percent cost of equity capital, which is 487 basis points higher than the current 4.13 percent yield on a Baa/BBB-rated utility bond, will provide RRUI 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 county where RRUI is located), and the Fed's decision to keep interest rates at their current levels over the next three years are all taken into consideration. As I noted earlier, the Hope decision determined that a utility is entitled to earn a rate of return that is commensurate with the returns it would make on other investments with comparable risk. I believe that my cost of equity analysis, which is 26 basis points more than the high end of the range of results I obtained from both the DCF and CAPM models, has produced such a return.

COST OF DEBT

Q. Have you reviewed RRUI's testimony on the Company-proposed cost of long-term debt?

A. Yes.

Q. What is RRUI proposing in regard to the cost of long term-debt?

A. RRUI is proposing a hypothetical cost of debt of 5.70 percent which was agreed on in the Company's prior rate case proceeding. As stated in Decision No. 72059, at the Commission's Regular Open Meeting held December 14 and 15, 2010, RRUI committed to file a financing application with the Commission in 2011 to infuse 20 percent debt into the Company's capital structure with an actual cost of debt of 5.70 percent. Based on that commitment, the Company offered to use a hypothetical capital structure of 20 percent debt and 80 percent equity, with a cost of debt of 5.70 percent.

Q. Did RRUI file a financing application with the Commission?

A. No it did not. As can be seen on Page 1 of the Company's Schedule D-2, RRUI has no outstanding debt at this time.

Q. What is RUCO's recommended cost of debt in this proceeding?

A. In the absence of an actual cost of debt, or a corresponding cost of debt, I am recommending a hypothetical cost of debt of 4.13 percent, which is the current yield on a Baa/BBB-rated utility bond.

Q. Why are you recommending the current yield on a Baa/BBB-rated utility bond?

A. In December of 2010, when Rio Rico agreed to a 5.70 percent cost of debt, the yields on A-rated and Baa/BBB-rated utility bonds were 5.80 percent and 6.15 percent respectively (Attachment E). As such, the cost of debt adopted by the Commission in RRUI's previous rate case was 10 basis points lower than the prevailing A-rated yield of 5.80 percent. As I've explained earlier in my direct testimony, the yields on bonds have been falling in the years since RRUI's current rates were approved. The current yields on A-rated and Baa/BBB-rated utility bonds now stand at 3.78 percent to 4.13 percent, respectively. Given this fact, I believe that the Company's hypothetical cost of debt should reflect the current yields on utility bonds. For this reason, I am recommending that the Commission adopt the higher 4.13 percent yield on a Baa/BBB rated utility bond as RRUI's hypothetical cost of debt.

CAPITAL STRUCTURE

Q. Have you reviewed RRUI's testimony regarding the Company's proposed capital structure?

A. Yes.

Q. Please describe the Company's proposed capital structure.

A. As agreed upon in the Company's previous rate case proceeding, the Company is proposing a hypothetical capital structure comprised of 80.00 percent common equity and 20.00 percent debt.

Q. What capital structure are you recommending for RRUI?

A. I am recommending that the Commission adopt the hypothetical capital structure comprised of 80.00 percent common equity and 20.00 percent debt as agreed upon in the Company's previous rate case proceeding.

Q. Is RRUI's hypothetical capital structure in line with industry averages?

A. No. As can be seen in Schedule WAR-9, RRUI's hypothetical capital structure is heavier in equity than the capital structures of the water utilities in my sample which had an average of 45.70 percent equity.

RRUI's hypothetical capital structure would be perceived by investors as having lower financial risk. The same is true in the case of my LDC sample which had an average of 50.30 percent equity.

Q. Have you made a downward adjustment to your recommended cost of equity that reflects the fact that RRUI's capital structure is heavier in equity than the capital structures of your sample utilities?

A. No. Although such an adjustment would be appropriate, I have not done so in order to mitigate any investor concerns of higher business risk that RRUI may face.

WEIGHTED AVERAGE COST OF CAPITAL

Q. What is your recommended weighted average cost of capital for RRUI?

A. I am recommending that the Commission adopt my recommended 8.03 percent weighted average cost of capital ("WACC") which is the weighted cost of my recommended costs of common equity and hypothetical debt.

Q. How does the Company's proposed WACC cost of capital compare with your recommendation?

A. The Company has proposed a WACC of 9.70 percent. This figure is the result of a weighted average of RRUI's proposed 10.70 percent cost of common equity and 5.70 percent hypothetical cost of debt. The

Company-proposed 9.70 percent weighted cost of capital is 167 basis points higher than the 8.03 percent weighted cost of capital that I am recommending.

COMMENTS ON THE COMPANY-PROPOSED COST OF EQUITY CAPITAL

Q. How does your recommended cost of equity capital compare with the cost of equity capital proposed by the Company?

A. The Company's cost of capital witness, Mr. Bourassa, is recommending a cost of common equity of 10.70 percent. His 10.70 percent cost of equity capital is 170 basis points higher than the 9.00 percent cost of equity capital that I am recommending.

Q. What methods did Mr. Bourassa use to arrive at his proposed cost of common equity for the Company?

A. Mr. Bourassa used both the DCF and CAPM methods. He also relies on a third valuation method known as a Build-up method that does not require the use of market betas as does the CAPM. His DCF analysis relies on the same constant growth version of the DCF model that I have used with two different growth estimates: a past and future growth estimate which produces a 9.70 percent indicated cost of equity, and a future growth estimate which produces an 11.30 percent indicated cost of equity. The average of the results of these two DCF methodologies is 10.50 percent. Mr. Bourassa's CAPM analysis also uses the same model that I have used, but he obtains two different results: one obtained by using an historical risk premium and the other by using a current market risk premium. His CAPM analysis produces results of 8.10 percent using an historical risk premium and 13.60 percent using a current market risk premium. His average CAPM result is 10.90 percent.

Q. What are the main reasons for the difference in the results that you obtained from your DCF analysis and the results that Mr. Bourassa obtained from his DCF analysis using the constant growth model?

A. Mr. Bourassa conducted his analysis during the early part of April 2012 and consequently much of the data that he used in his analysis is now eight months old. This can be seen in a price comparison of five of the water company stocks that we both used in our samples: The difference between the average adjusted closing stock prices used in my DCF model and spot prices used by Mr. Bourassa in his DCF models are as follows:

	Rigsby	Bourassa	Difference
AWR	$43.62	$36.36	$7.26
CWT	$17.96	$17.94	$0.02
MSEX	$18.61	$18.50	$0.11
SJW	$23.87	$24.32	($0.45)
WTR	$25.01	$22.23	$2.78

As can be seen above, four of the five water stocks that our samples have in common have increased in value since April 6, 2012 when Mr. Bourassa recorded the closing spot prices used in his DCF model. Also, since April 2012, all of the five companies that our samples have in common, dividends have increased as follows:

	Rigsby	Bourassa	Difference
AWR	$1.42	$1.04	$0.38
CWT	$0.63	$0.60	$0.03
MSEX	$0.74	$0.72	$0.02
SJW	$0.71	$0.68	$0.03
WTR	$0.70	$0.59	$0.11

The above changes in stock price and dividends resulted in higher dividend yields for the five sample companies which can be seen as follows:

	Rigsby	Bourassa	Difference
AWR	3.26%	3.11%	15 bps
CWT	3.51%	3.34%	17 bps
MSEX	3.98%	3.89%	9 bps
SJW	2.97%	2.80%	17 bps
WTR	2.80%	2.65%	15 bps

Q. What are the differences between your constant growth DCF results and Mr. Bourassa's constant growth models?

A. As I stated earlier, Mr. Bourassa did not rely on a sample of natural gas utilities so my comparison is limited to our respective water utility samples. Much of the difference between our results is attributable to the utilities that were included in our samples. As I explained earlier in my testimony, Mr. Bourassa's sample included one water company that I excluded (i.e. Connecticut Water Service, Inc.). I excluded Connecticut Water Service, Inc. because Value Line does not provide the long-term projections on it which I use to develop my growth estimates for the "g" component of the DCF model. The main reason for the higher average dividend yield of 3.33 in Mr. Bourassa's DCF model, as opposed to 3.21 percent in mine, was the inclusion of Connecticut Water Service, Inc. in his sample and his exclusion of American Water Works Company, Inc. which I included in my sample. Connecticut Water Service, Inc.'s dividend yield in April 2012 was 3.62 percent, while American Water Works Company, Inc. has a more recent dividend yield of 2.72 percent (based on my 8-week average adjusted closing prices listed above). In regard to our growth (i.e. "g" component of the DCF model) estimates, Mr. Bourassa's estimates of 6.33 percent to 7.11 percent are 154 basis points to 232 basis points higher than my average growth estimate of 4.79 percent. I attribute this difference to the different companies in our samples and the more recent lower growth projections from Value Line's analysts.

Q. Do you agree with Mr. Bourassa's rationale for not using Value Line estimates of DPS growth in the estimation of a growth rate for the DCF model?

A. No, I do not. In this case Mr. Bourassa admits that the projected DPS growth rate of 4.10 percent is higher than the historical growth rate of 3.33 percent. He has essentially made an argument in prior cases that the DPS element of growth should be selectively ignored if it depresses an overall growth rate that also includes EPS and BVPS.[28]

Q. Have you included DPS growth estimates in your DCF model?

A. Yes. I believe that DPS growth is considered by the investing public and DPS growth estimates should be included in the calculation of the growth component of the DCF model. This is what I've done to arrive at my DCF growth estimates.

Q. What are the main differences between your CAPM results and Mr. Bourassa's CAPM results?

A. The differences between our CAPM results is attributable to his selection of forecasted long-term U.S. Treasury instrument yields used as inputs for the risk-free rate of return and the time lapse since Mr. Bourassa filed his direct testimony. Mr. Bourassa's average beta of 0.72 has fallen to 0.71 since his testimony was filed, and his current market risk premium figure

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[28] Pages 33-34 of the direct testimony of Thomas J. Bourassa on Black Mountain Sewer Corporation filed on December 19, 2008, Docket No. SW-02361A-08-0609.

of 14.30 percent is simply not realistic when compared with the historic market risk premiums, ranging from 4.10 percent to 5.70 percent, that I obtained from Morningstar's 2012 SBBI Yearbook.

Q. Please explain the differences in your risk free rates of return.

A. I relied on an 8-week average yield of 2.86 percent on a 30-year treasury instrument whereas Mr. Bourassa relied on a 3.40 percent average of forecasted 30-year Treasury yields.

Q. Do you agree with Mr. Bourassa's reliance on forecasted yields of long-term Treasury instruments?

A. No. I believe that an average of the most recent yields on a Treasury instrument is the best indicator of future yields. Mr. Bourassa's 3.40 percent risk-free rate is based on analysts' forecasts for 2012 and 2013 and is 58 basis points higher than the current 2.82 percent yield on a 30-year Treasury bond (Attachment D). Further, the use of forecasted yields fails to take into consideration the Federal Reserve's current policy to maintain low interest rates and to drive down the yields on long-term treasury instruments over the next three years.

...

Q. What is the current average beta for the water utilities included in Mr. Bourassa's sample?

A. The current average beta for the water utilities included in Mr. Bourassa's sample is 0.71 as opposed to the 0.72 used in his CAPM analysis and the 0.69 average beta used in my CAPM analysis using a sample of water utilities.

Q. What are the differences in the market risk premiums that you used in your CAPM analyses?

A. As I explained earlier in my testimony, my market risk premiums are the 5.70 percent arithmetic and 4.10 percent geometric means of the differences between the return on the broader stock market and the yields of intermediate term U.S. Treasury instruments over the 1926 – 2011 time frame (obtained from Morningstar's 2012 SBBI Yearbook). Mr. Bourassa relied on a 6.60 percent historical risk premium (which also relied on Morningstar data) and a 14.30 percent current market risk premium, which was computed using the DCF model and data on 1,700 stocks followed by Value Line.

Q. Do you agree with Mr. Bourassa's 14.30 percent current market risk premium?

A. No. Mr. Bourassa's 14.30 percent market risk premium is clearly excessive and only represents a snapshot in time. He calculates his risk premium by using a DCF model that relies on stock price appreciation for the growth component (i.e. "g"). This results in a 14-month average expected return of 14.30 percent. Mr. Bourassa's current market risk premium is not even realistic considering the historic market risk premiums used in my model that take into consideration the full spectrum of economic conditions that have occurred since 1926.

Q. How did Mr. Bourassa arrive at his final 10.50 percent cost of common equity for the Company?

A. Mr. Bourassa's proposed 10.70 percent cost of common equity represents his own judgment and relies on the results of the midpoints of the ranges of estimates he obtained from his various models.

Q. Is there any merit in the rationale used by Mr. Bourassa in regard to the size arguments stated in his direct testimony?

A. No. One has to take into consideration the fact that the water utilities included in both Mr. Bourassa's and my samples are collections of water systems that are similar to RRUI and face the same types of risks as RRUI. Furthermore, RRUI's Parent is a large publicly traded entity that has access to the capital markets.

...

Q. Has the ACC ever granted a cost of equity based on company size?

A. To the best of my knowledge, the Commission has never granted a higher cost of common equity based on company size.

Q. Does your cost of capital recommendation take into consideration any perceived business risks that the Company might face?

A. Yes. As I stated earlier in my testimony, I believe that the amount of equity contained in my recommended capital structure, which is higher than the percentage of equity contained in my utility samples, and the fact that I have not made any downward adjustment to my recommended 9.00 percent cost of equity mitigates any perceived business risk.

Q. Does your silence on any of the issues, matters or findings addressed in the testimony of Mr. Bourassa or any other witness for RRUI constitute your acceptance of their positions on such issues, matters or findings?

A. No, it does not.

Q. Does this conclude your cost of capital testimony on RRUI?

A. Yes.

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 – October 2011

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	E-01933A-12-0291	Rate Increase

ATTACHMENT A

INDUSTRY TIMELINESS: 21 (of 98)

There have not been any major developments out of the Water Utility Industry of late. However, the group, as a whole, has soared into the upper rungs of *The Value Line Investment Survey* for Timeliness since our July review. It was ranked 54 out of 98 last time around.) Although providers posting the best company-specific results led the way in terms of price momentum, even those reporting far more-modest performances have done well relative to the broader market. Growing economic uneasiness overseas, coupled with still-tough domestic conditions, appear to have many investors looking to take shelter from the instability in the group's healthy dividends. Cloudiness regarding a global recovery is likely to continue painting a favorable backdrop for this space in the months ahead.

Nevertheless, the industry has does have some issues to contend with, looking ahead. Of specific concern is water utilities' extensive capital requirements and the financial constraints of those providing services. Many water infrastructures are in need of significant repairs and/or replacement. Although regulatory backing has been far better than in the past, the costs of doing business are likely to climb into the hundreds of millions of dollars over the next couple of years. Most companies operating in this space do not possess the cash to make the improvements, resulting in not only a great deal of consolidation, but also skepticism about the industry's future returns.

Industry Fundamentals

Water is obviously essential to sustain any form of life. Thus, demand is a necessity and is unwavering. This will probably never change, and demand is likely to continue to grow along with the population. Responsible for the safe and timely delivery of the liquid, water providers are nearly as important. That said, weather conditions are highly unpredictable, but definitely play a pivotal role in demand trends. Unexpected shifts in temperature or precipitation can definitely result in wild top- and bottom-line swings.

As a result, most regulators, which are responsible for, among other things, keeping the balance of power between providers and customers, have done a complete 180 degree turn and taken a far more business-friendly approach in recent years. True, purification and distribution standards remain stringent, but state regulatory boards, have, for the most part, been handing down more-timely and fairer case rate decisions. This has not always been so, but the improved backing has been a big boost for the industry, as the costs of doing business have increased tremendously, and are likely to continue to do so. State regulators review and rule on general rate case requests submitted by providers looking to recover costs incurred during distribution, and therefore are vital to each company's posterity. As is typically the case, all of the providers under our coverage have claims in the review process. The outcomes are highly anticipated and are likely to be very telling.

Game Changers

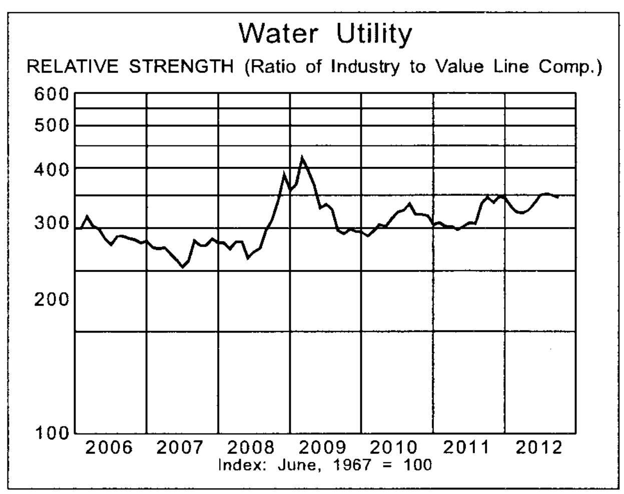
Regardless of the more favorable regulatory landscape, water providers are still left holding the bill for most of the infrastructure improvements that need to be made. Indeed, most infrastructures are old and are in great need of repair or rebuilding. Unfortunately, the majority of those operating here lack the finances to fund the improvements on their own, and must raise the capital via financing. And although external financing has become commonplace, the increased shares and or debt taken on in order to finance the upgrades are eating away at profits and diluting shareholder returns. Meanwhile, others not willing or capable of raising capital have been closing up shop. Indeed, M&A activity has continued at a healthy pace, with larger providers using bolt-on acquisitions to grow their businesses and expand their footprints. *Aqua America* has employed this methodology, a trend that is likely to remain a vital part of its business model.

Conclusion

There are a couple of stocks that stand out for Timeliness. *American Water Works* posted record earnings in the second quarter and is expected to maintain healthy bottom-line momentum in the months to come, thanks to the recent portfolio optimization efforts. Meanwhile, *Aqua America* is also favorably ranked for Timeliness, having jumped two notches since our last review. *Aqua* is benefiting from better cost management. Still, not a single stock in this group holds appealing 3- to 5-year share-price potential. Infrastructure maintenance costs are likely to continue to build, and the necessary financing will become a bigger drag.

True, the dividends offered in this space add a nice touch, especially for those seeking shelter during economic instability. However, we continue to contend that income-minded investors have better options to choose from elsewhere. Plus, our concerns regarding finances and the rising costs of doing business may well result in slower dividend growth eventually. (Note that most of the issues under our coverage are estimated to deliver lower yields by mid-decade.) Any stock would be unlikely to maintain its current valuation if that company decided to temper its payout structure. That is why it is imperative to note each company's financial composition and future cash flow projections before making a commitment here. The regulatory environment can change quickly as it has in the past.

Andre J. Costanza



AMERICAN WATER NYSE-AWK

RECENT PRICE 36.75 | P/E RATIO 16.7 (Trailing: 18.8 Median: NMF) | RELATIVE P/E RATIO 1.10 | DIV'D YLD 2.7% | VALUE LINE

TIMELINESS 2 Lowered 10/19/12

SAFETY 3 New 7/25/08

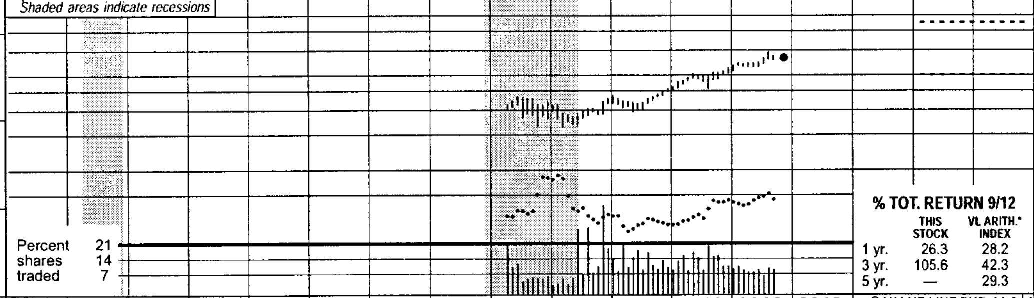
TECHNICAL 3 Raised 10/12/12

BETA .65 (1.00 = Market)

	2008	2009	2010	2011	2012
High:	23.7	23.0	25.8	32.8	39.4
Low:	16.5	16.2	19.4	25.2	31.3

Target Price Range 2015 | 2016 | 2017

LEGENDS
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+50%)	*13%*
Low	30	(-20%)	*-1%*

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	2	0	0	0	7	0	2	1	0
to Sell	2	0	0	0	7	0	2	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	181	164	176
to Sell	136	163	162
Hld's(000)	138169	141669	140028

Percent shares traded 21 14 7

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	26.3	28.2
3 yr.	105.6	42.3
5 yr.	—	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
--	--	--	--	--	--	--	--	--	--	13.08	13.84	14.61	13.98	15.49	15.18	*16.40*	*16.55*	Revenues per sh	*18.15*
--	--	--	--	--	--	--	--	--	--	.65	d.47	2.87	2.89	3.56	3.74	*4.25*	*4.30*	"Cash Flow" per sh	*4.70*
--	--	--	--	--	--	--	--	--	--	d.97	d2.14	1.10	1.25	1.53	1.72	*2.15*	*2.20*	Earnings per sh A	*2.40*
--	--	--	--	--	--	--	--	--	--	--	--	.40	.82	.86	.91	*.98*	*1.04*	Div'd Decl'd per sh B■	*1.25*
--	--	--	--	--	--	--	--	--	--	4.31	4.74	6.31	4.50	4.38	5.27	*5.35*	*5.30*	Cap'l Spending per sh	*5.00*
--	--	--	--	--	--	--	--	--	--	23.86	28.39	25.64	22.91	23.59	24.14	*25.40*	*25.70*	Book Value per sh D	*26.70*
--	--	--	--	--	--	--	--	--	--	160.00	160.00	160.00	174.63	175.00	175.66	*177.00*	*180.00*	Common Shs Outst'g C	*190.00*
--	--	--	--	--	--	--	--	--	--	--	--	18.9	15.6	14.6	16.7	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
--	--	--	--	--	--	--	--	--	--	--	--	1.14	1.04	.93	1.05	*Value Line*		Relative P/E Ratio	*1.25*
--	--	--	--	--	--	--	--	--	--	--	--	1.9%	4.2%	3.8%	3.1%	*estimates*		Avg Ann'l Div'd Yield	*2.8%*
						--	--	--	--	2093.1	2214.2	2336.9	2440.7	2710.7	2666.2	*2905*	*2975*	Revenues ($mill)	*3450*
						--	--	--	--	d155.8	d342.3	187.2	209.9	267.8	304.9	*380*	*395*	Net Profit ($mill)	*450*
						--	--	--	--	--	--	37.4%	37.9%	40.4%	39.5%	*41.0%*	*40.0%*	Income Tax Rate	*39.0%*
						--	--	--	--	--	--	--	--	12.5%	10.0%	*10.0%*	*10.0%*	AFUDC % to Net Profit	*15.0%*
						--	--	--	--	56.1%	50.9%	53.1%	56.9%	56.8%	55.6%	*54.0%*	*53.0%*	Long-Term Debt Ratio	*54.5%*
						--	--	--	--	43.9%	49.1%	46.9%	43.1%	43.2%	44.2%	*46.0%*	*47.0%*	Common Equity Ratio	*45.5%*
						--	--	--	--	8692.8	9245.7	8750.2	9289.0	9561.3	9601.5	*9750*	*9825*	Total Capital ($mill)	*11150*
						--	--	--	--	8720.6	9318.0	9991.8	10524	11059	11021	*11600*	*12175*	Net Plant ($mill)	*13750*
						--	--	--	--	NMF	NMF	3.7%	3.8%	4.4%	4.7%	*5.5%*	*5.5%*	Return on Total Cap'l	*6.0%*
						--	--	--	--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	*8.5%*	*8.5%*	Return on Shr. Equity	*9.0%*
						--	--	--	--	NMF	NMF	4.6%	5.2%	6.5%	7.2%	*8.5%*	*8.5%*	Return on Com Equity	*9.0%*
						--	--	--	--	NMF	NMF	3.0%	1.8%	2.8%	3.5%	*4.5%*	*4.5%*	Retained to Com Eq	*4.0%*
						--	--	--	--	--	--	34%	65%	56%	52%	*46%*	*47%*	All Div'ds to Net Prof	*53%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $5685.4 mill. **Due in 5 Yrs** $407.6 mill.
LT Debt $5203.1 mill. **LT Interest** $292.0 mill.
(Total interest coverage: 3.5x) (54% of Cap'l)

Leases, Uncapitalized: Annual rentals $21.5 mill.
Pension Assets-12/11 $981.1 mill
Oblig. $1402.0 mill.
Pfd Stock $19.3 mill. **Pfd Div'd** $.7 mill

Common Stock 176,430,023 shs.
as of 7/26/12

MARKET CAP: $6.5 billion (Large Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	13.1	14.2	12.9
Other	521.2	1383.5	593.5
Current Assets	534.3	1397.7	606.4
Accts Payable	199.2	243.7	183.9
Debt Due	44.8	543.9	482.3
Other	530.5	701.5	357.8
Current Liab.	774.5	1489.1	1018.0
Fix. Chg. Cov.	237%	256%	*300%*

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	--	--	*3.5%*
"Cash Flow"	--	--	*5.5%*
Earnings	--	--	*8.0%*
Dividends	--	--	*6.5%*
Book Value	--	--	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	550.2	612.7	680.0	597.8	2440.7
2010	588.1	671.2	786.9	664.5	2710.7
2011	596.7	668.8	760.9	639.8	2666.2
2012	618.6	745.6	*825.8*	*715*	*2905*
2013	*640*	*740*	*860*	*735*	*2975*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.19	.32	.52	.21	1.25
2010	.18	.42	.71	.23	1.53
2011	.23	.42	.73	.34	1.72
2012	.28	.66	*.81*	*.40*	*2.15*
2013	*.33*	*.65*	*.80*	*.42*	*2.20*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	--	--	.20	.20	.40
2009	.20	.20	.21	.21	.82
2010	.21	.21	.22	.22	.86
2011	.22	.23	.23	.23	.91
2012	.23	.23	.25		

BUSINESS: American Water Works Company, Inc. is the largest investor-owned water and wastewater utility in the U.S., providing services to over 15 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 88.9% of 2011 revenues. New Jersey is its biggest market accounting for 20.9% of revenues. Has roughly 7,000 employees. Depreciation rate, 2.5% in '11. BlackRock, Inc., owns 7.4% of the common stock outstanding. Off. & dir. own less than 1% (3/12 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 posted record earnings in the second quarter. The nation's largest publicly traded water utility recorded profits of $0.66 a share, 57% better than the year before. Revenue growth of 12% trounced expectations, thanks to favorable weather and strong pumpage, while costs remained relatively steady. The earlier portfolio optimization helped, removing less profitable businesses from the mix, but maybe more impressive was that management was able to keep maintenance costs under control.

We have raised our full-year share-net estimate by $0.20, but only tweaked our second-half call slightly upward. Our overall decision was largely a result of the aforementioned success. Although we believe that the top line will continue to benefit from favorable regulatory rulings, it is hard to imagine the cost base not rising going forward. Indeed, the company is slated to make a number of infrastructure upgrades as a result of aging systems. Thus, we look for costs to begin to mount, thereby cutting into margins, despite efforts to keep expenses in check.

This stock ought to interest momentum accounts. AWK is ranked 2 (Above Average) for Timeliness based on the recent earnings strength. Growth is likely to remain solid over the next six to 12 months, too, benefiting from a supportive regulatory body and more-streamlined operations. The company will probably not have to seek much outside financing in the near term, either, as the proceeds from divestitures ease capital burdens a bit.

That said, we are a bit more skeptical about growth prospects further out. Specifically, we worry about the American's financial situation and the capital-intensive nature of this business. The company is slated to spend over $900 million on its infrastructure this year, and we do not envision that figure trending much lower in the years ahead. This endeavor will easily eat up any cash reserves and cash flow being generated by operations. Management will have to float more debt and stock in order to meet these obligations, but such actions will temper investor gains. The dividend is better than that of the average issue covered in our *Survey*, but not of the average utility provider.

Andre J. Costanza *October 19, 2012*

(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 early Nov. 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 2011: $1.195 billion, $9.80/share.

Company's Financial Strength	B
Stock's Price Stability	95
Price Growth Persistence	85
Earnings Predictability	15

AMER. STATES WATER NYSE-AWR

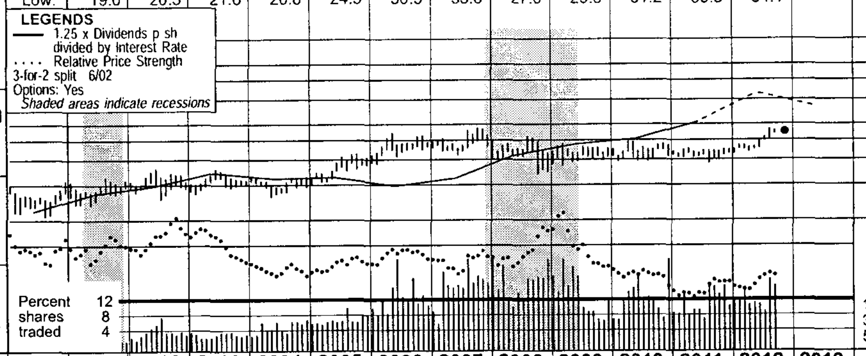
RECENT PRICE 44.03 | P/E RATIO 18.2 (Trailing: 17.5 / Median: 22.0) | RELATIVE P/E RATIO 1.20 | DIV'D YLD 3.2% | VALUE LINE

TIMELINESS 3 Lowered 9/28/12
SAFETY 2 Raised 7/20/12
TECHNICAL 3 Raised 10/12/12
BETA .70 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	26.4	29.0	29.0	26.8	34.6	43.8	46.1	42.0	38.8	39.6	36.4	45.4
Low:	19.0	20.3	21.6	20.8	24.3	30.3	33.6	27.0	29.8	31.2	30.5	34.1

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.25 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
3-for-2 split 6/02
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+35%)	11%
Low	45	(Nil)	4%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	5	2	0	2	2	0	4	2	0
to Sell	5	2	0	2	2	0	4	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	86	69	83
to Sell	40	63	50
Hld's(000)	11493	11810	11968

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	35.1	28.2
3 yr.	34.7	42.3
5 yr.	32.1	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
11.37	11.44	11.02	12.91	12.17	13.06	13.78	13.98	13.61	14.06	15.76	17.49	18.42	19.48	21.41	22.24	**23.40**	**23.45**	Revenues per sh	**27.80**
1.75	1.85	2.04	2.26	2.20	2.53	2.54	2.08	2.23	2.64	2.89	3.31	3.37	3.40	4.23	4.26	**4.60**	**5.00**	"Cash Flow" per sh	**5.50**
1.13	1.04	1.08	1.19	1.28	1.35	1.34	.78	1.05	1.32	1.33	1.62	1.55	1.62	2.22	2.23	**2.45**	**2.50**	Earnings per sh A	**2.80**
.82	.83	.84	.85	.86	.87	.87	.88	.89	.90	.91	.96	1.00	1.01	1.04	1.10	**1.27**	**1.44**	Div'd Decl'd per sh B■	**1.60**
2.40	2.58	3.11	4.30	3.03	3.18	2.68	3.76	5.03	4.24	3.91	2.89	4.45	4.18	4.24	4.26	**4.20**	**4.40**	Cap'l Spending per sh	**5.10**
11.01	11.24	11.48	11.82	12.74	13.22	14.05	13.97	15.01	15.72	16.64	17.53	17.95	19.39	20.26	21.68	**22.80**	**23.15**	Book Value per sh	**23.80**
13.33	13.44	13.44	13.44	15.12	15.12	15.18	15.21	16.75	16.80	17.05	17.23	17.30	18.53	18.63	18.85	**19.00**	**19.20**	Common Shs Outst'g C	**19.60**
12.6	14.5	15.5	17.1	15.9	16.7	18.3	31.9	23.2	21.9	27.7	24.0	22.6	21.2	15.7	15.7	*Bold figures are*		Avg Ann'l P/E Ratio	**19.0**
.79	.84	.81	.97	1.03	.86	1.00	1.82	1.23	1.17	1.50	1.27	1.36	1.41	1.00	1.01	*Value Line*		Relative P/E Ratio	**1.25**
5.8%	5.5%	5.0%	4.2%	4.2%	3.9%	3.6%	3.5%	3.6%	3.1%	2.5%	2.5%	2.9%	2.9%	3.0%	3.0%	*estimates*		Avg Ann'l Div'd Yield	**2.6%**

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
209.2	212.7	228.0	236.2	268.6	301.4	318.7	361.0	398.9	419.3	**445**	**460**	Revenues ($mill)	**545**
20.3	11.9	16.5	22.5	23.1	28.0	26.8	29.5	41.4	42.0	**45.0**	**48.0**	Net Profit ($mill)	**55.0**
38.9%	43.5%	37.4%	47.0%	40.5%	42.6%	37.8%	38.9%	43.2%	41.7%	**42.5%**	**42.0%**	Income Tax Rate	**40.0%**
--	--	--	--	12.2%	8.5%	6.9%	3.2%	5.8%	5.8%	**5.0%**	**5.0%**	AFUDC % to Net Profit	**5.0%**
52.0%	52.0%	47.7%	50.4%	48.6%	46.9%	46.2%	45.9%	44.3%	45.4%	**43.0%**	**43.0%**	Long-Term Debt Ratio	**42.0%**
48.0%	48.0%	52.3%	49.6%	51.4%	53.1%	53.8%	54.1%	55.7%	54.6%	**57.0%**	**57.0%**	Common Equity Ratio	**58.0%**
444.4	442.3	480.4	532.5	551.6	569.4	577.0	665.0	677.4	749.1	**760**	**780**	Total Capital ($mill)	**805**
563.3	602.3	664.2	713.2	750.6	776.4	825.3	866.4	855.0	896.5	**935**	**980**	Net Plant ($mill)	**1080**
6.5%	4.6%	5.2%	5.4%	6.0%	6.7%	6.4%	5.9%	7.6%	6.0%	**6.0%**	**6.0%**	Return on Total Cap'l	**7.0%**
9.5%	5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	**10.5%**	**11.0%**	Return on Shr. Equity	**12.0%**
9.5%	5.6%	6.6%	8.5%	8.1%	9.3%	8.6%	8.2%	11.0%	10.3%	**10.5%**	**11.0%**	Return on Com Equity	**12.0%**
3.3%	NMF	1.0%	2.8%	2.7%	3.9%	3.1%	3.2%	5.8%	5.2%	**5.0%**	**5.0%**	Retained to Com Eq	**5.0%**
65%	113%	84%	67%	67%	58%	64%	61%	47%	49%	**56%**	**58%**	All Div'ds to Net Prof	**57%**

CAPITAL STRUCTURE as of 6/30/12
Total Debt $341.7 mill. **Due in 5 Yrs** $280.0 mill.
LT Debt $341.5 mill. **LT Interest** $24.0 mill.
(LT interest earned: 5.5x: total interest coverage: 5.2x) (44% of Cap'l)

Leases, Uncapitalized: Annual rentals $3.3 mill.

Pension Assets-12/11 $92.9 mill.
Oblig. $146.1 mill.

Pfd Stock None.

Common Stock 18,923,668 shs.
as of 8/3/12
MARKET CAP: $825 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	4.2	1.3	25.9
Other	200.8	164.3	150.0
Current Assets	205.0	165.6	175.9
Accts Payable	36.2	37.9	39.1
Debt Due	61.3	.3	.2
Other	81.3	66.2	60.3
Current Liab.	178.8	104.4	99.6
Fix. Chg. Cov.	428%	401%	390%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	5.0%	7.5%	*4.5%*
"Cash Flow"	5.5%	9.5%	*4.5%*
Earnings	4.5%	11.5%	*5.5%*
Dividends	2.0%	2.5%	*7.5%*
Book Value	5.0%	5.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	79.6	93.6	101.5	86.3	361.0
2010	88.4	95.5	111.3	103.7	398.9
2011	94.3	109.8	119.9	95.3	419.3
2012	106.6	114.3	**124**	**100.1**	**445**
2013	**105**	**116**	**131**	**108**	**460**

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.28	.64	.52	.18	1.62
2010	.45	.47	.62	.68	2.22
2011	.37	.68	.83	.36	2.24
2012	.53	.79	**.80**	**.33**	**2.45**
2013	**.50**	**.75**	**.85**	**.40**	**2.50**

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.250	.250	.250	.250	1.00
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		

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 703 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 momentum will likely carry into the back half of the year. Indeed, share earnings in the first half of 2012 increased 17%, driven by the Golden State Water unit and an increase in Contracted Services activity. Construction activity and favorable changes in cost estimates at the Fort Bragg military base also contributed to the improved results. Going forward, we expect the company to remain focused on expanding the Contracted Services business, as it provides more favorable growth prospects compared to its Water and Electric businesses. In fact, we believe AWR's 50-year contract with Fort Bragg through its American States Utility Services subsidiary could provide a nice opportunity. We expect this longer-term relationship with the U.S. government to bolster the company's chances in booking more water and electric projects on other military bases.

Recent rate cases will provide some clarity for the coming years. In June, the Golden State Water case (which deals with general rates in 2013-2015) reached a proposed settlement between Golden State Water Company and two consumer advocacy groups. The agreement pends the approval of California Public Utilities Commission (CPUC) and nearly resolves all issues in the case. The decision would generate close to $9 million in additional annual revenue starting in 2013, compared to 2012 adopted revenues. Proposed rates are set to increase $8.0 million and $6.0 million in 2014 and 2015, respectively.

The ASUS operations have helped boost the quarterly dividend. The dividend has been increased to $0.36 from $0.28 due to ASUS' board of directors approval to help fund a portion of AWR's upcoming dividend. We anticipate that the subsidiary will continue to partially fund the company's dividend.

The Timeliness rank of this issue is 3 (Average). Income investors might find the stock of interest, as the dividend yield offers above-average return when compared to the *Value Line* median. However, we advise longer-term investors to look elsewhere, due to the below-average capital appreciation potential.

Michael Collins *October 19, 2012*

(A) Primary earnings. Excludes nonrecurring gains/(losses): '04, 14¢; '05, 25¢; '06, 6¢; '08, (27¢); '10, (45¢) '11, 20¢. Next earnings report due early November. 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

CALIFORNIA WATER NYSE-CWT

RECENT PRICE	18.57	P/E RATIO	19.1 (Trailing: 21.1 / Median: 21.0)	RELATIVE P/E RATIO	1.26	DIV'D YLD	3.4%	VALUE LINE

TIMELINESS 3 Raised 8/3/12

SAFETY 3 Lowered 7/27/07

TECHNICAL 2 Raised 10/19/12

BETA .65 (1.00 = Market)

High:	14.3	13.4	15.7	19.0	21.1	22.9	22.7	23.3	24.1	19.8	19.4	19.3	
Low:	11.4	10.2	11.8	13.0	15.6	16.4	17.1	13.8	16.7	16.9	16.7	17.1	

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

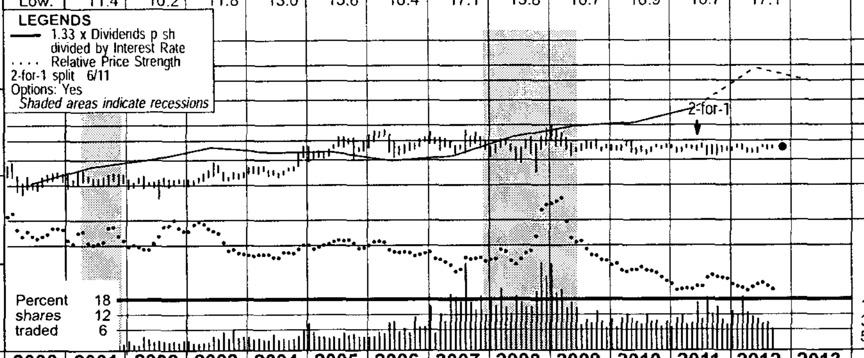
	Price	Gain	Ann'l Total Return
High	30	(+60%)	15%
Low	20	(+10%)	5%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	19	0	2	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	1	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	52	60	54
to Sell	58	55	53
Hld's(000)	20424	22431	21505



% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.0	28.2
3 yr.	5.9	42.3
5 yr.	14.0	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
7.24	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	*12.65*	*13.05*	Revenues per sh	*14.20*
1.25	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	*2.35*	*2.45*	"Cash Flow" per sh	*2.65*
.75	.92	.73	.77	.66	.47	.63	.61	.73	.74	.67	.75	.95	.98	.91	.86	*.95*	*1.05*	Earnings per sh A	*1.30*
.52	.53	.54	.54	.55	.56	.56	.56	.57	.57	.58	.58	.59	.59	.60	.62	*.63*	*.65*	Div'd Decl'd per sh B ■	*.72*
1.41	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	*2.90*	*2.85*	Cap'l Spending per sh	*3.05*
6.11	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	*11.05*	*11.25*	Book Value per sh C	*12.75*
25.24	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	*43.00*	*44.00*	Common Shs Outst'g D	*47.00*
11.9	12.6	17.8	17.8	19.6	27.1	19.8	22.1	20.1	24.9	29.2	26.1	19.8	19.7	20.3	21.3	*Bold figures are*		Avg Ann'l P/E Ratio	*19.0*
.75	.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	*Value Line*		Relative P/E Ratio	*1.25*
5.8%	4.6%	4.2%	4.0%	4.3%	4.4%	4.5%	4.2%	3.9%	3.1%	2.9%	3.0%	3.1%	3.1%	3.2%	3.4%	*estimates*		Avg Ann'l Div'd Yield	*2.9%*
						263.2	277.1	315.6	320.7	334.7	367.1	410.3	449.4	460.4	501.8	*545*	*575*	Revenues ($mill) E	*675*
						19.1	19.4	26.0	27.2	25.6	31.2	39.8	40.6	37.7	36.1	*40.0*	*45.0*	Net Profit ($mill)	*62.0*
						39.7%	39.9%	39.6%	42.4%	37.4%	39.9%	37.7%	40.3%	39.5%	40.5%	*41.0%*	*40.5%*	Income Tax Rate	*40.0%*
						--	10.3%	3.2%	3.3%	10.6%	8.3%	8.6%	7.6%	4.2%	5.0%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*10.0%*
						55.3%	50.2%	48.6%	48.3%	43.5%	42.9%	41.6%	47.1%	52.4%	51.7%	*51.0%*	*51.5%*	Long-Term Debt Ratio	*50.0%*
						44.0%	49.1%	50.8%	51.1%	55.9%	56.6%	58.4%	52.9%	47.6%	48.3%	*49.0%*	*48.5%*	Common Equity Ratio	*50.0%*
						453.1	498.4	565.9	568.1	670.1	674.9	690.4	794.9	914.7	931.5	*970*	*1025*	Total Capital ($mill)	*1200*
						697.0	759.5	800.3	862.7	941.5	1010.2	1112.4	1198.1	1294.3	1381.1	*1445*	*1505*	Net Plant ($mill)	*1725*
						5.9%	5.6%	6.1%	6.3%	5.2%	5.9%	7.1%	6.5%	5.5%	5.5%	*5.5%*	*6.0%*	Return on Total Cap'l	*7.0%*
						9.4%	7.8%	8.9%	9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	*8.5%*	*9.0%*	Return on Shr. Equity	*10.5%*
						9.5%	7.9%	9.0%	9.3%	6.8%	8.1%	9.9%	9.6%	8.6%	8.0%	*8.5%*	*9.0%*	Return on Com Equity	*10.5%*
						1.0%	.7%	2.1%	2.1%	1.0%	1.8%	3.8%	3.8%	3.0%	2.3%	*3.0%*	*3.5%*	Retained to Com Eq	*4.5%*
						90%	91%	77%	78%	86%	77%	61%	60%	66%	71%	*67%*	*63%*	All Div'ds to Net Prof	*55%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $574.5 mill. Due in 5 Yrs $85.7 mill.
LT Debt $480.0 mill. LT Interest $30.0 mill.
(LT interest earned: 3.8x; total int. cov.: 3.7x)
(49% of Cap'l)
Pension Assets-12/11 $155.7 mill.
Oblig. $346.3 mill.
Pfd Stock None

Common Stock 41,915,454 shs.
as of 7/30/12

MARKET CAP: $775 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	42.3	27.2	20.8
Other	83.9	86.7	114.1
Current Assets	126.2	113.9	134.9
Accts Payable	39.5	48.9	54.6
Debt Due	26.1	53.7	94.5
Other	41.7	49.3	61.6
Current Liab.	107.3	151.9	210.7
Fix. Chg. Cov.	304%	278%	285%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.5%	6.0%	*4.0%*
"Cash Flow"	4.5%	6.5%	*5.0%*
Earnings	4.0%	5.0%	*6.0%*
Dividends	1.0%	1.0%	*3.0%*
Book Value	5.0%	5.0%	*3.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.)E Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	86.6	116.7	139.2	106.9	449.4
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	*175*	*109.7*	*545*
2013	*120*	*150*	*185*	*120*	*575*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.06	.29	.47	.16	.98
2010	.05	.25	.49	.12	.91
2011	.03	.29	.50	.04	.86
2012	.03	.31	*.53*	*.08*	*.95*
2013	*.05*	*.32*	*.55*	*.13*	*1.05*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.147	.147	.147	.147	.59
2009	.148	.148	.148	.148	.59
2010	.149	.149	.149	.149	.60
2011	.154	.154	.154	.154	.62
2012	.1575	.1575	.1575	.1575	

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, '11: residential, 73%; business, 18%; public authorities, 5%; industrial, 4%. '11 reported depreciation rate: 2.7%. Has roughly 1,132 employees. President, Chairman, and CEO: Peter C. Nelson (4/11 Proxy). Inc.: Delaware. Address: 1720 North First Street, San Jose, California 95112-4598. Telephone: 408-367-8200. Internet: www.calwatergroup.com.

California Water Service Group continues to benefit from favorable regulatory backing. Indeed, the water utility bested second-quarter results, as earnings increased 7%, on a 9% revenue climb. Although operating expenses continued to mount, general rate case increases helped offset the margin pressures.

Higher operating costs are likely to surface in the second half of the year, however. Although recent improvements on the regulatory front will remain a boon, and the company is likely to receive additional relief in the years to come, we believe that expenses will tick higher. Maintenance costs dipped slightly lower in the June period, a trend that we find hard to believe will continue, given the age of many of the company's pipes and water systems. Note that last year's weak fourth-quarter results will make growth seem healthy at first blush, but deeper analysis reveals historical softness.

Infrastructure costs are likely to remain a problem further out, too. The need for water systems upgrades and/or complete renovation is expected to continue increasing as time goes on and units grow older. Unfortunately, the company does not have the finances to foot the bill. Cash on hand is minimal, and expected cash flow will be nowhere near sufficient enough to cover the costs, even with an improved regulatory backdrop. Absent an unforeseen event, CWT will have to seek outside financing in order to keep the doors open. Indeed, the added interest expense and increased share count associated with such maneuverings will undoubtedly diminish returns.

Most investors will want to take a pass on this issue. The capital-intensive nature of this industry erases much of the growth potential, whether it be over the coming six to 12 months or the next 3 to 5 ears, regardless of the top-line prospects brought forward by a more favorable regulatory board or additional traction with military bases. The dividend yield is solid, but there are better income-producing options to be had elsewhere. Also, though highly unlikely, the current yield could be compromised if industry fundamentals turn sour for a prolonged period or there is a bureaucratic change.

Andre J. Costanza *October 19, 2012*

(A) Basic EPS. Excl. nonrecurring gain (loss): '00, (4¢); '01, 2¢; '02, 4¢; '11, 4¢. Next earnings report due early Nov.

(B) Dividends historically paid in late Feb., May, Aug., and Nov. ■ Div'd reinvestment plan available.

(C) Incl. deferred charges. In '11: $2.2 mill., $0.05/sh.
(D) In millions, adjusted for splits.
(E) Excludes non-reg. rev.

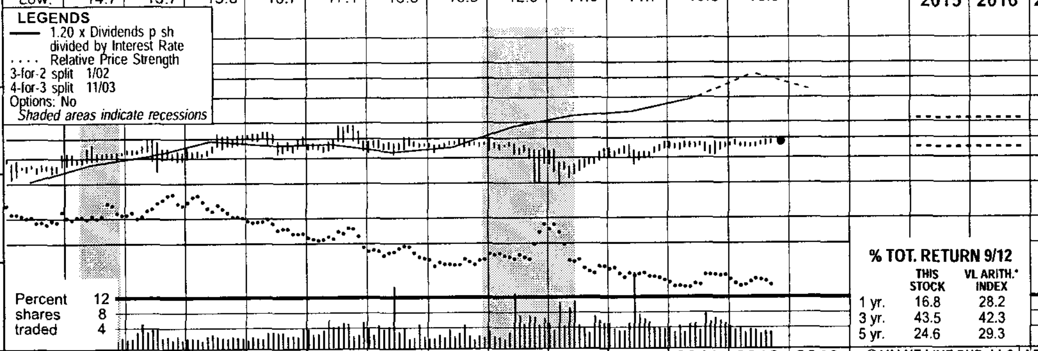
Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	55
Earnings Predictability	90

MIDDLESEX WATER NDQ-MSEX

RECENT PRICE 19.24 | P/E RATIO 20.5 (Trailing: 24.7 / Median: 22.0) | RELATIVE P/E RATIO 1.35 | DIV'D YLD 3.8% | VALUE LINE

TIMELINESS 3 Raised 8/31/12
SAFETY 2 New 10/21/11
TECHNICAL 3 Raised 6/29/12
BETA .70 (1.00 = Market)

High:	18.7	20.0	21.2	21.8	23.5	20.5	20.2	19.8	17.9	19.3	19.4	19.6
Low:	14.7	13.7	15.8	16.7	17.1	16.5	16.9	12.0	11.6	14.7	16.5	18.0



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	25	(+30%)	10%
Low	18	(-5%)	3%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	1	1
Options	0	0	0	0	0	0	0	0	0
to Sell	1	1	0	0	1	0	1	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	33	29	32
to Sell	27	31	30
Hld's(000)	6476	6511	6653

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.8	28.2
3 yr.	43.5	42.3
5 yr.	24.6	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
4.52	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	6.55	7.10	Revenues per sh	8.40
.94	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	1.52	1.50	1.75	"Cash Flow" per sh	2.20
.60	.67	.71	.76	.51	.66	.73	.61	.73	.71	.82	.87	.89	.72	.96	.84	.85	1.00	Earnings per sh A	1.25
.55	.57	.58	.60	.61	.62	.63	.65	.66	.67	.68	.69	.70	.71	.72	.73	.74	.75	Div'd Decl'd per sh B■	.80
.73	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	1.90	2.15	Cap'l Spending per sh	2.60
5.85	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	11.80	12.55	Book Value per sh	13.60
8.41	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	16.00	16.25	Common Shs Outst'g C	17.25
14.4	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	21.9	Bold figures are		Avg Ann'l P/E Ratio	17.0
.90	.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	1.32	Value Line		Relative P/E Ratio	1.15
6.4%	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%	4.2%	estimates		Avg Ann'l Div'd Yield	3.8%
						61.9	64.1	71.0	74.6	81.1	86.1	91.0	91.2	102.7	102.0	105	115	Revenues ($mill)	145
						7.8	6.6	8.4	8.5	10.0	11.8	12.2	10.0	14.3	13.5	14.0	16.0	Net Profit ($mill)	21.5
						33.3%	32.8%	31.1%	27.6%	33.4%	32.6%	33.2%	34.1%	32.1%	32.5%	32.0%	32.0%	Income Tax Rate	32.0%
						--	--	--	--	--	--	--	--	6.8%	7.5%	7.5%	7.5%	AFUDC % to Net Profit	7.0%
						52.1%	53.8%	53.8%	55.3%	49.5%	49.0%	45.6%	46.6%	43.1%	43.0%	42.0%	41.0%	Long-Term Debt Ratio	39.0%
						45.5%	44.0%	42.5%	41.3%	47.5%	49.6%	51.8%	52.1%	55.8%	57.0%	58.0%	59.0%	Common Equity Ratio	61.0%
						168.0	181.1	214.5	231.7	264.0	268.8	259.4	267.9	310.5	309.1	325	345	Total Capital ($mill)	385
						211.4	230.9	262.9	288.0	317.1	333.9	366.3	376.5	405.9	422.2	440	455	Net Plant ($mill)	500
						6.0%	5.0%	5.1%	5.0%	5.1%	5.6%	5.8%	5.0%	5.7%	5.3%	4.5%	4.5%	Return on Total Cap'l	5.5%
						9.6%	7.9%	8.5%	8.2%	7.5%	8.6%	8.6%	7.0%	8.1%	7.5%	7.5%	8.0%	Return on Shr. Equity	9.0%
						9.8%	8.0%	9.0%	8.6%	7.8%	8.7%	8.9%	7.0%	8.2%	7.6%	7.5%	8.0%	Return on Com Equity	9.0%
						1.3%	NMF	.9%	.6%	1.3%	1.8%	2.0%	.1%	2.1%	1.1%	1.0%	2.0%	Retained to Com Eq	3.0%
						87%	106%	90%	94%	84%	79%	78%	98%	75%	85%	85%	76%	All Div'ds to Net Prof	64%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $140.1 mill. **Due in 5 Yrs** $25.0 mill.
LT Debt $135.1 mill. **LT Interest** $6.0 mill.
(LT interest coverage: 4.5x)
(43% of Cap'l)

Pension Assets-12/11 $32.2 mill.
Oblig. $56.2 mill.
Pfd Stock $3.4 mill. **Pfd Div'd:** $.2 mill.

Common Stock 15,733,286 shs.
as of 7/31/12

MARKET CAP: $300 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	2.5	3.1	2.7
Other	20.3	19.8	20.7
Current Assets	22.8	22.9	23.4
Accts Payable	6.4	5.7	4.8
Debt Due	4.4	4.6	5.0
Other	29.9	36.4	38.7
Current Liab.	40.7	46.7	48.5
Fix. Chg. Cov.	400%	380%	300%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.0%	1.5%	4.0%
"Cash Flow"	3.5%	3.5%	7.0%
Earnings	2.5%	4.5%	7.0%
Dividends	2.0%	1.5%	1.5%
Book Value	4.5%	5.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	20.6	23.1	25.5	22.0	91.2
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	30.0	24.1	105
2013	28.0	28.0	32.0	27.0	115

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.10	.21	.29	.12	.72
2010	.11	.31	.37	.17	.96
2011	.17	.23	.32	.12	.84
2012	.11	.23	.33	.18	.85
2013	.20	.25	.35	.20	1.00

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.175	.175	.175	.178	.70
2009	.178	.178	.178	.180	.71
2010	.180	.180	.180	.183	.72
2011	.183	.183	.183	.185	.73
2012	.185	.185	.185		

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 2011, the Middlesex System accounted for 64% of total revenues. At 12/31/11, the company had 289 employees. Incorporated: NJ. President, CEO, and Chairman: Dennis W. Doll. Officers/directors own 3.39% of the common stock; BlackRock, 6.2%; The Vanguard Group, 5.4% (4/12 proxy). Address: 1500 Ronson Road, Iselin, NJ 08830. Tel.: 732-634-1500. Internet: www.middlesexwater.com.

Middlesex Water underperformed in the first half of the year. In fact, share earnings fell 15% compared to the same time frame last year. The bottom-line decline was attributable to higher costs related to employee benefits and continued softness in its New Jersey market. A number of its largest commercial and industrial customers decreased consumption due to reduced output from their production processes. This market could remain challenged in the near term, as New Jersey has an above-average unemployment rate and an anemic housing market that could hinder growth opportunities for the state in the coming years.

Rate increases should help stem rising costs. Over the summer, the company's Tidewater business in Delaware was approved for a $3.9 million increase in its base water rates. Additionally, the New Jersey Board of Public Utilities approved an $8.1 million increase for its New Jersey customers in its Middlesex System. (The company had requested a rate increase of $11.3 million per year.) Tidewater Environmental Services (TESI) also received a partial rate increase for its wastewater services business.

Capital investment will likely help longer-term growth. The company has invested half of the $22 million it has projected on storage tanks, water mains, and service lines. Additionally, capex outlays are expected to exceed $34 million over the next two years. The vast majority of these investments are targeted toward its Distribution systems. We believe the focus on water distribution infrastructure is crucial to help offset the weakening demand on the company's commercial and industrial customers. The residential market in New Jersey will probably continue to struggle, as an elevated unemployment rate and a slumping housing market hurt consumer demand.

The issue has a Timeliness rank of 3 (Average) and holds an above-average Safety rank. The income-minded investor may find these shares appealing, as the dividend yield is above the *Value Line* median. However, the stock's below-average 3- to 5-year capital appreciation potential is less than ideal for the longer-term investor at this time.

Michael Collins *October 19, 2012*

(A) Diluted earnings. Next earnings report due late October.
(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 2011: $8.2 million, $0.55 a share.

Company's Financial Strength	B+
Stock's Price Stability	95
Price Growth Persistence	35
Earnings Predictability	85

SJW CORP. NYSE-SJW

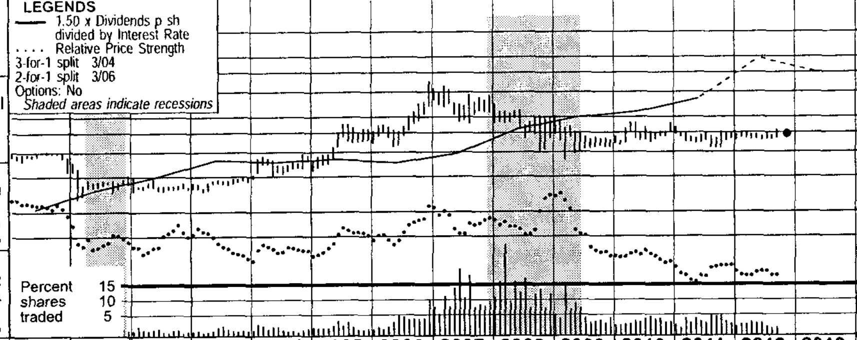
RECENT PRICE **24.55** | P/E RATIO **23.4** (Trailing: 21.7 / Median: 23.0) | RELATIVE P/E RATIO **1.54** | DIV'D YLD **2.9%** | VALUE LINE

TIMELINESS	3	Raised 8/12/11
SAFETY	3	New 4/22/11
TECHNICAL	3	Lowered 9/21/12

BETA .85 (1.00 = Market)

High:	17.8	15.1	15.0	19.6	27.8	45.3	43.0	35.1	30.4	28.2	26.8	25.8
Low:	11.6	12.7	12.6	14.6	16.1	21.2	27.7	20.0	18.2	21.6	20.9	22.7

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



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+65%)	15%
Low	30	(+20%)	7%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	1	1	0	0	0	0	0	1	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	24	34	34
to Sell	32	22	31
Hld's(000)	8847	9012	8955

Percent shares traded 15 10 5

Target Price Range 2015 | 2016 | 2017

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	20.0	28.2
3 yr.	21.1	42.3
5 yr.	-14.8	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
5.39	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	12.86	*12.50*	*12.60*	Revenues per sh	*13.70*
1.43	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	*2.85*	*2.90*	"Cash Flow" per sh	*3.05*
.96	.80	.76	.87	.58	.77	.78	.91	.87	1.12	1.19	1.04	1.08	.81	.84	1.11	*1.05*	*1.15*	Earnings per sh A	*1.35*
.37	.38	.39	.40	.41	.43	.46	.49	.51	.53	.57	.61	.65	.66	.68	.69	*.71*	*.73*	Div'd Decl'd per sh B■	*.80*
1.06	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	*4.10*	*4.75*	Cap'l Spending per sh	*3.70*
6.31	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	*15.30*	*15.70*	Book Value per sh	*17.15*
19.02	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	*20.00*	*21.00*	Common Shs Outst'g C	*23.00*
6.8	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	*Bold figures are*		Avg Ann'l P/E Ratio	*25.5*
.43	.65	.68	.88	2.15	.95	.94	.88	1.04	1.05	1.27	1.77	1.58	1.91	1.85	1.34	*Value Line*		Relative P/E Ratio	*1.70*
5.7%	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%	*estimates*		Avg Ann'l Div'd Yield	*2.3%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $344.2 mill. Due in 5 Yrs $8.3 mill.
LT Debt $335.9 mill. LT Interest $18.6 mill.
(Total interest coverage: 2.9x) (56% of Cap'l)

Leases, Uncapitalized: Annual rentals $4.5 mill.

Pension Assets-12/11 $62.8 mill. Oblig. $123.9 mill.

Pfd Stock None.

Common Stock 18,636,796 shs. as of 7/20/12

MARKET CAP: $450 million (Small Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
145.7	149.7	166.9	180.1	189.2	206.6	220.3	216.1	215.6	239.0	*255*	*275*	Revenues ($mill)	*315*
14.2	16.7	16.0	20.7	22.2	19.3	20.2	15.2	15.8	20.9	*21.0*	*24.0*	Net Profit ($mill)	*31.0*
40.4%	36.2%	42.1%	41.6%	40.8%	39.4%	39.5%	40.4%	38.8%	41.1%	*41.0%*	*41.0%*	Income Tax Rate	*40.0%*
4.2%	1.6%	2.1%	1.6%	2.1%	2.7%	2.3%	2.0%	2.0%	3.0%	*5.0%*	*5.0%*	AFUDC % to Net Profit	*5.0%*
41.7%	45.6%	43.7%	42.6%	41.8%	47.7%	46.0%	49.4%	53.7%	56.6%	*53.0%*	*53.0%*	Long-Term Debt Ratio	*52.0%*
58.3%	54.4%	56.3%	57.4%	58.2%	52.3%	54.0%	50.6%	46.3%	43.4%	*47.0%*	*47.0%*	Common Equity Ratio	*48.0%*
263.5	306.0	328.3	341.2	391.8	453.2	470.9	499.6	550.7	607.8	*650*	*705*	Total Capital ($mill)	*825*
390.8	428.5	456.8	484.8	541.7	645.5	684.2	718.5	785.5	756.2	*810*	*875*	Net Plant ($mill)	*1050*
6.9%	6.9%	6.5%	7.6%	7.0%	5.7%	5.8%	4.4%	4.3%	5.0%	*5.0%*	*5.0%*	Return on Total Cap'l	*5.0%*
9.3%	10.0%	8.7%	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	*7.0%*	*7.5%*	Return on Shr. Equity	*7.0%*
9.3%	10.0%	8.7%	10.6%	9.7%	8.2%	8.0%	6.0%	6.2%	7.9%	*7.0%*	*7.5%*	Return on Com Equity	*7.0%*
3.8%	4.7%	3.6%	5.6%	5.2%	3.5%	3.3%	1.2%	1.2%	3.1%	*2.0%*	*2.5%*	Retained to Com Eq	*3.0%*
59%	53%	58%	47%	46%	57%	59%	80%	80%	61%	*68%*	*64%*	All Div'ds to Net Prof	*59%*

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	1.7	26.7	9.3
Other	36.3	42.2	49.0
Current Assets	38.0	68.9	58.3
Accts Payable	5.5	7.4	14.3
Debt Due	5.1	.8	8.3
Other	18.6	20.1	23.3
Current Liab.	29.2	28.3	45.9
Fix. Chg. Cov.	262%	276%	250%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	4.5%	2.0%
"Cash Flow"	6.0%	2.5%	3.5%
Earnings	2.0%	-3.0%	6.5%
Dividends	5.0%	5.0%	3.0%
Book Value	5.5%	4.5%	3.5%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	40.0	58.2	69.3	48.6	216.1
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	*75.0*	*63.2*	*255*
2013	*55.0*	*70.0*	*82.0*	*68.0*	*275*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.01	.23	.43	.14	.81
2010	.05	.24	.44	.11	.84
2011	.03	.29	.44	.35	1.11
2012	.06	.28	*.45*	*.26*	*1.05*
2013	*.06*	*.33*	*.48*	*.28*	*1.15*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.16	.16	.16	.16	.64
2009	.165	.165	.165	.165	.66
2010	.17	.17	.17	.17	.68
2011	.173	.173	.173	.173	.69
2012	.1775	.1775	.1775		

BUSINESS: SJW Corporation engages in the production, purchase, storage, purification, distribution, and retail sale of water. It provides water service to approximately 226,000 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 375 employees. Chairman: Charles J. Toeniskoetter. Inc.: CA. Address: 110 W. Taylor Street, San Jose, CA 95110. Tel.: (408) 279-7800. Int:www.sjwater.com.

Rising costs of doing business weighed on SJW's earnings in the second quarter. Cumulative rate increases helped the water utility post an 11% sales increase, but 23% higher water production costs, due to a reduced supply and higher purchase and extraction prices, caused earnings to dip 4%. Higher administrative and interest expenses also took a toll.

We suspect that the earnings environment will remain difficult in the months ahead. There is no evidence that operating costs will subside anytime soon. In fact, maintenance expenses are likely to remain on an upswing, as water systems continue to age and systems require further repairs. Meanwhile, the company is expected to receive little, if any, help on the regulatory front in the upcoming months, as there are no rate case decisions likely to be handed down until yearend. That said, a favorable ruling on the 2013-2015 general rate case ought to provide moderate earnings upside next year.

Our longer-term expectations remain muted because of the likelihood of growing capital requirements. Infrastructure improvements are expected to cost hundreds of millions of dollars over the next few years. However, SJW's cash reserves are running on empty, and cash flow from operations is slated to fall well short of the amount needed to implement the necessary changes. The company will have to issue more stock and/or debt to make the changes, but such financial actions will dilute gains for the foreseeable future. As a result, we look for annual earnings gains to remain in the mid single digit range over the next 3- to 5-years.

We are not proponents of this stock at this time. It lacks growth appeal due to the capital-intensive nature of the industry and the company's aforementioned financial limitations regardless of whether or not regulatory backing improves in 2013. The dividend is solid and adds a nice touch, but those seeking an income producer have far better options to choose from elsewhere. Plus, we still contend that there remains the possibility that the company would have to revise the payout if operating conditions worsen and regulatory authorities decide to take on a more consumer-friendly stance.

Andre J. Costanza *October 19, 2012*

(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 October. 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	85

AQUA AMERICA NYSE-WTR

RECENT PRICE	24.79	P/E RATIO	23.2 (Trailing: 23.6 / Median: 25.0)	RELATIVE P/E RATIO	1.53	DIV'D YLD	2.7%	VALUE LINE

TIMELINESS 2 Raised 10/5/12
SAFETY 2 Raised 4/20/12
TECHNICAL 3 Lowered 9/14/12
BETA .60 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	14.8	15.0	16.8	18.5	29.2	29.8	26.6	22.0	21.5	23.0	23.8	26.9
Low:	9.4	9.6	11.8	14.2	17.5	20.1	18.9	12.2	15.4	16.5	19.3	21.1

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

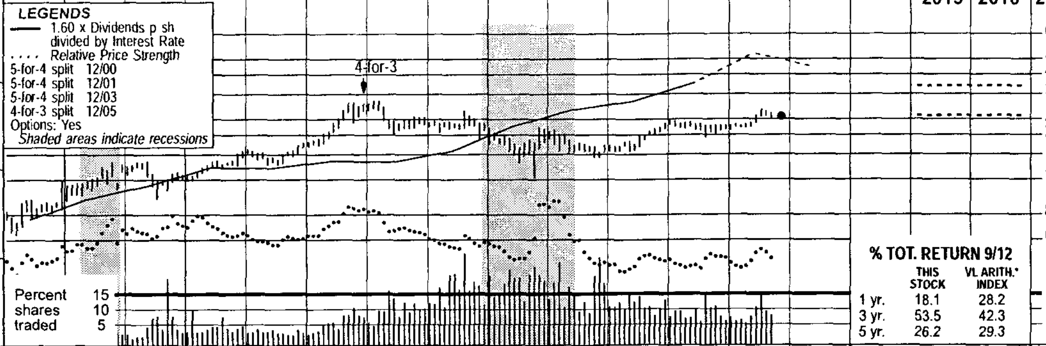
	Price	Gain	Ann'l Total Return
High	35	(+40%)	11%
Low	25	(Nil)	3%

Insider Decisions

	N	D	J	F	M	A	M	J	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	0	0	0	0	1	2	0	1
to Sell	0	0	0	0	0	0	3	1	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	119	114	112
to Sell	92	104	108
Hld's(000)	55535	57767	60392



% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	18.1	28.2
3 yr.	53.5	42.3
5 yr.	26.2	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
1.86	2.02	2.09	2.41	2.46	2.70	2.85	2.97	3.48	3.85	4.03	4.52	4.63	4.91	5.26	5.13	5.55	5.80	Revenues per sh	6.60
.50	.56	.61	.72	.76	.86	.94	.96	1.09	1.21	1.26	1.37	1.42	1.61	1.78	1.84	1.90	2.05	"Cash Flow" per sh	2.30
.30	.34	.40	.42	.47	.51	.54	.57	.64	.71	.70	.71	.73	.77	.90	1.03	1.05	1.15	Earnings per sh A	1.35
.23	.24	.26	.27	.28	.30	.32	.35	.37	.40	.44	.48	.51	.55	.59	.62	.66	.71	Div'd Decl'd per sh B■	.80
.48	.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	2.40	2.50	Cap'l Spending per sh	2.55
2.69	2.84	3.21	3.42	3.85	4.15	4.36	5.34	5.89	6.30	6.96	7.32	7.82	8.12	8.51	9.01	9.25	9.75	Book Value per sh	10.85
65.75	67.47	72.20	106.80	111.82	113.97	113.19	123.45	127.18	128.97	132.33	133.40	135.37	136.49	137.97	138.87	140.90	141.90	Common Shs Outst'g C	143.90
15.6	17.8	22.5	21.2	18.2	23.6	23.6	24.5	25.1	31.8	34.7	32.0	24.9	23.1	21.1	21.1	Bold figures are		Avg Ann'l P/E Ratio	21.0
.98	1.03	1.17	1.21	1.18	1.21	1.29	1.40	1.33	1.69	1.87	1.70	1.50	1.54	1.34	1.36	Value Line		Relative P/E Ratio	1.40
4.9%	3.9%	2.9%	3.0%	3.3%	2.5%	2.5%	2.5%	2.3%	1.8%	1.8%	2.1%	2.8%	3.1%	3.1%	3.1%	estimates		Avg Ann'l Div'd Yield	2.7%
						322.0	367.2	442.0	496.8	533.5	602.5	627.0	670.5	726.1	712.0	780	825	Revenues ($mill)	950
						62.7	67.3	80.0	91.2	92.0	95.0	97.9	104.4	124.0	143.1	145	160	Net Profit ($mill)	195
						38.5%	39.3%	39.4%	38.4%	39.6%	38.9%	39.7%	39.4%	39.2%	32.9%	40.0%	40.0%	Income Tax Rate	40.0%
						--	--	--	--	--	--	--	--	2.9%	3.1%	3.0%	3.0%	AFUDC % to Net Profit	2.0%
						54.2%	51.4%	50.0%	52.0%	51.6%	55.4%	54.1%	55.6%	56.6%	53.0%	52.0%	50.0%	Long-Term Debt Ratio	46.0%
						45.8%	48.6%	50.0%	48.0%	48.4%	44.6%	45.9%	44.4%	43.4%	47.0%	48.0%	50.0%	Common Equity Ratio	54.0%
						1076.2	1355.7	1497.3	1690.4	1904.4	2191.4	2306.6	2495.5	2706.2	2647.3	2715	2760	Total Capital ($mill)	2885
						1490.8	1824.3	2069.8	2280.0	2506.0	2792.8	2997.4	3227.3	3469.3	3612.9	3785	3960	Net Plant ($mill)	4320
						7.6%	6.4%	6.7%	6.9%	6.4%	5.9%	5.7%	5.6%	5.9%	6.8%	5.5%	6.0%	Return on Total Cap'l	4.5%
						12.7%	10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.4%	11.0%	11.5%	Return on Shr. Equity	12.5%
						12.7%	10.2%	10.7%	11.2%	10.0%	9.7%	9.3%	9.4%	10.6%	11.4%	11.0%	11.5%	Return on Com Equity	12.5%
						5.2%	4.2%	4.6%	4.9%	3.7%	3.2%	2.8%	2.7%	3.7%	4.6%	4.0%	4.5%	Retained to Com Eq	5.0%
						59%	59%	57%	56%	63%	67%	70%	72%	65%	60%	65%	63%	All Div'ds to Net Prof	59%

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1613.8 mill. **Due in 5 Yrs** $300 mill.
LT Debt $1569.5 mill. **LT Interest** $65.0 mill.
(LT interest earned: 4.5x; total interest coverage: 4.5x) (53% of Cap'l)

Pension Assets-12/11 $148.9 mill. **Oblig.** $237.1 mill.

Pfd Stock None
Common Stock 139,733,913 shares as of 7/20/12
MARKET CAP: $3.5 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	5.9	8.2	5.1
Receivables	85.9	81.1	99.0
Inventory (AvgCst)	9.2	11.2	11.7
Other	44.4	220.0	31.4
Current Assets	145.4	320.5	147.2
Accts Payable	45.3	68.3	42.0
Debt Due	28.5	80.4	44.3
Other	149.9	277.0	126.0
Current Liab.	223.7	425.7	212.3
Fix. Chg. Cov.	290%	367%	328%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.0%	7.5%	4.5%
"Cash Flow"	8.5%	8.0%	5.0%
Earnings	6.5%	4.5%	7.0%
Dividends	7.5%	8.0%	5.0%
Book Value	9.0%	7.0%	4.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	154.5	167.3	180.8	167.9	670.5
2010	160.5	178.5	207.8	179.3	726.1
2011	163.6	178.3	197.3	172.7	712.0
2012	170.2	198.2	210	201.6	780
2013	180	210	215	220	825

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.14	.19	.25	.19	.77
2010	.16	.22	.32	.20	.90
2011	.22	.27	.30	.25	1.03
2012	.20	.30	.35	.20	1.05
2013	.22	.29	.39	.25	1.15

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.125	.125	.125	.135	.51
2009	.135	.135	.135	.145	.55
2010	.145	.145	.145	.155	.59
2011	.155	.155	.155	.165	.63
2012	.165	.165	.165		

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 '11: residential, 59.5%; commercial, 14.5%; industrial & other, 26.0%. Officers and directors own 1.5% of the common stock (4/12 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 will likely grow at a mediocre pace in the back half of the year. Indeed, management expects share earnings to come in at $0.30 in the third quarter. This share-net figure would represent a flat year-over-year performance. That said, we are looking for the company to top expectations, due to the historically hot weather in August and September. Going forward, the non-regulated segment should continue to represent a larger portion of total income. On the cost side, the company has improved its operation and maintenance expense-to-revenue ratio on a year-over-year basis. This ratio will likely marginally improve, as the company consolidates its markets.

The Marcellus shale water pipeline venture should bolster longer-term profitability. We anticipate natural gas drilling in the U.S. to grow at a nice clip, as LNG export facilities are expected to come on line in the coming years. Aqua America and Penn Virginia's joint venture for a pipeline in Pennsylvania is progressing nicely. Construction on phase II of the pipeline is expected to be completed by the end of the year, at a cost of $20 million. The project will likely be completed by the end of 2014, and is expected to add $0.10 a share to 2014 and 2015 bottom-line results. However, further declines in natural gas prices would likely hurt drilling prospects and could throw a wrench in the company's underlying projections.

The company should realize operational efficiencies from its portfolio restructuring. Aqua America has offered to sell its Florida operations to the Florida Governmental Utility Authority for $95 million. This move would narrow its list of states served to eight, with the majority of its revenue generated from the Ohio, Pennsylvania, and New Jersey markets. We think the company's entrance into the Texas market should pay dividends, as favorable demographic trends and a burgeoning oil & gas industry stand to persist.

The stock is set to outperform the broader market averages in the near term. However, for longer-term investors the issue offers minimal capital appreciation potential and a below-average dividend yield compared to its peers.

Michael Collins *October 19, 2012*

(A) Diluted egs. Excl. nonrec. gains (losses): '99, (11¢); '00, 2¢; '01, 2¢; '02, 5¢; '03, 4¢. Excl. gain from disc. operations: '96, 2¢. Next earnings report due late October.

(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

ATTACHMENT B

Equities in the Natural Gas Utility Industry have been under some pressure over the past few months. This can be attributed partly to weakness in the general market. Indeed, there are worries about the possibility of the so-called fiscal cliff taking effect by the end of 2012, unless President Obama and the bitterly divided Congress act in time. (That event would be marked by an estimated $600 billion in automatic tax hikes and spending cuts.) Furthermore, there is investor uncertainty over the outcome of the sovereign debt crisis in Europe and concerns about the strength of the Chinese economy. But even under those circumstances, the equities in our Industry have tended to hold up relatively well. Indeed, their healthy levels of dividend income have provided a measure of much-needed stability.

The United States Economy

The economy perked up some in the third quarter, with Gross Domestic Product (GDP) increasing an estimated 2.7%, relative to 1.3% during the June interim and 2.0% in the first three months of 2012. Contributing factors included restocking by businesses and export growth outpacing a rise in imports. What's more, there was a turnaround in federal government expenditures, driven by higher defense outlays, as well as a strengthening housing market (reflecting a boost in residential construction).

Nevertheless, the pace of the economic recovery continues to be sluggish, attributable partially to the persistently high unemployment rate, hovering a little below 8% at present. Too, it appears that Hurricane Sandy, discussed in further detail below, will cost thousands of jobs, some of which will take some time to restore. Also, the fiscal cliff, if not resolved in time, has the potential to seriously damage the economy. Finally, the lingering European debt crisis has further complicated matters. In this difficult 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.

Hurricane Sandy

In late October, the powerful storm ravaged the eastern coast of the United States, particularly New Jersey and New York, leaving millions of people without power. As a result, we have scaled back our fourth-quarter GDP growth target by about 0.5%, to between 1.2% and 1.5%. True, a portion of this shortfall will be made up in 2013, as rebuilding initiatives take hold, but some might never be recaptured. (Current estimates state that the total damage from the storm could be more than $50 billion.)

Natural gas distribution pipelines are located mostly underground, providing a good measure of protection against adverse weather conditions. Even so, these assets can be damaged by uprooted trees and shifted foundations. In addition, fallen tree limbs and other debris can crush gas meters and associated piping near homes and other buildings. Still, it appears that companies in the group held up reasonably well during Hurricane Sandy.

INDUSTRY TIMELINESS: 27 (of 98)

Rate Cases

Rate cases are a very important issue 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.

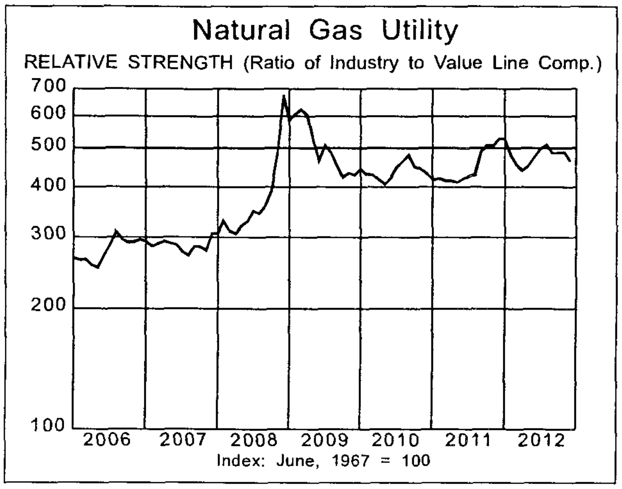
Dividends

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 around 4.0%, considerably higher than the *Value Line* median of 2.3%. 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



AGL RESOURCES NYSE-GAS

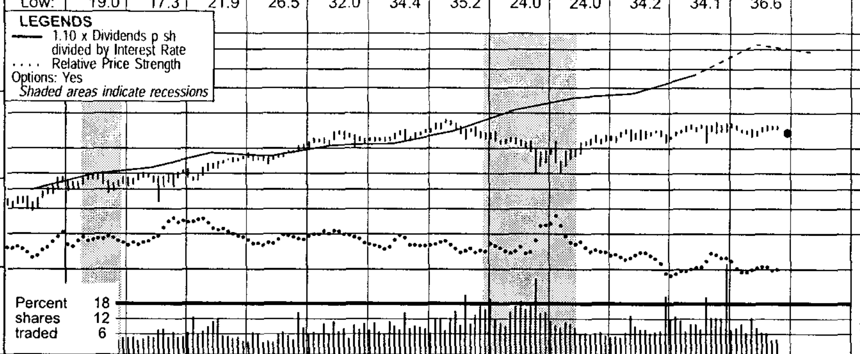
RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD	
38.41	11.0 (Trailing: 20.3 / Median: 13.0)	0.74	4.8%	VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 1 Raised 9/9/11
TECHNICAL 3 Lowered 11/23/12
BETA .75 (1.00 = Market)

High:	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9	
Low:	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6	

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.10 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	65	(+70%)	18%
Low	50	(+30%)	11%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	0	0	2	0	0	2	0
to Sell	0	1	0	0	2	0	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	258	153	136
to Sell	63	159	151
Hld's(000)	71384	71603	69954

Percent shares traded 18 12 6

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.9	10.8
3 yr.	34.2	48.5
5 yr.	31.4	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	20.00	**34.95**	**37.15**	Revenues per sh A	**44.30**
2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.05	**6.00**	**6.15**	"Cash Flow" per sh	**7.35**
1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	**2.70**	**3.20**	Earnings per sh A B	**3.80**
1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	1.90	**1.74**	**1.84**	Div'ds Decl'd per sh CF■	**1.96**
2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.42	**4.75**	**5.15**	Cap'l Spending per sh	**6.45**
10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.54	**30.90**	**31.65**	Book Value per sh D	**33.30**
55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.00	**117.00**	**117.00**	Common Shs Outst'g E	**117.0**
13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	**15.0**
.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	.82	*Value Line*		Relative P/E Ratio	**1.00**
5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	**3.5%**

CAPITAL STRUCTURE as of 9/30/12
Total Debt $4604 mill. **Due in 5 Yrs** $100 mill.
LT Debt $3330 mill. **LT Interest** $200 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/11 $754.0 mill.
Oblig. $968.0 mill.

Pfd Stock None

Common Stock 117,782,207 shs.
as of 10/23/12

MARKET CAP: $4.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	**4100**	**4350**	Revenues ($mill) A	**5180**
103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	**315**	**375**	Net Profit ($mill)	**445**
36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	**35.5%**	**32.0%**	Income Tax Rate	**32.0%**
11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	**7.7%**	**8.6%**	Net Profit Margin	**8.6%**
58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	52.0%	**52.0%**	**52.5%**	Long-Term Debt Ratio	**56.0%**
41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.0%	**48.0%**	**47.5%**	Common Equity Ratio	**44.0%**
1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	8238.0	**7535**	**7855**	Total Capital ($mill)	**8840**
2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	**8375**	**8875**	Net Plant ($mill)	**10570**
8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.0%	**5.5%**	**6.0%**	Return on Total Cap'l	**6.5%**
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	**9.0%**	**10.0%**	Return on Shr. Equity	**11.5%**
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	**3.0%**	**4.5%**	Return on Com Equity	**5.5%**
7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	**3.0%**	**4.0%**	Retained to Com Eq	**6.5%**
52%	53%	49%	52%	52%	58%	60%	57%	57%	86%	**65%**	**58%**	All Div'ds to Net Prof	**52%**

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	24	69	91
Other	2138	2677	2044
Current Assets	2162	2746	2135
Accts Payable	184	294	292
Debt Due	1032	1338	1274
Other	1212	1452	1198
Current Liab.	2428	3984	2764
Fix. Chg. Cov.	501%	325%	385%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	5.5%	9.0%
"Cash Flow"	6.5%	6.0%	9.0%
Earnings	9.0%	4.5%	6.0%
Dividends	5.0%	7.5%	1.5%
Book Value	7.0%	5.5%	5.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	995	377	307	638	2317
2010	1003	359	346	665	2373
2011	878	375	295	790	2338
2012	1404	686	614	**1396**	**4100**
2013	**1780**	**690**	**585**	**1295**	**4350**

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.12	.28	.08	**1.22**	**2.70**
2013	**1.95**	**.25**	**.15**	**.85**	**3.20**

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.42	.42	.42	.42	1.68
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	

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, and Virginia Natural Gas. Acquired Nicor in 2011. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, and Florida. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 6.8% of common stock; off./dir., less than 1.0% (3/12 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources reported mixed results in the third quarter. Revenues increased to $614 million (up 108% year over year); earnings were $0.08 a share compared to last year's $0.04-a-share loss. Still, earnings were lower than expected, and were hurt by a $16 million hedging loss. Revenues are expected to grow strongly in the fourth quarter, aided by the Nicor acquisition. Revenues and earnings, however, could be adversely affected if a warmer-than-usual winter occurs.

Hurricane Sandy may have a small negative effect on profits in the fourth quarter. AGL's subsidiary, Elizabethtown Gas, is located in central New Jersey, which took the brunt of the storm. Damages and losses due to wind and flooding were incurred, and revenue was lost due to customers losing power. The Virginia Natural Gas Company, another subsidiary that was projected to be in the storm's path, remained largely unaffected. The damage from the storm could have lingering effects on the top and bottom line in the fourth quarter.

AGL's subsidiaries continue to strive for growth. Atlanta Gas Light Co. recently inked an agreement that permits it to install five new compressed natural gas fueling stations throughout Georgia. The Nicor acquisition continues to be integrated, and costs savings are slowly being realized. Fourth-quarter earnings should be helped by these cost-savings initiatives.

We have lowered our Target Price Range from $55-$70 to $50-$65. Pressures from high supply in the natural gas market will hurt distributors and temper revenue and earnings gains, countering growth in new customers and projects.

This issue has retreated some since last report, increasing the dividend yield to 4.8% for new investors. We expect the payout to expand in 2013, as earnings continue to grow.

These shares' Timeliness rank is 3 (Average). AGL Resources will likely perform in line with the broader market over the next six to 12 months. However, those who seek dividend income should consider this issue due to its high yields, the likelihood of increased payouts and the Highest Safety rank of 1.

John E. Seibert III *December 7, 2012*

(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 January.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2011: $1918 million, $16.40/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	75

ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE	34.78	P/E RATIO	15.0 (Trailing: 15.1 / Median: 14.0)	RELATIVE P/E RATIO	1.01	DIV'D YLD	4.1%	VALUE LINE

TIMELINESS 2 Raised 8/17/12

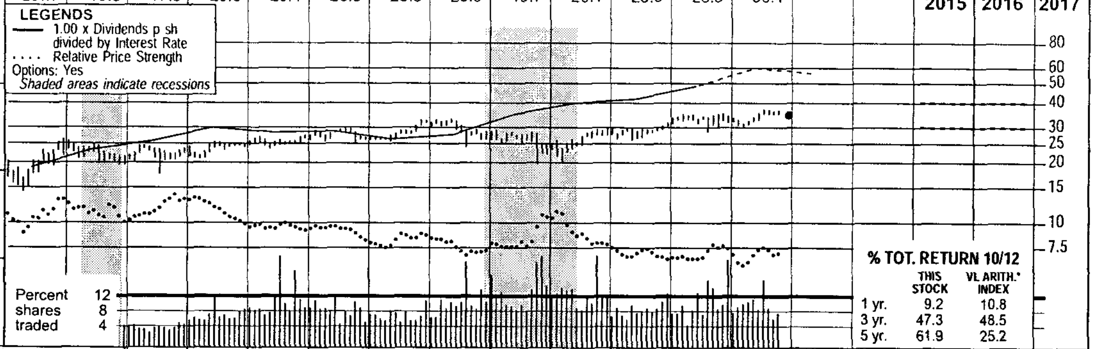
SAFETY 2 Raised 12/16/05

TECHNICAL 3 Lowered 11/23/12

BETA .70 (1.00 = Market)

High:	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3	
Low:	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4	

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	7%
Low	30	(-15%)	1%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	0	0	0	0	2	0	0	1	0
to Sell	0	0	1	0	0	1	0	2	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	132	127	112
to Sell	103	117	131
Hld's(000)	48646	50572	51653

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	9.2	10.8
3 yr.	47.3	48.5
5 yr.	61.9	25.2

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.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	*38.20*	*41.75*	Revenues per sh A	*63.10*
3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	*4.75*	*5.10*	"Cash Flow" per sh	*5.65*
1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	2.10	*2.35*	Earnings per sh A B	*2.70*
1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	1.38	*1.40*	Div'ds Decl'd per sh C■	*1.48*
3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	*8.15*	*8.50*	Cap'l Spending per sh	*8.80*
13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	*26.20*	*29.00*	Book Value per sh	*34.65*
41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	*90.00*	*91.00*	Common Shs Outst'g D	*103.00*
15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	15.9		Avg Ann'l P/E Ratio	*13.0*
.83	.76	.84	.86	.73	.84	.82	.83	.84	.90	1.01		Relative P/E Ratio	*.85*
5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	4.1%		Avg Ann'l Div'd Yield	*4.2%*
950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	3438.5	*3800*	Revenues ($mill) A	*6500*
59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	192.2	*215*	Net Profit ($mill)	*280*
37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	33.8%	*35.0%*	Income Tax Rate	*38.5%*
6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	5.6%	*5.7%*	Net Profit Margin	*4.3%*
53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	*45.5%*	*45.0%*	Long-Term Debt Ratio	*49.0%*
46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	*54.5%*	*55.0%*	Common Equity Ratio	*51.0%*
1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	*4315*	*4800*	Total Capital ($mill)	*7000*
1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	*5475*	*5800*	Net Plant ($mill)	*6700*
6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*5.5%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*8.0%*	*8.0%*	Return on Shr. Equity	*8.0%*
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	*8.0%*	*8.0%*	Return on Com Equity	*8.0%*
1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
82%	70%	77%	73%	63%	65%	65%	68%	62%	62%	*65%*	*59%*	All Div'ds to Net Prof	*54%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2419.9 mill. **Due in 5 Yrs** $660.0 mill.
LT Debt $1956.3 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/11 $280.2 mill. **Oblig.** $429.4 mill.
Common Stock 90,173,217 shs. **as of 8/3/12**
MARKET CAP: $3.1 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	132.0	131.4	27.7
Other	743.2	879.6	748.0
Current Assets	875.2	1011.0	775.7
Accts Payable	266.2	291.2	178.2
Debt Due	486.2	208.8	463.6
Other	413.7	367.6	468.4
Current Liab.	1166.1	867.6	1110.2
Fix. Chg. Cov.	440%	432%	430%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.5%	-3.5%	*3.5%*
"Cash Flow"	4.5%	4.5%	*3.5%*
Earnings	7.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	6.5%	4.5%	*6.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1716.3	1821.4	780.8	650.6	4969.1
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	*1095*	*1300*	*725*	*680*	*3800*

Fiscal Year Ends	EARNINGS PER SHARE A B E Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.83	1.29	.02	d.17	1.97
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	*.74*	*1.36*	*.22*	*.03*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.33	1.31
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	

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2011 gas volumes: 281.5 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2011 depreciation rate 3.3%. Has around 4,750 employees. Officers and directors own 1.5% of common stock (12/11 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

We believe that Atmos Energy will stage an earnings turnaround in the new fiscal year, which began on October 1st. The core natural gas distribution segment stands to benefit from a rise in throughput, if weather conditions cooperate (leading to a boost in consumption levels). Moreover, the other operations, including the natural gas marketing business and pipeline unit, ought to perform reasonably well, overall. As a result, we expect consolidated share net to climb about 12%, to $2.35, in fiscal 2013. Assuming additional expansion of operating margins, the bottom line could well advance roughly 5% or so, to $2.45 a share, the following year.

Steady, although unspectacular, results appear to be in store for the company over the 2015-2017 time frame. The utility ranks as one of the country's biggest natural gas-only distributors, boasting roughly three million customers across nine states. Furthermore, the other businesses, especially pipelines, possess healthy overall expansion prospects. Finally, we believe that the company will eventually resume its successful strategy of purchasing less efficient utilities and shoring up their profitability through expense-reduction efforts, rate relief, and aggressive marketing initiatives. (The last major transaction occurred in October, 2004, when Atmos Energy bought TXU Gas Company.) But given our exclusion of future acquisitions, because of size and timing issues, annual earnings-per-share growth may be in the mid-single-digit range over the coming three to five years.

The stock offers an appealing dividend yield, which is higher than the average of all gas utility equities tracked by *Value Line*. Our 2015-2017 projections indicate that further, albeit moderate, increases in the distribution are likely to take place. The payout ratio ought to remain within a manageable range (i.e., 50% to 60%). What's more, these shares currently hold a 2 (Above Average) rank for both Safety and Timeliness, as well as an excellent score for Price Stability. All things considered, a variety of investors might wish to take a look here.

Frederick L. Harris, III *December 7, 2012*

(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¢. Next egs. rpt. due early Feb. (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

LACLEDE GROUP NYSE-LG

RECENT PRICE	39.89	P/E RATIO	13.7 (Trailing: 14.3; Median: 14.0)	RELATIVE P/E RATIO	0.92	DIV'D YLD	4.3%	VALUE LINE

TIMELINESS **3** Lowered 9/23/11

SAFETY **2** Raised 6/20/03

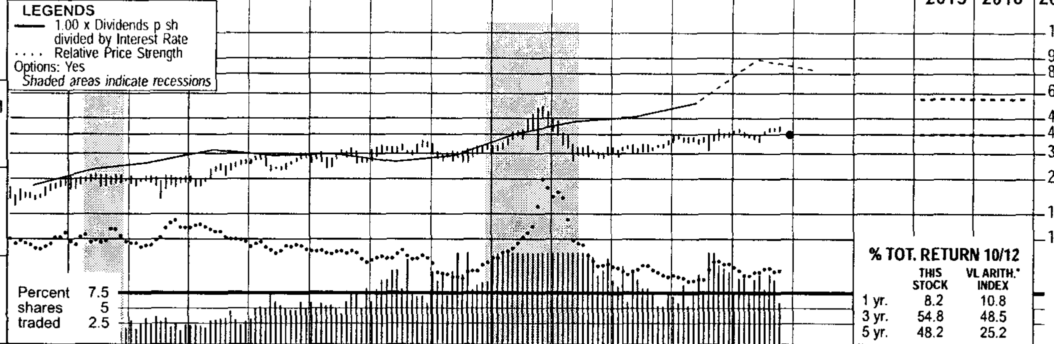
TECHNICAL **3** Lowered 11/23/12

BETA .55 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	25.5	25.0	30.0	32.5	34.3	37.5	36.0	55.8	48.3	37.8	42.8	44.0
Low:	21.3	19.0	21.8	26.0	26.9	29.1	28.8	31.9	29.3	30.8	32.9	36.5

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.00 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+50%)	14%
Low	45	(+15%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	64	62	62
to Sell	58	71	64
Hld's(000)	10812	11161	10921

Percent shares traded 7.5 / 5 / 2.5

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.2	10.8
3 yr.	54.8	48.5
5 yr.	48.2	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
31.03	34.33	31.04	26.04	29.99	53.08	39.84	54.95	59.59	75.43	93.51	93.40	100.44	85.49	77.83	71.48	49.76	50.40	Revenues per sh A	52.00
3.29	3.32	3.02	2.56	2.68	3.00	2.56	3.15	2.79	2.98	3.81	3.87	4.22	4.56	4.11	4.62	4.58	4.65	"Cash Flow" per sh	5.20
1.87	1.84	1.58	1.47	1.37	1.61	1.18	1.82	1.82	1.90	2.37	2.31	2.64	2.92	2.43	2.86	2.79	2.85	Earnings per sh A B	3.30
1.26	1.30	1.32	1.34	1.34	1.34	1.34	1.34	1.35	1.37	1.40	1.45	1.49	1.53	1.57	1.61	1.66	1.74	Div'ds Decl'd per sh C■	1.84
2.35	2.44	2.68	2.58	2.77	2.51	2.80	2.67	2.45	2.84	2.97	2.72	2.57	2.36	2.56	3.02	4.71	2.85	Cap'l Spending per sh	3.00
13.72	14.26	14.57	14.96	14.99	15.26	15.07	15.65	16.96	17.31	18.85	19.79	22.12	23.32	24.02	25.56	26.60	28.35	Book Value per sh D	33.00
17.56	17.56	17.63	18.88	18.88	18.88	18.96	19.11	20.98	21.17	21.36	21.65	21.99	22.17	22.29	22.43	22.62	23.0	Common Shs Outst'g E	23.5
11.9	12.5	15.5	15.8	14.9	14.5	20.0	13.6	15.7	16.2	13.6	14.2	14.3	13.4	13.7	13.0	14.5		Avg Ann'l P/E Ratio	15.5
.75	.72	.81	.90	.97	.74	1.09	.78	.83	.86	.73	.75	.86	.89	.87	.81	.97		Relative P/E Ratio	1.05
5.6%	5.6%	5.4%	5.8%	6.6%	5.7%	5.7%	5.4%	4.7%	4.4%	4.3%	4.4%	3.9%	3.9%	4.7%	4.3%	4.1%		Avg Ann'l Div'd Yield	3.8%
						755.2	1050.3	1250.3	1597.0	1997.6	2021.6	2209.0	1895.2	1735.0	1603.3	1125.5	1150	Revenues ($mill) A	1225
						22.4	34.6	36.1	40.1	50.5	49.8	57.6	64.3	54.0	63.8	63.1	65.0	Net Profit ($mill)	78.0
						35.4%	35.0%	34.8%	34.1%	32.5%	33.4%	31.3%	33.6%	33.4%	31.4%	32.0%	31.0%	Income Tax Rate	33.0%
						3.0%	3.3%	2.9%	2.5%	2.5%	2.5%	2.6%	3.4%	3.1%	4.0%	5.6%	5.6%	Net Profit Margin	6.4
						47.5%	50.4%	51.6%	48.1%	49.5%	45.3%	44.4%	42.9%	40.5%	38.9%	36.0%	38.5%	Long-Term Debt Ratio	37.5%
						52.3%	49.4%	48.3%	51.8%	50.4%	54.6%	55.5%	57.1%	59.5%	61.1%	64.0%	61.5%	Common Equity Ratio	62.5%
						546.6	605.0	737.4	707.9	798.9	784.5	876.1	906.3	899.9	937.7	941.0	1050	Total Capital ($mill)	1240
						594.4	621.2	646.9	679.5	763.8	793.8	823.2	855.9	884.1	928.7	1019.3	1025	Net Plant ($mill)	1100
						6.0%	7.4%	6.6%	7.6%	8.4%	8.5%	8.1%	8.7%	7.4%	8.1%	6.5%	7.5%	Return on Total Cap'l	7.5%
						7.8%	11.5%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	9.5%	Return on Shr. Equity	10.0%
						7.8%	11.6%	10.1%	10.9%	12.5%	11.6%	11.8%	12.4%	10.1%	11.1%	10.6%	9.5%	Return on Com Equity	10.0%
						NMF	3.1%	2.7%	3.1%	5.1%	4.3%	5.2%	5.9%	3.6%	4.9%	4.3%	4.0%	Retained to Com Eq	4.5%
						NMF	74%	73%	72%	59%	63%	56%	53%	64%	56%	60%	61%	All Div'ds to Net Prof	55%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $364.4 mill. **Due in 5 Yrs** $50.0 mill.
LT Debt $339.4 mill. **LT Interest** $25.0 mill.
(Total interest coverage: 4.6x)

Leases, Uncapitalized Annual rentals $.9 mill.
Pension Assets-9/11 $248.0 mill. **Oblig.** $384.2 mill.
Pfd Stock None
Common Stock 22,262,000 shs.
as of 9/30/12

MARKET CAP: $900 million (Small Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	86.9	43.3	27.5
Other	327.3	325.8	315.5
Current Assets	414.2	369.1	343.0
Accts Payable	95.6	96.6	89.5
Debt Due	154.6	46.0	25.0
Other	83.7	89.3	137.6
Current Liab.	333.9	231.9	252.1
Fix. Chg. Cov.	391%	463%	242%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.0%	.5%	-6.5%
"Cash Flow"	5.0%	7.0%	2.5%
Earnings	6.5%	6.0%	3.0%
Dividends	1.5%	2.5%	2.5%
Book Value	5.0%	6.5%	4.5%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.)A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	674.3	659.1	309.9	251.9	1895.2
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	365	400	210	175	1150

Fiscal Year Ends	EARNINGS PER SHARE A B F Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.42	1.40	.31	d.22	2.92
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	1.20	1.35	.40	d.10	2.85

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.375	1.50
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	

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 8% of common shares (1/12 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.

Laclede Group's fourth-quarter results were better than expected (Years end September). Revenues decreased to $169.5 million, due to lower commodities costs, which were passed through to natural gas customers. Losses were narrowed to $0.03 a share compared to last year's deficit of $0.13. Margin expansion (5.6% in 2012 versus 4.0% in 2011) played a major factor in this year's earnings decreasing only slightly, even though there was a large decline in sales.

Increases in infrastructure replacement spending are a key component of Laclede's growth strategy. Over half of the $115 million spent on infrastructure is eligible to be recovered through the Infrastructure System Replacement Surcharge (ISRS), which charges customers for infrastructure replacement and improvement. This program leads to higher fixed revenues with greater margins, which allows for more consistent financial results.

Laclede is investing in emerging technologies in its non-regulated division, such as compressed natural gas (CNG) for vehicles. This segment advanced 37% over fiscal 2011. Commercial vehicle fleets, like the one at AT&T, are increasingly using CNG as an economical fuel source. As this trend plays out, Laclede's earnings will increasingly come from the nonregulated gas division, which should grow margins further.

Laclede raised its quarterly dividend to $0.425 a share, increasing the payout by 2.4% per year. The share price has come down since our last report bringing the yield up to 4.3%. This is well covered by earnings. Dividend growth has the potential to be quite noticeable over the next few years. This is the 10th year in a row that Laclede has raised its dividend, and this trend is likely to persist.

Laclede has a Timeliness rank of 3 (Average). This issue is likely to track the broader averages over the next six to 12 months. Its Above-Average Safety rank and growing dividend may appeal to income investors. This dividend also has the potential to be one of the strongest in the natural gas distribution field, thanks to the company's stronger-than-average cash flow potential.

John E. Seibert III *December 7, 2012*

(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 January. (C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available. (D) Incl. deferred charges. In '11: $429.9 mill., $19.17/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	80

NEW JERSEY RES. NYSE-NJR

RECENT PRICE	40.33	P/E RATIO	14.1 (Trailing: 13.4; Median: 15.0)	RELATIVE P/E RATIO	0.95	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS 3 Raised 9/14/12

SAFETY 1 Raised 9/15/06

TECHNICAL 3 Lowered 11/30/12

BETA .65 (1.00 = Market)

	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:			21.7	22.4	26.4	29.7	32.9	35.4	37.6	41.1	42.4	44.1	50.5	50.3			
Low:			16.6	16.2	20.0	24.3	27.1	27.7	30.3	24.6	30.0	33.5	39.6	38.5			

Target Price Range 2015 | 2016 | 2017

2015-17 PROJECTIONS

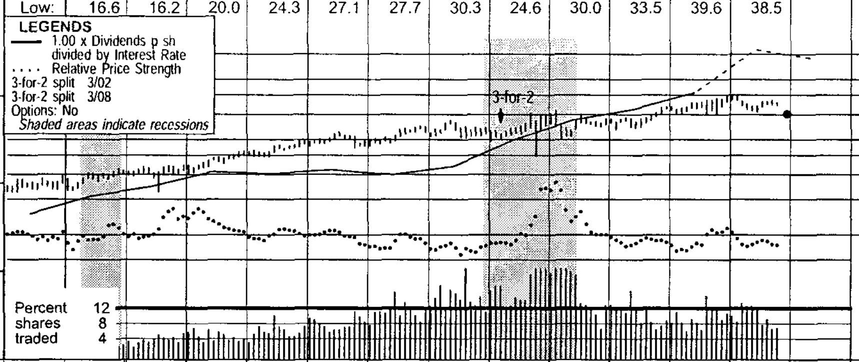
	Price	Gain	Ann'l Total Return
High	50	(+25%)	9%
Low	45	(+10%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	1	0	0	0	0	0	0	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	2	0	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	66	75	68
to Sell	65	71	80
Hld's(000)	24285	24119	23904



% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-2.2	10.8
3 yr.	40.2	48.5
5 yr.	61.0	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
13.48	17.31	17.73	22.65	29.42	51.22	44.11	62.29	60.89	76.19	79.63	72.62	90.74	62.34	64.10	72.60	54.16	*70.00*	Revenues per sh A	*76.50*
1.48	1.63	1.74	1.86	1.99	2.12	2.14	2.38	2.50	2.62	2.73	2.44	3.62	3.16	3.26	3.40	*3.74*	*3.85*	"Cash Flow" per sh	*4.45*
.92	.99	1.04	1.11	1.20	1.30	1.39	1.59	1.70	1.77	1.87	1.55	2.70	2.40	2.46	2.58	2.71	*2.90*	Earnings per sh B	*3.40*
.69	.71	.73	.75	.76	.78	.80	.83	.87	.91	.96	1.01	1.11	1.24	1.36	1.44	1.52	*1.60*	Div'ds Decl'd per sh C■	*1.68*
1.19	1.15	1.07	1.21	1.23	1.10	1.02	1.14	1.45	1.28	1.28	1.46	1.72	1.81	2.10	2.26	*2.00*	*2.00*	Cap'l Spending per sh	*2.00*
6.73	6.92	7.26	7.57	8.29	8.80	8.71	10.26	11.25	10.60	15.00	15.50	17.28	16.59	17.62	18.73	*18.15*	*19.10*	Book Value per sh D	*24.20*
40.69	40.23	40.07	39.92	39.59	40.00	41.50	40.85	41.61	41.32	41.44	41.61	42.06	41.59	41.17	41.45	41.53	*40.00*	Common Shs Outst'g E	*40.00*
13.6	13.5	15.3	15.2	14.7	14.2	14.7	14.0	15.3	16.8	16.1	21.6	12.3	14.9	15.0	16.8	16.8		Avg Ann'l P/E Ratio	*14.0*
.85	.78	.80	.87	.96	.73	.80	.80	.81	.89	.87	1.15	.74	.99	.95	1.05	1.08		Relative P/E Ratio	*.95*
5.6%	5.3%	4.6%	4.5%	4.4%	4.2%	3.9%	3.7%	3.3%	3.1%	3.2%	3.0%	3.3%	3.5%	3.7%	3.3%	3.3%		Avg Ann'l Div'd Yield	*3.5%*
						1830.8	2544.4	2533.6	3148.3	3299.6	3021.8	3816.2	2592.5	2639.3	3009.2	2248.9	*2800*	Revenues ($mill) A	*3060*
						56.8	65.4	71.6	74.4	78.5	65.3	113.9	101.0	101.8	106.5	*112*	*120*	Net Profit ($mill)	*140*
						38.7%	39.4%	39.1%	39.1%	38.9%	38.8%	37.8%	27.1%	41.4%	30.2%	*35.0%*	*35.0%*	Income Tax Rate	*35.0%*
						3.1%	2.6%	2.8%	2.4%	2.4%	2.2%	3.0%	3.9%	3.9%	3.5%	*5.0%*	*4.3%*	Net Profit Margin	*4.5%*
						50.6%	38.1%	40.3%	42.0%	34.8%	37.3%	38.5%	39.8%	37.2%	35.5%	39.2%	*39.5%*	Long-Term Debt Ratio	*34.0%*
						49.4%	61.9%	59.7%	58.0%	65.2%	62.7%	61.5%	60.2%	62.8%	64.5%	60.8%	*60.5%*	Common Equity Ratio	*66.0%*
						732.4	676.8	783.8	755.3	954.0	1028.0	1182.1	1144.8	1154.4	1203.1	1339.0	*1265*	Total Capital ($mill)	*1470*
						756.4	852.6	880.4	905.1	934.9	970.9	1017.3	1064.4	1135.7	1295.9	1484.9	*1350*	Net Plant ($mill)	*1430*
						8.7%	10.7%	10.1%	11.2%	9.6%	7.7%	10.7%	9.7%	9.7%	9.7%	*9.5%*	*10.5%*	Return on Total Cap'l	*10.0%*
						15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*14.0%*	*16.0%*	Return on Shr. Equity	*14.0%*
						15.7%	15.6%	15.3%	17.0%	12.6%	10.1%	15.7%	14.6%	14.0%	13.7%	*14.0%*	*16.0%*	Return on Com Equity	*14.0%*
						6.9%	7.7%	7.8%	8.5%	6.3%	3.6%	9.5%	7.2%	6.7%	6.2%	*6.0%*	*7.5%*	Retained to Com Eq	*7.5%*
						56%	51%	49%	50%	50%	64%	40%	50%	52%	55%	*56%*	*53%*	All Div'ds to Net Prof	*49%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $812.8 mill. **Due in 5 Yrs** $214.3 mill.
LT Debt $525.2 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 41,689,123 shs. as of 11/23/12
MARKET CAP: $1.7 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	.9	7.4	4.5
Other	784.1	725.0	642.8
Current Assets	785.0	732.4	647.3
Accts Payable	47.3	66.0	265.8
Debt Due	178.9	166.9	287.6
Other	479.6	470.5	99.7
Current Liab.	705.8	703.4	653.1
Fix. Chg. Cov.	700%	700%	700%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	7.0%	-1.5%	*2.5%*
"Cash Flow"	5.0%	4.5%	*5.0%*
Earnings	7.5%	7.0%	*5.5%*
Dividends	6.0%	8.0%	*4.0%*
Book Value	8.0%	7.5%	*5.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	801.3	937.5	441.1	412.6	2592.5
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	*790*	*765*	*575*	*670*	*2800*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	.77	1.71	.03	d.12	2.40
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	*1.15*	*1.84*	*.15*	*d.24*	*2.90*

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	.38	1.52
2013	.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 494,964 customers at 9/30/11 in Monmouth and Ocean Counties, and other N.J. Counties. Fiscal 2011 volume: 178 bill. cu. ft. (5% interruptible, 35% residential and commercial and electric utility, 60% incentive programs). N.J. Natural Energy subsidiary provides unregulated retail/wholesale natural gas and related energy svcs. 2011 dep. rate: 2.2%. Has 891 empls. Off./dir. own about 1.1% of common (12/11 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 fiscal 2012 (ended September 30th). Indeed, the top line declined approximately 25% on a year-over-year basis. This reflected diminished volumes at both the utility and nonutility divisions. However, this was not alarming, being largely due to lower year-to-year comparable natural gas prices. Overall, management was successful at trimming unnecessary expenses, thereby boosting profitability for the year. And, on balance, NJR logged a modest 5% earnings advance, to $2.71 a share. However, this was slightly lower than we had previously anticipated. Consequently,

We have reduced our top- and bottom-line estimates for 2013 accordingly. Helped by low natural gas prices, New Jersey Resources has been quite successful at growing the number of customer accounts at the New Jersey Natural Gas regulated utility division. That unit comprises the bulk of the company's business mix, and is expected to add 6,000 to 7,000 new customers this year alone. Elsewhere, the NJR Clean Energy Ventures segment has multiple capital projects for alternative energy investments in its pipeline. On the downside, the NJR Energy services unit will likely continue to experience difficulties this year, as historically low natural gas prices and reduced volatility weigh on the wholesale market's profitability. Meanwhile, cost-cutting efforts that helped to boost the bottom line in 2012, will not be as effective with sustained top-line weakness this year. Thus, we have reduced our earnings estimate by $0.25, to $2.90 a share, for fiscal 2013.

The board recently approved a quarterly divided increase of about 5%, to $0.40 a share. This payout came on the heels of the regularly scheduled fourth-quarter dividend, due to concerns that the tax rate on dividends may rise next year.

These neutrally ranked shares are trading down roughly 13% in price since our September review. The bulk of this move likely stemmed from concerns for how the effects of Hurricane Sandy may weigh on the company's operations, as well as general concerns over higher taxes on dividends and capital gains.

Bryan J. Fong *December 7, 2012*

(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 Jan.
(C) Dividends historically paid in early January, April, July, and October. ■ Dividend reinvestment plan available.
(D) Includes regulatory assets in 2011: $434.2 million, $10.48/share.
(E) In millions, adjusted for splits.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	50

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **43.28** | P/E RATIO **18.5** (Trailing: 18.4 Median: 17.0) | RELATIVE P/E RATIO **1.15** | DIV'D YLD **4.2%** | **VALUE LINE**

TIMELINESS **3** Raised 9/21/12

SAFETY **1** Raised 3/18/05

TECHNICAL **3** Lowered 12/7/12

BETA .55 (1.00 = Market)

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+40%)	12%
Low	50	(+15%)	8%

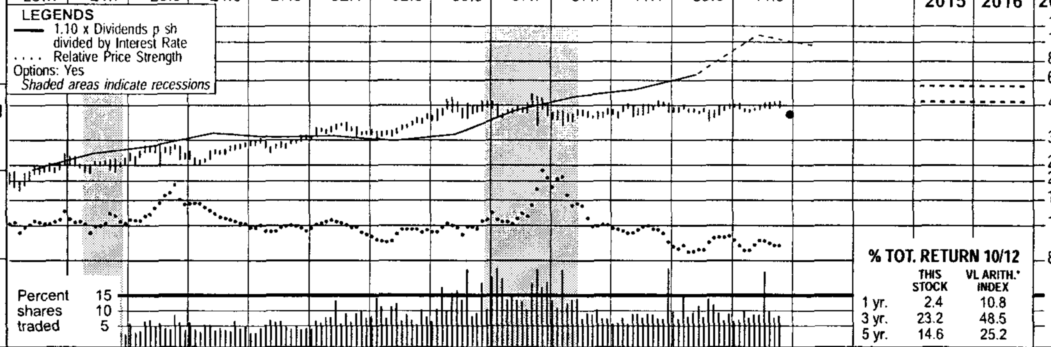
Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	2	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	72	69	70
to Sell	43	58	51
Hld's(000)	16071	16355	16429

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	26.8	30.7	31.3	34.1	39.6	43.7	52.8	55.2	46.5	50.9	49.0	50.8
Low:	21.7	23.5	24.0	27.5	32.4	32.8	39.8	37.7	37.7	41.1	39.6	41.0



% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	2.4	10.8
3 yr.	23.2	48.5
5 yr.	14.6	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	*29.25*	*29.10*	Revenues per sh	*30.55*
3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	*4.50*	*4.60*	"Cash Flow" per sh	*4.95*
1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	*2.25*	*2.45*	Earnings per sh A	*3.15*
1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	*1.79*	*1.83*	Div'ds Decl'd per sh B■	*1.96*
3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	*6.60*	*7.00*	Cap'l Spending per sh	*8.10*
15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	*26.95*	*27.35*	Book Value per sh D	*27.75*
22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	*27.00*	*27.50*	Common Shs Outst'g C	*28.00*
11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	Bold figures are		Avg Ann'l P/E Ratio	*17.0*
.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.20	Value Line		Relative P/E Ratio	*1.15*
5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	estimates		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $817.5 mill. Due in 5 Yrs $200 mill.
LT Debt $641.7 mill. LT Interest $45.0 mill.

(Total interest coverage: 3.4x)

Pension Assets-12/11 $216 mill.
Oblig. $391.1 mill.

Pfd Stock None

Common Stock 26,902,000 shares

MARKET CAP $1.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	*790*	*800*	Revenues ($mill)	*855*
43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	*60.0*	*70.0*	Net Profit ($mill)	*90.0*
34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	*38.5%*	*36.0%*	Income Tax Rate	*32.5%*
6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	*8.1%*	*8.8%*	Net Profit Margin	*10.3%*
47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	*47.0%*	*47.0%*	Long-Term Debt Ratio	*48.5%*
51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	*53.0%*	*53.0%*	Common Equity Ratio	*52.5%*
937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	*1370*	*1410*	Total Capital ($mill)	*1515*
995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	*1985*	*1895*	Net Plant ($mill)	*1895*
5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	*6.0%*	*6.5%*	Return on Total Cap'l	*7.0%*
8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*8.5%*	*9.5%*	Return on Shr. Equity	*11.5%*
8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*8.5%*	*9.0%*	Return on Com Equity	*11.5%*
1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	*2.5%*	*3.0%*	Retained to Com Eq	*4.0%*
79%	72%	69%	63%	59%	52%	59%	56%	61%	73%	*80%*	*75%*	All Div'ds to Net Prof	*62%*

CURRENT POSITION ($MILL.)

	2010	2011	9/30/12
Cash Assets	3.5	5.8	5.7
Other	326.8	342.9	192.2
Current Assets	330.3	348.7	197.9
Accts Payable	93.2	86.3	61.3
Debt Due	267.4	181.6	175.8
Other	107.6	146.6	108.3
Current Liab.	468.2	414.5	345.4
Fix. Chg. Cov.	366%	334%	344%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	1.0%	-1.5%
"Cash Flow"	3.0%	3.5%	-0.5%
Earnings	4.0%	4.5%	3.0%
Dividends	3.0%	4.5%	2.5%
Book Value	4.0%	4.0%	1.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.4	149.1	116.9	309.3	1012.7
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	*276.1*	*790*
2013	*315*	*140*	*90*	*255*	*800*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.78	.12	d.25	1.18	2.83
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	*1.08*	*2.25*
2013	*1.50*	*.15*	*d.25*	*1.05*	*2.45*

Cal-endar	QUARTERLY DIVIDENDS PAID B■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.395	1.52
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	

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, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.8% of shares; officers and directors, 1.7% (4/12 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 Co.'s third-quarter results were mixed. Revenues decreased to $89.8 million, down 4% year over year. Losses narrowed to $0.29 a share compared to last year's $0.31. Margins expanded while sales declined. Increases in natural gas storage income (up 8%) likely will have a small but positive effect on profits and sales.

NW Natural received mixed results from a base rate case filed in Oregon. The Oregon Public Utility Commission (PUC) allowed the company to collect higher fixed charges, increasing revenues by $8.7 million. The PUC also lowered rates that NW Natural charges for natural gas. Although margins should decline as a result of this rate decrease, total volume should increase over the next few years, somewhat limiting the downside effect. As a result, we have lowered our earnings estimate for 2012 to $2.25 a share from $2.45. The higher fixed charges could lower earnings variability. Pension cost base-rate decisions were deferred by the PUC, but the outcome will have an effect on future profitability.

NW Natural is focused on increasing its industrial customer base. By filing to lower the base rate by 14%, the company would entice more businesses to switch to natural gas for their processes. This would potentially grow and diversify the customer base while increasing revenues. The company is also on track with its joint venture with Encana in the Jonah field, which should produce 8%-10% of the annual natural gas requirements. Both these initiatives are crucial to long-term growth.

NW Natural has raised its annual dividend to $1.82 a share. This is the 57th consecutive year that the company has increased its dividend and this trend is likely to continue. The stock retreat since our last report and the dividend increase have caused the yield to expand, but it is still below average for gas utilities.

NW Natural has a Timeliness rank of 3 (Average). Although this issue has below market average appreciation potential, conservative investors with an income objective should consider this issue because it has a high and growing yield and High-est Safety rank (1); however, this issue is not for performance-minded investors.

John E. Seibert III *December 7, 2012*

(A) Diluted earnings per share. Excludes non-recurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢; Next earnings report due late January.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes intangibles. In 2011: $371.4 million, $13.88/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	90

PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE	30.34	P/E RATIO	17.8 (Trailing: 19.4 / Median: 18.0)	RELATIVE P/E RATIO	1.20	DIV'D YLD	4.0%	VALUE LINE

TIMELINESS **3** Raised 6/22/12

SAFETY **2** New 7/27/90

TECHNICAL **2** Raised 11/2/12

BETA .65 (1.00 = Market)

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+30%)	11%
Low	30	(Nil)	4%

Insider Decisions

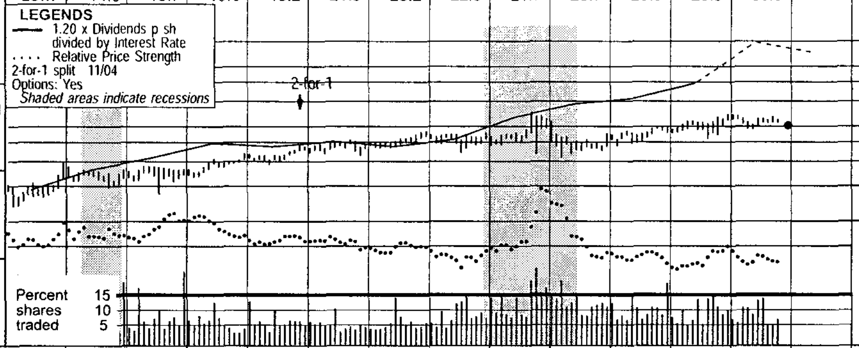
	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	1	2	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	85	68	84
to Sell	85	92	74
Hld's(000)	32579	32684	33222

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6
Low:	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.5

Target Price Range 2015 | 2016 | 2017



% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	1.1	10.8
3 yr.	52.2	48.5
5 yr.	50.0	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	*15.75*	*17.85*	Revenues per sh A	*20.10*
1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	*3.05*	*3.20*	"Cash Flow" per sh	*3.45*
.84	.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	*1.60*	*1.70*	Earnings per sh AB	*1.85*
.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	1.19	*1.23*	Div'ds Decl'd per sh C■	*1.35*
1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	*7.75*	*7.85*	Cap'l Spending per sh	*8.10*
6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	*13.85*	*14.00*	Book Value per sh D	*14.60*
59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	72.32	*71.00*	*70.00*	Common Shs Outst'g E	*68.00*
13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	18.9	*19.9*		Avg Ann'l P/E Ratio	*18.0*
.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	*1.28*		Relative P/E Ratio	*1.20*
4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	3.7%		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 7/31/12
Total Debt $1175.0 mill. Due in 5 Yrs $175.0 mill.
LT Debt $975.0 mill. LT Interest $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/11 $259.5 mill. **Oblig.** $236.6 mill.

Pfd Stock None

Common Stock 72,076,431 shs.
as of 9/4/12

MARKET CAP: $2.2 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	*1120*	*1250*	Revenues ($mill) A	*1365*
62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	*115*	*120*	Net Profit ($mill)	*125*
33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	*10.2%*	*9.6%*	Net Profit Margin	*9.3%*
43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	*49.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	*1960*	*1955*	Total Capital ($mill)	*1995*
1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	*2900*	*2950*	Net Plant ($mill)	*3050*
7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Shr. Equity	*12.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Com Equity	*12.5%*
1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	*3.0%*	*3.5%*	Retained to Com Eq	*3.5%*
83%	74%	66%	68%	74%	70%	69%	64%	72%	73%	*74%*	*72%*	All Div'ds to Net Prof	*73%*

CURRENT POSITION ($MILL.)	2010	2011	7/31/12
Cash Assets	5.6	6.8	5.7
Other	322.2	279.2	283.4
Current Assets	327.8	286.0	289.1
Accts Payable	115.7	129.7	117.9
Debt Due	302.0	331.0	200.0
Other	80.9	72.9	80.4
Current Liab.	498.6	534.1	398.3
Fix. Chg. Cov.	323%	323%	325%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	-1.5%	*-1.0%*
"Cash Flow"	5.5%	4.0%	*2.5%*
Earnings	5.0%	4.5%	*2.5%*
Dividends	4.5%	4.0%	*3.5%*
Book Value	5.0%	3.0%	*1.5%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	779.6	455.4	180.3	222.8	1638.1
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	161.1	*178.7*	*1120*
2013	*505*	*340*	*195*	*210*	*1250*

Fiscal Year Ends	EARNINGS PER SHARE A B Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	1.10	.73	d.10	d.06	1.67
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.09*	*1.60*
2013	*1.18*	*.70*	*d.09*	*d.09*	*1.70*

Cal-endar	QUARTERLY DIVIDENDS PAID C■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.25	.26	.26	.26	1.03
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	.30	

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 968,188 customers in North Carolina, South Carolina, and Tennessee. 2011 revenue mix: residential (46%), commercial (27%), industrial (7%), other (20%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 60.0% of revenues. '11 deprec. rate: 3.2%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,782 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.6% (1/12 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 likely posted a mixed bag of financial results for fiscal 2012 (ended October 31st). Indeed, we expect a year-to-year top-line decline of approximately 22%. This is largely a reflection of lower pass-through costs for natural gas. Meanwhile, on the profitability front, the company has been successful in trimming its cost of goods sold for the bulk of the year, and we expect that trend continued in the fourth quarter and for the year, as a whole. Customer additions were another boon to the bottom line. At the end of the third quarter, Piedmont had added more than 8,700 accounts to its system. Elsewhere, gains ought to have stemmed from a rise in income from equity-method investments, as higher contributions come in from the energy services and pipeline divisions. Combined, we think PNY's 2012 share-net figure ticked about 2% higher, to $1.60.

Capital projects augur well for prospects down the road. At this point, Piedmont finished the first four power generation delivery projects for Duke Energy. The fifth project, related to the Sutton Facility, is well under way, and has a targeted in-service date of June, 2013. These developments equate to an investment of $500 million, and they are boosting throughput on the Cardinal Pipeline.

We look for steady top- and bottom-line advances in fiscal 2013. This ought to be supported by continued customer additions, a wider geographic footprint due to capital expenditures, and a diligent eye on efficiency initiatives. And a recently announced 24% equity stake in Constitution Pipeline Company, LLC., a natural gas pipeline project slated to be in service in 2015 adds to the PNY's prospects.

However, the financial position has deteriorated a bit over the course of the year. Cash reserves declined 16%, through the end of the third quarter (the last period for which financial information was available), to just under $6 million. And the company has taken on about 45% more long-term debt over this time frame.

These neutrally ranked shares have remained relatively steady since our September review. And PNY's yield is on par with the *Value Line* average for the utility group.

Bryan J. Fong *December 7, 2012*

(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 Dec. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2011: $527.6 million, $7.29/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

SOUTH JERSEY INDS. NYSE-SJI

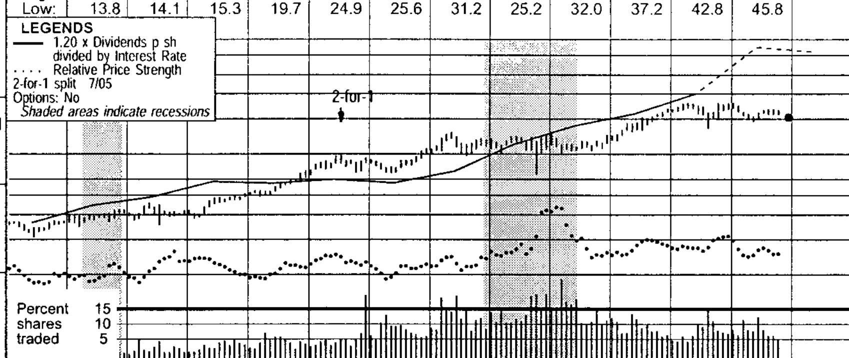
RECENT PRICE 48.96 | P/E RATIO 15.2 (Trailing: 15.7, Median: 15.0) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 3.6% | VALUE LINE

TIMELINESS 3 Lowered 11/23/12
SAFETY 2 Lowered 1/4/91
TECHNICAL 2 Raised 10/19/12
BETA .65 (1.00 = Market)

High:	17.0	18.3	20.3	26.5	32.4	34.3	41.3	40.6	40.8	54.2	58.0	58.0
Low:	13.8	14.1	15.3	19.7	24.9	25.6	31.2	25.2	32.0	37.2	42.8	45.8

Target Price Range 2015 | 2016 | 2017

LEGENDS
— 1.20 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
2-for-1 split 7/05
Options: No
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+45%)	12%
Low	55	(+10%)	7%

Insider Decisions

	J	F	M	A	M	J	J	A	S
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	3	0	1	3	0	3	2

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	59	68	78
to Sell	60	64	55
Hld's(000)	17847	17213	18018

Percent shares traded 15 10 5

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-7.3	10.8
3 yr.	56.9	48.5
5 yr.	57.3	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.52	16.18	20.89	17.60	22.43	35.30	20.69	26.34	29.51	31.78	31.76	32.30	32.36	28.37	30.97	27.42	*23.00*	*26.45*	Revenues per sh	*33.35*
1.54	1.60	1.44	1.84	1.95	1.90	2.12	2.24	2.44	2.51	3.51	3.20	3.48	3.72	4.21	4.46	*4.60*	*4.75*	"Cash Flow" per sh	*6.25*
.85	.86	.64	1.01	1.08	1.15	1.22	1.37	1.58	1.71	2.46	2.09	2.27	2.38	2.70	2.89	*3.15*	*3.35*	Earnings per sh A	*4.50*
.72	.72	.72	.72	.73	.74	.75	.78	.82	.86	.92	1.01	1.11	1.22	1.36	1.50	*1.65*	*1.82*	Div'ds Decl'd per sh B ■	*2.30*
2.01	2.30	3.06	2.19	2.21	2.82	3.47	2.36	2.67	3.21	2.51	1.88	2.08	3.67	5.59	6.39	*6.20*	*6.45*	Cap'l Spending per sh	*7.20*
8.03	6.43	6.23	6.74	7.25	7.81	9.67	11.26	12.41	13.50	15.11	16.25	17.33	18.24	19.08	20.66	*23.00*	*24.60*	Book Value per sh C	*27.80*
21.51	21.54	21.56	22.30	23.00	23.72	24.41	26.46	27.76	28.98	29.33	29.61	29.73	29.80	29.87	30.21	*31.50*	*32.50*	Common Shs Outst'g D	*36.00*
13.3	13.8	21.2	13.3	13.0	13.6	13.5	13.3	14.1	16.6	11.9	17.2	15.9	15.0	16.8	18.4	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.83	.80	1.10	.76	.85	.70	.74	.76	.74	.88	.64	.91	.96	1.00	1.07	1.16	*Value Line*		Relative P/E Ratio	*.95*
6.4%	6.1%	5.3%	5.4%	5.2%	4.7%	4.6%	4.3%	3.7%	3.0%	3.2%	2.8%	3.1%	3.4%	3.0%	2.8%	*estimates*		Avg Ann'l Div'd Yield	*3.7%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $906.8 mill. **Due in 5 Yrs** $434.0 mill.
LT Debt $566.4 mill. **LT Interest** $16.0 mill.
(Total interest coverage: 6.3x)

Pension Assets-12/11 $116.7 mill. **Oblig.** $195.0 mill.

Pfd Stock None

Common Stock 31,262,570 common shs. **as of 11/1/12**

MARKET CAP: $1.5 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
505.1	696.8	819.1	921.0	931.4	956.4	962.0	845.4	925.1	828.6	*725*	*860*	Revenues ($mill)	*1200*
29.4	34.6	43.0	48.6	72.0	61.8	67.7	71.3	81.0	87.0	*100*	*105*	Net Profit ($mill)	*160*
41.4%	40.6%	40.9%	41.5%	41.3%	41.9%	47.7%	23.0%	15.2%	22.4%	*20.0%*	*25.0%*	Income Tax Rate	*30.0%*
5.8%	5.0%	5.2%	5.3%	7.7%	6.5%	7.0%	8.4%	8.8%	10.5%	*13.8%*	*12.2%*	Net Profit Margin	*13.3%*
53.6%	50.8%	48.7%	44.9%	44.7%	42.7%	39.2%	36.5%	37.4%	40.5%	*44.0%*	*43.0%*	Long-Term Debt Ratio	*43.0%*
46.1%	49.0%	51.0%	55.1%	55.3%	57.3%	60.8%	63.5%	62.6%	59.5%	*56.0%*	*57.0%*	Common Equity Ratio	*57.0%*
512.5	608.4	675.0	710.3	801.1	839.0	848.0	856.4	910.1	1048.3	*1300*	*1400*	Total Capital ($mill)	*1750*
666.6	748.3	799.9	877.3	920.0	948.9	982.6	1073.1	1193.3	1352.4	*1480*	*1600*	Net Plant ($mill)	*1900*
7.6%	7.3%	7.9%	8.3%	10.1%	8.6%	8.9%	9.0%	9.5%	8.9%	*8.5%*	*8.0%*	Return on Total Cap'l	*9.5%*
12.4%	11.5%	12.4%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	*14.0%*	*13.0%*	Return on Shr. Equity	*16.0%*
12.5%	11.6%	12.5%	12.4%	16.3%	12.8%	13.1%	13.1%	14.2%	13.9%	*14.0%*	*13.0%*	Return on Com Equity	*16.0%*
4.7%	5.0%	5.9%	6.2%	10.2%	6.7%	6.7%	6.4%	7.1%	6.7%	*6.5%*	*5.5%*	Retained to Com Eq	*7.5%*
62%	57%	52%	50%	37%	48%	49%	51%	50%	52%	*52%*	*56%*	All Div'ds to Net Prof	*52%*

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	2.4	7.5	4.2
Other	421.4	333.1	319.6
Current Assets	423.8	340.6	323.8
Accts Payable	165.2	153.7	111.1
Debt Due	362.1	323.6	340.4
Other	113.2	110.7	101.3
Current Liab.	640.5	588.0	552.8
Fix. Chg. Cov.	532%	505%	570%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	*2.5%*
"Cash Flow"	8.0%	8.0%	*7.0%*
Earnings	9.5%	7.0%	*9.0%*
Dividends	6.5%	9.5%	*9.0%*
Book Value	10.5%	7.0%	*6.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	362.2	134.5	127.1	221.6	845.4
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	*216.3*	*725*
2013	*305*	*150*	*150*	*255*	*860*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.46	.15	d.06	.83	2.38
2010	1.49	.24	.10	.87	2.70
2011	1.63	.20	.01	1.05	2.89
2012	1.65	.28	.13	*1.09*	*3.15*
2013	*1.70*	*.30*	*.15*	*1.20*	*3.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	--	.270	.270	.568	1.11
2009	--	.298	.298	.628	1.22
2010	--	.330	.330	.695	1.36
2011	--	.365	.365	.768	1.50
2012	--	.403	.403	.845	

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 '11: residential, 41%; commercial, 20%; cogeneration and electric generation, 14%; industrial, 25%. Non-utility operations include: South Jersey Energy, South Jersey Resources Group, Marina Energy, and South Jersey Energy Service Plus. Has 675 employees. Off./dir. control 1.0% of common shares; BlackRock Inc., 7.8% (3/12 proxy). Chrmn. & CEO: Edward Graham. Inc.: NJ. Address: 1 South Jersey Plaza, Folsom, NJ 08037. Telephone: 609-561-9000. Internet: www.sjindustries.com.

Shares of South Jersey Industries have pulled back somewhat over the past two months. Revenue declined for the third quarter, but that was largely due to a lower natural gas pricing environment. The mainstay utility segment reported a moderate top-line decline, and the nonutility businesses posted considerably lower revenues. But operating costs also declined, and the bottom-line picture was much brighter. Share net came in at $0.13, well above the prior-year tally.

The company appears to have made it through Hurricane Sandy in good shape. Flooding and high winds from the super storm dealt a significant blow to New Jersey residents. But service disruption at the utility was minimal, and SJI's nonutility energy projects experienced mostly superficial damage.

We look for moderate earnings growth going forward. We expect healthy results from most of SJI's businesses. Utility South Jersey Gas ought to benefit from modest customer growth going forward. Natural gas remains the fuel of choice within its service territory, and the utility should continue to benefit from customer interest in converting from other sources of fuel. In addition, spending on infrastructure projects under the Capital Investment Recovery Tracker program ought to improve service and allow the utility to earn a good return on these investments. On the nonutility side, healthy demand for renewable and natural gas-fired energy projects should benefit the Retail Energy line. Efforts to reposition the marketing unit may also bear fruit.

The board of directors has increased the dividend by roughly 10%. The quarterly dividend is now $0.4425 per share, beginning with the December payout. The company cited strong recent performance and myriad growth opportunities as reasons for the hike. Dividend increases will likely continue in the coming years.

These shares are neutrally ranked for Timeliness. We anticipate higher revenues and earnings for the company by 2015-2017. Moreover, South Jersey earns good marks for Safety, Price Stability, and Earnings Predictability. This equity offers decent, and fairly well-defined, total return potential for the coming years.

Michael Napoli, CFA *December 7, 2012*

(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. Excl. nonrecur. gain (loss): '01, $0.13; '08, $0.31; '09, ($0.44); '10, ($0.47); '11, $0.08. Excl gain (losses) from discont. ops.: '01, ($0.02); '02, ($0.04); '03, ($0.09); '05, ($0.02); '06, ($0.02); '07, $0.01. Next egs. report due in February. (B) Div'ds paid early April, July, Oct., and late Dec. ■ Div. reinvest. plan avail. (C) Incl. reg. assets. In 2011: $315.2 mill., $10.43 per shr. (D) In mill., adj. for split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	85

SOUTHWEST GAS NYSE-SWX

RECENT PRICE	41.30	P/E RATIO	13.8 (Trailing: 15.2 / Median: 17.0)	RELATIVE P/E RATIO	0.93	DIV'D YLD	3.1%	VALUE LINE

TIMELINESS 3 Lowered 11/16/12

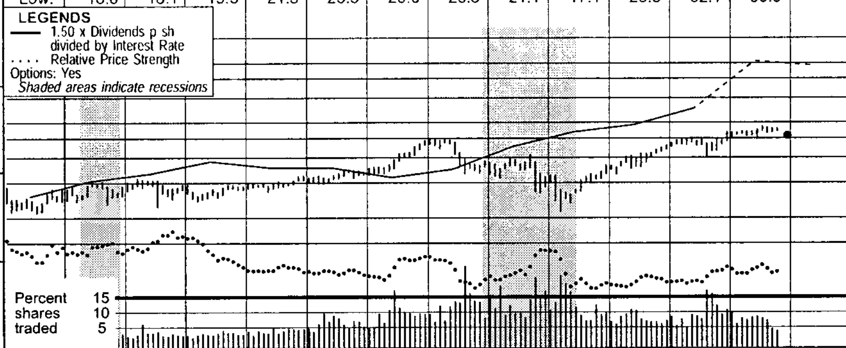
SAFETY 3 Lowered 1/4/91

TECHNICAL 3 Raised 8/10/12

BETA .75 (1.00 = Market)

High:	24.7	25.3	23.6	26.2	28.1	39.4	39.9	33.3	29.5	37.3	43.2	46.1
Low:	18.6	18.1	19.3	21.5	23.5	26.0	26.5	21.1	17.1	26.3	32.1	39.0

LEGENDS
— 1.50 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



Target Price Range
2015 | 2016 | 2017

128 / 96 / 80 / 64 / 48 / 40 / 32 / 24 / 16 / 12

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+70%)	17%
Low	45	(+10%)	6%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	1	0	0	0	0	0	1
Options	0	0	2	0	0	2	0	0	1
to Sell	1	0	4	0	1	3	0	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	56	64	85
to Sell	95	79	70
Hld's(000)	34237	35127	34847

Percent shares traded 15 / 10 / 5

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	10.8
3 yr.	90.0	48.5
5 yr.	70.9	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
24.09	26.73	30.17	30.24	32.61	42.98	39.68	35.96	40.14	43.59	48.47	50.28	48.53	42.00	40.18	41.07	*42.25*	*43.10*	Revenues per sh	52.00
3.00	3.85	4.48	4.45	4.57	4.79	5.07	5.11	5.57	5.20	5.97	6.21	5.76	6.16	6.46	6.81	*7.40*	*7.75*	"Cash Flow" per sh	9.40
.25	.77	1.65	1.27	1.21	1.15	1.16	1.13	1.66	1.25	1.98	1.95	1.39	1.94	2.27	2.43	*2.72*	*2.85*	Earnings per sh A	3.75
.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.82	.86	.90	.95	1.00	1.06	*1.18*	*1.30*	Div'ds Decl'd per sh B■†	1.60
8.19	6.19	6.40	7.41	7.04	8.17	8.50	7.03	8.23	7.49	8.27	7.96	6.79	4.81	4.73	8.29	*7.85*	*8.50*	Cap'l Spending per sh	9.60
14.20	14.09	15.67	16.31	16.82	17.27	17.91	18.42	19.18	19.10	21.58	22.98	23.49	24.44	25.62	26.66	*27.95*	*30.85*	Book Value per sh	36.00
26.73	27.39	30.41	30.99	31.71	32.49	33.29	34.23	36.79	39.33	41.77	42.81	44.19	45.09	45.56	45.96	*46.50*	*47.00*	Common Shs Outst'g C	50.00
69.3	24.1	13.2	21.1	16.0	19.0	19.9	19.2	14.3	20.6	15.9	17.3	20.3	12.2	14.0	15.7	Bold figures are		Avg Ann'l P/E Ratio	15.0
4.34	1.39	.69	1.20	1.04	.97	1.09	1.09	.76	1.10	.86	.92	1.22	.81	.89	.99	Value Line		Relative P/E Ratio	1.00
4.7%	4.4%	3.8%	3.1%	4.2%	3.8%	3.6%	3.8%	3.5%	3.2%	2.6%	2.6%	3.2%	4.0%	3.2%	2.8%	estimates		Avg Ann'l Div'd Yield	2.8%

CAPITAL STRUCTURE as of 9/30/12
Total Debt $1261.1 mill. **Due in 5 Yrs** $343.0 mill.
LT Debt $1256.0 mill. **LT Interest** $70.0 mill.
(Total interest coverage: 3.8x) (50% of Cap'l)
Leases, Uncapitalized Annual rentals $6.0 mill.
Pension Assets-12/11 $551.8 mill.
Oblig. $832.8 mill.

Pfd Stock None

Common Stock 46,140,788 shs.
as of 10/26/12

MARKET CAP: $1.9 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
1320.9	1231.0	1477.1	1714.3	2024.7	2152.1	2144.7	1893.8	1830.4	1887.2	*1965*	*2025*	Revenues ($mill)	2600
38.6	38.5	58.9	48.1	80.5	83.2	61.0	87.5	103.9	112.3	*125*	*135*	Net Profit ($mill)	190
32.8%	30.5%	34.8%	29.7%	37.3%	36.5%	40.1%	34.0%	34.7%	36.2%	*36.0%*	*35.0%*	Income Tax Rate	35.0%
2.9%	3.1%	4.0%	2.8%	4.0%	3.9%	2.8%	4.6%	5.7%	6.0%	*6.4%*	*6.7%*	Net Profit Margin	7.3%
62.5%	66.0%	64.2%	63.8%	60.6%	58.1%	55.3%	53.5%	49.1%	43.2%	*49.0%*	*48.0%*	Long-Term Debt Ratio	48.5%
34.1%	34.0%	35.8%	36.2%	39.4%	41.9%	44.7%	46.5%	50.9%	56.8%	*51.0%*	*52.0%*	Common Equity Ratio	51.5%
1748.3	1851.6	1968.6	2076.0	2287.8	2349.7	2323.3	2371.4	2291.7	2155.9	*2550*	*2800*	Total Capital ($mill)	3500
1979.5	2175.7	2336.0	2489.1	2668.1	2845.3	2983.3	3034.5	3072.4	3218.9	*3320*	*3400*	Net Plant ($mill)	3750
4.3%	4.2%	5.0%	4.3%	5.5%	5.5%	4.5%	5.4%	6.1%	6.4%	*6.5%*	*6.5%*	Return on Total Cap'l	7.0%
5.9%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Shr. Equity	10.5%
6.5%	6.1%	8.3%	6.4%	8.9%	8.5%	5.9%	7.9%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Com Equity	10.5%
1.9%	1.7%	4.3%	2.2%	5.2%	4.8%	2.1%	4.1%	5.1%	5.3%	*5.5%*	*5.0%*	Retained to Com Eq	6.0%
70%	72%	49%	65%	42%	44%	63%	48%	43%	43%	*44%*	*45%*	All Div'ds to Net Prof	42%

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	116.1	21.9	22.1
Other	329.8	439.7	327.7
Current Assets	445.9	461.6	349.8
Accts Payable	165.5	186.8	90.6
Debt Due	75.1	322.6	5.1
Other	356.4	338.2	369.5
Current Liab.	597.0	847.6	465.2
Fix. Chg. Cov.	299%	359%	375%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-1.5%	4.0%
"Cash Flow"	3.5%	3.0%	6.5%
Earnings	6.0%	6.5%	9.0%
Dividends	2.0%	4.0%	8.0%
Book Value	4.5%	5.0%	6.0%

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	689.9	387.6	317.5	498.8	1893.8
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	*525.8*	*1965*
2013	*670*	*420*	*390*	*545*	*2025*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.12	d.01	d.18	1.01	1.94
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	*1.19*	*2.72*
2013	*1.80*	*.10*	*d.30*	*1.25*	*2.85*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.215	.225	.225	.225	.89
2009	.225	.238	.238	.238	.94
2010	.238	.250	.250	.250	.99
2011	.250	.265	.265	.265	1.05
2012	.265	.295	.295	.295	

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. 2011 margin mix: residential and small commercial, 86%; large commercial and industrial, 4%; transportation, 10%. Total throughput: 2.1 billion therms. Sold PriMerit Bank, 7/96. Has 5,754 employees. Off. & Dir. own 1.6% of common stock; BlackRock Inc., 8.5%; GAMCO Investors, Inc., 8.3%; T. Rowe Price Associates, Inc., 6.7% (3/12 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 improved results for the third quarter. Revenues increased at a moderate clip, and the company posted a much lower share loss for the interim, partly because Southwest experienced healthy growth in the construction business. Utility revenues were roughly flat, compared with the prior-year period, but were supported by higher rates in Arizona. Efforts to control operating costs benefited the bottom line. We anticipate healthy results for the fourth quarter, and greater revenues and share net for full-year 2012.

The Public Utilities Commission of Nevada has approved a $7 million annualized rate increase. The new rates became effective in November. However, the rate hike is much lower than the $27 million increase the company had been seeking. Including other aspects of the decision, Southwest estimates an annual operating income benefit of around $11.4 million. The company also identified several items it may request to have formally reconsidered by the commission. Southwest's focus on this matter is to be expected, as it depends on approved revenue increases to help it cope with higher costs and as compensation for infrastructure investment.

Performance may well continue to improve in 2013. The utility business should benefit from modest customer growth and recently granted rate relief. Meantime, the construction services subsidiary should continue to experience healthy demand, given the need to replace aging infrastructure.

The stock is not without risk. The company will probably incur greater operating expenses as it continues to expand. Moreover, lagging rate relief or unfavorable temperature variations could hurt the performance of the utility business.

This stock is now neutrally ranked for Timeliness. But the shares have some positive characteristics. Namely, Southwest Gas earns good marks for Price Stability and Earnings Predictability. Dividend growth ought to continue, as well, though the yield will probably remain below the industry average. Even so, this stock has decent total return potential for the coming years.

Michael Napoli, CFA *December 7, 2012*

(A) Based on avg. shares outstand. thru. '96, then diluted. Excl. nonrec. gains (losses): '97, 16¢; '02, (10¢); '05, (11¢); '06, 7¢. Next egs. report due late February. (B) Dividends historically paid early March, June, September, December. ■† Div'd reinvestment and stock purchase plan avail. (C) In millions.

Company's Financial Strength	B
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	75

WGL HOLDINGS NYSE-WGL

RECENT PRICE **37.81** | P/E RATIO **14.8** (Trailing: 14.1; Median: 15.0) | RELATIVE P/E RATIO **1.00** | DIV'D YLD **4.2%** | **VALUE LINE**

TIMELINESS 3 Raised 9/9/11
SAFETY 1 Raised 4/2/93
TECHNICAL 2 Raised 11/2/12
BETA .65 (1.00 = Market)

High:	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0			Target Price Range		
Low:	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	36.0			2015	2016	2017

2015-17 PROJECTIONS

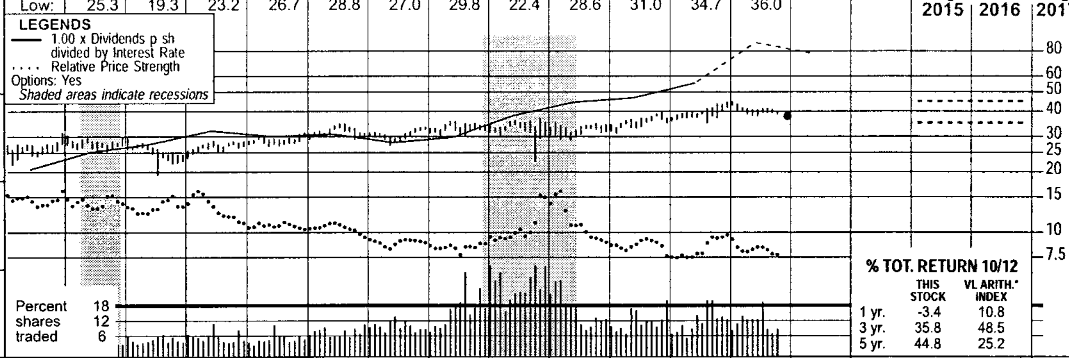
	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-5%)	3%

Insider Decisions

	J	F	M	A	M	J	J	A	S
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	1	0	0	0	0	0	3	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	88	81	86
to Sell	80	96	83
Hld's(000)	31882	31569	31990



% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	-3.4	10.8
3 yr.	35.8	48.5
5 yr.	44.8	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	*47.09*	*51.20*	Revenues per sh A	*55.70*
2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	*4.60*	*4.40*	"Cash Flow" per sh	*4.65*
1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	2.68	*2.50*	Earnings per sh B	*2.75*
1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	1.59	*1.63*	Div'ds Decl'd per sh C■	*1.75*
2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	*5.85*	*4.85*	Cap'l Spending per sh	*4.80*
12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	*24.75*	*25.55*	Book Value per sh D	*28.65*
43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	*51.50*	*51.75*	Common Shs Outst'g E	*52.00*
11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	15.3		Avg Ann'l P/E Ratio	*15.0*
.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	.99		Relative P/E Ratio	*1.00*
5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	4.3%		Avg Ann'l Div'd Yield	*4.1%*
						1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	2425.3	*2650*	Revenues ($mill) A	*2895*
						55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	115.5	*138.3*	*130*	Net Profit ($mill)	*145*
						34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
						3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	*5.7%*	*4.9%*	Net Profit Margin	*5.0%*
						45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	*31.0%*	*30.5%*	Long-Term Debt Ratio	*28.5%*
						52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	*67.5%*	*68.0%*	Common Equity Ratio	*70.5%*
						1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	1886.9	*1945*	Total Capital ($mill)	*2115*
						1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	2667.4	*2855*	Net Plant ($mill)	*3515*
						5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	8.3%	*7.5%*	Return on Total Cap'l	*7.5%*
						7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	*10.9%*	*10.0%*	Return on Shr. Equity	*9.5%*
						7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	*11.0%*	*10.0%*	Return on Com Equity	*9.5%*
						NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	4.3%	*3.5%*	Retained to Com Eq	*3.5%*
						112%	56%	65%	62%	69%	66%	57%	57%	67%	64%	59%	*65%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 9/30/12
Total Debt $836.9 mill. **Due in 5 Yrs** $112.0 mill.
LT Debt $589.2 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 51,613,381 shs.
as of 10/31/12

MARKET CAP: $2.0 billion (Mid Cap)

CURRENT POSITION ($MILL.)	2010	2011	9/30/12
Cash Assets	8.9	4.3	10.3
Other	708.4	720.4	822.5
Current Assets	717.3	724.7	832.8
Accts Payable	225.4	279.4	270.4
Debt Due	130.5	116.5	247.7
Other	188.2	180.8	238.9
Current Liab.	544.1	576.7	757.0
Fix. Chg. Cov.	536%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.5%	2.5%	.5%
"Cash Flow"	3.0%	1.5%	1.5%
Earnings	3.0%	3.0%	2.5%
Dividends	2.0%	2.5%	2.5%
Book Value	4.0%	5.0%	4.0%

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1056.6	459.7	465.2	2708.9
2011	795.9	1017.2	490.3	448.1	2751.5
2012	727.8	839.4	438.3	419.8	2425.3
2013	*785*	*895*	*495*	*475*	*2650*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.03	1.65	.11	d.25	2.53
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	d.03	d.26	2.25
2012	1.13	1.58	.08	d.10	2.68
2013	*1.08*	*1.54*	*.03*	*d.15*	*2.50*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.34	.36	.36	.36	1.42
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	

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 (1,082,983 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. Black Rock Inc. owns 7.4% of common stock; Off./dir. less than 1% (1/12 proxy). Chrmn. & 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 a mixed bag of financial results for fiscal 2012 (ended September 30th). Revenues declined approximately 12% due to similar downturns at both the utility and nonutility divisions. This largely reflected lower natural gas prices on a year-over-year basis. Nonetheless, this was offset by a tight handle on costs, which helped to reduce operating expenses by 210 basis points as a function of the top line. Consequently, the annual bottom line advanced 19%, to $2.68 for the year, supported by solid contributions at the Regulated Utility, Retail Energy-Marketing, and Commercial Energy Systems units.

However, this year's prospects do not appear to be as bright. Indeed, WGL's management recently released its 2013 earnings guidance of $2.37 to $2.49 per share. This has prompted us to trim a dime off our estimates for this time frame, to $2.50, a move that would represent an annual declined of almost 7%. The bulk of this downturn will likely stem from rising costs for operations & maintenance and employee pension & post retirement benefits. Too, accelerated expenses for pipeline integrity and compliance will also be a detractor this year. And an active capital expenditures pipeline adds to the margin compression. Indeed, WGL has plans for approximately $1.8 billion in growth projects through 2017. However, it is important to note that many of this year's higher costs will be recouped through rate cases down the road, and the diminished bottom line is more of an issue with the timing of expenses, rather than a breakdown in the fundamentals of the company's business. That said, WGL Holdings is expecting to add about 10,500 customer meters this year, and is actively expanding its alternative energy division.

Our Timeliness Ranking System pegs these shares to mirror the broader market averages in the coming six to 12 months. Over that time frame, WGL may appeal to investors with an eye on income generation. In fact, the yield here is above the average of the natural gas utilities group. However, on the downside, capital appreciation potential for the pull to 2015-2017 is limited, due to the stock's steady price action.

Bryan J. Fong *December 7, 2012*

(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 Jan. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '11: $594.4 million, $11.56/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

ATTACHMENT C

American Water Works Co Inc: (NYSE: AWK)

ZACKS RANK: 3-HOLD

$38.00 -0.17 (-0.45%) VOLUME 377,259 DEC 03 02:27 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

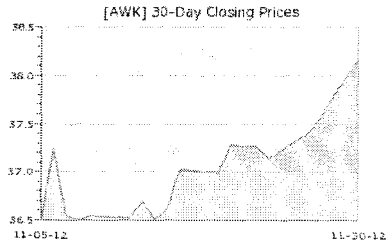
GENERAL INFORMATION

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	09/30/2012
Next EPS Date	03/04/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	38.17
52 Week High	39.38
52 Week Low	30.34
Beta	0.29
20 Day Moving Average	757,416.50
Target Price Consensus	42.05



% Price Change

4 Week	4.58
12 Week	2.39
YTD	19.80

% Price Change Relative to S&P 500

4 Week	4.43
12 Week	3.96
YTD	4.04

Share Information

Shares Outstanding (millions)	176.43
Market Capitalization (millions)	6,734.33
Short Ratio	0.85
Last Split Date	NA

Dividend Information

Dividend Yield	2.62%
Annual Dividend	$1.00
Payout Ratio	0.47
Change in Payout Ratio	-0.12
Last Dividend Payout / Amount	11/14/2012 / $0.25

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.40
Current Year EPS Consensus Estimate	2.19
Estimated Long-Term EPS Growth Rate	8.30
Next EPS Report Date	03/04/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.29
30 Days Ago	1.29
60 Days Ago	1.29
90 Days Ago	1.29

FUNDAMENTAL RATIOS

American Sts Wtr Co: (NYSE: AWR)

ZACKS RANK: 1-STRONG BUY

$45.36 -0.14 (-0.31%) VOLUME 43,098 DEC 03 02:29 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

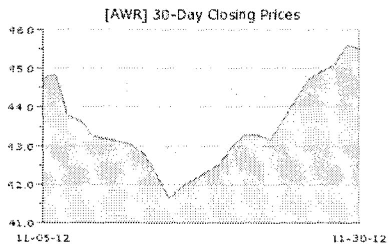
GENERAL INFORMATION

AMER STATES WTR
630 E FOOTHILL BLVD
SAN DIMAS, CA 91773-9016
Phone: 9093943600
Fax: 909-394-1382
Web: http://www.aswater.com
Email: investorinfo@aswater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	03/11/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	45.50
52 Week High	45.95
52 Week Low	34.07
Beta	0.34
20 Day Moving Average	91,862.10
Target Price Consensus	44.00



% Price Change

4 Week	4.65
12 Week	3.55
YTD	30.37

% Price Change Relative to S&P 500

4 Week	4.50
12 Week	5.14
YTD	10.39

Share Information

Shares Outstanding (millions)	18.92
Market Capitalization (millions)	861.04
Short Ratio	6.26
Last Split Date	06/10/02

Dividend Information

Dividend Yield	3.12%
Annual Dividend	$1.42
Payout Ratio	0.54
Change in Payout Ratio	-0.04
Last Dividend Payout / Amount	11/07/2012 / $0.35

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.37
Current Year EPS Consensus Estimate	2.66
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	03/11/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.71
30 Days Ago	2.71
60 Days Ago	2.71
90 Days Ago	2.43

FUNDAMENTAL RATIOS

California Wtr Svc Group: (NYSE: CWT)

ZACKS RANK: 3-HOLD

$17.91 -0.09 (-0.50%) VOLUME 83,940 DEC 03 02:30 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

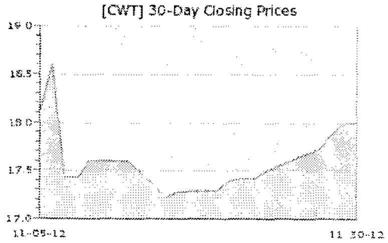
GENERAL INFORMATION

CALIF WATER SVC
1720 N FIRST ST C/O CALIFORNIA WATER SERVICE CO
SAN JOSE, CA 95112
Phone: 408-367-8200
Fax: 831-427-9185
Web: http://www.calwatergroup.com
Email: NA

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	03/06/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	18.00
52 Week High	19.25
52 Week Low	16.84
Beta	0.27
20 Day Moving Average	198,340.20
Target Price Consensus	20.00



% Price Change

4 Week	-0.33
12 Week	-1.69
YTD	-1.42

% Price Change Relative to S&P 500

4 Week	-0.47
12 Week	-0.18
YTD	-14.47

Share Information

Shares Outstanding (millions)	41.92
Market Capitalization (millions)	754.47
Short Ratio	5.83
Last Split Date	06/13/11

Dividend Information

Dividend Yield	3.50%
Annual Dividend	$0.63
Payout Ratio	0.59
Change in Payout Ratio	-0.08
Last Dividend Payout / Amount	11/07/2012 / $0.16

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.09
Current Year EPS Consensus Estimate	0.98
Estimated Long-Term EPS Growth Rate	5.00
Next EPS Report Date	03/06/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.57
30 Days Ago	2.38
60 Days Ago	2.38
90 Days Ago	2.38

FUNDAMENTAL RATIOS

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FINANCIALS
- Financial Overview
- Income Statements
- Balance Sheet
- Cash flow Statements

Middlesex Water Co: (NASD: MSEX)

ZACKS RANK: 2-BUY

$18.54 -0.17 (-0.91%) **VOLUME 14,683** **DEC 03 02:31 PM ET**

Full Company Report Get Full Company Report for: Enter Symbol GO

Middlesex Water Company treats, stores and distributes water for residential, commercial, industrial and fire prevention purposes.

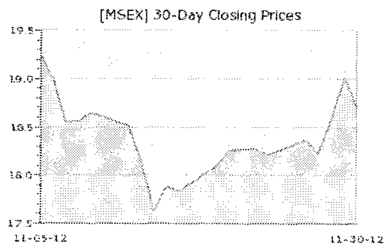
GENERAL INFORMATION

MIDDLESEX WATER
1500 RONSON RD P O BOX 1500
ISELIN, NJ 08830
Phone: 7326341500
Fax: 732-638-7515
Web: http://www.middlesexwater.com
Email: bsohler@middlesexwater.com

Industry	**UTIL-WATER SPLY**
Sector	**Utilities**
Fiscal Year End	**December**
Last Reported Quarter	**09/30/2012**
Next EPS Date	**03/07/2013**

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	**18.71**
52 Week High	**19.64**
52 Week Low	**17.48**
Beta	**0.48**
20 Day Moving Average	**29,044.65**
Target Price Consensus	**20.50**



% Price Change

4 Week	**-1.53**
12 Week	**-1.73**
YTD	**0.27**

% Price Change Relative to S&P 500

4 Week	**-1.66**
12 Week	**-0.22**
YTD	**-12.91**

Share Information

Shares Outstanding (millions)	**15.73**
Market Capitalization (millions)	**294.36**
Short Ratio	**11.78**
Last Split Date	**11/17/03**

Dividend Information

Dividend Yield	**4.01%**
Annual Dividend	**$0.75**
Payout Ratio	**0.88**
Change in Payout Ratio	**0.09**
Last Dividend Payout / Amount	**11/13/2012 / $0.19**

EPS INFORMATION

Current Quarter EPS Consensus Estimate	**0.19**
Current Year EPS Consensus Estimate	**0.92**
Estimated Long-Term EPS Growth Rate	**NA**
Next EPS Report Date	**03/07/2013**

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	**2.33**
30 Days Ago	**2.33**
60 Days Ago	**2.33**
90 Days Ago	**2.33**

FUNDAMENTAL RATIOS

Sjw Corp: (NYSE: SJW)

ZACKS RANK: 3-HOLD

$24.10 -0.36 (-1.46%) **VOLUME 6,067** DEC 03 02:22 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.

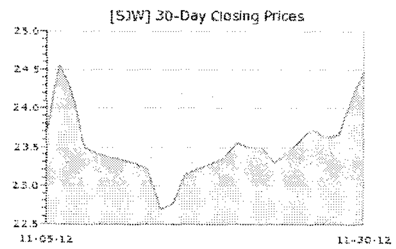
GENERAL INFORMATION

SJW CORP
110 W. TAYLOR STREET
SAN JOSE, CA 95110
Phone: 4082797800
Fax: 4082797917
Web: http://www.sjwater.com/
Email: boardofdirectors@sjwater.com

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	02/19/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	24.46
52 Week High	25.99
52 Week Low	22.56
Beta	0.61
20 Day Moving Average	16,750.30
Target Price Consensus	27.25



% Price Change

4 Week	4.44
12 Week	1.58
YTD	3.47

% Price Change Relative to S&P 500

4 Week	4.29
12 Week	3.14
YTD	-12.08

Share Information

Shares Outstanding (millions)	18.64
Market Capitalization (millions)	455.86
Short Ratio	15.88
Last Split Date	03/17/06

Dividend Information

Dividend Yield	2.90%
Annual Dividend	$0.71
Payout Ratio	0.68
Change in Payout Ratio	-0.04
Last Dividend Payout / Amount	11/01/2012 / $0.18

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.18
Current Year EPS Consensus Estimate	1.05
Estimated Long-Term EPS Growth Rate	NA
Next EPS Report Date	02/19/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.50
30 Days Ago	1.50
60 Days Ago	1.50
90 Days Ago	1.50

FUNDAMENTAL RATIOS

Aqua America Inc: (NYSE: WTR)

ZACKS RANK: 3-HOLD

$25.34 -0.20 (-0.78%) **VOLUME 376,108** **DEC 03 02:32 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.

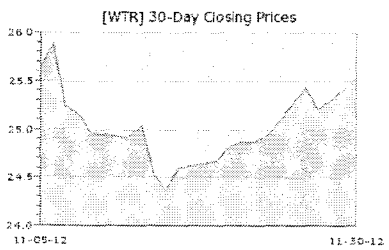
GENERAL INFORMATION

AQUA AMER INC
762 W. LANCASTER AVE
BRYN MAWR, PA 19010-3489
Phone: 610-527-8000
Fax: 610-645-1061
Web: http://www.aquaamerica.com
Email: NA

Industry	UTIL-WATER SPLY
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	03/04/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	25.54
52 Week High	26.93
52 Week Low	21.06
Beta	0.19
20 Day Moving Average	417,420.59
Target Price Consensus	26.71



% Price Change

4 Week	1.03
12 Week	1.23
YTD	15.83

% Price Change Relative to S&P 500

4 Week	0.89
12 Week	2.78
YTD	0.90

Share Information

Shares Outstanding (millions)	139.73
Market Capitalization (millions)	3,568.81
Short Ratio	6.79
Last Split Date	12/02/05

Dividend Information

Dividend Yield	2.74%
Annual Dividend	$0.70
Payout Ratio	0.62
Change in Payout Ratio	-0.07
Last Dividend Payout / Amount	11/14/2012 / $0.17

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.24
Current Year EPS Consensus Estimate	1.09
Estimated Long-Term EPS Growth Rate	6.90
Next EPS Report Date	03/04/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.46
30 Days Ago	2.54
60 Days Ago	2.54
90 Days Ago	2.54

FUNDAMENTAL RATIOS

Agl Resources Inc: (NYSE: GAS)

ZACKS RANK: 3-HOLD

$38.75 -0.23 (-0.59%) **VOLUME 198,688** DEC 03 02:00 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.

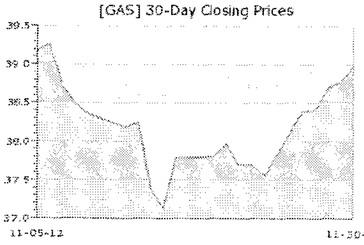
GENERAL INFORMATION

AGL RESOURCES
TEN PEACHTREE PLACE
ATLANTA, GA 30309
Phone: 4045844000
Fax: 404-584-3714
Web: http://www.aglresources.com
Email: sstashak@aglresources.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	02/20/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	38.98
52 Week High	43
52 Week Low	36.59
Beta	0.41
20 Day Moving Average	376,822.59
Target Price Consensus	41.40



% Price Change

4 Week	-1.49
12 Week	-4.62
YTD	-7.76

% Price Change Relative to S&P 500

4 Week	-1.63
12 Week	-3.16
YTD	-20.70

Share Information

Shares Outstanding (millions)	117.52
Market Capitalization (millions)	4,580.77
Short Ratio	4.18
Last Split Date	12/04/95

Dividend Information

Dividend Yield	4.72%
Annual Dividend	$1.84
Payout Ratio	0.76
Change in Payout Ratio	0.13
Last Dividend Payout / Amount	11/14/2012 / $0.46

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.05
Current Year EPS Consensus Estimate	2.66
Estimated Long-Term EPS Growth Rate	4.40
Next EPS Report Date	02/20/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.57
30 Days Ago	2.57
60 Days Ago	2.57
90 Days Ago	2.57

FUNDAMENTAL RATIOS

Atmos Energy Corp: (NYSE: ATO)

ZACKS RANK: 3-HOLD

$35.33 0.32 (0.91%) VOLUME 336,981 DEC 03 02:43 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.

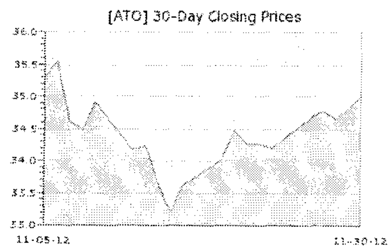
GENERAL INFORMATION

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	09/30/2012
Next EPS Date	02/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	35.01
52 Week High	37.33
52 Week Low	30.39
Beta	0.44
20 Day Moving Average	386,889.50
Target Price Consensus	36.80



% Price Change

4 Week	-0.74
12 Week	-0.85
YTD	4.98

% Price Change Relative to S&P 500

4 Week	-0.88
12 Week	0.67
YTD	-8.48

Share Information

Shares Outstanding (millions)	90.17
Market Capitalization (millions)	3,156.96
Short Ratio	2.87
Last Split Date	05/17/94

Dividend Information

Dividend Yield	4.00%
Annual Dividend	$1.40
Payout Ratio	0.59
Change in Payout Ratio	-0.05
Last Dividend Payout / Amount	11/21/2012 / $0.35

EPS INFORMATION

Current Quarter EPS Consensus Estimate	0.78
Current Year EPS Consensus Estimate	2.47
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	02/05/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.57
30 Days Ago	2.57
60 Days Ago	2.57
90 Days Ago	2.57

FUNDAMENTAL RATIOS

Laclede Group Inc: (NYSE: LG)

ZACKS RANK: 2-BUY

$39.94 -0.77 (-1.89%) VOLUME 77,663 DEC 03 02:42 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.

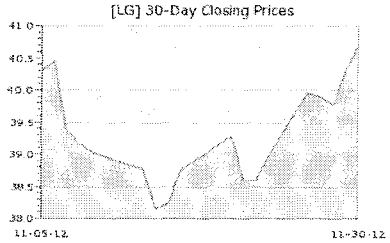
GENERAL INFORMATION

LACLEDE GRP INC
720 OLIVE ST
ST LOUIS, MO 63101
Phone: 3143420500
Fax: 3144211979
Web: http://www.thelacledegroup.com
Email: mkullman@lacledegas.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	09/30/2012
Next EPS Date	01/24/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	40.71
52 Week High	44.04
52 Week Low	36.53
Beta	0.07
20 Day Moving Average	89,380.95
Target Price Consensus	42.50



% Price Change

4 Week	0.17
12 Week	-3.55
YTD	0.59

% Price Change Relative to S&P 500

4 Week	0.03
12 Week	-2.07
YTD	-13.97

Share Information

Shares Outstanding (millions)	22.51
Market Capitalization (millions)	916.38
Short Ratio	13.85
Last Split Date	03/08/94

Dividend Information

Dividend Yield	4.08%
Annual Dividend	$1.66
Payout Ratio	0.59
Change in Payout Ratio	0.00
Last Dividend Payout / Amount	09/07/2012 / $0.41

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.10
Current Year EPS Consensus Estimate	2.77
Estimated Long-Term EPS Growth Rate	3.00
Next EPS Report Date	01/24/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.00
30 Days Ago	3.00
60 Days Ago	3.00
90 Days Ago	3.00

FUNDAMENTAL RATIOS

New Jersey Resources Corp: (NYSE: NJR)

ZACKS RANK: 4-SELL

$40.95 0.37 (0.91%) VOLUME 150,435 DEC 03 02:45 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.

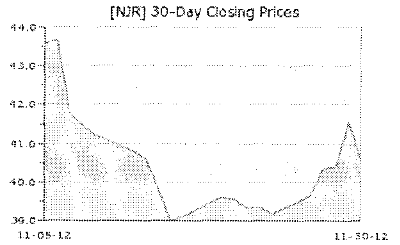
GENERAL INFORMATION

NJ RESOURCES
1415 WYCKOFF RD PO BOX 1468
WALL, NJ 07719
Phone: 9089381494
Fax: 732-938-2134
Web: http://www.njresources.com
Email: dpurna@njresources.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	09/30/2012
Next EPS Date	02/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	40.58
52 Week High	50.48
52 Week Low	38.51
Beta	0.23
20 Day Moving Average	182,559.09
Target Price Consensus	45.20



% Price Change

4 Week	-6.93
12 Week	-10.22
YTD	-17.52

% Price Change Relative to S&P 500

4 Week	-7.06
12 Week	-8.84
YTD	-28.91

Share Information

Shares Outstanding (millions)	41.59
Market Capitalization (millions)	1,687.68
Short Ratio	12.11
Last Split Date	03/04/08

Dividend Information

Dividend Yield	3.94%
Annual Dividend	$1.60
Payout Ratio	0.59
Change in Payout Ratio	NA
Last Dividend Payout / Amount	09/20/2012 / $0.40

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.28
Current Year EPS Consensus Estimate	2.76
Estimated Long-Term EPS Growth Rate	3.40
Next EPS Report Date	02/05/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.14
30 Days Ago	3.14
60 Days Ago	3.14
90 Days Ago	3.14

FUNDAMENTAL RATIOS

Northwest Natural Gas: (NYSE: NWN)

ZACKS RANK: 3-HOLD

$43.48 -0.38 (-0.87%) VOLUME 24,744 DEC 03 02:45 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.

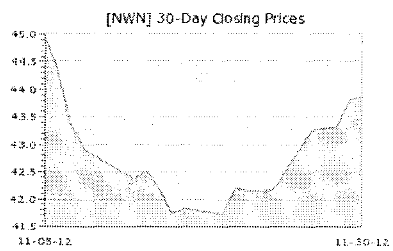
GENERAL INFORMATION

NORTHWEST NAT G
ONE PACIFIC SQUARE 220 NW SECOND AVE
PORTLAND, OR 97209
Phone: 5032264211
Fax: 503-273-4824
Web: http://www.nwnatural.com
Email: bob.hess@nwnatural.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	03/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	43.86
52 Week High	50.8
52 Week Low	41.01
Beta	0.26
20 Day Moving Average	114,028.20
Target Price Consensus	45.75



% Price Change

4 Week	-2.36
12 Week	-9.73
YTD	-8.49

% Price Change Relative to S&P 500

4 Week	-2.50
12 Week	-8.35
YTD	-21.48

Share Information

Shares Outstanding (millions)	26.83
Market Capitalization (millions)	1,176.85
Short Ratio	11.99
Last Split Date	09/09/96

Dividend Information

Dividend Yield	4.15%
Annual Dividend	$1.82
Payout Ratio	0.75
Change in Payout Ratio	0.13
Last Dividend Payout / Amount	10/29/2012 / $0.46

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.12
Current Year EPS Consensus Estimate	2.36
Estimated Long-Term EPS Growth Rate	4.20
Next EPS Report Date	03/05/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.13
30 Days Ago	3.38
60 Days Ago	2.88
90 Days Ago	2.63

FUNDAMENTAL RATIOS

Piedmont Natural Gas Co Inc: (NYSE: PNY)

ZACKS RANK: 4-SELL

$30.91 0.05 (0.16%) VOLUME 113,271 DEC 03 02:47 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.

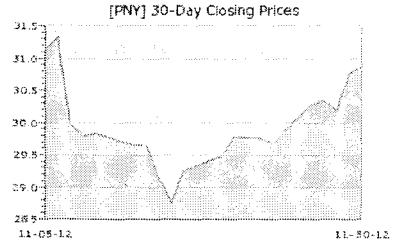
GENERAL INFORMATION

PIEDMONT NAT GA
4720 PIEDMONT ROW DR
CHARLOTTE, NC 28233
Phone: 7043643120
Fax: 704-365-3849
Web: http://www.piedmontng.com
Email: investorrelations@piedmontng.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	October
Last Reported Quarter	10/31/2012
Next EPS Date	12/14/2012

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	30.86
52 Week High	34.74
52 Week Low	28.51
Beta	0.30
20 Day Moving Average	212,593.50
Target Price Consensus	31.80



% Price Change

4 Week	-1.06
12 Week	-3.89
YTD	-9.18

% Price Change Relative to S&P 500

4 Week	-1.20
12 Week	-2.42
YTD	-22.08

Share Information

Shares Outstanding (millions)	72.08
Market Capitalization (millions)	2,224.27
Short Ratio	12.68
Last Split Date	11/01/04

Dividend Information

Dividend Yield	3.89%
Annual Dividend	$1.20
Payout Ratio	0.77
Change in Payout Ratio	NA
Last Dividend Payout / Amount	09/20/2012 / $0.30

EPS INFORMATION

Current Quarter EPS Consensus Estimate	-0.07
Current Year EPS Consensus Estimate	1.61
Estimated Long-Term EPS Growth Rate	5.20
Next EPS Report Date	12/14/2012

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	3.14
30 Days Ago	3.29
60 Days Ago	3.29
90 Days Ago	3.29

FUNDAMENTAL RATIOS

South Jersey Industries Inc: (NYSE: SJI)

ZACKS RANK: 2-BUY

$49.68 -0.29 (-0.58%) VOLUME 52,158 DEC 03 02:46 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.

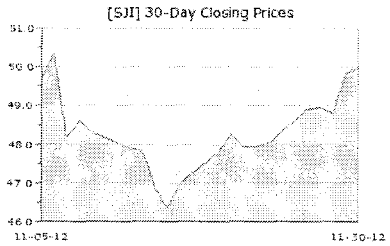
GENERAL INFORMATION

SOUTH JERSEY IN
1 SOUTH JERSEY PLAZA ROUTE 54
FOLSOM, NJ 08037
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	09/30/2012
Next EPS Date	03/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	49.97
52 Week High	57.99
52 Week Low	45.81
Beta	0.31
20 Day Moving Average	99,954.75
Target Price Consensus	61.00



% Price Change

4 Week	-0.06
12 Week	-2.88
YTD	-12.04

% Price Change Relative to S&P 500

4 Week	-0.20
12 Week	-1.39
YTD	-24.52

Share Information

Shares Outstanding (millions)	30.87
Market Capitalization (millions)	1,542.37
Short Ratio	9.21
Last Split Date	07/01/05

Dividend Information

Dividend Yield	3.22%
Annual Dividend	$1.61
Payout Ratio	0.52
Change in Payout Ratio	-0.01
Last Dividend Payout / Amount	09/06/2012 / $0.40

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.08
Current Year EPS Consensus Estimate	3.10
Estimated Long-Term EPS Growth Rate	6.00
Next EPS Report Date	03/05/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	1.50
30 Days Ago	1.50
60 Days Ago	1.50
90 Days Ago	1.50

FUNDAMENTAL RATIOS

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FINANCIALS
Financial Overview
Income Statements
Balance Sheet
Cash flow Statements

Southwest Gas Corp: (NYSE: SWX)

ZACKS RANK: 2-BUY

$41.94 0.00 (0.00%) VOLUME 96,187 DEC 03 02:49 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.

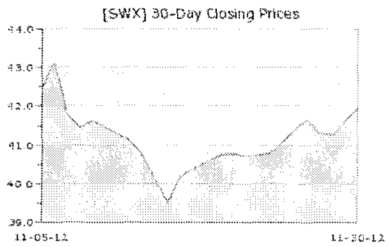
GENERAL INFORMATION

SOUTHWEST GAS
5241 SPRING MOUNTAIN . PO BOX 98510RD
LAS VEGAS, NV 89193-8510
Phone: 7028767237
Fax: 702-876-7037
Web: http://www.swgas.com
Email: NA

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	December
Last Reported Quarter	09/30/2012
Next EPS Date	03/05/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	41.94
52 Week High	46.08
52 Week Low	38.2
Beta	0.69
20 Day Moving Average	125,787.80
Target Price Consensus	46.00



% Price Change

4 Week	-2.06
12 Week	-4.55
YTD	-1.29

% Price Change Relative to S&P 500

4 Week	-2.19
12 Week	-3.09
YTD	-14.35

Share Information

Shares Outstanding (millions)	46.13
Market Capitalization (millions)	1,934.78
Short Ratio	6.89
Last Split Date	NA

Dividend Information

Dividend Yield	2.81%
Annual Dividend	$1.18
Payout Ratio	0.40
Change in Payout Ratio	-0.06
Last Dividend Payout / Amount	11/13/2012 / $0.29

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.24
Current Year EPS Consensus Estimate	2.72
Estimated Long-Term EPS Growth Rate	5.00
Next EPS Report Date	03/05/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.38
30 Days Ago	2.38
60 Days Ago	2.38
90 Days Ago	2.38

FUNDAMENTAL RATIOS

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ESTIMATES
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CHART
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RESEARCH
- Full Company Report
- Zacks Equity Research
- Earnings Announcements
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- Annual Report

FINANCIALS
- Financial Overview
- Income Statements
- Balance Sheet
- Cash flow Statements

Wgl Holdings Inc: (NYSE: WGL)

ZACKS RANK: 3-HOLD

$38.66 -0.40 (-1.02%) VOLUME 153,727 DEC 03 02:51 PM ET

Full Company Report Get Full Company Report for: Enter Symbol GO

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.

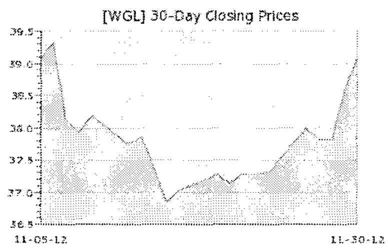
GENERAL INFORMATION

WGL HLDGS INC
101 CONSTITUTION AVE N.W.
WASHINGTON, DC 20080
Phone: 2026246011
Fax: 703-750-4828
Web: http://www.wglholdings.com
Email: douglas.bonawitz@washgas.com

Industry	UTIL-GAS DISTR
Sector	Utilities
Fiscal Year End	September
Last Reported Quarter	09/30/2012
Next EPS Date	02/08/2013

PRICE AND VOLUME INFORMATION

Zacks Rank	
Yesterday's Close	39.06
52 Week High	44.99
52 Week Low	35.96
Beta	0.22
20 Day Moving Average	224,912.66
Target Price Consensus	40.83



% Price Change

4 Week	0.21
12 Week	-2.69
YTD	-11.67

% Price Change Relative to S&P 500

4 Week	0.07
12 Week	-1.20
YTD	-24.72

Share Information

Shares Outstanding (millions)	51.57
Market Capitalization (millions)	2,014.48
Short Ratio	12.29
Last Split Date	05/02/95

Dividend Information

Dividend Yield	4.10%
Annual Dividend	$1.60
Payout Ratio	0.59
Change in Payout Ratio	-0.02
Last Dividend Payout / Amount	10/05/2012 / $0.40

EPS INFORMATION

Current Quarter EPS Consensus Estimate	1.02
Current Year EPS Consensus Estimate	2.43
Estimated Long-Term EPS Growth Rate	5.30
Next EPS Report Date	02/08/2013

CONSENSUS RECOMMENDATIONS

Current (1=Strong Buy, 5=Strong Sell)	2.43
30 Days Ago	2.57
60 Days Ago	2.57
90 Days Ago	2.57

FUNDAMENTAL RATIOS

ATTACHMENT D

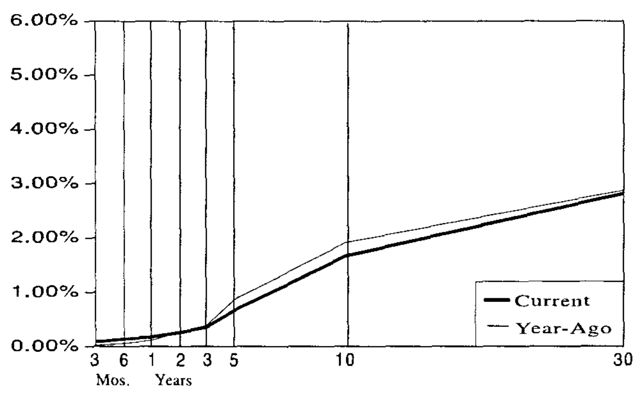
Selected Yields

	Recent (11/20/12)	3 Months Ago (8/22/12)	Year Ago (11/22/11)
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)	0.22	0.31	0.44
3-month LIBOR	0.31	0.43	0.50
Bank CDs			
6-month	0.11	0.17	0.17
1-year	0.16	0.21	0.21
5-year	0.76	0.96	1.14
U.S. Treasury Securities			
3-month	0.09	0.10	0.02
6-month	0.14	0.13	0.06
1-year	0.18	0.18	0.11
5-year	0.67	0.70	0.87
10-year	1.67	1.70	1.92
10-year (inflation-protected)	-0.76	-0.58	0.01
30-year	2.82	2.82	2.88
30-year Zero	3.04	3.00	3.05

	Recent (11/20/12)	3 Months Ago (8/22/12)	Year Ago (11/22/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.73	0.96	1.25
FHLMC 5.5% (Gold)	2.09	2.12	2.33
FNMA 5.5%	1.73	1.94	2.05
FNMA ARM	2.19	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.91	3.09	4.45
Industrial (25/30-year) A	3.78	3.82	4.20
Utility (25/30-year) A	3.78	3.85	4.06
Utility (25/30-year) Baa/BBB	4.13	4.28	4.74
Foreign Bonds (10-Year)			
Canada	1.76	1.84	2.08
Germany	1.42	1.46	1.92
Japan	0.74	0.83	0.97
United Kingdom	1.85	1.63	2.17
Preferred Stocks			
Utility A	5.12	5.32	5.84
Financial BBB	6.09	6.08	6.31
Financial Adjustable A	5.52	5.52	5.52
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.41	3.80	4.09
25-Bond Index (Revs)	4.17	4.52	5.09
General Obligation Bonds (GOs)			
1-year Aaa	0.17	0.20	0.24
1-year A	0.78	0.88	1.06
5-year Aaa	0.67	0.79	1.22
5-year A	1.65	1.85	2.33
10-year Aaa	1.76	2.06	2.48
10-year A	2.80	3.19	3.53
25/30-year Aaa	3.13	3.36	3.97
25/30-year A	4.70	4.79	5.34
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.18	4.27	4.60
Electric AA	4.27	4.55	4.82
Housing AA	4.64	4.73	5.53
Hospital AA	4.30	4.48	4.92
Toll Road Aaa	4.22	4.31	4.58

Source: Bloomberg Finance L.P.

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 11/14/12	10/31/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1438804	1422943	15861	1430434	1449840	1479638
Borrowed Reserves	1128	1363	-235	1961	3513	5862
Net Free/Borrowed Reserves	1437676	1421580	16096	1428473	1446327	1473776

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

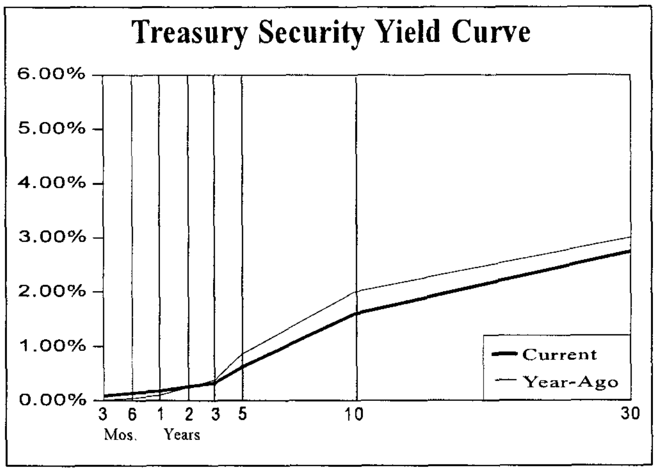
	Recent Levels 11/5/12	10/29/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2420.9	2419.4	1.5	20.3%	15.9%	13.6%
M2 (M1+savings+small time deposits)	10291.9	10255.5	36.4	12.1%	8.5%	7.6%

Source: United States Federal Reserve Bank

Selected Yields

TAXABLE	Recent (11/14/12)	3 Months Ago (8/15/12)	Year Ago (11/16/11)
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)	0.23	0.21	0.47
3-month LIBOR	0.31	0.43	0.47
Bank CDs			
6-month	0.11	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.76	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.08	0.01
6-month	0.14	0.14	0.04
1-year	0.18	0.18	0.10
5-year	0.63	0.80	0.87
10-year	1.60	1.82	2.00
10-year (inflation-protected)	-0.84	-0.45	0.03
30-year	2.74	2.92	3.00
30-year Zero	2.95	3.12	3.21

	Recent (11/14/12)	3 Months Ago (8/15/12)	Year Ago (11/16/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.95	1.03	1.25
FHLMC 5.5% (Gold)	2.15	1.89	2.35
FNMA 5.5%	1.74	1.69	2.09
FNMA ARM	2.20	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.79	3.23	4.38
Industrial (25/30-year) A	3.67	3.96	4.31
Utility (25/30-year) A	3.66	3.95	4.17
Utility (25/30-year) Baa/BBB	4.00	4.39	4.85
Foreign Bonds (10-Year)			
Canada	1.70	1.95	2.10
Germany	1.34	1.56	1.82
Japan	0.75	0.82	0.95
United Kingdom	1.75	1.68	2.16
Preferred Stocks			
Utility A	5.11	5.31	5.26
Financial BBB	6.09	6.07	6.30
Financial Adjustable A	5.51	5.51	5.52



TAX-EXEMPT	Recent (11/14/12)	3 Months Ago (8/15/12)	Year Ago (11/16/11)
Bond Buyer Indexes			
20-Bond Index (GOs)	3.55	3.75	4.02
25-Bond Index (Revs)	4.23	4.50	5.00
General Obligation Bonds (GOs)			
1-year Aaa	0.22	0.17	0.24
1-year A	0.82	0.85	1.07
5-year Aaa	0.68	0.77	1.26
5-year A	1.67	1.83	2.33
10-year Aaa	1.84	1.96	2.50
10-year A	2.89	3.10	3.51
25/30-year Aaa	3.20	3.31	4.01
25/30-year A	4.72	4.78	5.38
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.20	4.21	4.56
Electric AA	4.29	4.49	4.89
Housing AA	4.66	4.67	5.57
Hospital AA	4.35	4.46	4.93
Toll Road Aaa	4.24	4.30	4.57

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...		
	10/31/12	10/17/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1422945	1423709	-764	1439552	1451187	1482492
Borrowed Reserves	1363	1527	-164	2325	3906	6227
Net Free/Borrowed Reserves	1421582	1422182	-600	1437227	1447281	1476265

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/29/12	10/22/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2419.5	2401.6	17.9	18.1%	15.3%	13.3%
M2 (M1+savings+small time deposits)	10257.3	10211.8	45.5	9.8%	7.7%	7.4%

Source: United States Federal Reserve Bank

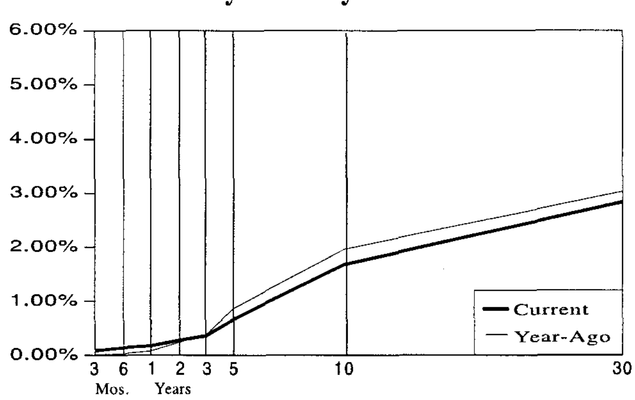
Selected Yields

	Recent (11/07/12)	3 Months Ago (8/08/12)	Year Ago (11/09/11)
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)	0.23	0.30	0.49
3-month LIBOR	0.31	0.44	0.45
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.81	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.11	0.01
6-month	0.14	0.14	0.03
1-year	0.17	0.18	0.08
5-year	0.67	0.73	0.87
10-year	1.68	1.65	1.96
10-year (inflation-protected)	-0.82	-0.63	-0.05
30-year	2.84	2.75	3.03
30-year Zero	3.05	2.95	3.25

	Recent (11/07/12)	3 Months Ago (8/08/12)	Year Ago (11/09/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.53	0.96	1.37
FHLMC 5.5% (Gold)	1.83	1.72	2.35
FNMA 5.5%	1.42	1.52	2.03
FNMA ARM	2.19	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.90	3.16	4.09
Industrial (25/30-year) A	3.71	3.83	4.23
Utility (25/30-year) A	3.77	3.81	4.14
Utility (25/30-year) Baa/BBB	4.12	4.24	4.83
Foreign Bonds (10-Year)			
Canada	1.75	1.82	2.09
Germany	1.38	1.42	1.72
Japan	0.76	0.80	0.98
United Kingdom	1.76	1.57	2.18
Preferred Stocks			
Utility A	5.11	5.11	5.82
Financial BBB	6.08	5.90	5.70
Financial Adjustable A	5.51	5.51	5.51
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.67	3.66	4.02
25-Bond Index (Revs)	4.29	4.46	5.05
General Obligation Bonds (GOs)			
1-year Aaa	0.21	0.18	0.25
1-year A	0.83	0.87	1.06
5-year Aaa	0.74	0.73	1.27
5-year A	1.72	1.79	2.33
10-year Aaa	1.95	1.91	2.51
10-year A	3.01	3.05	3.52
25/30-year Aaa	3.28	3.29	4.01
25/30-year A	4.79	4.78	5.35
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.17	4.56
Electric AA	4.33	4.53	4.90
Housing AA	4.70	4.67	5.58
Hospital AA	4.42	4.44	4.92
Toll Road Aaa	4.27	4.30	4.55

Source: Bloomberg Finance L.P.

Treasury Security Yield Curve



Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 10/31/12	10/17/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1422927	1423708	-781	1439550	1451186	1482491
Borrowed Reserves	1363	1527	-164	2325	3906	6227
Net Free/Borrowed Reserves	1421564	1422181	-617	1437225	1447280	1476264

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

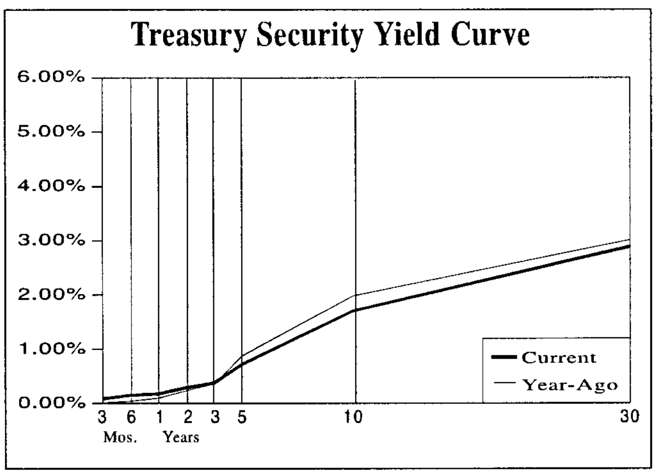
	Recent Levels 10/22/12	10/15/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2401.7	2386.8	14.9	16.6%	13.8%	12.2%
M2 (M1+savings+small time deposits)	10211.8	10210.8	1.0	8.1%	8.0%	7.2%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/31/12)	3 Months Ago (8/01/12)	Year Ago (11/02/11)
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)	0.24	0.30	0.51
3-month LIBOR	0.31	0.44	0.43
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.81	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.09	0.01
6-month	0.15	0.14	0.04
1-year	0.18	0.17	0.10
5-year	0.73	0.64	0.88
10-year	1.71	1.55	1.99
10-year (inflation-protected)	-0.81	-0.69	-0.10
30-year	2.89	2.62	3.01
30-year Zero	3.08	2.79	3.22

	Recent (10/31/12)	3 Months Ago (8/01/12)	Year Ago (11/02/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.42	0.93	1.62
FHLMC 5.5% (Gold)	1.76	1.63	2.34
FNMA 5.5%	1.42	1.53	2.10
FNMA ARM	2.27	2.27	2.43
Corporate Bonds			
Financial (10-year) A	2.96	3.04	4.15
Industrial (25/30-year) A	3.77	3.72	4.18
Utility (25/30-year) A	3.83	3.69	4.12
Utility (25/30-year) Baa/BBB	4.20	4.13	4.76
Foreign Bonds (10-Year)			
Canada	1.79	1.71	2.17
Germany	1.46	1.37	1.83
Japan	0.78	0.78	1.00
United Kingdom	1.85	1.52	2.29
Preferred Stocks			
Utility A	5.10	5.12	5.82
Financial BBB	6.06	5.92	6.57
Financial Adjustable A	5.50	5.50	5.50



	Recent (10/31/12)	3 Months Ago (8/01/12)	Year Ago (11/02/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.68	3.61	4.12
25-Bond Index (Revs)	4.33	4.44	5.10
General Obligation Bonds (GOs)			
1-year Aaa	0.22	0.17	0.24
1-year A	0.84	0.90	1.05
5-year Aaa	0.73	0.73	1.28
5-year A	1.71	1.79	2.35
10-year Aaa	1.95	1.84	2.57
10-year A	3.02	2.99	3.56
25/30-year Aaa	3.29	3.27	4.03
25/30-year A	4.80	4.75	5.37
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.13	4.55
Electric AA	4.33	4.49	4.90
Housing AA	4.70	4.61	5.59
Hospital AA	4.43	4.44	4.94
Toll Road Aaa	4.27	4.35	4.55

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...		
	10/17/12	**10/3/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1423708	1371236	52472	1449745	1457405	1488008
Borrowed Reserves	1527	1662	-135	2734	4309	6596
Net Free/Borrowed Reserves	1422181	1369574	52607	1447011	1453096	1481412

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/15/12	**10/8/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2386.9	2371.5	15.4	17.8%	13.3%	11.6%
M2 (M1+savings+small time deposits)	10211.3	10182.4	28.9	7.9%	7.1%	7.2%

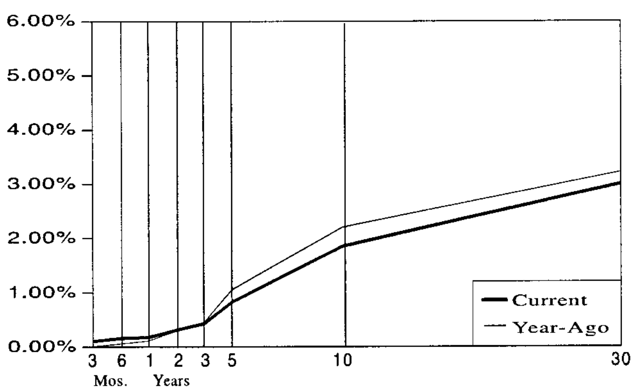
Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/24/12)	3 Months Ago (7/25/12)	Year Ago (10/26/11)
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)	0.23	0.32	0.49
3-month LIBOR	0.31	0.45	0.42
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.81	1.09	1.14
U.S. Treasury Securities			
3-month	0.11	0.10	0.01
6-month	0.16	0.14	0.06
1-year	0.18	0.17	0.11
5-year	0.83	0.58	1.06
10-year	1.85	1.42	2.20
10-year (inflation-protected)	-0.69	-0.68	0.12
30-year	3.00	2.48	3.22
30-year Zero	3.17	2.64	3.43

	Recent (10/24/12)	3 Months Ago (7/25/12)	Year Ago (10/26/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.40	1.06	1.76
FHLMC 5.5% (Gold)	1.85	1.52	2.39
FNMA 5.5%	1.48	1.54	2.19
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.07	3.00	4.41
Industrial (25/30-year) A	3.81	3.62	4.49
Utility (25/30-year) A	3.85	3.59	4.41
Utility (25/30-year) Baa/BBB	4.23	4.01	5.05
Foreign Bonds (10-Year)			
Canada	1.85	1.59	2.38
Germany	1.56	1.26	2.04
Japan	0.78	0.73	1.00
United Kingdom	1.85	1.46	2.47
Preferred Stocks			
Utility A	5.10	5.23	5.21
Financial BBB	6.06	5.92	6.49
Financial Adjustable A	5.50	5.50	5.50

Treasury Security Yield Curve



	Recent (10/24/12)	3 Months Ago (7/25/12)	Year Ago (10/26/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.68	3.75	4.08
25-Bond Index (Revs)	4.33	4.51	5.07
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.19	0.29
1-year A	0.86	0.90	1.00
5-year Aaa	0.73	0.75	1.41
5-year A	1.70	1.80	2.42
10-year Aaa	1.95	1.87	2.69
10-year A	3.04	2.98	3.60
25/30-year Aaa	3.30	3.29	4.10
25/30-year A	4.81	4.74	5.42
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.24	4.16	4.56
Electric AA	4.32	4.52	4.94
Housing AA	4.69	4.64	5.66
Hospital AA	4.43	4.44	4.97
Toll Road Aaa	4.26	4.32	4.57

Source: Bloomberg Finance L.P.

Federal Reserve Data

BANK RESERVES
(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels 10/17/12	10/3/12	Change	Average Levels Over the Last... 12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1423713	1371238	52475	1449746	1457406	1488008
Borrowed Reserves	1527	1662	-135	2734	4309	6596
Net Free/Borrowed Reserves	1422186	1369576	52610	1447012	1453097	1481412

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels 10/8/12	10/1/12	Change	Ann'l Growth Rates Over the Last... 3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2371.4	2374.1	-2.7	18.9%	13.0%	11.1%
M2 (M1+savings+small time deposits)	10182.4	10194.9	-12.5	8.5%	7.0%	7.1%

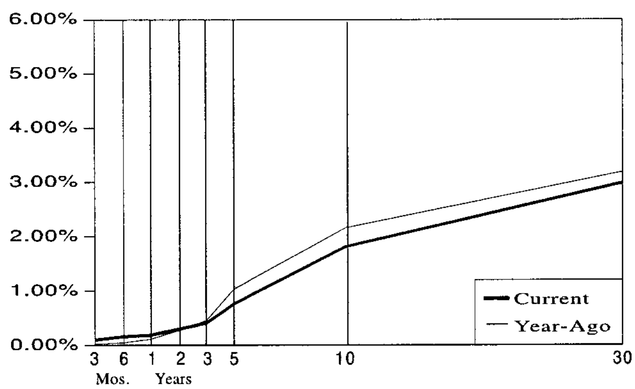
Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/17/12)	3 Months Ago (7/18/12)	Year Ago (10/19/11)
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)	0.25	0.26	0.44
3-month LIBOR	0.32	0.46	0.41
Bank CDs			
6-month	0.12	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.86	1.09	1.14
U.S. Treasury Securities			
3-month	0.10	0.09	0.02
6-month	0.16	0.13	0.05
1-year	0.19	0.16	0.11
5-year	0.77	0.61	1.04
10-year	1.81	1.50	2.16
10-year (inflation-protected)	-0.67	-0.64	0.20
30-year	2.98	2.60	3.18
30-year Zero	3.23	2.80	3.38

	Recent (10/17/12)	3 Months Ago (7/18/12)	Year Ago (10/19/11)
Mortgage-Backed Securities			
GNMA 5.5%	1.05	1.13	1.84
FHLMC 5.5% (Gold)	1.89	1.61	2.36
FNMA 5.5%	1.54	1.60	2.17
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.10	3.11	4.33
Industrial (25/30-year) A	3.88	3.78	4.53
Utility (25/30-year) A	3.94	3.74	4.40
Utility (25/30-year) Baa/BBB	4.27	4.17	4.92
Foreign Bonds (10-Year)			
Canada	1.81	1.62	2.33
Germany	1.63	1.20	2.06
Japan	0.77	0.76	1.02
United Kingdom	1.92	1.48	2.47
Preferred Stocks			
Utility A	5.09	5.39	5.25
Financial BBB	6.05	6.51	6.69
Financial Adjustable A	5.49	5.49	5.49

Treasury Security Yield Curve



	Recent (10/17/12)	3 Months Ago (7/18/12)	Year Ago (10/19/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.64	3.83	4.17
25-Bond Index (Revs)	4.32	4.56	5.06
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.19	0.25
1-year A	0.84	0.89	1.08
5-year Aaa	0.68	0.79	1.39
5-year A	1.67	1.88	2.40
10-year Aaa	1.89	1.92	2.69
10-year A	3.01	3.03	3.67
25/30-year Aaa	3.28	3.35	4.09
25/30-year A	4.79	4.77	5.45
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.23	4.26	4.56
Electric AA	4.31	4.58	4.94
Housing AA	4.68	4.72	5.64
Hospital AA	4.41	4.50	4.97
Toll Road Aaa	4.23	4.35	4.57

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...		
	10/3/12	9/19/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1371241	1424682	-53441	1454652	1462067	1492376
Borrowed Reserves	1662	2007	-345	3176	4706	6963
Net Free/Borrowed Reserves	1369579	1422675	-53096	1451477	1457362	1485413

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

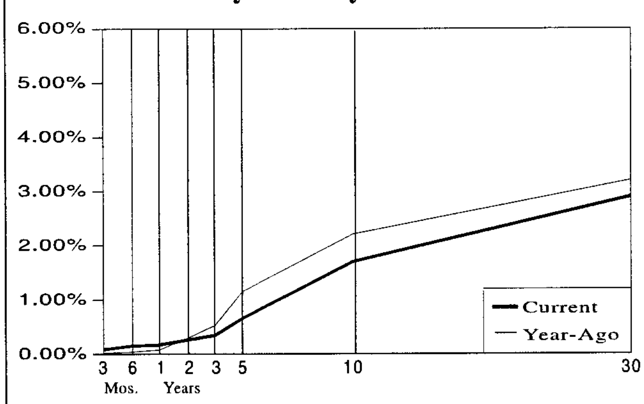
	Recent Levels			Ann'l Growth Rates Over the Last...		
	10/1/12	9/24/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2374.3	2391.1	-16.8	22.7%	13.8%	11.6%
M2 (M1+savings+small time deposits)	10197.0	10123.0	74.0	9.1%	7.2%	7.2%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/10/12)	3 Months Ago (7/11/12)	Year Ago (10/12/11)
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)	0.26	0.36	0.38
3-month LIBOR	0.34	0.46	0.40
Bank CDs			
6-month	0.13	0.20	0.17
1-year	0.16	0.31	0.21
5-year	0.86	1.09	1.14
U.S. Treasury Securities			
3-month	0.09	0.09	0.02
6-month	0.15	0.15	0.04
1-year	0.17	0.19	0.08
5-year	0.66	0.64	1.15
10-year	1.70	1.52	2.21
10-year (inflation-protected)	-0.83	-0.61	0.23
30-year	2.90	2.61	3.20
30-year Zero	3.11	2.81	3.39

Treasury Security Yield Curve



	Recent (10/10/12)	3 Months Ago (7/11/12)	Year Ago (10/12/11)
Mortgage-Backed Securities			
GNMA 5.5%	0.78	1.17	1.89
FHLMC 5.5% (Gold)	1.84	1.66	2.32
FNMA 5.5%	1.52	1.60	2.17
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.03	3.19	4.37
Industrial (25/30-year) A	3.80	3.82	4.59
Utility (25/30-year) A	3.84	3.80	4.53
Utility (25/30-year) Baa/BBB	4.15	4.25	4.99
Foreign Bonds (10-Year)			
Canada	1.79	1.68	2.35
Germany	1.49	1.27	2.19
Japan	0.77	0.79	1.00
United Kingdom	1.77	1.57	2.64
Preferred Stocks			
Utility A	5.09	5.38	5.57
Financial BBB	6.04	6.41	6.81
Financial Adjustable A	5.49	5.49	5.49
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.61	3.94	4.14
25-Bond Index (Revs)	4.28	4.65	5.04
General Obligation Bonds (GOs)			
1-year Aaa	0.20	0.20	0.26
1-year A	0.83	0.89	1.11
5-year Aaa	0.67	0.82	1.41
5-year A	1.66	1.90	2.43
10-year Aaa	1.87	2.01	2.63
10-year A	2.99	3.09	3.75
25/30-year Aaa	3.29	3.47	4.12
25/30-year A	4.79	4.84	5.50
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.23	4.30	4.59
Electric AA	4.31	4.62	4.97
Housing AA	4.68	4.76	5.63
Hospital AA	4.41	4.55	5.00
Toll Road Aaa	4.23	4.39	4.60

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...		
	10/3/12	9/19/12	Change	12 Wks.	26 Wks.	52 Wks.
Excess Reserves	1371232	1425102	-53870	1454711	1462097	1492391
Borrowed Reserves	1662	2007	-345	3176	4706	6963
Net Free/Borrowed Reserves	1369570	1423095	-53525	1451536	1457391	1485429

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

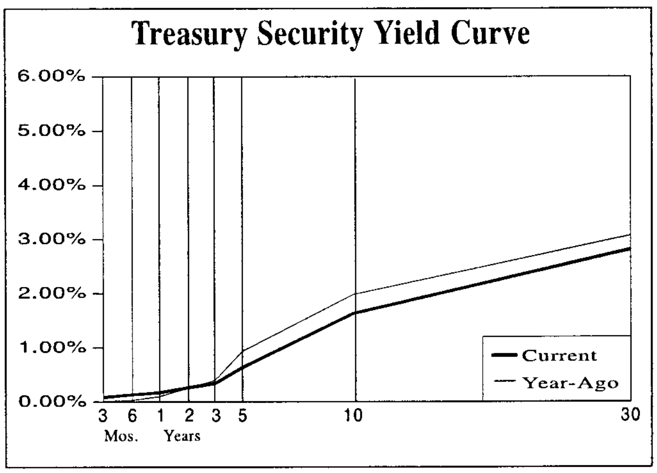
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/24/12	9/17/12	Change	3 Mos.	6 Mos.	12 Mos.
M1 (Currency+demand deposits)	2393.3	2385.9	7.4	27.2%	16.2%	13.0%
M2 (M1+savings+small time deposits)	10138.2	10138.1	0.1	7.8%	6.4%	6.7%

Source: United States Federal Reserve Bank

Selected Yields

	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
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)	0.28	0.26	0.41
3-month LIBOR	0.35	0.46	0.38
Bank CDs			
6-month	0.13	0.20	0.17
1-year	0.16	0.32	0.21
5-year	0.86	1.09	1.18
U.S. Treasury Securities			
3-month	0.09	0.08	0.01
6-month	0.13	0.15	0.02
1-year	0.16	0.20	0.09
5-year	0.62	0.70	0.95
10-year	1.57	1.63	1.89
10-year (inflation-protected)	-0.90	-0.51	0.08
30-year	2.68	2.74	2.85
30-year Zero	3.08	2.95	3.03

	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
Mortgage-Backed Securities			
GNMA 5.5%	0.77	1.39	1.54
FHLMC 5.5% (Gold)	2.00	1.92	2.23
FNMA 5.5%	1.69	1.84	2.13
FNMA ARM	2.22	2.27	2.47
Corporate Bonds			
Financial (10-year) A	3.00	3.33	3.88
Industrial (25/30-year) A	3.78	3.99	4.29
Utility (25/30-year) A	3.84	3.93	4.21
Utility (25/30-year) Baa/BBB	4.16	4.37	4.65
Foreign Bonds (10-Year)			
Canada	1.74	1.71	2.14
Germany	1.47	1.45	1.84
Japan	0.77	0.82	0.97
United Kingdom	1.72	1.72	2.36
Preferred Stocks			
Utility A	5.14	5.39	5.29
Financial BBB	6.51	6.53	6.51
Financial Adjustable A	5.48	5.48	5.48



	Recent (10/3/12)	3 Months Ago (7/03/12)	Year Ago (10/05/11)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	3.67	3.95	3.93
25-Bond Index (Revs)	4.31	4.69	5.01
General Obligation Bonds (GOs)			
1-year Aaa	0.19	0.19	0.20
1-year A	0.82	0.91	0.97
5-year Aaa	0.69	0.86	1.13
5-year A	1.62	1.91	2.18
10-year Aaa	1.90	2.04	2.36
10-year A	3.01	3.13	3.47
25/30-year Aaa	3.30	3.55	3.88
25/30-year A	4.73	4.87	5.53
Revenue Bonds (Revs) (25/30-Year)			
Education AA	4.22	4.32	4.56
Electric AA	4.30	4.63	4.92
Housing AA	4.67	4.75	5.55
Hospital AA	4.42	4.57	4.92
Toll Road Aaa	4.23	4.40	4.58

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...		
	9/19/12	**9/5/12**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	1425100	1450818	-25718	1462603	1471716	1498949
Borrowed Reserves	2007	2516	-509	3670	5115	7331
Net Free/Borrowed Reserves	1423093	1448302	-25209	1458934	1466600	1491618

MONEY SUPPLY
(One-Week Period; in Billions, Seasonally Adjusted)

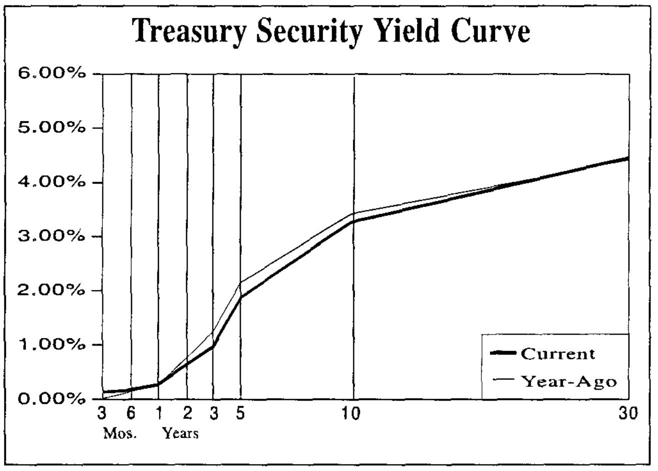
	Recent Levels			Ann'l Growth Rates Over the Last...		
	9/17/12	**9/10/12**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	2385.8	2373.4	12.4	25.8%	15.7%	12.7%
M2 (M1+savings+small time deposits)	10137.9	10124.1	13.8	8.5%	7.2%	7.1%

Source: United States Federal Reserve Bank

ATTACHMENT E

Selected Yields

	Recent (12/08/10)	3 Months Ago (9/08/10)	Year Ago (12/09/09)		Recent (12/08/10)	3 Months Ago (9/08/10)	Year Ago (12/09/09)
TAXABLE							
Market Rates				**Mortgage-Backed Securities**			
Discount Rate	0.75	0.75	0.50	GNMA 6.5%	1.13	1.72	3.22
Federal Funds	0.00-0.25	0.00-0.25	0.00-0.25	FHLMC 6.5% (Gold)	2.29	2.24	1.94
Prime Rate	3.25	3.25	3.25	FNMA 6.5%	1.99	2.11	1.95
30-day CP (A1/P1)	0.27	0.22	0.12	FNMA ARM	2.80	2.90	2.41
3-month LIBOR	0.30	0.29	0.26	**Corporate Bonds**			
Bank CDs				Financial (10-year) A	4.70	4.20	5.34
6-month	0.14	0.35	0.31	Industrial (25/30-year) A	5.57	4.89	5.68
1-year	0.40	0.61	0.54	Utility (25/30-year) A	5.80	4.98	5.71
5-year	2.00	1.72	1.95	Utility (25/30-year) Baa/BBB	6.15	5.48	6.32
U.S. Treasury Securities				**Foreign Bonds (10-Year)**			
3-month	0.14	0.13	0.02	Canada	3.26	2.92	3.31
6-month	0.18	0.17	0.14	Germany	3.01	2.30	3.14
1-year	0.27	0.23	0.27	Japan	1.25	1.14	1.25
5-year	1.88	1.45	2.15	United Kingdom	3.55	2.99	3.67
10-year	3.27	2.66	3.43	**Preferred Stocks**			
10-year (inflation-protected)	0.81	0.99	1.27	Utility A	6.08	6.08	6.08
30-year	4.46	3.73	4.42	Financial A	6.66	6.69	7.17
30-year Zero	4.76	3.99	4.63	Financial Adjustable A	5.53	5.53	5.54



	Recent (12/08/10)	3 Months Ago (9/08/10)	Year Ago (12/09/09)
TAX-EXEMPT			
Bond Buyer Indexes			
20-Bond Index (GOs)	4.65	3.86	4.24
25-Bond Index (Revs)	5.18	4.63	4.98
General Obligation Bonds (GOs)			
1-year Aaa	0.42	0.29	0.33
1-year A	1.38	1.09	1.25
5-year Aaa	1.48	1.09	1.47
5-year A	2.60	2.11	2.67
10-year Aaa	3.09	2.30	3.07
10-year A	4.19	3.56	4.04
25/30-year Aaa	4.59	4.08	4.47
25/30-year A	5.67	5.36	5.41
Revenue Bonds (Revs) (25/30-Year)			
Education AA	5.01	4.60	4.74
Electric AA	5.05	4.60	4.61
Housing AA	5.86	5.36	5.65
Hospital AA	5.19	4.87	5.17
Toll Road Aaa	5.04	4.58	4.77

Federal Reserve Data

BANK RESERVES

(Two-Week Period; in Millions, Not Seasonally Adjusted)

	Recent Levels			Average Levels Over the Last...		
	12/1/10	**11/17/10**	**Change**	**12 Wks.**	**26 Wks.**	**52 Wks.**
Excess Reserves	978795	966251	12544	977407	1003315	1043533
Borrowed Reserves	46562	46634	-72	49574	58212	88329
Net Free/Borrowed Reserves	932233	919617	12616	927833	945103	955204

MONEY SUPPLY

(One-Week Period; in Billions, Seasonally Adjusted)

	Recent Levels			Growth Rates Over the Last...		
	11/22/10	**11/15/10**	**Change**	**3 Mos.**	**6 Mos.**	**12 Mos.**
M1 (Currency+demand deposits)	1816.5	1798.2	18.3	18.3%	14.2%	7.7%
M2 (M1+savings+small time deposits)	8809.2	8798.9	10.3	7.5%	5.3%	3.3%

RIO RICO UTILITIES, INC.
DOCKET NO. WS-02676A-12-0196
TABLE OF CONTENTS TO SCHEDULES WAR

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
COST OF CAPITAL SUMMARY

WEIGHTED AVERAGE COST OF CAPITAL - WATER AND WASTEWATER DIVISIONS

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST
1	Long-Term Debt	20.00%	4.13%	0.83%
2	Common Equity	80.00%	9.00%	7.20%
3	Total Capitalization	100.00%		
4	**WEIGHTED AVERAGE COST OF CAPITAL**			**8.03%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): LINE 1; TESTIMONY WAR, LINE 2; SCHEDULE WAR-1, PAGE 2
COLUMN (C): LINES 1 & 2; COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 4; LINE 1 + LINE 2

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
COST OF CAPITAL SUMMARY

COST OF COMMON EQUITY CALCULATION

LINE NO.			
1	**DCF METHODOLOGY**		
2	DCF - WATER COMPANY SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.00%	SCHEDULE WAR-2, COLUMN (C), LINE 5
3	DCF - NATURAL GAS LDC SINGLE-STAGE CONSTANT GROWTH MODEL ESTIMATE	8.74%	SCHEDULE WAR-2, COLUMN (C), LINE 13
4	**AVERAGE OF DCF ESTIMATES**	**8.37%**	(LINE 2 + LINE 3) ÷ 2
5	**CAPM METHODOLOGY**		
6	CAPM - WATER COMPANY GEOMETRIC MEAN ESTIMATE	5.69%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 5
7	CAPM - NATURAL GAS LDC GEOMETRIC MEAN ESTIMATE	5.54%	SCHEDULE WAR-7 PAGE 1, COLUMN (B), LINE 13
8	CAPM - WATER COMPANY ARITHMETIC MEAN ESTIMATE	6.80%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 5
9	CAPM - NATURAL GAS LDC ARITHMETIC MEAN ESTIMATE	6.59%	SCHEDULE WAR-7 PAGE 2, COLUMN (B), LINE 13
10	**AVERAGE OF CAPM ESTIMATES**	**6.16%**	(SUM OF LINES 6 THRU 9) ÷ 4
11	**AVERAGE OF DCF AND CAPM ESTIMATES**	**7.26%**	(SUM OF LINES 4 AND 10) ÷ 2
12	**FINAL COST OF COMMON EQUITY ESTIMATE**	9.00%	TESTIMONY WAR

RIO RICO UTILITIES, INC.
DOCKET NO. WS-02676A-12-0196
DCF COST OF EQUITY CAPITAL

DOCKET NO. WS-02676A-12-0196
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.	2.72%	+	4.58%	=	7.31%
2	AWR	AMERICAN STATES WATER CO.	3.26%	+	5.56%		8.81%
3	CWT	CALIFORNIA WATER SERVICE GROUP	3.51%	+	5.31%	=	8.82%
4	MSEX	MIDDLESEX WATER COMPANY	3.98%	+	3.55%	=	7.52%
5	SJW	SJW CORPORATION	2.97%	+	4.00%	=	6.98%
6	WTR	AQUA AMERICA, INC.	2.80%	+	5.74%	=	8.54%
7	**WATER COMPANY AVERAGE**						**8.00%**
8	GAS	AGL RESOURCES, INC.	4.72%	+	2.00%	=	6.72%
9	ATO	ATMOS ENERGY CORP.	4.02%	+	3.93%	=	7.95%
10	LG	LACLEDE GROUP, INC.	4.07%	+	4.17%	=	8.24%
11	NJR	NEW JERSEY RESOURCES CORPORATION	3.74%	+	7.01%	=	10.75%
12	NWN	NORTHWEST NATURAL GAS CO.	4.00%	+	4.31%	=	8.31%
13	PNY	PIEDMONT NATURAL GAS COMPANY	3.90%	+	3.01%	=	6.90%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	3.24%	+	9.54%	=	12.78%
15	SWX	SOUTHWEST GAS CORPORATION	2.79%	+	6.38%	=	9.18%
16	WGL	WGL HOLDINGS, INC.	4.14%	+	3.67%	=	7.81%
17	**NATURAL GAS LDC AVERAGE**						**8.74%**

REFERENCES:
COLUMN (A): SCHEDULE WAR - 3, COLUMN C
COLUMN (B): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
DIVIDEND YIELD CALCULATION

DOCKET NO. WS-02676A-12-0196
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.	$1.00	/	$36.74	=	2.72%
2	AWR	AMERICAN STATES WATER CO.	1.42	/	43.62	=	3.26%
3	CWT	CALIFORNIA WATER SERVICE GROUP	0.63	/	17.96	=	3.51%
4	MSEX	MIDDLESEX WATER COMPANY	0.74	/	18.61	=	3.98%
5	SJW	SJW CORPORATION	0.71	/	23.87		2.97%
6	WTR	AQUA AMERICA, INC.	0.70	/	25.01	=	2.80%
7	**WATER COMPANY AVERAGE**						**3.21%**
8	GAS	AGL RESOURCES, INC.	$1.84	/	$39.01	=	4.72%
9	ATO	ATMOS ENERGY CORP.	1.40	/	34.84	=	4.02%
10	LG	LACLEDE GROUP, INC.	1.66	/	40.80	=	4.07%
11	NJR	NEW JERSEY RESOURCES CORPORATION	1.60	/	42.73	=	3.74%
12	NWN	NORTHWEST NATURAL GAS CO.	1.82	/	45.49	=	4.00%
13	PNY	PIEDMONT NATURAL GAS COMPANY	1.20	/	30.79	=	3.90%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	1.61	/	49.78	=	3.24%
15	SWX	SOUTHWEST GAS CORPORATION	1.18	/	42.23	=	2.79%
16	WGL	WGL HOLDINGS, INC.	1.60	/	38.61	=	4.14%
17	**NATURAL GAS LDC AVERAGE**						**3.85%**

REFERENCES:
COLUMN (A): ESTIMATED 12 MONTH DIVIDEND REPORTED IN VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 10/19/2012 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's).
COLUMN (B): EIGHT WEEK AVERAGE OF ADJUSTED CLOSING PRICES FROM 10/09/2012 TO 11/30/2012 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.

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
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.	4.25%	+	0.33%	=	4.58%
2	AWR	AMERICAN STATES WATER CO.	5.10%	+	0.46%	=	5.56%
3	CWT	CALIFORNIA WATER SERVICE GROUP	4.50%	+	0.81%	=	5.31%
4	MSEX	MIDDLESEX WATER COMPANY	3.00%	+	0.55%	=	3.55%
5	SJW	SJW CORPORATION	2.80%	+	1.20%	=	4.00%
6	WTR	AQUA AMERICA, INC.	5.25%	+	0.49%	=	5.74%
7	**WATER COMPANY AVERAGE**						**4.79%**
8	GAS	AGL RESOURCES, INC.	2.00%	+	0.00%	=	2.00%
9	ATO	ATMOS ENERGY CORP.	3.50%	+	0.43%	=	3.93%
10	LG	LACLEDE GROUP, INC.	3.90%	+	0.27%	=	4.17%
11	NJR	NEW JERSEY RESOURCES CORPORATION	7.00%	+	0.01%	=	7.01%
12	NWN	NORTHWEST NATURAL GAS CO.	4.00%	+	0.31%	=	4.31%
13	PNY	PIEDMONT NATURAL GAS COMPANY	3.00%	+	0.01%	=	3.01%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	7.50%	+	2.04%	=	9.54%
15	SWX	SOUTHWEST GAS CORPORATION	6.00%	+	0.38%	=	6.38%
16	WGL	WGL HOLDINGS, INC.	3.50%	+	0.17%	=	3.67%
17	**NATURAL GAS LDC AVERAGE**						**4.89%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): SCHEDULE WAR - 4, PAGE 2, COLUMN C
COLUMN (C): COLUMN (A) + COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
DIVIDEND GROWTH RATE CALCULATION

DOCKET NO. WS-02676A-12-0196
SCHEDULE WAR - 4
PAGE 2 OF 2

LINE NO.	STOCK SYMBOL	COMPANY	(A) SHARE GROWTH	x	(B) { [((M ÷ B) + 1) / 2] - 1 }	=	(C) EXTERNAL GROWTH (sv)
1	AWK	AMERICAN WATER WORKS COMPANY, INC.	1.50%	x	{ [((1.45) + 1) / 2] - 1 }	=	0.33%
2	AWR	AMERICAN STATES WATER CO.	1.00%	x	{ [((1.91) + 1) / 2] - 1 }	=	0.46%
3	CWT	CALIFORNIA WATER SERVICE GROUP	2.60%	x	{ [((1.63) + 1) / 2] - 1 }	=	0.81%
4	MSEX	MIDDLESEX WATER COMPANY	1.90%	x	{ [((1.58) + 1) / 2] - 1 }	=	0.55%
5	SJW	SJW CORPORATION	4.30%	x	{ [((1.56) + 1) / 2] - 1 }	=	1.20%
6	WTR	AQUA AMERICA, INC.	0.60%	x	{ [((2.65) + 1) / 2] - 1 }	=	0.49%
7	**WATER COMPANY AVERAGE**						**0.64%**
8	GAS	AGL RESOURCES, INC.	0.01%	x	{ [((1.26) + 1) / 2] - 1 }	=	0.00%
9	ATO	ATMOS ENERGY CORP.	2.60%	x	{ [((1.33) + 1) / 2] - 1 }	=	0.43%
10	LG	LACLEDE GROUP, INC.	1.00%	x	{ [((1.53) + 1) / 2] - 1 }	=	0.27%
11	NJR	NEW JERSEY RESOURCES CORPORATION	0.01%	x	{ [((2.35) + 1) / 2] - 1 }	=	0.01%
12	NWN	NORTHWEST NATURAL GAS CO.	0.90%	x	{ [((1.69) + 1) / 2] - 1 }	=	0.31%
13	PNY	PIEDMONT NATURAL GAS COMPANY	0.01%	x	{ [((2.22) + 1) / 2] - 1 }	=	0.01%
14	SJI	SOUTH JERSEY INDUSTRIES, INC.	3.50%	x	{ [((2.16) + 1) / 2] - 1 }	=	2.04%
15	SWX	SOUTHWEST GAS CORPORATION	1.50%	x	{ [((1.51) + 1) / 2] - 1 }	=	0.38%
16	WGL	WGL HOLDINGS, INC.	0.60%	x	{ [((1.56) + 1) / 2] - 1 }	=	0.17%
17	**NATURAL GAS LDC AVERAGE**						**0.40%**

REFERENCES:
COLUMN (A): TESTIMONY, WAR
COLUMN (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 10/19/2012 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's)
COLUMN (C): COLUMN (A) x COLUMN (B)

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
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, IN	2007	-		NMF		-	28.39	160.00	
2			2008	0.6364		4.60%		2.93%	25.64	160.00	
3			2009	0.3440		5.20%		1.79%	22.91	174.63	
4			2010	0.4379		6.50%		2.85%	23.59	175.00	
5			2011	0.4709		7.20%		3.39%	24.14	175.66	
6			GROWTH 2007 - 2011					2.74%	-		2.36%
7			2012	0.5442		8.50%		4.63%		177.00	0.76%
8			2013	0.5273		8.50%		4.48%		180.00	1.23%
9			2015-17	0.4792		9.00%		4.31%	2.00%	190.00	1.58%
10											
11	AWR	AMERICAN STATES WATER CO.	2007	0.4074		9.30%		3.79%	17.53	17.23	
12			2008	0.3548		8.60%		3.05%	17.95	17.30	
13			2009	0.3765		8.20%		3.09%	19.39	18.53	
14			2010	0.5315		11.00%		5.85%	20.26	18.63	
15			2011	0.5067		10.30%		5.22%	21.68	18.85	
16			GROWTH 2007 - 2011					4.20%	5.00%		2.27%
17			2012	0.4816		10.50%		5.06%		19.00	0.80%
18			2013	0.4240		11.00%		4.66%		19.20	0.92%
19			2015-17	0.4286		12.00%		5.14%	4.00%	19.60	0.78%
20											
21	CWT	CALIFORNIA WATER SERVICE GROUP	2007	0.2267		8.10%		1.84%	9.25	41.33	
22			2008	0.3789		9.90%		3.75%	9.72	41.45	
23			2009	0.3980		9.60%		3.82%	10.13	41.53	
24			2010	0.3407		8.60%		2.93%	10.45	41.67	
25			2011	0.2791		8.00%		2.23%	10.76	41.82	
26			GROWTH 2007 - 2011					2.91%	5.00%		0.30%
27			2012	0.3368		8.50%		2.86%		43.00	2.82%
28			2013	0.3810		9.00%		3.43%		44.00	2.57%
29			2015-17	0.4462		10.50%		4.68%	3.50%	47.00	2.36%
30											
31	MSEX	MIDDLESEX WATER COMPANY	2007	0.2069		8.70%		1.80%	10.05	13.25	
32			2008	0.2135		8.90%		1.90%	10.03	13.40	
33			2009	0.0139		7.00%		0.10%	10.33	13.52	
34			2010	0.2500		8.20%		2.05%	11.13	15.57	
35			2011	0.1310		7.60%		1.00%	11.27	15.70	
36			GROWTH 2007 - 2011					1.37%	5.50%		4.33%
37			2012	0.1294		7.50%		0.97%		16.00	1.91%
38			2013	0.2500		8.00%		2.00%		16.25	1.74%
39			2015-17	0.3600		9.00%		3.24%	3.50%	17.25	1.90%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 10/19/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2006 - 2011

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

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
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	SJW	SJW CORPORATION									
2			2007	0.4135		8.20%		3.39%	12.90	18.36	
3			2008	0.3981		8.00%		3.19%	13.99	18.18	
4			2009	0.1852		6.00%		1.11%	13.66	18.50	
5			2010	0.1905		6.20%		1.18%	13.75	18.55	
6			2011	0.3784		7.90%		2.99%	14.20	18.59	
7			GROWTH 2007 - 2011					2.37%	4.50%		0.31%
8			2012	0.3238		7.00%		2.27%		20.00	7.58%
9			2013	0.3652		7.50%		2.74%		21.00	6.28%
10			2015-17	0.4074		7.00%		2.85%	3.50%	23.00	4.35%
11	WTR	AQUA AMERICA, INC.									
12			2007	0.3239		9.70%		3.14%	7.32	133.40	
13			2008	0.3014		9.30%		2.80%	7.82	135.37	
14			2009	0.2857		9.40%		2.69%	8.12	136.49	
15			2010	0.3444		10.60%		3.65%	8.51	137.97	
16			2011	0.3981		11.40%		4.54%	9.01	138.87	
17			GROWTH 2007 - 2011					3.36%	7.00%		1.01%
18			2012	0.3909		11.50%		4.50%		139.90	0.74%
19			2013	0.4083		12.00%		4.90%		140.90	0.73%
			2015-17	0.4357		12.50%		5.45%	4.50%	142.90	0.57%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 10/19/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, & 16, SIMPLE AVERAGE GROWTH, 2007 - 2011

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

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
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.	2007	0.3971		12.70%		5.04%	21.74	76.40	
2			2008	0.3801		12.60%		4.79%	21.48	76.90	
3			2009	0.4028		12.50%		5.03%	22.95	77.54	
4			2010	0.4133		12.90%		5.33%	23.24	78.00	
5			2011	0.1038		5.20%		0.54%	28.54	117.00	
6			GROWTH 2007 - 2011					4.15%	5.50%		11.24%
7			2012	0.3556		3.00%		1.07%		117.00	0.00%
8			2013	0.4250		4.50%		1.91%		117.00	0.00%
9			2015-17	0.4842		5.50%		2.66%	5.00%	117.00	0.00%
10											
11	ATO	ATMOS ENERGY CORP.	2007	0.3402		8.70%		2.96%	22.01	89.33	
12			2008	0.3500		8.80%		3.08%	22.60	90.81	
13			2009	0.3299		8.30%		2.74%	23.52	92.55	
14			2010	0.3796		9.20%		3.49%	24.16	90.16	
15			2011	0.3982		8.80%		3.50%	24.98	90.30	
16			GROWTH 2007 - 2011					3.16%	4.50%		0.27%
17			2012	0.3429		8.00%		2.74%		90.00	-0.33%
18			2013	0.4043		8.00%		3.23%		91.00	0.39%
19			2015-17	0.4519		8.00%		3.61%	6.00%	103.00	2.67%
20											
21	LG	LACLEDE GROUP, INC.	2007	0.3723		11.60%		4.32%	19.79	21.65	
22			2008	0.4356		11.80%		5.14%	22.12	21.99	
23			2009	0.4760		12.40%		5.90%	23.32	22.17	
24			2010	0.3539		10.10%		3.57%	24.02	22.29	
25			2011	0.4371		11.10%		4.85%	25.56	22.43	
26			GROWTH 2007 - 2011					4.76%	6.50%		0.89%
27			2012	0.4050		10.60%		4.29%		22.62	0.85%
28			2013	0.3895		9.50%		3.70%		23.00	1.26%
29			2015-17	0.4424		10.00%		4.42%	4.50%	23.50	0.94%
30											
31	NJR	NEW JERSEY RESOURCES CORPORATION	2007	0.3484		10.10%		3.52%	15.50	41.61	
32			2008	0.5889		15.70%		9.25%	17.28	42.06	
33			2009	0.4833		14.60%		7.06%	16.59	41.59	
34			2010	0.4472		14.00%		6.26%	17.62	41.17	
35			2011	0.4419		13.70%		6.05%	18.73	41.45	
36			GROWTH 2007 - 2011					6.43%	7.50%		-0.10%
37			2012	0.4391		14.00%		6.15%		41.53	0.19%
38			2013	0.4483		16.00%		7.17%		40.00	-1.76%
39			2015-17	0.5059		14.00%		7.08%	5.50%	40.00	-0.71%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/07/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

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

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
DIVIDEND GROWTH COMPONENTS

DOCKET NO. WS-02676A-12-0196
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PAGE 4 OF 5

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.	2007	0.4783		12.50%		5.98%	22.52	26.41		75
2			2008	0.4086		10.90%		4.45%	23.71	26.50		
3			2009	0.4346		11.40%		4.95%	24.88	26.53		
4			2010	0.3846		10.50%		4.04%	26.08	26.58		
5			2011	0.2678		8.90%		2.38%	26.70	26.76		
6			GROWTH 2007 - 2011					4.36%	4.00%		0.33%	
7			2012	0.2044		8.50%		1.74%		27.00	0.90%	
8			2013	0.2531		9.00%		2.28%		27.50	1.37%	
9			2015-17	0.3778		11.50%		4.34%	1.00%	28.00	0.91%	
10												
11	PNY	PIEDMONT NATURAL GAS COMPANY	2007	0.2929		11.90%		3.49%	11.99	73.23		90
12			2008	0.3087		12.40%		3.83%	12.11	73.26		
13			2009	0.3593		13.20%		4.74%	12.67	73.27		
14			2010	0.2839		11.60%		3.29%	13.35	72.28		
15			2011	0.2675		11.40%		3.05%	13.79	72.32		
16			GROWTH 2007 - 2011					3.68%	3.00%		-0.31%	
17			2012	0.2563		11.50%		2.95%		71.00	-1.83%	
18			2013	0.2765		12.00%		3.32%		70.00	-1.62%	
19			2015-17	0.2703		12.50%		3.38%	1.50%	68.00	-1.22%	
20												
21	SJI	SOUTH JERSEY INDUSTRIES, INC.	2007	0.5167		12.80%		6.61%	16.25	29.61		105
22			2008	0.5110		13.10%		6.69%	17.33	29.73		
23			2009	0.4874		13.10%		6.38%	18.24	29.80		
24			2010	0.4963		14.20%		7.05%	19.08	29.87		
25			2011	0.4810		13.90%		6.69%	20.66	30.21		
26			GROWTH 2007 - 2011					6.69%	7.00%		0.50%	
27			2012	0.4762		14.00%		6.67%		31.50	4.27%	
28			2013	0.4567		13.00%		5.94%		32.50	3.72%	
29			2015-17	0.4889		16.00%		7.82%	6.00%	36.00	3.57%	
30												
31	SWX	SOUTHWEST GAS CORPORATION	2007	0.5590		8.50%		4.75%	22.98	42.81		120
32			2008	0.3525		5.90%		2.08%	23.49	44.19		
33			2009	0.5103		7.90%		4.03%	24.44	45.09		
34			2010	0.5595		8.90%		4.98%	25.62	45.56		
35			2011	0.5638		9.20%		5.19%	26.66	45.96		
36			GROWTH 2007 - 2011					4.21%	5.00%		1.79%	
37			2012	0.5662		9.50%		5.38%		46.50	1.17%	
38			2013	0.5439		9.50%		5.17%		47.00	1.13%	
39			2015-17	0.5733		10.50%		6.02%	6.00%	50.00	1.70%	

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/07/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINES 6, 16, 26 & 36, SIMPLE AVERAGE GROWTH, 2007 - 2011

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COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
DIVIDEND GROWTH COMPONENTS

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PAGE 4 OF 5

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.	2007	0.4783		12.50%		5.98%	22.52	26.41	
2			2008	0.4086		10.90%		4.45%	23.71	26.50	
3			2009	0.4346		11.40%		4.95%	24.88	26.53	
4			2010	0.3846		10.50%		4.04%	26.08	26.58	
5			2011	0.2678		8.90%		2.38%	26.70	26.76	
6			GROWTH 2007 - 2011					4.36%	4.00%		0.33%
7			2012	0.2044		8.50%		1.74%		27.00	0.90%
8			2013	0.2531		9.00%		2.28%		27.50	1.37%
9			2015-17	0.3778		11.50%		4.34%	1.00%	28.00	0.91%
10											
11	PNY	PIEDMONT NATURAL GAS COMPANY	2007	0.2929		11.90%		3.49%	11.99	73.23	
12			2008	0.3087		12.40%		3.83%	12.11	73.26	
13			2009	0.3593		13.20%		4.74%	12.67	73.27	
14			2010	0.2839		11.60%		3.29%	13.35	72.28	
15			2011	0.2675		11.40%		3.05%	13.79	72.32	
16			GROWTH 2007 - 2011					3.68%	3.00%		-0.31%
17			2012	0.2563		11.50%		2.95%		71.00	-1.83%
18			2013	0.2765		12.00%		3.32%		70.00	-1.62%
19			2015-17	0.2703		12.50%		3.38%	1.50%	68.00	-1.22%
20											
21	SJI	SOUTH JERSEY INDUSTRIES, INC.	2007	0.5167		12.80%		6.61%	16.25	29.61	
22			2008	0.5110		13.10%		6.69%	17.33	29.73	
23			2009	0.4874		13.10%		6.38%	18.24	29.80	
24			2010	0.4963		14.20%		7.05%	19.08	29.87	
25			2011	0.4810		13.90%		6.69%	20.66	30.21	
26			GROWTH 2007 - 2011					6.69%	7.00%		0.50%
27			2012	0.4762		14.00%		6.67%		31.50	4.27%
28			2013	0.4567		13.00%		5.94%		32.50	3.72%
29			2015-17	0.4889		16.00%		7.82%	6.00%	36.00	3.57%
30											
31	SWX	SOUTHWEST GAS CORPORATION	2007	0.5590		8.50%		4.75%	22.98	42.81	
32			2008	0.3525		5.90%		2.08%	23.49	44.19	
33			2009	0.5103		7.90%		4.03%	24.44	45.09	
34			2010	0.5595		8.90%		4.98%	25.62	45.56	
35			2011	0.5638		9.20%		5.19%	26.66	45.96	
36			GROWTH 2007 - 2011					4.21%	5.00%		1.79%
37			2012	0.5662		9.50%		5.38%		46.50	1.17%
38			2013	0.5439		9.50%		5.17%		47.00	1.13%
39			2015-17	0.5733		10.50%		6.02%	6.00%	50.00	1.70%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
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COLUMN (D): LINES 6, 16, 26 & 36, COMPOUND GROWTH RATE
COLUMN (E): VALUE LINE INVESTMENT SURVEY
COLUMN (F): COMPOUND GROWTH RATES OF DATES SHOWN

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
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	WGL	WGL HOLDINGS, INC.	2007	0.3445		10.40%		3.58%	19.83	49.45	
2			2008	0.4221		10.40%		4.39%	20.99	49.92	
3			2009	0.4190		11.60%		4.86%	21.89	50.14	
4			2010	0.3392		9.90%		3.36%	22.82	50.54	
5			2011	0.3111		9.50%		2.96%	23.49	51.20	
6			GROWTH 2007 - 2011					3.83%	5.00%		0.87%
7			2012	0.4067		11.00%		4.47%		51.50	0.59%
8			2013	0.3480		10.00%		3.48%		51.75	0.54%
9			2015-17	0.3636		9.50%		3.45%	4.00%	52.00	0.31%

REFERENCES:
COLUMNS (A) & (B): VALUE LINE INVESTMENT SURVEY
- RATINGS & REPORTS DATED 12/07/2012
COLUMN (C): COLUMN (A) x COLUMN (B)
COLUMN (C): LINE 6, SIMPLE AVERAGE GROWTH, 2007 - 2011

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

RIO RICO UTILITIES, INC.
DOCKET NO. WS-02676A-12-0196
GROWTH RATE COMPARISON

DOCKET NO. WS-02676A-12-0196
SCHEDULE WAR - 6

WATER COMPANY SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	AWK	4.58%	8.30%	8.00%	6.50%	2.00%	-	-	-	6.20%	-	-	-3.97%
2	AWR	5.56%	6.00%	5.50%	7.50%	4.00%	11.50%	2.50%	5.00%	6.00%	8.32%	3.46%	5.46%
3	CWT	5.31%	5.00%	6.00%	3.00%	3.50%	5.00%	1.00%	5.00%	4.07%	3.48%	1.68%	3.85%
4	MSEX	3.55%	-	7.00%	1.50%	3.50%	4.50%	1.50%	5.50%	3.92%	-0.87%	1.42%	2.91%
5	SJW	4.00%	-	6.50%	3.00%	3.50%	-3.00%	5.00%	4.50%	3.25%	1.64%	3.13%	2.43%
6	WTR	5.74%	6.90%	8.50%	5.50%	4.50%	4.50%	8.00%	7.00%	6.41%	9.75%	6.61%	5.33%
7				6.92%	4.50%	3.50%	4.50%	3.60%	5.40%		4.46%	3.26%	2.67%
8	AVERAGES	4.79%	6.55%		4.97%			4.50%		4.98%		3.46%	

NATURAL GAS LDC SAMPLE:

LINE NO.	STOCK SYMBOL	(A) (br) + (sv)	(B) ZACKS EPS	(C) VALUE LINE PROJECTED EPS	(C) DPS	(C) BVPS	(D) VALUE LINE HISTORIC EPS	(D) DPS	(D) BVPS	(E) VALUE LINE & ZACKS AVGS.	(F) 5 - YEAR COMPOUND HISTORY EPS	(F) DPS	(F) BVPS
1	GAS	2.00%	4.30%	6.00%	1.50%	5.00%	4.50%	7.50%	5.50%	4.90%	-6.04%	3.75%	7.04%
2	ATO	3.93%	4.30%	4.00%	1.50%	6.00%	4.00%	1.50%	4.50%	3.69%	3.89%	1.53%	3.22%
3	LG	4.17%	3.00%	3.00%	2.50%	4.50%	6.00%	2.50%	6.50%	4.00%	5.48%	2.65%	6.61%
4	NJR	7.01%	3.40%	5.50%	4.00%	5.50%	7.00%	8.00%	7.50%	5.84%	13.59%	9.27%	4.85%
5	NWN	4.31%	4.20%	3.00%	2.50%	1.00%	4.50%	4.50%	4.00%	3.39%	-3.53%	5.00%	4.35%
6	PNY	3.01%	5.20%	2.50%	3.50%	1.50%	4.50%	4.00%	3.00%	3.46%	2.91%	3.82%	3.56%
7	SJI	9.54%	6.00%	9.00%	9.00%	6.00%	7.00%	9.50%	7.00%	7.64%	8.44%	10.39%	6.19%
8	SWX	6.38%	5.00%	9.00%	8.00%	6.00%	6.50%	4.00%	5.00%	6.21%	5.66%	5.37%	3.78%
9	WGL	3.67%	5.30%	2.50%	2.50%	4.00%	3.00%	2.50%	5.00%	3.54%	1.86%	3.13%	4.33%
10				4.94%	3.89%	4.39%	5.22%	4.89%	5.33%		3.58%	4.99%	4.88%
11	AVERAGES	4.89%	4.52%		4.41%			5.15%		4.74%		4.48%	

REFERENCES:
COLUMN (A): SCHEDULE WAR - 4, PAGE 1, COLUMN C
COLUMN (B): ZACKS INVESTMENT RESEARCH (www.zacks.com)
COLUMN (C): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 10/19/2012 (WATER COMPANIES) AND 12/07/2012 (NATURAL GAS LDC's)
COLUMN (D): VALUE LINE INVESTMENT SURVEY - RATINGS & REPORTS DATED 10/09/2012 (WATER COMPANIES) AND 12/07/2012 (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 10/19/2012 (WATER COMPANIES) AND 12/07/2012 (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	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
2	AWR	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
3	CWT	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
4	MSEX	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
5	SJW	k	=	2.86%	+ [	0.85	x (	9.80%	-	5.70%	)]	=	6.34%
6	WTR	k	=	2.86%	+ [	0.60	x (	9.80%	-	5.70%	)]	=	5.32%
7	**WATER COMPANY AVERAGE**					0.69							**5.69%**
8	GAS	k	=	2.86%	+ [	0.75	x (	9.80%	-	5.70%	)]	=	5.93%
9	ATO	k	=	2.86%	+ [	0.70	x (	9.80%	-	5.70%	)]	=	5.73%
10	LG	k	=	2.86%	+ [	0.55	x (	9.80%	-	5.70%	)]	=	5.11%
11	NJR	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
12	NWN	k	=	2.86%	+ [	0.55	x (	9.80%	-	5.70%	)]	=	5.11%
13	PNY	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
14	SJI	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
15	SWX	k	=	2.86%	+ [	0.75	x (	9.80%	-	5.70%	)]	=	5.93%
16	WGL	k	=	2.86%	+ [	0.65	x (	9.80%	-	5.70%	)]	=	5.52%
17	**NATURAL GAS LDC AVERAGE**					0.66							**5.54%**

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 10/12/2012 THROUGH 11/30/2012 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	=	2.86%	+ [	0.65	x (	11.80%	-	6.10%	)]	=	6.56%
2	AWR	k	=	2.86%	+ [	0.70	x (	11.80%	-	6.10%	)]	=	6.85%
3	CWT	k	=	2.86%	+ [	0.65	x (	11.80%	-	6.10%	)]	=	6.56%
4	MSEX	k	=	2.86%	+ [	0.70	x (	11.80%	-	6.10%	)]	=	6.85%
5	SJW	k	=	2.86%	+ [	0.85	x (	11.80%	-	6.10%	)]	=	7.70%
6	WTR	k	=	2.86%	+ [	0.60	x (	11.80%	-	6.10%	)]	=	6.28%
7	**WATER COMPANY AVERAGE**					0.69							**6.80%**
8	GAS	k	=	2.86%	+ [	0.75	x (	11.80%	-	6.10%	)]	=	7.13%
9	ATO	k	=	2.86%	+ [	0.70	x (	11.80%	-	6.10%	)]	=	6.85%
10	LG	k	=	2.86%	+ [	0.55	x (	11.80%	-	6.10%	)]	=	5.99%
11	NJR	k	=	2.86%	+ [	0.65	x (	11.80%	-	6.10%	)]	=	6.56%
12	NWN	k	=	2.86%	+ [	0.55	x (	11.80%	-	6.10%	)]	=	5.99%
13	PNY	k	=	2.86%	+ [	0.65	x (	11.80%	-	6.10%	)]	=	6.56%
14	SJI	k	=	2.86%	+ [	0.65	x (	11.80%	-	6.10%	)]	=	6.56%
15	SWX	k	=	2.86%	+ [	0.75	x (	11.80%	-	6.10%	)]	=	7.13%
16	WGL	k	=	2.86%	+ [	0.65	x (	11.80%	-	6.10%	)]	=	6.56%
17	**NATURAL GAS LDC AVERAGE**					0.66							**6.59%**

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 10/12/2012 THROUGH 11/30/2012 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 - 2011 PERIOD MINUS TOTAL RETURNS ON LONG-TERM TREASURIES DURING THE SAME F
THE DATA WAS OBTAINED FROM MORNINGSTAR'S STOCKS, BONDS, BILLS AND INFLATION: 2012 YEARBOC

RIO RICO UTILITIES, INC.
DOCKET NO. WS-02676A-12-0196
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. WS-02676A-12-0196
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	CURRENT	1.80%	2.70%	3.25%	0.75%	0.00% - 0.25%	0.09%	2.82%	3.78%	4.13%

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 11/30/2012
COLUMN (F) THROUGH (I): CURRENT, THE VALUE LINE INVESTMENT SURVEY, DATED 11/30/2012
COLUMN (H) THROUGH (I): 1990 - 2000, MOODY'S PUBLIC UTILITY REPORTS
COLUMN (H) THROUGH (I): 2001, MERGENT 2002 PUBLIC UTILITY MANUAL
COLUMN (H) THROUGH (I): 2003 MERGENT NEWS REPORTS

RIO RICO UTILITIES, INC.
TEST YEAR ENDED FEBRUARY 29, 2012
ECONOMIC INDICATORS - 1990 TO PRESENT

DOCKET NO. WS-02676A-12-0196
SCHEDULE WAR - 9

AVERAGE CAPITAL STRUCTURES OF SAMPLE WATER COMPANIES (000's)

	AWK	PCT.	AWR	PCT.	CWT	PCT.	SJW	PCT.	MSEX	PCT.
DEBT	$ 5,339.9	55.6%	$ 340.6	45.5%	$ 479.2	52.4%	$ 343.8	56.6%	$ 132.2	42.3%
PREFERRED STOCK	25.7	0.3%	0.0	0.0%	0.0	0.0%	0.0	0.0%	3.3	1.1%
COMMON EQUITY	4,235.8	44.1%	408.6	54.5%	435.5	47.6%	264.0	43.4%	177.0	56.6%
TOTALS	$ 9,601.4	100%	$ 749.2	100%	$ 914.7	100%	$ 607.8	100%	$ 312.5	100%

	WTR	PCT.	WATER COMPANY AVERAGE	PCT.
DEBT	$ 1,395.4	52.7%	$ 1,338.5	54.1%
PREFERRED STOCK	0.0	0.0%	4.8	0.2%
COMMON EQUITY	1,251.8	47.3%	1,128.8	45.7%
TOTALS	$ 2,647.2	100%	$ 2,472.1	100%

AVERAGE CAPITAL STRUCTURES OF SAMPLE NATURAL GAS COMPANIES (000's)

	AGL	PCT.	ATO	PCT.	LG	PCT.	NJR	PCT.	NWN	PCT.
DEBT	$ 3,561.0	51.6%	$ 1,956.3	45.3%	$ 339.4	40.9%	$ 525.1	39.2%	$ 641.7	47.3%
PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%	0.0	0.0%
COMMON EQUITY	3,339.0	48.4%	2,359.2	54.7%	491.3	59.1%	813.9	60.8%	714.5	52.7%
TOTALS	$ 6,900.0	100%	$ 4,315.5	100%	$ 830.7	100%	$ 1,339.0	100%	$ 1,356.2	100%

	PNY	PCT.	SJI	PCT.	SWX	PCT.	WGL	PCT.	NATURAL GAS LDC AVERAGE	PCT.
DEBT	$ 675.0	40.4%	$ 424.2	40.5%	$ 930.8	43.2%	$ 589.2	31.2%	$ 1,071.4	44.8%
PREFERRED STOCK	0.0	0.0%	0.0	0.0%	0.0	0.0%	28.2	1.5%	$ 3.1	0.1%
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%
TOTALS	$ 1,671.9	100%	$ 1,048.3	100%	$ 2,155.8	100%	$1,886.9	100%	$ 2,389.4	100%

	WATER & LDC AVERAGE	PCT.
DEBT	$ 1,205.0	49.6%
PREFERRED STOCK	1.6	0.1%
COMMON EQUITY	1,221.8	50.3%
TOTALS	$ 2,428.3	100%

REFERENCE:
MOST RECENT SEC 10-K FILINGS OR ANNUAL REPORTS

RIO RICO UTILITIES, INC.

DOCKET NO. WS-2676A-12-0196

REDACTED DIRECT TESTIMONY

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

DECEMBER 31, 2012

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Rio Rico Utilities, Inc. ("RRUI" or "Company") is a Class "B" public service water and wastewater corporation. The Company serves approximately 6,750 water only and 2,200 water and wastewater utility customers in portions of Santa Cruz County, Arizona, pursuant to certificates of convenience and necessity ("CC&N") granted by the Arizona Corporation Commission ("Commission" or "ACC").

RRUI filed general rate applications for both the Company's Water and Wastewater Divisions with the Commission on May 31, 2012 using a test year ("Test Year") ending on February 29, 2012. The Company is seeking an order from the Commission establishing the fair value of its plant and property used in the provision of its utility services in order to obtain permanent rates and charges designed to produce a fair return thereon. The present rates and charges were approved by the ACC in Decision No. 72059, dated January 6, 2011, that used a Test Year ending December 31, 2008.

For RRUI's Water Division, the Company is requesting a gross revenue increase of $604,079 or a 21.16 percent increase over Test Year adjusted revenue of $2,854,838. For the Wastewater Division, the Company requests an increase of $393,612 or a 28.93 percent increase over Test Year adjusted revenue of $1,360,583.

For RRUI's Water Division, RUCO is recommending a $90,894 or 3.14 percent increase over RUCO's Test Year adjusted revenue of $2,896,635. For the Wastewater Division, RUCO is recommending a $3,060 or 0.22 percent increase over RUCO's Test Year adjusted revenue of $1,402,212.

The Company uses its original cost rate base for both its Water and Wastewater Divisions in this proceeding as its fair value rate base. RRUI is seeking a 9.70 percent rate of return on a $7,629,607 Water Division fair value rate base, which results in an operating income of $740,072. RUCO recommends an 8.03 percent rate of return on a $7,681,547 fair value rate base for an operating income of $616,521.

For the Wastewater Division, the Company is also seeking a 9.70 percent rate of return on a $4,600,012 fair value rate base, which results in an operating income of $446,201. RUCO recommends an 8.03 percent rate of return on a $4,663,510 fair value rate base for an operating income of $374,293.

RUCO's adjusted Test Year rate base and operating income recommendations for RRUI's Water Division are comprised of four rate base adjustments totaling $51,939 that increased the Company-proposed rate base from $7,629,607 to $7,681,547; and eleven operating income adjustments totaling $185,781, which increased the Company's Test Year adjusted operating income from $375,933 to $561,714.

For the Company's Wastewater Division, RUCO's adjusted Test Year rate base and operating income recommendations are comprised of five rate base adjustments totaling $63,498 that increased the Company-proposed rate base from $4,600,012 to $4,663,510; and fourteen operating income adjustments totaling $158,622, which increased the Company's Test Year adjusted operating income from $213,826 to $372,448.

RUCO will provide and file separate testimony on rate design on January 7, 2012.

In addition to the adjustments described above, RUCO disagrees with the Company's recommended level of depreciation expense, which continues to depreciate utility plant that has been fully depreciated.

RUCO's Chief of Accounting and Rates, William A. Rigsby, will provide direct testimony on RUCO's recommended cost of capital and other policy issues proposed by the Company in its Application.

INTRODUCTION

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

A. My Name is Timothy J. Coley. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Appendix 1, which is attached to this testimony, describes my educational background and includes a list of the rate cases and regulatory matters in which I have participated.

Q. Please state the purpose of your testimony.

A. The purpose of my testimony is to present RUCO's recommendations regarding RRUI Utilities, Inc.'s ("RRUI" or "Company") rate Application for a determination of the current fair value of both its Water and Wastewater utility plant and property that results in a permanent increase in its rates and charges based thereon for its utility service. The test year utilized by the Company in connection with the preparation of its Application is the twelve-month period that ended February 29, 2012 ("Test Year").

BACKGROUND

Q. Please describe your work effort on this project.

A. I obtained and reviewed data and performed analytical procedures necessary to understand the Company's filing as it relates to rate base, operating income, and the Company's overall revenue requirement. My recommendations are based on these analyses. Procedures performed include the in-house formulation and analysis of twelve sets of data requests as of this writing, reviewed and analyzed the Company's responses to RUCO and Commission Staff data requests, and reviewed prior ACC dockets related to RRUI and other company's dockets.

RUCO's participation in this proceeding is the cumulative effort of me (Timothy J. Coley) and William A. Rigsby. RUCO analyst, Robert Mease, also participated and reviewed the Application prior to me being assigned to it. I performed the revenue requirement analysis on the Company's rate base and operating income. Mr. Rigsby will provide his analysis and recommendation for the cost of capital along with other policy issues requested by the Company. I will also file RUCO's recommended rate design for this proceeding on January 7, 2012 under separate testimony. RUCO analyzed the Water and Wastewater Divisions on a stand-alone basis.

...

Q. Please identify the Schedules and Exhibits you are sponsoring in this testimony.

A. I am sponsoring the rate base and operating income schedules for both the Water and Wastewater Divisions of RRUI, which are numbered TJC-1 through TJC-28 along with RUCO Exhibits 1 through 3.

SUMMARY OF RATE BASE ADJUSTMENTS

Q. Please summarize RUCO's recommended rate base adjustments.

A. All of RUCO's rate base adjustments are common to both Water and Wastewater Divisions unless otherwise noted. A summary of RUCO's rate base adjustments are as follows:

<u>Rate Base Adjustment No. 1(a) – Reconstruction of Gross Utility Plant in Service ("UPIS")</u> – This adjustment starts with the UPIS balances approved in RRUI's prior rate case that was authorized in ACC Decision No. 72059,[1] dated January 6, 2011. The adjustment reconstructs all plant additions, retirements, and adjustments since Decision No. 72059. RUCO is in agreement with the Company's reconstruction of UPIS as filed in the Application for both Water and Wastewater Divisions with the exception of RUCO rate base adjustments numbered two through five.[2]

[1] Decision No. 72059 was based on a test year ended December 31, 2008.
[2] RUCO and the Company are apparently in agreement with RUCO rate base adjustments two and four, as evidenced by RRUI responses to RUCO 2.1 and Staff MJR 1-15.

Rate Base Adjustment No. 1(b) – Reconstruction of Accumulated Depreciation Balances - This adjustment decreases the accumulated depreciation balance for both the Water and Wastewater Divisions by $114,014 and $78,260 respectively. The mechanics of this adjustment is similar to 1(a) above and reflects RUCO's recommended level of accumulated depreciation balances since the last rate case. RUCO started with the Commission's last approved UPIS balances, accumulated depreciation balances, and reconstructed all plant additions, retirements, and adjustments at the approved depreciation rates going forward to Test Year end to derive RUCO's recommended accumulated depreciation balances in its reconstruction schedules.

Rate Base Adjustment No. 2(a) & (b) – Reclassify Capital Expenditures Related to Nogales Wastewater Treatment Plant ("NWWTP") – This adjustment removes $15,362 of UPIS from the Water Division and adds the same amount to the Wastewater Division in the NWWTP account. Those expenditures are related to the NWWTP and should be classified as such.[3]

A companion adjustment to accumulated depreciation is also necessary to complete this adjustment. RUCO removed $418 of accumulated depreciation from the Water Division and added the same amount to the

[3] RRUI agreed that these capital expenditures should be reclassified accordingly in RUCO DR 2.1.

accumulated depreciation balance in the Wastewater Division's NWWTP account.

Rate Base Adjustment No. 3(a) & (b) – Reclassify Wastewater Account 380 Capacity Charges to NWWTP Account – This adjustment is unique to the Wastewater Division only and removes $1,008,000 from the Wastewater Division's Account 380 – Treatment & Disposal Equipment and adds the same amount to the NWWTP account. These expenditures are related to NWWTP and should be classified in that account. The net plant adjustment is zero for the Wastewater Division.

A companion adjustment to the accumulated depreciation is also necessary to complete this adjustment. RUCO removed $623,352 of accumulated depreciation from the Wastewater Division's account 380 and added the same amount to the NWWTP accumulated depreciation balance. The net accumulated depreciation adjustment is zero for the Wastewater Division.

Rate Base Adjustment No. 4(a) & (b) – Remove Affiliate Profits Per Company Response to Staff DR MJR 1-15 – This adjustment removes affiliate profits that were inadvertently left in some plant accounts as filed in the Company's Application for both the Water and Wastewater Divisions. The adjustment removes $1,708 from four different plant accounts in the Water Division and removes $415 from one account in the Wastewater Division.

A companion adjustment to accumulated depreciation is also necessary to complete this adjustment too. In the Water Division, RUCO removed $33 of accumulated depreciation associated with the same four accounts referenced above based on the half-year convention method of depreciation. In the Wastewater Division, RUCO removed $4 of accumulated depreciation from the same account referenced above based on the same depreciation method as utilized in the Water Division.

<u>Rate Base Adjustment No. 5 – Accumulated Deferred Income Taxes ("ADIT")</u> – This adjustment calculates the amount of ADIT based on RUCO's recommended level of fixed assets, accumulated depreciation, and effective income tax rates. The adjustment increases the ADIT balance, which decreases rate base, by $45,456 and $29,295 for the Water and Wastewater Divisions' respectively.

SUMMARY OF OPERATING INCOME ADJUSTMENTS

Q. Please summarize RUCO's recommended operating income adjustments.

A. RUCO is recommending the following operating income adjustments that will be discussed in greater detail later in my testimony:

Operating Income Adjustment No. 1 – Depreciation Expense – This adjustment reflects RUCO's recommended level of depreciation and amortization expense. The adjustment decreases the Water Division's depreciation expense by $198,500 and also decreases the Wastewater Division's depreciation expense by $150,435.

Operating Income Adjustment No. 2 – Property Tax Expense – This adjustment reflects RUCO's adjusted Test Year gross revenues, recommended level of gross revenue increase, and effective property tax rate. For the Water Division, the adjustment decreases the Company's adjusted Test Year property tax expense by $148 and increases RUCO's recommended proposed level of property tax expense by $1,634.

For the Wastewater Division, the adjustment increases the Company's adjusted Test Year property tax expense by $1,103 and increases RUCO's recommended proposed level of property tax expense by $55.

Operating Income Adjustment No. 3 – Rate Case Expense – This adjustment reflects RUCO's recommended four-year normalization period rather than the Company's three-year proposed amortization[4] period. The adjustment decreases the Water Division's rate case expense by $21,875

[4] RUCO normalizes rate case expense whereas the Company utilizes the amortization terminology for rate case expense.

and also decreases the Wastewater Division's rate case expense by $7,292.

Operating Income Adjustment No. 4 – Revenue Annualization of 6-Inch Meter – This adjustment annualizes the revenues of the 6-Inch Meter for both the Water and Wastewater Divisions. The adjustment increases the Water Division's revenue by $20,898 and also increases the Wastewater Division's revenue by $12,213 per Company response to RUCO DR 10.8 and 4.2 respectively.

Operating Income Adjustment No. 5 – Missing Accounts from the Bill Counts – This adjustment is unique to the Wastewater Division only. The adjustment increases the Wastewater Division's revenue by $4,305 to account for four customers that were not in the bill counts per Company response to RUCO DR 6.1. There is no adjustment for the Water Division.

Operating Income Adjustment No. 6 – Revenue Accrual for the 6-Inch Meters – This adjustment is necessary to reconcile the recorded general ledger ("GL") revenues to the bill count revenues per the Company's response to RUCO DR 9.1. The adjustment increases both the Water and Wastewater Divisions revenue by $20,898 and $20,805 respectively.

Operating Income Adjustment No. 7 – Revenue Accrual for the Missing Accounts from the Bill Counts - This adjustment is unique to the Wastewater Division only. This adjustment is necessary to reconcile the recorded general ledger revenues to the bill count revenues per the Company's response to RUCO DR 9.1. The adjustment increases the Wastewater Division's revenue by $4,305 and is a companion adjustment to RUCO operating income adjustment number five above.

Operating Income Adjustment No. 8 – Expense Annualization - This is a corresponding adjustment to RUCO's revenue annualization adjustments to account for the additional gallons of water to be produced and/or additional gallons of wastewater to be pumped and treated. The adjustment increases the Company's purchased power and chemical expenses by $355 for the Water Division and $546 for the Wastewater Division for the same two expenses.

Operating Income Adjustment No. 9 – Intentionally Left Blank for Future Use – There is not an adjustment number nine for either the Water or Wastewater Divisions.

Operating Income Adjustment No. 10 – Miscellaneous Expenses - This adjustment is unique to the Water Division only. The adjustment disallows expenses in ratepayers' rates related to charitable donations and the 2011 Christmas party in the amount of $1,802 for the Water Division only.

Operating Income Adjustment No. 11 – Achievement/Incentive Pay – This adjustment allocates 50 percent of the Test Year's achievement/incentive pay expense to the shareholders to be shared 50/50 between ratepayers and shareholders. The adjustment decreases the Company's adjusted Test Year expense by [BEGIN CONFIDENTIAL END CONFIDENTIAL] for the Water Division and [BEGIN CONFIDENTIAL END CONFIDENTIAL] for the Wastewater Division.

Operating Income Adjustment No. 12 – Merit Pay - This adjustment allocates 50 percent of the Test Year's merit pay expense to the shareholders to be shared 50/50 between ratepayers and shareholders. The adjustment decreases the Company's adjusted Test Year expense by [BEGIN CONFIDENTIAL END CONFIDENTIAL] for the Water Division and [BEGIN CONFIDENTIAL END CONFIDENTIAL] for the Wastewater Division.

Operating Income Adjustment No. 13 – Adjust Test Year NWWTP O&M Treatment Expense – This adjustment is unique to the Wastewater Division only. The adjustment is necessary to reflect a known and measurable change in an operating and maintenance ("O&M") expense going forward in determining rates to be embedded in rates paid by ratepayers. The adjustment decreases the Wastewater Division's adjusted Test Year O&M expense by $56,897 for the Wastewater Division only.

Operating Income Adjustment No. 14 – Reclassify RUCO's Adjusted Treatment Expense - This adjustment is unique to the Wastewater Division only. The adjustment reclassifies RUCO's adjusted annual treatment expense of $108,999 from Management Services - Other account to the Purchased Wastewater Treatment account in the amount of $108,999. The net operating income impact of this adjustment is zero.

Operating Income Adjustment No. 15 – Algonquin Power Utility Corporation ("APUC") Corporate Cost Allocations – In Commission Decision No. 72059 on pages 21-23 dated January 6, 2011, the Commission adopted Judge Rodda's Recommended Opinion and Order ("ROO") to allocate central office costs related to audit, tax services, legal, and license fees and permits to RRUI. The Decision determined that some of t he expense pool should be borne by the shareholders and unregulated utilities of Algonquin Power Utility Corporation ("APUC"). This adjustment removes some corporate allocations that RUCO finds as unnecessary in the provision of water and wastewater service to RRUI's ratepayers. The adjustment decreases the cost allocations to the Water

Division by $31,266 and also decreases the cost allocations to the Wastewater Division by $10,225.

Operating Income Adjustment No. 16 – Income Taxes – This adjustment reflects RUCO's level of income taxes on its recommended adjusted Test Year operating income before income taxes.

SUMMARY OF REVENUE REQUIREMENTS

Q. Please summarize the results of RUCO's analysis of the Company's filing and provide RUCO's recommended revenue requirements for RRUI's Water and Wastewater Divisions.

A. As can also be seen on RUCO Schedules TJC-1, a comparison between the Company and RUCO's recommended revenue increases for the Water and Wastewater Divisions are presented below:

Water Division

RRUI Revenue $'s Increase	RRUI Revenue % Increase	RUCO Revenue $'s Increase	RUCO Revenue % Increase
$ 604,079	21.16%	$ 90,894	3.14%

Wastewater Division

RRUI Revenue $'s Increase	RUCO Revenue % Increase	RRUI Revenue $'s Increase	RUCO Revenue % Increase
$ 393,612	28.93%	28.93%	0.22%

SUMMARY OF OTHER ISSUES

Q. Please summarize any other issues RUCO has pertaining to the Company's Application.

A. During the course of RUCO's audit, there were three issues noticed that need to be corrected in the Company's direct filing as follows:

1. Wastewater Division's Applicable Federal Income Tax Rate is 34% not 35.36%;
2. The correction noted in one above will also necessitate the correction of the erroneous gross revenue conversion figure used in Wastewater Division; and
3. Bill counts need to be updated to reflect proper billing determinants and the revenue annualization adjustments for the Company's operating income schedules.

RATE BASE ADJUSTMENTS

Q. Please address and explain the rate base adjustments made by RUCO in this proceeding.

A. RUCO made four rate base adjustments to the Company-proposed level of rate base for the Water Division and five adjustments to the Wastewater Division, which are explained in detail on the succeeding pages.

Rate Base Adjustment No. 1(a) – Reconstruction of Gross Utility Plant in Service (UPIS)

Q. Please explain the procedures RUCO utilized in determining RRUI's plant in service balances at Test Year end.

A. RUCO reconstructed the plant and accumulated depreciation balances by establishing a starting point that reflects the Commission's last authorized plant in service and accumulated depreciation balances from Decision No. 72059 dated January 6, 2011. The starting balances at January 1, 2009 are shown on Schedules TJC-5(c) on page 1 of 4. All annual plant additions, adjustments, and retirements were added to and deducted from that starting point in 2009. RUCO depreciated the UPIS balances at the approved depreciation rates established in Decision No. 72059. This process results in RUCO's recommended Test Year end plant and accumulated depreciation balances for this case that have occurred since the Company's last rate case.

Q. Does RUCO's reconstruction of plant and accumulated depreciation balances agree with the Company's reconstruction schedule balances?

A. Yes. RUCO's recompilation of UPIS determined that RUCO and the Company are in agreement on the Test Year end UPIS balances at this point in time for both the Water and Wastewater Divisions. However, RUCO Schedule TJC-5(c), page 4 of 4 on line 40 shows that the

Company calculated $114,014 and $78,260 more of accumulated depreciation than RUCO did. RUCO's accumulated depreciation adjustment will be discussed next.

Rate Base Adjustment No. 1(b) – Accumulated Depreciation

Q. Does RUCO agree with the Company-proposed level of accumulated depreciation as filed in its Application for the Water and Wastewater Divisions?

A. No.

Q. Please explain RUCO's adjustments to accumulated depreciation for the Water and Wastewater Divisions.

A. The mechanics of RUCO's accumulated depreciation adjustments are identical to RUCO's plant in service calculations. RUCO's accumulated depreciation adjustments arise predominantly whenever the Company has a fully depreciated plant account or net book value of zero[5] from the previous year and a plant addition is made in the following year. The reason for RUCO's accumulated depreciation adjustments is because the Company fully depreciates certain plant additions in the year it is placed in service, which violates the matching principle. The Company's depreciation treatment of that plant addition fails to recognize and

[5] Net book value of zero means the plant account balance of the asset(s) and the accumulated depreciation balance for the same account are equal to each other as shown in the example provided later in this testimony using the Company's B-2 Schedules for the Wastewater Division.

consistently utilize the half-year convention of depreciation, which most water and wastewater utilities use in Arizona. The Company utilizes the half-year convention of depreciation for its new plant additions in most all other instances when calculating its accumulated depreciation balance <u>except</u> when a plant account was fully depreciated, or near full depreciation the previous year. This will be discussed with more specificity later.

Q. What exactly is the half-year convention of depreciation?

A. Plant assets are seldom purchased on the first day of a fiscal period or disposed of on the last day of a fiscal period. Therefore, the half-year convention assumes that all plant assets were purchased and placed in service at the mid-point (i.e. half-year) of the year or fiscal period. In computing depreciation expense using the half-year convention, it's simply a full-year of depreciation expense divided by two or half of a full year of depreciation expense.

...

Q. Would you please provide an example using the Company's schedules to illustrate and add specificity when the Company fails to use the half-year convention of depreciation for new plant additions whenever the plant account was fully depreciated in the previous year?

A. Yes. RUCO has attached RUCO Exhibit 1, which are copies of RRUI Wastewater Division's B-2 Schedules pages 3.2 through 3.5, to this testimony for the convenience and ease for the reader to follow along. On Company Revised Schedule B-2 pages 3.3 and 3.4 for the Wastewater Division, the pumping equipment account on line number 14 in year 2010 shows a plant balance of $1,588,356 and the accumulated depreciation balance also has a $1,588,356 balance, which means the account has been fully depreciated with a net book value of zero. In the following year, 2011, the Company made plant additions for that account in the amount of $94,151. The Company's calculated depreciation in year 2011 for pumping equipment was $94,151 or 100 percent of the cost for the asset in the first year placed in service, which violates the matching principle's underlined goal of matching the expenses to the revenues in the period incurred or earned. The account is fully depreciated again in year 2011 with a net book value of zero because the plant balance and accumulated depreciation balance are the same $1,682,507 amounts. The Company's depreciation calculation fails to utilize the half-year convention in this instance. This is not an isolated incident. It recurs in this same account for the Water Division in years 2010 and 2011 as well as other accounts for both the Water and Wastewater Divisions. This particular account will be used in other parts of RUCO's testimony to explain additional RUCO adjustments later.

Q. What would the depreciation calculation be in that year using the half-year convention of depreciation for the same $94,151 plant addition?

A. Using the half-year convention, depreciation on the $94,151 plant addition would be $5,884 rather than the entire $94,151 taken by the Company, which is the reason for RUCO's downward adjustments to accumulated depreciation.

Q. Is the Company utilizing the group depreciation methodology?

A. No. Based on the schedules in RRUI's Application, the Company is tracking each individual account's accumulated depreciation balance. When both the plant and accumulated depreciation balances are the same, the Company stops depreciating the account. That is not using the group depreciation method. Group depreciation would continue to depreciate the plant balance regardless of whether the additional accumulated depreciation would result in a negative net book value.

...

Q. What effect does this have on the UPIS balance in rate base?

A. It increased the net UPIS balance in rate base because the Company stopped depreciating each individual account's accumulated depreciation balance when it reached a net book value of zero.

Q. Briefly explain how other water utilities in Arizona depreciate UPIS for its plant accounts.

A. Arizona Water Company ("AWC") does <u>not</u> track each individual plant account's accumulated depreciation or net book value balances. AWC depreciates the previous years' plant balance and uses the half-year convention on the plant additions in the current year placed in service, which is consistent with group depreciation. That depreciation methodology increases the accumulated depreciation balance and thus reduces rate base by more than the method used in this case.

Q. Does RUCO take issue with the Company's methodology of tracking each accounts accumulated depreciation balance and stopping depreciation when the net book value is zero?

A. If the Company was consistent with its treatment of depreciation on both the rate base and operating income sides, RUCO would have had no problem with the Company's depreciation methodology but it wasn't. The Company took individual depreciation on its plant schedules and tried to use group depreciation on its operating income schedules. This is unfair to the ratepayers. First, the Company fails to continue depreciating the prior year's plant balance that had a net book value of zero in its plant schedules. Second, the Company used group depreciation on its operating income schedules attempting to collect depreciation expense on plant that was previously fully depreciated. The Company cannot have it both ways.

Q. What adjustments to the Company's accumulated depreciation balances does RUCO recommend to recognize the half-year convention of depreciation for the Water and Wastewater Divisions?

A. RUCO's adjustments to the Water and Wastewater Divisions decrease the Company's accumulated depreciation balances by $114,014 and $78,260 respectively. These adjustments are shown on the respective Water and Wastewater Schedules TJC-2 and TJC-3 with the details shown on TJC-5(b) and TJC-5(c) on page 4 of 4.

Rate Base Adjustment No. 2 – Reclassify Accounts to Nogales Wastewater Treatment Plant ("NWWTP") Account

Q. Please explain RUCO's adjustment that reclassifies capital expenditures for both the Water and Wastewater Divisions that more appropriately should be charged only to the Wastewater Division's NWWTP account.

A. Company witness, Mr. Sorensen, on page eight of his direct testimony stated that "the approximate $181,000 of additional costs" associated with the Nogales Treatment Plant upgrades were legal and consulting costs when the Company was sued by the City of Nogales. The approximate costs of $181,000 were charged to a number of the Water and Wastewater Divisions plant accounts to be capitalized. Those costs are more directly related to the litigation between RRUI and the City of Nogales regarding the treatment upgrade obligations. The Company agreed in response to RUCO DR 2.1 that the costs should be classified to the NWWTP account rather than where they were originally charged. In addition, the Company later identified $169,004 of legal related costs rather than the approximate $181,000 identified earlier.

Q. What adjustments are necessary to reclassify these costs to the NWWTP account in the Wastewater Division?

A. The Company had originally recorded $15,362 to the Water Division in two different plant accounts. RRUI acknowledges that it should remove those capital expenditures and reclassify them to the Wastewater Division's NWWTP account in response to Staff DR MJR 1-15. A companion adjustment to remove the accumulated depreciation associated with those two Water Division's accounts was required that reduced total accumulated depreciation by $418 in the same two accounts. These adjustments are shown on Schedule TJC-2 and TJC-3 with the details shown on TJC-6(a) and 6(b).

For the Wastewater Division, the Company acknowledges that it is necessary to reclassify $153,642 from Account 380 – Treatment & Disposal Equipment to the NWWTP account. Including the $15,362 reclassified from the Water Division, the NWWTP account increased by the Company identified $169,004 for the costs associated with the Nogales upgrades. A companion adjustment to remove the accumulated depreciation associated with the Wastewater Division's Account 380 was required that reduced the accumulated depreciation in that account by $3,841 and reclassified the same amount to the NWWTP accumulated depreciation balance. These adjustments are shown on Schedule TJC-2 and TJC-3 with the details shown on TJC-6(a) and 6(b).

Rate Base Adjustment No. 3 – Reclassify Account 380 Capacity Related Costs to Nogales Wastewater Treatment Plant ("NWWTP") Account

Q. **Please explain RUCO's adjustment that reclassifies $1,008,000 from Account 380 – Treatment & Disposal Equipment to NWWTP account.**

A. This adjustment attempts to segregate all identifiable costs, past and present, from accounts that had costs related to NWWTP to the NWWTP account. The costs that RUCO reclassifies in this adjustment are capacity costs that RRUI had purchased over the course of time in different capacity increments (i.e. 250,000 gallons per day (gpd) to 100,000 gpd allotments from the City of Nogales), which total RRUI's total capacity of 550,000 gpd at the NWWTP. The $1,008,000 reclassified in this adjustment was removed from Account 380 – Treatment & Disposal Equipment and reclassified the same costs to the NWWTP account.

Q. **How did RUCO ascertain the $1,008,000 of capacity costs that RRUI had purchased from the City of Nogales over a period of several years since 1996?**

A. RUCO ascertained the $1,008,000 capacity costs through discovery in RUCO DR 5.7. The Company identified the years since 1996 that RRUI made capacity purchases from the City of Nogales. The first purchase for 250,000 gpd did not have a known dollar amount for that particular increment. The other three increments of 100,000 gpd did have known costs associated with those three incremental purchases, which totaled

$1,008,000. RUCO also calculated the accumulated depreciation associated with those capacity costs and reclassified those balances along with the plant costs to NWWTP account.

Q. What adjustments are necessary to reclassify these costs to the NWWTP account in the Wastewater Division?

A. This adjustment is unique to the Wastewater Division only. RUCO removed the $1,008,000 from Account 380 – Treatment & Disposal Equipment and reclassified the costs to the NWWTP account. RUCO's calculated companion adjustment to accumulated depreciation mentioned above reclassified $623,352 from Account 380 to the NWWTP account's accumulated depreciation balance. There is no net impact on the Wastewater Division's total UPIS or accumulated depreciation balances. This is more of a housecleaning adjustment. These adjustments are shown on Schedule TJC-2 and TJC-3 with the details shown on TJC-7(a) and 7(b).

Rate Base Adjustment No. 4 – Remove Affiliate Profits

Q. Please explain RUCO's adjustment that removes $2,123 from the Water and Wastewater Divisions' plant accounts.

A. The Company responded to Staff DR MJR 1-15 that RRUI had identified $2,123 in affiliate profits charged to some plant accounts that should have been removed before filing its Application. This adjustment removes those affiliate profits that were inadvertently left in the plant accounts as filed in the Company's Application for both the Water and Wastewater Divisions. The adjustment removes a total of $1,708 from four different plant accounts in the Water Division and removes $415 from one account in the Wastewater Division.

A companion adjustment to accumulated depreciation is also necessary to complete this adjustment too. In the Water Division, RUCO removed $33 of accumulated depreciation associated with the same four accounts referenced above based on the half-year convention method of depreciation. In the Wastewater Division, RUCO removed $4 of accumulated depreciation from the same account referenced above based on the same depreciation method as utilized in the Water Division. These adjustments are shown on Schedule TJC-2 and TJC-3 with the details shown on TJC-8(a) and 8(b).

<u>Rate Base Adjustment No. 5 – Accumulated Deferred Income Tax ("ADIT")</u>

Q. Please explain RUCO's adjustments to the ADIT for the Water and Wastewater Divisions' rate base.

A. There are three causes leading to RUCO's adjustments to the Company's ADIT balance as filed. First, RUCO's ADIT adjustments are based and calculated on the amount of RUCO's recommended level of fixed assets and accumulated depreciation balances for the Water and Wastewater Divisions. Second, the Company's effective federal income tax rate in its ADIT Schedule B-2 on page 7.0 is not the same rate that was calculated in its Gross Revenue Conversion Factor ("GRCF") Schedule C-3. RUCO's ADIT Schedule TJC-9 on page 1 properly reflects RUCO's effective federal income tax rate for the particular division in question. Third, RUCO's allocation factor that allocates the calculated ADIT balance is not exactly the same as the Company's because there are slight difference in our two rate bases before ADIT[6], which RUCO and the Company utilize to allocate the ADIT balance to the two divisions. The adjustment increases the ADIT balance, which is a decrease in rate base, by $45,456 and $29,295 for the Water and Wastewater Divisions respectively.

OPERATING INCOME ADJUSTMENTS

Operating Income Adjustment No. 1 – Depreciation Expense

Q. Does RUCO agree with the Company-proposed level of depreciation expense as filed in its Application for the Water and Wastewater Divisions?

A. No.

[6] This is because of RUCO's rate base adjustments one(b) through four.

Q. Please explain the reason(s) for RUCO's adjustments to the Company-proposed depreciation expense for the Water and Wastewater Divisions.

A. RUCO will again refer the reader to RUCO Exhibit 1 attached to this testimony and use the actual scenario that is reflected in the Company's B-2 Schedules on pages 3.2 through 3.5 of the Wastewater Division. The B-2 Schedule on page 3.2 at line 14 shows year 2009 having an annual depreciation amount of $188,030 or ($1,504,181 x 12.50%) + ($112 x 6.25%) = $188,030, which RUCO is in total agreement with the Company at that point. The Company utilizes the half-year convention of depreciation for the $112 plant addition in that instance by using half of the full 12.50% annual depreciation rate, which is 6.25 percent as reflected above. One can easily see that the difference in the plant balance and accumulated depreciation balance for that account is $83,582, which is the net book value for that account. The account's net book value is less than the annual depreciation taken in year 2009 and is close to being fully depreciated.

In year 2010, the net book value on line number 14 in the amount of $83,582 is shown. The Company made an $84,064 plant addition in year 2010. Instead of using the full group depreciation concept and depreciating a full year of the total 2009 plant balance, the Company simply depreciates the net book value of $83,582 plus the $84,064 plant addition for a total annual depreciation amount of $167,646 ($83,582 + $84,064 = $167,646) in year 2010. The Company fails to use the half-year convention for the plant addition in 2010 where it did use it in 2009 for that plant addition as illustrated in the previous paragraph. The Company is tracking each account's accumulated depreciation and net book value but never depreciates any more than the net book value, which is inappropriate if not done consistently. However, the Company inconsistently applies the group depreciation concept and is not being consistent with the half-year convention in its plant schedules either. The account is fully depreciated in year 2010 because the net book value is zero, which is not shown in the next year as it was for 2010.

In year 2011, there is no net book value shown for this year on line number 14, but it was fully depreciated in the previous year with a net book value of zero. The Company made another plant addition in 2011 in the amount of $94,151. Again, instead of using the full group depreciation concept and depreciating a full year of the total 2010 plant balance, the Company simply depreciates the $94,151 plant addition, which keeps the accumulated depreciation at a lesser amount and rate base higher, Because the account had a net book value of zero in 2010 the only depreciation for 2011 is the Company's depreciation methodology of the full $94,151 plant addition. Again, the Company fails to use the half-year convention for the plant addition in 2011 when it did use it for the plant addition in 2009, as illustrated two paragraphs earlier. Moreover, the Company is tracking each individual account's net book value and never depreciates any more than the net book value of that account, which RUCO would have no problem with if consistently applied, but it's not. The Company inconsistently applies the full group depreciation concept and is also being inconsistent with the half-year convention. The account was fully depreciated again in 2011, which is two-years straight because the net book value is zero, which is not shown on the 2011 schedules as it was in year 2010.

Year 2012 is a unique period when compared to the prior three periods discussed thus far. In 2012, there are only two-months, or 1/6th of a year, for the Test Year end February 29, 2012. For the two-months of this year, there is no net book value shown for this year on line number 14 either, but we know this account was fully depreciated in 2011 with a net book value of zero for the second straight year. The Company made another $30,433 plant addition in the last month of the Test Year in February 2012. Again, the Company should not have depreciated the plant for a full year of the prior year's plant balance in this instance because there were only two-months in this period. Instead, the Company fails to depreciate any of the prior year's plant balance and only depreciated 1/6th of the $30,433 plant addition (1/6 x $30,433 = $5,072). Again, the Company failed to use the half-year convention for the plant addition at Test Year end 2012. If the

Company is tracking each account's net book value and never depreciates any more than the net book value of that account, then the Company should not be calculating depreciation expense on more than the net value because the remaining plant balance has been fully depreciated.

Q. You mentioned several times that the "Company is tracking each account's net book value and never depreciates any more than the net book value of that account, which RUCO has no problem with as long as consistency is maintained" in the depreciation method. How does that statement apply to the Company-proposed depreciation expense on Schedule C-2, page 2?

A. Again using Account 371 – Pumping Equipment in the Wastewater Division, we saw that the Company has calculated a net book value of $25,361 on its B-2 Schedules at Test Year end and would never depreciate any more than the net book value of that account in the succeeding years. As RUCO has said several times over the last several pages and mentioned in the question above also, the same consistency should be applied to the depreciation expense for the operating income side too for a depreciation methodology to be accepted and valid. The Company now fails to maintain its depreciation consistency, as it did for UPIS page after page, for its depreciation expense on an annual going forward basis.

Q. Please explain what the Company is proposing for its depreciation expense for Account 371 – Pumping Equipment?

A. The Company is now proposing to depreciate the total plant balance of $1,712,940 as reflected in the Company's B-2 and C-2 Schedules on page 2 at line 18, attached as RUCO Exhibit 2 instead of the net book value of that account in the amount of $25,361 for its depreciation expense. Remember that the Company is tracking each account's net book value and never depreciates any more than the net book value of that account when calculating the accumulated depreciation in its plant schedules. The Company's B-2 Schedule indicates that net book value of account 371 is $25,361, not $1,712,940. Of the $1,712,940 in account 371 that the Company proposes to depreciate in this instance, $1,682,507 has already been depreciated at the end of 2011 as shown in RUCO Exhibit 1. The Company is now proposing full group depreciation expense of $214,118 on an account that has been fully depreciated for two-years before the $30,433 plant addition in the last month of the Test Year. The Company is inconsistent. It is using net book value to determine the depreciation to be added to the accumulated depreciation balance, but not to calculate depreciation expense on its income statement.

Q. How much depreciation expense does the Company request using this methodology of depreciation?

A. The Company is requesting $214,118 in depreciation expense for account 371, as shown on the Company's Schedule C-2 on page 2 at line 18.

Q. What amount of depreciation expense would the Company be requesting for that account had the $30,433 plant addition not been made in the last month of the Test Year?

A. Zero. The Company's other accounts on lines 24, 26, and 31 have a zero net book value and the Company requests zero depreciation expense because those accounts are fully depreciated. Dissimilarly, although account 371 had been fully depreciated too at the end of both years 2010 and 2011, because the Company added a $30,433 plant addition to the account, it now seeks $214,118 in depreciation expense for plant that previously had been fully depreciated at the end of both of the prior two-years. More clearly, the Company wants $214,118 a year for an additional $30,433 investment until the next rate case on an account that had been fully depreciated in both 2010 and 2011.

Q. So in RUCO's opinion, should the ratepayers be paying for plant that they have already fully paid for in rates?

A. No. Mr. Bourassa's own calculations reflect that the Company has fully recovered the costs of the plant through rates paid by RRUI's customers. The Company should not be able to recover the costs again.

Q. Are there other accounts in the Wastewater Division that has similar issues as just explained that RUCO made adjustments too?

A. Yes. Account 354 was fully depreciated at year end 2011 and only the plant additions in the last two-months of the Test Year should be depreciable going forward. Some other depreciable plant balance differences between the Company and RUCO are due to reclassifications that RUCO recommended in its rate base adjustments. However, the account RUCO used in its illustration (Account 371) is the primary reason for RUCO's depreciation expense adjustment for the Wastewater Division. RUCO's adjustment reflects the use of the same depreciation methodology being used on both the rate base and operating income side, and the appropriate use of the half-year convention.

Q. Did the same issue persist in Water Division?

A. Yes. Coincidentally, it was the same pumping equipment account, but numbered Account 311 rather than 371 as in the Wastewater Division. The Water Division's pumping equipment account was fully depreciated at year end 2011 per Company's B-2 Schedules and only the plant additions in the last two-months of the Test Year are depreciable going forward under RUCO's depreciation expense recommendation. Likewise, RUCO calculated a depreciation expense for the transportation equipment account by adding the net book value at the end of 2011 to the 2012 plant additions to obtain a depreciable balance going forward. Some other depreciable plant balance differences are due to reclassifications that RUCO recommended in its Water Division's rate base adjustments. However, the account RUCO used in its illustration, in this case Account 311, is the primary reason for RUCO's depreciation expense adjustment for the Water Division.

Q. If the Company used the full group depreciation concept to account for its plant, what would the result be?

A. The Company would have more accumulated depreciation and thus, less rate base if accumulated depreciation is not tracked by individual accounts.[7] The group depreciation concept continues to depreciate plant regardless of the accounts net book value.

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[7] Arizona Water Company uses the full group depreciation concept.

Q. Are there any more areas that RUCO takes issue with regarding depreciation expense?

A. Yes. RUCO would argue that four of the Wastewater Division's accounts are fully depreciated at Test Year end rather than the three accounts claimed by the Company.

Q. What is the fourth account that RUCO believes is fully depreciated?

A. Account 398 – Other Tangible Plant should have been fully depreciated in year 2011 as evidenced by the Company's own plant reconstruction schedules if properly depreciated in that year.

Q. What adjustments to depreciation expense does RUCO recommend to maintain the depreciation consistency?

A. RUCO recommends decreasing the Company's depreciation expense by $198,500 and $150,435 for the Water and Wastewater Divisions respectively. Those adjustments are on Schedules TJC-10 and TJC-11, with the supporting detail on Schedules TJC-12 on page 1 of 1.

<u>Operating Income Adjustment No. 2 – Property Tax Expense</u>

Q. Has RUCO made an adjustment to the Company's adjusted Test Year property tax expense?

A. Yes.

Q. Please explain the reasons why RUCO has made an adjustment to the Company's adjusted Test Year property tax expense?

A. There are essentially three reasons that led to RUCO's adjusted Test Year property tax expense adjustment. First, RUCO's gross revenues for both the adjusted Test Year and proposed gross revenues are different than the Company's revenues. Second, RUCO's net book value of vehicles is slightly different than the Company's net book values. Third, RUCO has a slightly lower effective property tax rate than the Company.

RUCO divided the property tax paid by the full cash value of the property. The Company divided the property tax paid by a number that is less than full cash value of the property, which results in a higher effective property tax rate than RUCO's.

Q. What adjustment does RUCO recommend to the Company's adjusted Test Year and proposed level of property tax expense?

A. The adjustment reflects RUCO's adjusted Test Year gross revenues, recommended level of gross revenue increase, and the effective property tax rate. For the Water Division, the adjustment decreases the Company's adjusted Test Year property tax expense by $148 and increases the proposed level of property tax expense by $1,634.

For the Wastewater Division, the adjustment increases the Company's adjusted Test Year property tax expense by $1,103 and increases the proposed level of property tax expense by $55. These adjustments are shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-13.

Operating Income Adjustment No. 3 – Rate Case Expense

Q. Does RUCO find RRUI's amount of rate case expense reasonable?

A. Yes.

Q. Did RUCO make an adjustment to the Company's rate case expense?

A. Yes.

Q. Please explain RUCO's adjustment to the Company's rate case expense?

A. This adjustment reflects RUCO's recommended four-year normalization period rather than the Company's three-year proposed amortization[8] period. The four-year period is more reflective of the time between rate cases for RRUI.

[8] RUCO normalizes rate case expense whereas the Company utilizes the amortization terminology for rate case expense.

Q. What adjustment was necessary to recognize a four-year period of normalizing the rate case expense rather than the Company's three-year amortization period?

A. It was necessary to decrease the Water Division's rate case expense by $21,875 and also decrease the Wastewater Division's rate case expense by $7,292 to reflect the four-year period of normalizing the expense. These adjustments are shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-14.

<u>Operating Income Adjustment No. 4 – Annualize the Revenues for the 6-Inch Meter for Both the Water and Wastewater Customer's</u>

Q. Did the Company annualize the Water Division's revenues for the 6-Inch bulk water sales customer in its Application?

A. No.

Q. Why didn't the Company annualize this customer's revenue going forward to account for the future revenues?

A. Through several data requests regarding this customer, the Company responded that the customer is at best an intermittent customer with its own wells. Therefore, the Company claims it did not annualize the revenue because it asserts it could not expect this customer to be receiving water on a continuing basis.

Q. Did RRUI make any water sales to this customer during the Test Year?

A. Yes. RRUI sold $29,625 over a four-month period of November 2011 through the end of the Test Year of February 29, 2012. The customer pays a monthly minimum charge of $549 plus a special contracted commodity usage charge. The Company can charge this customer a non-tariffed commodity rate because the customer is not in the Company's CC&N.

Q. How much water did this customer consume during the four-months of the Test Year?

A. The customer used 7.6 million gallons during the four-month period of the Test Year.

Q. Was RUCO able to obtain any information regarding this 6-Inch bulk water sales customer?

A. Yes. In response to RUCO DR 10.7, the Company stated that the customer is Morning Star Ranch. Morning Star Ranch is a 5,500 acre development of 121+ large residential tracts. Fifty-five of the tracts have already sold. There are also 21 residential homes built on the property today. This includes a clubhouse from RUCO's understa nding. The development is represented by Brasher Real Estate. RUCO spoke with a realtor, Fred Johnson of Brasher Real Estate in Tubac. He stated that the community was receiving water from RRUI via a 6-Inch metered interconnection. He stated that he did not anticipate the wells on the property would ever be used again and mentioned the wells had real problems. He assured RUCO that the water being provided by Liberty Utilities was sufficient because Liberty had a 100-year guaranteed water supply. He indicated the homes are not individually metered today. The only meter that is in place today is at the 6-Inch interconnect. The HOA paid for the 6-Inch interconnection with RRUI and paid for upgrades at a RRUI's pump station to adequately pump the water to the interconnection. Mr. Johnson said plans are being made to meter each individual home in the near future. He also mailed a packet of information to me regarding the development.

Based on this information, it is clear that Morning Star Ranch is not an intermittent construction customer as the Company claimed. This is a growing development that will require more water as tracts continue to sell and new homes are built. The homes on the property are not model homes. This is an upscale desert development. In response to RUCO DR 10.8, the Company provided another eight-month, March through October 2012, of monthly water sales to Morning Star Ranch by Liberty Utilities. Based on the information, it is clear that the Company's sales to Morning Star Ranch are a stable source of revenues, which should have been annualized as a continuous known and measurable monthly water sale.

Q. Does RRUI have a contract with Morning Star Ranch?

A. Yes. RRUI provided a copy of its contract with Morning Star Ranch in response to Staff DR MJR 1-04. From the reading of the contract, it apparently has been extended at least once since its inception on March 31, 2010 since the contract stated it is renewable every subsequent two-years.

Q. What adjustment was necessary to recognize Morning Star Ranch as a continuing customer?

A. RUCO annualized the four-months in the Test Year and the eight-months of known and measurable water use obtained from the Company via RUCO DR 10.8. It was necessary to increase the Water Division's revenue by $20,898. This adjustment is shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-15 on page 1 of 21.

Q. Please discuss RUCO's 6-Inch revenue annualization to account for the Wastewater Division's commercial customer.

A. During RUCO's review of the Company's H Schedules and bill counts, RUCO found it peculiar that the Water Division had 6-Inch commercial water customer for each of the twelve-months of the Test Year, but the

Wastewater Division had one customer for only four-months. RUCO presumed that this must be the same customer for both divisions and should also be receiving wastewater service for the same twelve-months that was reflected in the Water Division's bill counts. RUCO issued a series of data requests regarding various bill count questions to the Company. In RRUI's responses, the Company identified an issue that lead to some accounts being lost or terminated. The Company said that whenever RRUI went out to check or change a water meter at the Santa Cruz Valley School District, the wastewater billings were no longer in the Company's billing system after that visit. The bills were not included in the bill counts and thus not included in the billing determinants in the Application. The Company appears to agree that an adjustment is necessary based on its response to RUCO DR 4.2.

Q. What adjustment was necessary to recognize the school districts bill counts as an active wastewater customer?

A. Per the Company's response to RUCO DR 4.2, it is necessary to include this customer in the other eight-months not shown in the bill counts and annualize one-year of bill counts accordingly. RUCO is in agreement with the Company's response that a $12,213 adjustment is necessary to increase revenue in order to account for the eight additional bills not included in the bill counts. This adjustment is shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-15 on page 1 of 21.

Operating Income Adjustment No. 5 – Annualize the Revenues for the Four Missing Wastewater Customers' Bill Counts

Q. Please explain RUCO's adjustment that includes four missing customers' bill counts in the billing determinates.

A. The Company responded to RUCO DR 6.1 and stated, "As part of the analysis performed in letter C above, the Company found only four accounts missing from the bill counts. The total uncollected revenue was approximately $4,305..." RUCO is in agreement with RRUI's statement and increases the Wastewater Division's revenue by $4,305 accordingly. There is no Water Division adjustment here only Wastewater. This adjustment is shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-16 on page 1 of 1.

Operating Income Adjustment No. 6 – 6-Inch Meter Revenue Accrual

Q. Please explain RUCO's revenue accrual adjustments for the Water and Wastewater Divisions.

A. This is a companion adjustment to RUCO adjustment number four above. The adjustment is necessary to reconcile the recorded general ledger ("GL") revenues to the bill count revenues per the Company's response to RUCO DR 9.1. The adjustment increases both the Water and Wastewater Divisions revenue by $20,898 and $20,805 respectively. These adjustments are shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-17 on page 1 of 1.

Operating Income Adjustment No. 7 – Four Missing Accounts Revenue Accrual

Q. Please explain RUCO's revenue accrual adjustment.

A. This is companion adjustment to RUCO adjustment number five above. This adjustment is necessary to reconcile the recorded general ledger ("GL") revenues to the bill count revenues per the Company's response to RUCO DR 9.1. The adjustment increases the Wastewater Divisions revenue by $4,305. There is no corresponding adjustment for the Water Division. This adjustment is shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-18 on page 1 of 1.

Operating Income Adjustment No. 8 – Expense Annualization

Q. Please explain RUCO's adjustment for expense annualization.

A. This is a corresponding adjustment to RUCO's revenue annualization adjustments numbers four, five, and six to account for the additional gallons of water to be produced and/or additional gallons of wastewater to be pumped and treated. The adjustment increases the Company's purchased power and chemical expenses by $355 for the Water Division and $546 for the Wastewater Division for the same two expenses. These adjustments are shown on Schedule TJC-10 and TJC-11, with the details shown on TJC-19.

Operating Income Adjustment No. 9 – Intentionally Left Blank For Future Use

Operating Income Adjustment No. 10 – Miscellaneous Expense

Q. Please explain the adjustment RUCO makes to miscellaneous expense.

A. This adjustment is unique to the Water Division only. The adjustment disallows expenses in ratepayers' rates, which are unnecessary in the provision of utility service. The expenses in the Test Year were related to charitable donations and the 2011 Christmas party in the amount of $1,802 for the Water Division only. The Company provided the receipts and invoices in response to Staff DR MJR 3.4. The adjustment is shown on Schedule TJC-10 and TJC-11, with the details on TJC-21.

Operating Income Adjustment No. 11 – Achievement/Incentive Pay

Q. Please explain RUCO's adjustment to achievement and incentive pay.

A. This adjustment provides for the allocation of 50 percent of Test Year expense for the achievement/ incentive pay to shareholders.

Q. Please explain why a 50 percent allocation to shareholders is appropriate in this case for an achievement/incentive compensation program.

A. Generally, achievement/incentive pay programs can provide benefits to both shareholders and ratepayers. The shareholders stand to gain from potential cost savings while the ratepayers may benefit through superior customer service. The adjustment essentially provides an equal sharing of such costs and the potential benefits that may be derived from the program(s). This provides an appropriate balance between the shareholders and ratepayers for the benefits achieved. The shareholders stand to benefit as much as the ratepayer does. Therefore, an equal sharing of the costs is appropriate. There is no certainty that the same level of costs will reoccur on a going forward basis as the new rates will have some of the burden placed equally on both the shareholders and ratepayers.

Q. Has the Commission in the past ordered an equal sharing between the shareholders and ratepayers of such costs?

A. Yes. In numerous Commission decisions,[9] the Commission has ordered a 50/50 sharing of incentive pay programs and provides for a fair and reasonable balancing of the interests between the ratepayers and shareholders.

[9] See Decision No. 70011 at 27, Decision No. 70360 at 21, Decision No. 68487 at 18, Decision No. 70665 at 16, and Decision No. 71623 at 31.

Q. What adjustments is RUCO recommending in order to share these costs in a manner that balances the interests between ratepayers and shareholders?

A. RUCO recommends allocating 50 percent of the incentive pay costs. See Company response to RUCO DR 2.13 (Confidential Response). RUCO recommends the removal of [BEGIN CONFIDENTIAL END CONFIDENTIAL] and [BEGIN CONFIDENTIAL END CONFIDENTIAL] of Test Year achievement/incentive pay expense from the Water and Wastewater Divisions respectively. These adjustments are shown on the respective Schedules TJC-10 and TJC-11, with the details on TJC-22.

<u>Operating Income Adjustment No. 12 – Merit Pay Expense</u>

Q. Please explain RUCO's adjustment that allocates 50 percent of the merit pay Test Year expense to the shareholders.

A. RUCO's basis for the merit pay expense adjustment is the same as provided in RUCO's previous operating income adjustment number eleven. The adjustment provides a fair and reasonable balancing of the interests between the ratepayers and shareholders.

Q. What adjustments is RUCO recommending in order to share these costs in a manner that balances the interests between ratepayers and shareholders?

A. RUCO recommends allocating 50 percent of the costs. See Company response to Staff DR MJR 3.11 (Confidential Response). RUCO recommends the removal of [BEGIN CONFIDENTIAL END CONFIDENTIAL] and [BEGIN CONFIDENTIAL END CONFIDENTIAL] of Test Year merit pay expense from the Water and Wastewater Divisions respectively. These adjustments are shown on the respective Schedules TJC-10 and TJC-11, with the details on TJC-23.

<u>Operating Income Adjustment No. 13 – Adjust City of Nogales O & M Treatment Expense</u>

Q. Please explain RUCO's adjustment to the Wastewater Division's treatment expense.

A. The City of Nogales charges RRUI a monthly amount for treatment expenses related to its 550,000 gallons per day ("gpd") of wastewater treatment capacity at the Nogales International Wastewater Treatment Plant ("NWWTP"). The Company's Application as filed contained $165,896 in Test Year expenses from the City of Nogales in actual charges for treating RRUI's wastewater capacity at NWWTP or $13,824.65 per month. RUCO requested a Public Records Request from the City of Nogales during the course of the instant proceeding. The public records request included a letter from the City of Nogales dated May 10, 2012 that was sent to RRUI's legal representative in Phoenix, which has been included as RUCO Exhibit 3. Attached to the letter was a billing summary page that included past and future monthly billings from August 13, 2010 to November 15, 2012.

The monthly billing summary is also included in RUCO Exhibit 3. The billing summary shows some billing adjustments and reversals on March 14, 2012, which was for the service period of February 3 through March 13, 2012, which relates back to the Test Year. The billing adjustments and reversals appear to be for establishing a new known and measurable monthly charge going forward from those dates as referenced above. The new monthly charge going forward is $9,083.26 per month rather than the Test Year monthly charge of $13,824.65.

Q. Did RUCO contact the Company regarding this matter?

A. Yes. The Company stated in a data response to RUCO DR 11.5, "The Company was charged an estimate of the operations & maintenance treatment expense. A final reconciliation is expected in the first quarter of 2013 and will be provided as soon as available."

Q. What recommendation and/or adjustment is RUCO asserting at this juncture of the proceeding?

A. At this point of the proceeding, RUCO recommends an adjustment that reduces the Company's Test Year treatment expense by $56,896.68 or $4,741.39 per month for twelve-months. This adjustment is unique to the Wastewater Division only. Unless the Company's proposed final reconciliation expected in the first quarter of 2013 provides otherwise, RUCO's adjustment will reflect a new known and measurable monthly charge in its direct testimony for now. RUCO did not see any reconciliation on the billing summary page other than adjustments to set a new rate going forward. This adjustment is shown on Schedule TJC-10 and TJC-11, with the details on TJC-24. There is no adjustment for the Water Division.

Operating Income Adjustment No. 14 – Reclassify RRUI's Treatment Expenses

Q. Please explain RUCO's adjustment that reclassifies RRUI's Wastewater Division's treatment expense.

A. Currently, this expense is embedded in the Management Services – Other account. It would be more appropriately classified in the Purchased Wastewater Treatment expense account. That account has a zero balance in the Company's filing. RUCO's reclassification adjustment seems rationale and segregates this expense in a way that is more easily identifiable.

Q. What adjustment is necessary to reclassify this expense to an account that better characterizes this expense?

A. After RUCO's previous adjustment number 13, it is necessary to remove the remaining balance of the treatment expense in the amount of $108,999 from the less specific Management Services – Other account and classify it in the better characterized and identifiable Purchased Wastewater Treatment expense account for the same $108,999. This adjustment's net effect on total expense is zero. This adjustment is shown on Schedule TJC-10 and TJC-11, with the details on TJC-25. There is no adjustment for the Water Division.

<u>Operating Income Adjustment No. 15 – Algonquin Power Utility Corporation ("APUC") Cost Allocations</u>

Q. Did RUCO make any adjustments to the APUC cost allocations?

A. Yes.

Q. Briefly describe the APUC cost allocations?

A. APUC now pools costs from twenty-four distinct areas, such as audit, tax services, unit holder communications, trustee fees, and escrow/transfer fees etc. In RRUI's last rate case, the cost pool was comprised of only twelve distinct areas. APUC allocates those costs to its regulated and unregulated entities. The regulated entity, Liberty Utilities, further allocates its share of the cost pool to the operating entities, which includes RRUI. The total amount allocated to the regulated entity, Liberty Utilities, is approximately $1,041,705[10] per Company response to RUCO DR 3.7. Liberty Utilities allocates 9.21 percent or $92,162of its share of the costs to RRUI's Water Division and 3.01 percent or $30,142 of the costs to RRUI's Wastewater Division by customer counts.

Q. What rationales did RUCO rely on when making its adjustments to the Company's APUC cost allocations?

A. RUCO relied on four separate rationales when making these adjustments.

Q. Please discuss each of the four rationales that RUCO relied on when making its adjustments to the APUC cost allocations.

A. The first rationale involved Commission Decision No. 72059 dated January 6, 2011. On page 22 at lines 15-16, it stated "we will allow APT central costs related to audit, tax, legal, and license fees and permits to be allocated to RRUI..."

[10] The amount of Liberty Utilities cost pool allocation has been converted from Canadian dollars to US dollars by a currency conversion factor of 1.05.

Q. Did RUCO allow those costs in this case?

A. Yes. Based on the Commission's prior Decision, RUCO believes that those costs should be allowed.

Q. What is second rationale that RUCO relied on when making its adjustments to the cost allocations?

A. The second rationale is based on the comparable amount of expenses sought in the last case and in this case. Essentially, there is not a lot of difference in the amounts requested. In the last case, the Company allocated $137,706 to RRUI and in this case the allocation is $127,253 or only $10,453 less than in the last case. RUCO found the $137,706 in the last rate case to be excessive and demonstrated so through its total labor / wage dollars per customer analysis when compared to other Arizona water and wastewater companies. There is no reason to believe that $10,453 less in this case would cause RUCO to deviate from the same conclusion this time.

Q. What is the third rationale that RUCO relied upon when making its adjustments to the cost allocations?

A. The third rationale is based on the costs that RUCO determined to be reasonable in the last case, which should also apply to this case. Again, there is no reason for RUCO to reach a different conclusion on basically the same level and type of costs. In RUCO's opinion, the levels of costs are still excessive in this case also and are not reasonably necessary in the provisioning of water and wastewater utility service in Arizona.

Q. What is the fourth rationale that RUCO relied upon when making its adjustments to the cost allocations?

A. RUCO shares the same overall concerns iterated in Judge Rodda's Recommended Opinion and Order ("ROO") and adopted in Decision 72059 on pages 21 through 23. The intervening parties in this case are the only defense that the ratepayers of RRUI have in safeguarding them from charges incurred at the parental level and allocated to Liberty Utilities, which is essentially a captive of its parent, and ultimately allocated on down to the captive utility customers at RRUI. RUCO does not believe all the charges being allocated down to the Company's customers are reasonably necessary in the provision of water and wastewater utility services in Arizona. The parent Company may have incurred these costs, but are they "reasonable and reasonably necessary for the provision of utility service."[11] RUCO thinks not. A portion of the allocated charges should be borne by the shareholders and unregulated utilities.

[11] See Commission Decision No. 72059 at page 21 on line 14.

Q. What adjustment does RUCO recommend for the APUC cost allocations?

A. RUCO recommends reducing the amounts allocated to RRUI as shown on Schedules TJC-26 by $31,266 for the Water Division and by $10,225 for the Wastewater Division.

Q. How does the amount of the APUC cost allocations allowed by RUCO compare to the amount ordered in Decision No. 72059?

A. RUCO's recommended cost allocations are approximately twice the amount granted in Decision No. 72059 for both the Water and Wastewater Divisions. RUCO finds that is a fair and reasonable amount on both the ratepayers and Company's behalf in this case.

Q. Did RUCO take issue with the Liberty Utility allocations for its shared service model?

A. Other than RUCO's achievement/incentive pay programs and merit pay adjustments that share those costs fairly and equally between the shareholders and ratepayers, RUCO did not take issue with the Liberty Utilities shared service model.

Operating Income Adjustment No. 16 – Income Taxes

Q. Have you calculated income tax expense based on both RUCO's recommended adjusted operating income and the recommended operating income associated with RUCO's revenue increase?

A. Yes. These adjustments for RUCO's recommended adjusted operating income and the recommended operating income associated with RUCO's revenue increase are shown on Schedules TJC-10 with the details shown on TJC-27 and TJC-1 on page 2 respectively for the Water and Wastewater Divisions.

Q. Have you included an interest synchronization calculation in your computation of income tax expense?

A. Yes. The interest synchronization calculation, which computes an interest expense deduction for income taxes, can be viewed in the schedules noted above. The interest synchronization calculation is the adjusted rate base multiplied by the weighted cost of debt. The income tax gross up revenue conversion factor includes an element for the increase in property taxes due to RUCO's recommended level of increased revenues.

OTHER ISSUES

Q. Please summarize any other issues RUCO has pertaining to the Company's Application.

A. During the course of RUCO's audit, there were three issues noticed that stand to be corrected in the Company's rebuttal filing as follows:

1. Wastewater Division's Applicable Federal Income Tax Rate of 35.36%, which should be 34%;
2. The correction noted in one above should also correct the erroneous gross revenue conversion factor used in Wastewater Division; and
3. Bill counts need to be updated to reflect proper billing determinants and the revenue annualization.

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

A. No, it does not.

Q. Does this conclude your testimony on RRUI?

A. Yes, it does.

APPENDIX 1

Qualifications of Timothy J. Coley

WORK HISTORY

July 2000 – Present: **RESIDENTIAL UTILITY CONSUMER OFFICE,** Phoenix, Arizona
Public Utilities Analyst V. The Residential Utility Consumer Office (RUCO) is a consumer advocate group providing residential consumers a voice in utility regulation and backed by a professional staff with legal and financial expertise. Responsibilities include: audited, reviewed and analyzed public utility companies various filings; prepared written testimony, schedules, financial statements, and spreadsheet models and analyses. Testified and stand cross-examination before the Arizona Corporation Commission.

January 2000 - April 2000: **JACKSON HEWITT TAX SERVICE,** Phoenix, Arizona
Tax Preparer. Interviewed clients, determined tax situation, and explained how the tax laws benefited them in their specific situation. Ensured that each customer received every deduction that they were entitled. Prepared individual and business income tax returns, which best utilized each specific situation that minimized their tax obligations.

May 1998 - November 1999: **BENEFITS CONSULTING,** Cypress, Texas
Consultant Assistant. The consulting firm specialized in alleged medical claim charges brought against the government of Harris County in Houston, Texas. Assisted in the review, examination, and analysis of the attested charges. Determined if the purported medical claim charges were prudent, customary, and reasonable for the alleged sustained injuries. The firm analyzed cases for both the County's Risk Department and Attorneys Office.

January 1992 - April 1998: **PHOENIX SERVICES,** Villa Rica, Georgia
Owner. Provided landscaping services primarily in a high growth gated community where the Property Owners' Association approved mandated ordinances to be strictly adhered and abided by. Coordinated and supervised all aspects of projects from inception to completion, from master planning to site design to installation.

May 1989 - October 1991: **GEORGIA PUBLIC SERVICE COMMISSION,** Atlanta, GA
Senior Auditor. The Public Service Commission (PSC) was responsible for regulating many intrastate telecommunications, electric, and gas utility industries operating in Georgia. It was the PSC's job to ensure that consumers received adequate and reliable service at reasonable rates. It must also assure the utility companies and investors an opportunity to earn a fair rate of return on prudent investments. The Commission participated significantly in Georgia's economic health and growth. I was promoted to the PSC's Electric/Gas Division where I examined, verified, and analyzed various financial documents, accounting records, reports, ledgers, and statements. In addition, I was assigned to automate the PSC's Electric Division where I utilized a computer application process that I had developed earlier while with the (PSC) Telecommunication Division. I was later ascribed to work in conjunction with the Engineering Department and established a procedure to track and compare costs of operation and maintenance (O&M) expenses of nuclear electric generating plants. This effort determined a comparative price per kilowatt-hour produced that influenced the awareness for the company to control the O&M costs, which benefited the consumer through lower prices.

- Developed computer application system that streamlined audit procedures by 30 – 40%.
- Various other schedules were implemented to track, maintain, and control costs.

GEORGIA PUBLIC SERVICE COMMISSION (continued)

November 1986 - April 1989: **Georgia Public Service Commission,** Atlanta, Georgia
Auditor. Regulated telecommunications and also oversaw the deregulation process that was currently under way in that industry. Examined and analyzed accounting records to determine financial status of companies and prepared financial reports concerning audit findings. Reviewed data including payroll, time sheets, purchase vouchers, cash receipt ledgers, financial reports, and disbursements. Verified statewide telephone company transaction classifications and documentation.

- Developed computer application utilizing Lotus to completely automate and streamline the entire telecommunication audit process. The results saved 25% in field audit time and produced a product of professional appearance.
- Created, coordinated, and implemented "Operational Project Training" automated procedure-training program. Trained and supervised staff of five auditors.
- Computerized "Desk Audit Analysis" program that identified 11 independent telephone companies in the state of over-earning and resulted in $4.1M annual savings to the Georgia ratepayers affected.

October 1985 - October 1986: **Georgia Public Service Commission,** Atlanta, Georgia
Junior Auditor. Assisted in planning and performing telecommunication audit engagements. Examined financial records, internal management control, correspondence, bills, and records of services delivered in order to verify or recommend compliance with company specifications contained in contracts, agreements, regulations, and/or laws.

- As a special project, I was assigned to analyze the results of a survey designed to evaluate "Interest in Organizing a Multi-State Nuclear Management Review Group" by the Director of Utilities. Wrote the draft and findings for the speech that was presented to all participatory commissions.

PROFESSIONAL MEMBERSHIPS

- Elected Member of the National Honor Society for Public Affairs and Administration.
- Active Member of Delta Sigma Pi - Professional Business Fraternity.

SPECIAL TRAINING AND CERTIFICATES

- The Graduate School of Business Administration - Michigan State University; completed the Annual Regulatory Studies Program of the National Association of Regulatory Utility Commissioners.
- Completed Graduate Exit Paper on "Deregulation of the Electric Industry".
- Attended Eastern Utility Rate School in 2000 and 2005.

EDUCATION

- Currently enrolled at Arizona State University - West in the Post Baccalaureate Graduate Certificate Program in Accountancy with two courses remaining.
- Master of Public Administration, State University of West Georgia, 1997, GPA 3.5.
- BS Business Management & Administration, Minor in Economics, Sorrel School of Business, Troy State University, 1985.
- AA Business Administration, Miles Community College, 1981.

RESUME OF PUBLIC UTILITY RATE CASES & AUDITS PARTICIPATION

Residential Utility Consumer Office For Years 2000 To Present

Arizona-American Water Company – Docket No. WS-01303A-05-0405

Arizona Public Service Co. – Docket No. E-01345A-03-0437

Tucson Electric Power Company – Docket No. E-01933A-04-0408

UniSource Merger – Docket No. E-04230A-03-0933

Arizona-American Water Company – Docket No. WS-01303A-02-0867

Arizona Water Company (Eastern Group) – Docket No. W01445A-02-0619

Litchfield Park Service Company – Docket Nos. W-01427A-01-0487 &
SW-01428A-01-0487

Arizona Water Company (Northern Group) – Docket No. W-01445A-00-0962

Rio Verde Utilities, Inc. – Docket Nos. W-02156A-00-0321 &
SW-02156A-00-0323

Arizona-American Water Company (Paradise Valley) –
Docket Nos. W-01303A-05-0405 &
W-01303A-05-0910

Arizona-American Water Company (Mohave District) –
Docket No. WS-01303A-06-0014

Arizona-American Water Company (Sun City & Sun Cit West Wastewater) –
Docket No. WS-01303A-06-0491

Arizona-American Water Company - Docket No. W-01303A-07-0209

Chaparral City Water Company – Docket No. W-02113A-07-0551

Arizona-American Water Company - Docket No. W-01303A-08-0227

Residential Utility Consumer Office For Years 2000 To Present (cont'd)

Arizona Water Company - Docket No. W-01445A-08-0440

Far West Water & Sewer Company - WS-03478A-08-0608

Rio Rico Utilities, Inc. - WS-02676A-08-09-0257

Bella Vista Water Company – Docket No. W-02465A-09-0411

Goodman Water Company – Docket No. W-02500A-10-0382

Arizona Water Company – Western Group – Docket No. W-01445A-10-0517

Pima Utility Company – Docket No. W-02199A-11-0329 et al.

Georgia Public Service Commission For Years 1985 – 1991

Atlanta Gas Light Company

Georgia Power Company

Atlanta Gas Light Company (Management Audit)

Georgia Power Company

Trenton Telephone Company

Fairmount Telephone Company

Ellijay Telephone Company

GTE, Inc.

ALL-TEL Telephone Company

Citizens Utilities Co.

Ball Ground Telephone Company

Lanett Telephone Company

Brantley Telephone Company

Blue Ridge Telephone Company

Waverly Hall Telephone Company

St. Marys Telephone Company

Darien Telephone Company

Statesboro Telephone Company

Statesboro Telephone Co-op

Wilkes Telephone Company

RUCO

EXHIBIT

1

Rio Rico Utilities - Sewer Division
Plant Additions and Retirements

Exhibit
Schedule B-2
Page 3.2
Witness: Bourassa
REVISED

				Per Decision 72059		2009							
Line No.	NARUC Account No.	Description	Allowed Deprec. Rate	Plant at 12/31/2008	Accum. Deprec. At 12/31/2008	Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements (Per Books)	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.
1	351	Organization	0.00%	5,785	-			-			-	5,785	-
2	352	Franchise	0.00%	417	-			-			-	417	-
3	353	Land	0.00%	7,545	-			-			-	7,545	-
4	354	Structures & Improvements	3.33%	28,548	27,203	294		294			956	28,842	28,159
5	355	Power Generation	5.00%	-	-			-			-	-	-
6	360	Collection Sewer Forced	2.00%	636,023	(38,371)			-			12,720	636,023	(25,651)
7	361	Collection Sewers Gravity	2.00%	5,945,962	2,213,553	130,091		130,091			120,220	6,076,053	2,333,773
8	362	Special Collecting Structures	2.00%		-			-			-	-	-
9	363	Customer Services	2.00%	1,145,530	595,856	7,994		7,994	245		22,988	1,153,279	618,599
10	364	Flow Measuring Devices	10.00%	55,988	31,043	8,964		8,964			6,047	64,952	37,090
11	366	Reuse Services	2.00%		-			-			-	-	-
12	367	Reuse Meters And Installation	8.33%		-			-			-	-	-
13	370	Receiving Wells	3.33%	867,120	238,710			-			28,875	867,120	267,585
14	371	Pumping Equipment	12.50%	1,504,181	1,232,681	112		112			188,030	1,504,292	1,420,711
15	374	Reuse Distribution Reservoirs	2.50%		-			-			-	-	-
16	375	Reuse Trans. and Dist. System	2.50%		-			-			-	-	-
17	380	Treatment & Disposal Equipment	5.00%	1,006,848	665,783	14,462		14,462			50,704	1,021,310	716,486
18	381	Plant Sewers	5.00%		-			-			-	-	-
19	382	Outfall Sewer Lines	3.33%		-			-			-	-	-
20	389	Other Sewer Plant & Equipment	6.67%	68,869	65,244			-			3,625	68,869	68,869
21	390	Office Furniture & Equipment	6.67%	110,454	8,021			-			7,367	110,454	15,388
22	390.1	Computers and Software	20.00%	4,025	4,025			-			-	4,025	4,025
23	391	Transportation Equipment	20.00%		-			-			-	-	-
24	392	Stores Equipment	4.00%		-			-			-	-	-
25	393	Tools, Shop And Garage Equip	5.00%	4,897	4,156			-			245	4,897	4,401
26	394	Laboratory Equip	10.00%		-			-			-	-	-
27	396	Communication Equip	10.00%	5,936	5,936			-			-	5,936	5,936
28	398	Other Tangible Plant	10.00%	3,913	2,815			-			391	3,913	3,206
29		Nogales WWTP	4.72%	427,000	53,375			-			20,154	427,000	73,529
30					-			-			-	-	-
31					-			-			-	-	-
32					-			-			-	-	-
33					-			-			-	-	-
34		Plant Held for Future Use						-			-	-	-
35													
36		TOTALS		11,829,042	5,110,028	161,917	-	161,917	245	-	462,323	11,990,714	5,572,107

Rio Rico Utilities - Sewer Division
Plant Additions and Retirements

Exhibit
Schedule B-2
Page 3.3
Witness: Bourassa
REVISED

Line No.	NARUC Account No.	Description	Allowed Deprec. Rate	Net Plant	2010 Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements (Per Books)	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.
1	351	Organization	0.00%	5,785			-			-	5,785	-
2	352	Franchise	0.00%	417			-			-	417	-
3	353	Land	0.00%	7,545			-			-	7,545	-
4	354	Structures & Improvements	3.33%	683			-			683	28,842	28,842
5	355	Power Generation	5.00%	-			-			-	-	-
6	360	Collection Sewer Forced	2.00%	661,674			-			12,720	636,023	(12,930)
7	361	Collection Sewers Gravity	2.00%	3,742,280	108		108			121,522	6,076,161	2,455,296
8	362	Special Collecting Structures	2.00%	-			-			-	-	-
9	363	Customer Services	2.00%	534,680	36,522		36,522			23,431	1,189,801	642,030
10	364	Flow Measuring Devices	10.00%	27,863			-			6,495	64,952	43,585
11	366	Reuse Services	2.00%	-			-			-	-	-
12	367	Reuse Meters And Installation	8.33%	-			-			-	-	-
13	370	Receiving Wells	3.33%	599,535			-			28,875	867,120	296,460
14	371	Pumping Equipment	12.50%	83,582	84,064		84,064			167,646	1,588,356	1,588,356
15	374	Reuse Distribution Reservoirs	2.50%	-			-			-	-	-
16	375	Reuse Trans. and Dist. System	2.50%	-			-			-	-	-
17	380	Treatment & Disposal Equipment	5.00%	304,824	609		609			51,081	1,021,920	767,567
18	381	Plant Sewers	5.00%	-			-			-	-	-
19	382	Outfall Sewer Lines	3.33%	-			-			-	-	-
20	389	Other Sewer Plant & Equipment	6.67%	-			-			-	68,869	68,869
21	390	Office Furniture & Equipment	6.67%	95,066			-			7,367	110,454	22,755
22	390.1	Computers and Software	20.00%	-			-			-	4,025	4,025
23	391	Transportation Equipment	20.00%	-			-			-	-	-
24	392	Stores Equipment	4.00%	-			-			-	-	-
25	393	Tools, Shop And Garage Equip	5.00%	496			-			245	4,897	4,646
26	394	Laboratory Equip	10.00%	-			-			-	-	-
27	396	Communication Equip	10.00%	-			-			-	5,936	5,936
28	398	Other Tangible Plant	10.00%	707			-			391	3,913	3,597
29		Nogales WWTP	4.72%	353,471			-			20,154	427,000	93,684
30				-			-			-	-	-
31				-			-			-	-	-
32				-			-			-	-	-
33				-			-			-	-	-
34		Plant Held for Future Use		-			-			-	-	-
35												
36		TOTALS		6,418,607	121,303	-	121,303	-	-	440,611	12,112,017	6,012,718

Rio Rico Utilities - Sewer Division
Plant Additions and Retirements

Exhibit
Schedule B-2
Page 3.4
Witness: Bourassa
REVISED

Line No.	NARUC Account No.	Description	Allowed Deprec. Rate	2011 Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements (Per Books)	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.
1	351	Organization	0.00%			-			-	5,785	-
2	352	Franchise	0.00%			-			-	417	-
3	353	Land	0.00%			-			-	7,545	-
4	354	Structures & Improvements	3.33%			-			-	28,842	28,842
5	355	Power Generation	5.00%			-			-	-	-
6	360	Collection Sewer Forced	2.00%			-			12,720	636,023	(210)
7	361	Collection Sewers Gravity	2.00%	652		652			121,530	6,076,813	2,576,825
8	362	Special Collecting Structures	2.00%			-			-	-	-
9	363	Customer Services	2.00%	7,319		7,319			23,869	1,197,120	665,899
10	364	Flow Measuring Devices	10.00%			-			6,495	64,952	50,080
11	366	Reuse Services	2.00%			-			-	-	-
12	367	Reuse Meters And Installation	8.33%			-			-	-	-
13	370	Receiving Wells	3.33%			-			28,875	867,120	325,335
14	371	Pumping Equipment	12.50%	94,151		94,151			94,151	1,682,507	1,682,507
15	374	Reuse Distribution Reservoirs	2.50%			-			-	-	-
16	375	Reuse Trans. and Dist. System	2.50%			-			-	-	-
17	380	Treatment & Disposal Equipment	5.00%	99,979		99,979	3,400		53,510	1,118,499	817,678
18	381	Plant Sewers	5.00%			-			-	-	-
19	382	Outfall Sewer Lines	3.33%			-			-	-	-
20	389	Other Sewer Plant & Equipment	6.67%			-			-	68,869	68,869
21	390	Office Furniture & Equipment	6.67%			-			7,367	110,454	30,122
22	390.1	Computers and Software	20.00%			-			-	4,025	4,025
23	391	Transportation Equipment	20.00%	67		67			7	67	7
24	392	Stores Equipment	4.00%			-			-	-	-
25	393	Tools, Shop And Garage Equip	5.00%	139		139			248	5,036	4,894
26	394	Laboratory Equip	10.00%			-			-	-	-
27	396	Communication Equip	10.00%			-			-	5,936	5,936
28	398	Other Tangible Plant	10.00%			-			-	3,913	3,597
29		Nogales WWTP	4.72%			-			20,154	427,000	113,838
30						-			-	-	-
31						-			-	-	-
32						-			-	-	-
33						-			-	-	-
34		Plant Held for Future Use				-			-	-	-
35											
36		TOTALS		202,307	-	202,307	3,400	-	368,928	12,310,924	6,378,246

Rio Rico Utilities - Sewer Division
Plant Additions and Retirements

Exhibit
Schedule B-2
Page 3.5
Witness: Bourassa
REVISED

Line No.	NARUC Account No.	Description	Allowed Deprec. Rate	2012 (2 months through 2/29) Plant Additions (Per Books)	Plant Adjustments[1]	Plant Adjustments[2]	Adjusted Plant Additions	Plant Retirements (Per Books)	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.
1	351	Organization	0.00%				-			-	5,785	-
2	352	Franchise	0.00%				-			-	417	-
3	353	Land	0.00%				-			-	7,545	-
4	354	Structures & Improvements	3.33%	14		121,438	121,452			497	150,294	29,339
5	355	Power Generation	5.00%				-			-	-	-
6	360	Collection Sewer Forced	2.00%				-			2,120	636,023	1,910
7	361	Collection Sewers Gravity	2.00%	(85,159)			(85,159)			20,114	5,991,654	2,596,939
8	362	Special Collecting Structures	2.00%				-			-	-	-
9	363	Customer Services	2.00%	7,009	(16)		6,993			4,002	1,204,113	669,901
10	364	Flow Measuring Devices	10.00%	1,387			1,387			1,094	66,339	51,174
11	366	Reuse Services	2.00%				-			-	-	-
12	367	Reuse Meters And Installation	8.33%				-			-	-	-
13	370	Receiving Wells	3.33%				-			4,813	867,120	330,148
14	371	Pumping Equipment	12.50%	30,433			30,433			5,072	1,712,940	1,687,580
15	374	Reuse Distribution Reservoirs	2.50%				-			-	-	-
16	375	Reuse Trans. and Dist. System	2.50%				-			-	-	-
17	380	Treatment & Disposal Equipment	5.00%	10,176			10,176			9,363	1,128,675	827,041
18	381	Plant Sewers	5.00%	13,690			13,690			57	13,690	57
19	382	Outfall Sewer Lines	3.33%				-			-	-	-
20	389	Other Sewer Plant & Equipment	6.67%	280	(4,221)		(3,941)			-	64,928	68,869
21	390	Office Furniture & Equipment	6.67%	6,483			6,483			1,264	116,937	31,386
22	390.1	Computers and Software	20.00%				-			-	4,025	4,025
23	391	Transportation Equipment	20.00%	50			50			3	117	10
24	392	Stores Equipment	4.00%				-			-	-	-
25	393	Tools, Shop And Garage Equip	5.00%	103			103			42	5,139	4,937
26	394	Laboratory Equip	10.00%				-			-	-	-
27	396	Communication Equip	10.00%				-			-	5,936	5,936
28	398	Other Tangible Plant	10.00%				-			65	3,913	3,662
29		Nogales WWTP	4.72%	1,828,600			1,828,600			10,552	2,255,600	124,390
30							-			-	-	-
31							-			-	-	-
32							-			-	-	-
33							-			-	-	-
34		Plant Held for Future Use					-			-	-	-
35												
36		TOTALS		1,813,066	(4,237)	121,438	1,930,267	-	-	59,059	14,241,191	6,437,304

1 - Affliate Profit from prior case
2- Allocate office building costs to sewer

RUCO

EXHIBIT

2

Rio Rico Utilities, Inc. - Wastewater Division
Test Year Ended February 29, 2012
Adjustments to Revenues and Expenses
Adjustment Number 1

Exhibit
Schedule C-2
Page 2
Witness: Bourassa

Depreciation Expense

Line No.	Acct. No.	Description	Adjusted Original Cost	Proposed Rates	Depreciation Expense
1					
2					
3					
4					
5	351	Organization	5,785	0.00%	-
6	352	Franchise	417	0.00%	-
7	353	Land	7,545	0.00%	-
8	354	Structures & Improvements	150,294	3.33%	5,005
9	355	Power Generation	-	5.00%	-
10	360	Collection Sewer Forced	636,023	2.00%	12,720
11	361	Collection Sewers Gravity	5,991,654	2.00%	119,833
12	362	Special Collecting Structures	-	2.00%	-
13	363	Customer Services	1,204,113	2.00%	24,082
14	364	Flow Measuring Devices	66,339	10.00%	6,634
15	366	Reuse Services	-	2.00%	-
16	367	Reuse Meters And Installation	-	8.33%	-
17	370	Receiving Wells	867,120	3.33%	28,875
18	371	Pumping Equipment	1,712,940	12.50%	214,118
19	374	Reuse Distribution Reservoirs	-	2.50%	-
20	375	Reuse Trans. and Dist. System	-	2.50%	-
21	380	Treatment & Disposal Equipment	1,128,675	5.00%	56,434
22	381	Plant Sewers	13,690	5.00%	685
23	382	Outfall Sewer Lines	-	3.33%	-
24	389	Other Sewer Plant & Equipment	64,928	6.67%	- *
25	390	Office Furniture & Equipment	116,937	6.67%	7,800
26	390.1	Computers and Software	4,025	20.00%	- *
27	391	Transportation Equipment	117	20.00%	23
28	392	Stores Equipment	-	4.00%	-
29	393	Tools, Shop And Garage Equip	5,139	5.00%	257
30	394	Laboratory Equip	-	10.00%	-
31	396	Communication Equip	5,936	10.00%	- *
32	398	Other Tangible Plant	3,913	10.00%	391
33		Nogales WWTP	2,255,600	4.00%	90,224
34					-
35					-
36					-
37					-
38		TOTALS	$ 14,241,191		$ 567,081
39					
40			Gross CIAC	Amort. Rate	
41	Less: Amortization of Contributions		$ 5,152,673	4.0261%	$ (207,451)
42	Total Depreciation Expense				$ 359,629
43					
44	Adjusted Test Year Depreciation Expense				1,256,386
45					
46	Increase (decrease) in Depreciation Expense				(896,757)
47					
48	Adjustment to Revenues and/or Expenses				$ (896,757)
49					
50	SUPPORTING SCHEDULE				
51	B-2, page 3				

RUCO

EXHIBIT

3

CITY OF
NOGALES

OFFICE OF THE CITY ATTORNEY

VIA EMAIL ONLY

May 10, 2012

Kristin Paiva
Fennemore Craig, P.C.
3003 N. Central Avenue, Suite 2600
Phoenix, AZ 85012

Re: Rio Rico Utility's cost of treatment

Dear Kristin,

Section 8 of the parties' Wastewater Treatment Services Agreement states that Rio Rico will be billed 11.36 percent of the City of Nogales' actual costs of treatment, plus a one percent administration fee. Nogales is billed by the U.S. Section of the International Boundary and Water Commission, which operates the Nogales International Wastewater Treatment Plant, quarterly in arrears. These bills have tended to vary fairly significantly as many costs in plant operation can and have been shifted between quarters based on IBWC's budget needs and spending authority. Yet for the last few years, Nogales' actual costs have been fairly constant at around $950,000/fiscal year, which is the amount Nogales is again budgeting for the next fiscal year.

In view of the above, Nogales proposes billing Rio Rico $9,083.26 per month ($950,000/12 x .1136 x 1.01), retroactive to March 1, 2012 (May's bill will reflect the two months' credit) for the remainder of this calendar year. After the federal fiscal year closes out on September 30, IBWC sends to Nogales a final reconciliation reflecting total actual costs of operation for the immediately prior fiscal year. This reconciliation report is usually received in December. January's bill to Rio Rico (and those of each successive January) will include a reconciliation that reflects actual costs of operating the treatment plant for the previous federal fiscal year. Next January's reconciliation will compare the difference between what Rio Rico will have paid during the remainder of the fiscal year (7 x $9,083.27) against the total cost of operation for the fiscal year, multiplied by a ratio of 7/12 (March through September) and Rio Rico's 11.36 percent share and one percent administrative charge, with January's bill adjusted accordingly. Nogales will supply Rio Rico with the relevant documents reflecting actual costs of operation with the January bill.

Please confirm that this approach is acceptable to your client.

Sincerely yours,

Michael Massee
Deputy City Attorney

777 NORTH GRAND AVENUE NOGALES, ARIZONA 85621 · (520) 287-6571 FAX (520) 285-5628 T.D.D. (520) 287-5477

Account Number - 10-2600-00 RIO RICO UTILITIES INC Service Address: 0 RIO RICO SEWER

Date	Packet	Type	Receipt #	Reference	Debits	Credits	Balance
11/15/2012	038015	Bill		10/09-11/08 11/30	9,083.26		9,083.26
10/26/2012	037679	Payment	482411	014099		9,083.26	0.00
10/16/2012	037495	Bill		9/09-10/09 10/30	9,083.26		9,083.26
09/28/2012	037188	Payment	476560	013698		9,083.26	0.00
09/17/2012	036958	Bill		8/10- 9/09 10/01	9,083.26		9,083.26
08/31/2012	036749	Payment	470772	013177		9,083.26	0.00
08/14/2012	036511	Bill		7/11- 8/10 08/31	9,083.26		9,083.26
07/30/2012	036202	Payment	464159	012616		9,083.26	0.00
07/16/2012	035944	Bill		6/11- 7/11 07/30	9,083.26		9,083.26
06/29/2012	035733	Payment	457683	012181		9,083.26	0.00
06/14/2012	035486	Bill		5/12- 6/11 06/29	9,083.26		9,083.26
05/30/2012	035244	Payment	451094	011325		13,425.13	0.00
05/14/2012	034990	Bill		4/12- 5/12 05/29	9,083.26		13,425.13
04/13/2012	034989	Bill-Adjustment		3/13- 4/12 MANUAL	9,083.26		4,341.87
04/13/2012	034989	Bill-Reverse		3/13- 4/12 MANUAL		13,824.65	4,741.39CR
03/14/2012	034989	Bill-Adjustment		2/03- 3/13 MANUAL	9,083.26		9,083.26
03/14/2012	034989	Bill-Reverse		2/03- 3/13 MANUAL		13,824.65	0.00
04/13/2012	034536	Bill-Void		3/13- 4/12	13,824.65		13,824.65
04/06/2012	034404	Payment	439781	010589		13,824.65	0.00
03/14/2012	034037	Bill-Void		2/03- 3/13	13,824.65		13,824.65
03/07/2012	033933	Payment	433232	010185		13,824.65	0.00
02/14/2012	033541	Bill		1/04- 2/03 02/29	13,824.65		13,824.65
02/02/2012	033323	Payment	425644	009685		13,824.65	0.00
01/20/2012	033084	Payment	422417	009396		13,824.65	13,824.65
01/17/2012	033038	Bill		12/05- 1/04 02/01	13,824.65		27,649.30
12/20/2011	032608	Payment	414251	9073		13,824.65	13,824.65
12/14/2011	032561	Bill		11/05-12/05 12/30	13,824.65		27,649.30
11/15/2011	032126	Bill		10/06-11/05 12/01	13,824.65		13,824.65
11/15/2011	032096	Payment	407202	8425		13,824.65	0.00
10/14/2011	031650	Bill		9/06-10/06 11/01	13,824.65		13,824.65
10/11/2011	031551	Payment	400050	8153		13,824.65	0.00
09/15/2011	031224	Bill		8/07- 9/06 10/03	13,824.65		13,824.65
09/06/2011	031046	Payment	392475	007693		13,824.65	0.00
08/12/2011	030738	Bill		7/08- 8/07 08/31	13,824.65		13,824.65
08/16/2011	030727	Payment	388300	007337		13,824.65	0.00
07/15/2011	030273	Bill		6/08- 7/08 07/29	13,824.65		13,824.65
06/29/2011	030008	Payment	378634	6738		13,824.65	0.00
06/14/2011	029765	Bill		5/09- 6/08 06/29	13,824.65		13,824.65
06/01/2011	029596	Payment	372258	6584		13,824.65	0.00
05/13/2011	029335	Bill		4/09- 5/09 05/27	13,824.65		13,824.65
05/05/2011	029173	Payment	366850	006187		13,824.65	0.00
04/14/2011	028883	Bill		3/10- 4/09 04/28	13,824.65		13,824.65
04/06/2011	028771	Payment	360750	5885		13,824.65	0.00
03/14/2011	028403	Bill		2/08- 3/10 03/28	13,824.65		13,824.65
03/09/2011	028345	Payment	354855	005581		13,824.65	0.00
02/14/2011	028005	Bill		1/09- 2/08 02/28	13,824.65		13,824.65
02/09/2011	027950	Payment	348693	005260		13,824.65	0.00
01/14/2011	027605	Bill		12/07- 1/09 02/02	13,824.65		13,824.65
12/28/2010	027353	Payment	338052	4958		13,824.65	0.00
12/14/2010	027188	Bill		11/07-12/07 12/28	13,824.65		13,824.65
11/29/2010	026962	Payment	331406	4526		13,824.65	0.00
11/15/2010	026840	Bill		10/08-11/07 11/30	13,824.65		13,824.65
11/01/2010	026685	Payment	326448	4248		13,824.65	0.00
10/14/2010	026448	Bill		9/08-10/08 10/28	13,824.65		13,824.65
10/05/2010	026305	Payment	320628	004013		13,824.65	0.00
09/15/2010	026045	Bill		8/09- 9/08 09/30	13,824.65		13,824.65
09/03/2010	025919	Payment	314320	003535		13,824.65	0.00
08/13/2010	025673	Bill		7/10- 8/09 08/31	13,824.65		13,824.65

TABLE OF CONTENTS TO TJC SCHEDULES

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY OCRB/FVRB COST	[B] RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 7,629,607	$ 7,681,547
2			
3	Adjusted Operating Income (Loss)	$ 375,933	$ 561,714
4			
5	Current Rate of Return (L3 / L1)	4.93%	7.31%
6			
7	Required Operating Income (L9 X L1)	$ 740,072	$ 616,521
8			
9	Required Rate of Return on Fair Value Rate Base	9.70%	8.03%
10			
11	Operating Income Deficiency (L7 - L3)	$ 364,139	$ 54,807
12			
13	Gross Revenue Conversion Factor (TJC-1, Page 2 of 2)	1.6589	1.6585
14			
15	Required Increase in Gross Revenue Requirement (L11 X L13)	$ 604,079	$ 90,894
16			
17	Adjusted Test Year Revenue	$ 2,854,838	$ 2,896,635
18			
19	Proposed Annual Revenue (L15 + L17)	$ 3,458,917	$ 2,987,529
20			
21	Required Percentage Increase in Revenue (L15 / L17)	21.16%	3.14%
22			
23			
24	Rate of Return on Common Equity	10.70%	9.00%

References:
Column [A]: Company Schs. A-1, B-1 and C-1
Column [B]: RUCO Schedules TJC-2, TJC-3, TJC-10 and TJC-11

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	[A]	[B]	[C]	[D]
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	100.0000%			
2	Proposed Bad Debt Expense (Per Co. Workpapers)	0.0000%			
3	Subtotal (L1 thru L2)	100.0000%			
4	Combined Federal, State, Property Tax Rate (L22)	39.7027%			
5	Subtotal (L3 - L4)	60.2973%			
6	Gross Revenue Conversion Factor (L1 / L5)	1.6585			
7					
8	CALCULATION OF EFFECTIVE TAX RATE:				
9	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
10	Arizona State Income Tax Rate	6.9680%			
11	Federal Taxable Income (L9 - L10)	93.0320%			
12	Applicable Federal Income Tax Rate (L58)	34.0000%			
13	Effective Federal Income Tax Rate (L11 X L12)	31.6309%			
14	Combined Federal and State Income Tax Rate (L10 + L13)	38.5989%			
15					
16	CALCULATION OF EFFECTIVE PRPERTY TAX FACTOR:				
17	Unity	100.0000%			
18	Combined Federal and State Tax Rate	38.5989%			
19	1 Minus Combined Income Tax Rate	61.4011%			
20	Property Tax Factor	1.7978%			
21	Effective Property Tax Factor (L19 x L 20)	1.1039%			
22	Combined Federal, State & Property Tax RateTax Rate (L14 + L21)	39.7027%			
23					
24	RUCO Required Operating Income (Sch. TJC-1, Col. [B], L7)	$ 616,521			
25	RUCO Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Col. [B], L3)	561,714			
26	Required Increase in Operating Income (L24 - L25)		$ 54,807		
27					
28	Income Taxes On Recommended Revenue (Col. [D], L53)	$ 347,680			
29	Income Taxes On Test Year Revenue (Col. [D], L55)	313,226			
30	Required Increase in Revenue To Provide For Income Taxes (L28 - L29)		$ 34,453		
31					
32	Property Tax with Recommended Revenue (Sch. TJC-10, Col. [E], L33)	157,290			
33	Propertry Tax on TestYear Revenue (Sch. TJC-10, Col. [C], L33)	155,656			
34	Increase in Property Tax Due to Increase in Revenue (L32 - L33)		$ 1,634		
35					
36	Total Required Increase in Revenue (L26 + L30 + L34)		$ 90,894		
37				RUCO	
38	RUCO's CALCULATION OF INCOME TAX :			Recommended	
39	RUCO Proposed Revenue (Sch. TJC-1, Col. [B], L19)			$ 2,987,529	
40	Less:				
41	Operating Expense Excluding Income Tax (Sch. TJC-10, Col. [E], L36 - L34)			2,023,328	
42	Synchronized Interest (Col. [C], L63)			63,450	
43	Arizona Taxable Income (L39 - L41 - L42)			$ 900,751	
44	Arizona State Income Tax Rate			6.9680%	
45	Arizona Income Tax (L43 X L44)				$ 62,764
46	Fed. Taxable Income (L43 - L45)			$ 837,987	
47	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
48	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
49	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
50	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
51	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 171,016	
52	Total Federal Income Tax (L47 thru L 51)				$ 284,916
53	Combined Federal And State Income Tax (L45+ L52)				$ 347,680
54					
55	RUCO Adj'd Test Year Combined Federal and State Income Tax (Sch. TJC-10, Col. [C], L34)				$ 313,226
56	RUCO Proposed Income Tax Adjustment (L53 - L55)				$ 34,453
57					
58	Applicable Federal Income Tax Rate				34.00%
59					
60	NOTE (A): Interest Synchronization				
61	RUCO Adjusted Rate Base (Sch. TJC-2, Col. [C], L23)			$ 7,681,547	
62	RUCO Weighted Cost Of Debt (Sch. TJC-27, Col. [D], L1)			0.83%	
63	RUCO Interest Expense (L61 X L62)			$ 63,450	

RATE BASE SUMMARY - ORIGINAL COST/FAIR VALUE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED OCRB/FVRB	[B] RUCO OCRB/FVRB ADJUSTMENTS	[C] RUCO ADJ'TED OCRB/FVRB
1				
2	Gross Utility Plant in Service	$ 36,146,219	$ (17,070)	$ 36,129,149
3				
4	Accumulated Depreciation	(15,784,381)	114,465	(15,669,915)
5	Net Utility Plant In Service (L2 + L4)	$ 20,361,839	$ 97,395	$ 20,459,234
6				
7	**Less:**			
8	Advances In Aid Of Construction (AIAC)	$ (660,955)	$ -	$ (660,955)
9				
10	Contribution In Aid Of Construction (CIAC)	(20,179,119)	-	(20,179,119)
11	Accumulated Amortization of CIAC	8,797,261	-	8,797,261
12	NET CIAC (L10 + L11)	$ (11,381,858)	$ -	$ (11,381,858)
13				
14	Deferred Income Tax	$ (405,395)	$ (45,456)	$ (450,850)
15				
16	Customer Deposits	(284,024)	-	(284,024)
17				
18				
19				
20				
21				
22				
23	TOTAL RATE BASE (L5+L8+L12+L14+L16)	$ 7,629,607	$ 51,939	$ 7,681,547

References:
Column [A]: Company Schedule B-1
Column [B]: Schedule TJC-3 Column [H]
Column [C]: Column [A] + Column [B]

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012

ORIGINAL COST/FAIR VALUE RATE BASE - RUCO ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED OCRB/FVRB	[B] RUCO ADJUSTMENT NO. 1(a) RECONSTRUCT PLANT BALANCES	[C] RUCO ADJUSTMENT NO. 1(b) ACCUM. DEPRE. BALANCE	[D] RUCO ADJUSTMENT NO. 2 RECLASSIFY NWWTP PLANT ACCOUNTS	[E] RUCO ADJUSTMENT NO. 3 INTENTIONALLY LEFT BLANK	[F] RUCO ADJUSTMENT NO. 4 REMOVE AFFILIATE PROFITS PER MJR 1-15	[G] RUCO ADJUSTMENT NO. 5 ADIT BALANCE	[H] RUCO Total Pro Forma Adjustments	[I] RUCO ADJTED OCRB/FVRB
1										
2	Gross Utility Plant in Service	$ 36,146,219	$ -	$ -	$ (15,362)	$ -	$ (1,708)	$ -	$ (17,070)	$ 36,129,149
3										
4	Accumulated Depreciation	(15,784,381)	-	114,014	418	-	33	-	114,465	(15,669,915)
5	Net Utility Plant in Service (L2 + L4)	$ 20,361,839	$ -	$ 114,014	$ (14,944)	$ -	$ (1,675)	$ -	$ 97,395	$ 20,459,234
6										
7	**Less:**									
8	Advances In Aid Of Construction (AIAC)	$ (660,955)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (660,955)
9										
10	Contribution In Aid Of Construction (CIAC)	(20,179,119)	-	-	-	-	-	-	-	(20,179,119)
11	Accumulated Amortization of CIAC	8,797,261	-	-	-	-	-	-	-	8,797,261
12	NET CIAC (L10 + L11)	$ (11,381,858)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (11,381,858)
13										
14	Deferred Income Tax	(405,395)	-	-	-	-	-	(45,456)	(45,456)	(450,850)
15										
16	Customer Deposits	(284,024)	-	-	-	-	-	-	-	(284,024)
17										
18										
19										
20										
21										
22										
23	TOTAL RATE BASE (L5+L8+L12+L14+L16)	$ 7,629,607	$ -	$ 114,014	$ (14,944)	$ -	$ (1,675)	$ (45,456)	$ 51,939	$ 7,681,547

References:
Column [A]: Company Schedule B-1 as Filed
Column [B] Thru [G]: RUCO Recommended Adjustments
Column [H]: Sum of Columns [B] Thru [G]
Column [I]: Column [A] + Column[H]

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012

TOTAL UTILITY PLANT IN SERVICE SUMMARY SCHEDULE

Line No.	NARUC Account	Description	Company Plant in Service Balance As Filed	RUCO Adjustment No. 1(a) Plant In Service Reconstruction Adjustment	RUCO Adjustment No. 2(a) Reclassify NWWTP Accounts Per RUCO DR 2.1	RUCO Adjustment No. 3(a) Intentionally Left Blank	RUCO Adjustment No. 4(a) Remove Affiliate Profits Per Staff DR MJR 1.15	RUCO Total Adjustments	RUCO Total Plant in Service Balance
1	301	Organization Cost	$ 5,785	$ -	$ -	$ -	$ -	$ -	$ 5,785
2	302	Franchise Cost	417	-	-	-	-	-	417
3	303	Land and Land Rights	44,194	-	-	-	-	-	44,194
4	304	Structures & Improvements	3,432,930	-	-	-	(35)	(35)	3,432,895
5	305	Collecting & Impounding Reservoirs	-	-	-	-	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-	-	-	-	-
7	307	Wells & Springs	562,944	-	-	-	(7)	(7)	562,937
8	308	Infiltration Galleries	-	-	-	-	-	-	-
9	309	Raw Water Supply Mains	279,157	-	-	-	-	-	279,157
10	310	Power Generation Equipment	219,360	-	-	-	-	-	219,360
11	311	Pumping Equipment	3,147,011	-	-	-	(303)	(303)	3,146,708
12	320	Water Treatment Equipment	369,100	-	(5,658)	-	-	(5,658)	363,442
13	320.1	Water Treatment Plants	-	-	-	-	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-	-	-	-	-
15	330	Distribution Reservoirs & Standpipe	759,861	-	-	-	-	-	759,861
16	330.1	Storage Tanks	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-	-
18	331	Transmission & Distribution Mains	22,339,256	-	-	-	(1,363)	(1,363)	22,337,894
19	333	Services	2,768,122	-	-	-	-	-	2,768,122
20	334	Meters	1,010,366	-	-	-	-	-	1,010,366
21	335	Hydrants	572,321	-	-	-	-	-	572,321
22	336	Backflow Prevention Devices	15,855	-	(9,704)	-	-	(9,704)	6,151
23	339	Other Plant & Misc Equipment	123,778	-	-	-	-	-	123,778
24	340	Office Furniture & Equipment	29,265	-	-	-	-	-	29,265
25	340.1	Computers & Software	76,919	-	-	-	-	-	76,919
26	341	Transportation Equipment	142,188	-	-	-	-	-	142,188
27	342	Stores Equipment	-	-	-	-	-	-	-
28	343	Tools, Shop & Garage Equipment	18,203	-	-	-	-	-	18,203
29	344	Laboratory Equipment	3,061	-	-	-	-	-	3,061
30	345	Power Operated Equipment	-	-	-	-	-	-	-
31	346	Communication Equipment	212,996	-	-	-	-	-	212,996
32	347	Miscellaneous Equipment	13,128	-	-	-	-	-	13,128
33	348	Other Tangible Plant	-	-	-	-	-	-	-
34		Plant Held for Future Use	-	-	-	-	-	-	-
35									
36		RUCO Increase/(Decrease) Adj.	$ 36,146,219	$ -	$ (15,362)	$ -	$ (1,708)	$ (17,070)	$ 36,129,149

References:
Adjustment No. 1(a) - Schedule TJC-5(c), pages 1-4
Adjustment No. 2(a) - Schedule TJC-6(a)
Adjustment No. 3(a) - Intentionally Left Blank (Used for Wastewater Division)
Adjustment No. 4(a) - Schedule TJC-8(a)

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012

TOTAL ACCUMULATED DEPRECIATION SUMMARY SCHEDULE

Line No.	NARUC Account	Description	Company Accum. Depre. Balance As Filed	RUCO Adjustment No. 1(b) Accumulated Depreciation Adjustment	RUCO Adjustment No. 2(b) Reclassify NWWTP Accounts Per RUCO DR 2.1	RUCO Adjustment No. 3(b) Intentionally Left Blank	RUCO Adjustment No. 4(b) Remove Affiliate Profits Per Staff DR MJR 1.15	RUCO Total Adjustments	RUCO Total Accum. Depre. Balance
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchise Cost	-	-	-	-	-	-	-
3	303	Land and Land Rights	-	-	-	-	-	-	-
4	304	Structures & Improvements	(598,813)	-	-	-	1	1	(598,813)
5	305	Collecting & Impounding Reservoirs	-	-	-	-	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-	-	-	-	-
7	307	Wells & Springs	(219,473)	(0)	-	-	0	0	(219,473)
8	308	Infiltration Galleries	-	-	-	-	-	-	-
9	309	Raw Water Supply Mains	(43,831)	-	-	-	-	-	(43,831)
10	310	Power Generation Equipment	(103,188)	(0)	-	-	-	(0)	(103,188)
11	311	Pumping Equipment	(2,859,238)	113,110	-	-	19	113,129	(2,746,108)
12	320	Water Treatment Equipment	(183,785)	-	94	-	-	94	(183,690)
13	320.1	Water Treatment Plants	-	-	-	-	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-	-	-	-	-
15	330	Distribution Reservoirs & Standpipes	(191,697)	-	-	-	-	-	(191,697)
16	330.1	Storage Tanks	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-	-
18	331	Transmission & Distribution Mains	(9,566,814)	-	-	-	14	14	(9,566,800)
19	333	Services	(869,455)	-	-	-	-	-	(869,455)
20	334	Meters	(536,110)	-	-	-	-	-	(536,110)
21	335	Hydrants	(184,803)	(0)	-	-	-	(0)	(184,803)
22	336	Backflow Prevention Devices	(2,366)	-	324	-	-	324	(2,043)
23	339	Other Plant & Misc Equipment	(30,527)	(0)	-	-	-	(0)	(30,527)
24	340	Office Furniture & Equipment	(22,865)	100	-	-	-	100	(22,765)
25	340.1	Computers & Software	(76,919)	-	-	-	-	-	(76,919)
26	341	Transportation Equipment	(121,824)	803	-	-	-	803	(121,021)
27	342	Stores Equipment	-	-	-	-	-	-	-
28	343	Tools, Shop & Garage Equipment	(11,766)	-	-	-	-	-	(11,766)
29	344	Laboratory Equipment	(3,061)	-	-	-	-	-	(3,061)
30	345	Power Operated Equipment	-	-	-	-	-	-	-
31	346	Communication Equipment	(147,813)	(0)	-	-	-	(0)	(147,813)
32	347	Miscellaneous Equipment	(10,032)	(0)	-	-	-	(0)	(10,032)
33	348	Other Tangible Plant	-	-	-	-	-	-	-
34		Plant Held for Future Use	-	-	-	-	-	-	-
35									
36		RUCO Increase/(Decrease) Adj.	$ (15,784,381)	$ 114,014	$ 418	$ -	$ 33	$ 114,465	$ (15,669,915)

References:
Adjustment No. 1(b) - Schedule TJC-5(c), pages 1-4
Adjustment No. 2(b) - Schedule TJC-6(b)
Adjustment No. 3(b) - Intentionally Left Blank (Used for Wastewater Division)
Adjustment No. 4(b) - Schedule TJC-8(b)

RUCO RATE BASE ADJUSTMENT NO. 1(a)
RECONSTRUCTION OF UTILITY PLANT IN SERVICE ("UPIS")

Line No.	NARUC Account No.	Description	Company Plant in Service Balance As Filed	RUCO Adjustments	RUCO As Calculated
1	301	Organization Cost	$ 5,785	$ -	$ 5,785
2	302	Franchise Cost	417	-	417
3	303	Land and Land Rights	44,194	-	44,194
4	304	Structures & Improvements	3,432,930	-	3,432,930
5	305	Collecting & Impounding Reservoirs	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-
7	307	Wells & Springs	562,944	-	562,944
8	308	Infiltration Galleries	-	-	-
9	309	Raw Water Supply Mains	279,157	-	279,157
10	310	Power Generation Equipment	219,360	-	219,360
11	311	Pumping Equipment	3,147,011	-	3,147,011
12	320	Water Treatment Equipment	369,100	-	369,100
13	320.1	Water Treatment Plants	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-
15	330	Distribution Reservoirs & Standpipes	759,861	-	759,861
16	330.1	Storage Tanks	-	-	-
17	330.2	Pressure Tanks	-	-	-
18	331	Transmission & Distribution Mains	22,339,256	-	22,339,256
19	333	Services	2,768,122	-	2,768,122
20	334	Meters	1,010,366	-	1,010,366
21	335	Hydrants	572,321	-	572,321
22	336	Backflow Prevention Devices	15,855	-	15,855
23	339	Other Plant & Misc Equipment	123,778	-	123,778
24	340	Office Furniture & Equipment	29,265	-	29,265
25	340.1	Computers & Software	76,919	-	76,919
26	341	Transportation Equipment	142,188	-	142,188
27	342	Stores Equipment	-	-	-
28	343	Tools, Shop & Garage Equipment	18,203	-	18,203
29	344	Laboratory Equipment	3,061	-	3,061
30	345	Power Operated Equipment	-	-	-
31	346	Communication Equipment	212,996	-	212,996
32	347	Miscellaneous Equipment	13,128	-	13,128
33	348	Other Tangible Plant	-	-	-
34		Plant Held for Future Use	-	-	-
35					
36		RUCO TOTALS	$ 36,146,219	$ -	$ 36,146,219
37					
38		Company As Calculated & Filed			36,146,219
39					
40		RUCO Increase/(Decrease) Adj.			$ -

References: Sch. TJC-5, Pages 1-4, Plant Reconstruction Schedules - Years 2009 Through Feb. 2012

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012

Rio Rico - Water Division
Direct Schedule TJC-5(b)

RUCO RATE BASE ADJUSTMENT NO. 1(b)
RECONSTRUCTION OF ACCUMULATED DEPRECIATION

Line No.	NARUC Account No.	Description	Company Accum. Depre. Balance As Filed	RUCO Adjustments	RUCO As Calculated
1	301	Organization Cost	$ -	$ -	$ -
2	302	Franchise Cost	-	-	-
3	303	Land and Land Rights	-	-	-
4	304	Structures & Improvements	(598,813)	-	(598,813)
5	305	Collecting & Impounding Reservoirs	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-
7	307	Wells & Springs	(219,473)	(0)	(219,473)
8	308	Infiltration Galleries	-	-	-
9	309	Raw Water Supply Mains	(43,831)	-	(43,831)
10	310	Power Generation Equipment	(103,188)	(0)	(103,188)
11	311	Pumping Equipment	(2,859,238)	113,110	(2,746,127)
12	320	Water Treatment Equipment	(183,785)	-	(183,785)
13	320.1	Water Treatment Plants	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-
15	330	Distribution Reservoirs & Standpipes	(191,697)	-	(191,697)
16	330.1	Storage Tanks	-	-	-
17	330.2	Pressure Tanks	-	-	-
18	331	Transmission & Distribution Mains	(9,566,814)	-	(9,566,814)
19	333	Services	(869,455)	-	(869,455)
20	334	Meters	(536,110)	-	(536,110)
21	335	Hydrants	(184,803)	(0)	(184,803)
22	336	Backflow Prevention Devices	(2,366)	-	(2,366)
23	339	Other Plant & Misc Equipment	(30,527)	(0)	(30,527)
24	340	Office Furniture & Equipment	(22,865)	100	(22,765)
25	340.1	Computers & Software	(76,919)	-	(76,919)
26	341	Transportation Equipment	(121,824)	803	(121,021)
27	342	Stores Equipment	-	-	-
28	343	Tools, Shop & Garage Equipment	(11,766)	-	(11,766)
29	344	Laboratory Equipment	(3,061)	-	(3,061)
30	345	Power Operated Equipment	-	-	-
31	346	Communication Equipment	(147,813)	(0)	(147,813)
32	347	Miscellaneous Equipment	(10,032)	(0)	(10,032)
33	348	Other Tangible Plant	-	-	-
34		Plant Held for Future Use	-	-	-
35					
36		RUCO TOTALS	$ (15,784,381)	$ 114,014	$ (15,670,367)
37					
38		Company As Calculated & Filed			(15,784,381)
39					
40		RUCO (Increase)/Decrease Adj.			$ 114,014

References: Sch. TJC-5(c), Pages 1-4, Plant Reconstruction Schedules - Years 2009 Through Feb. 2012

PLANT RECONSTRUCTION SCHEDULE

				Per Decision 72059			2009								
Line No.	NARUC Account No.	Description	Allowed Deprec. Rate	Plant at 12/31/2008	Accum. Deprec. At 12/31/2008	Net Plant at 12/31/2008	Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	301	Organization Cost	0.00%	$ 5,785	-	$ 5,785	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	302	Franchise Cost	0.00%	417	-	417	-	-	-	-	-	-	417	-	417
3	303	Land and Land Rights	0.00%	44,194	-	44,194	-	-	-	-	-	-	44,194	-	44,194
4	304	Structures & Improvements	3.33%	2,732,833	(306,347)	2,426,487	16,449	-	16,449	-	-	91,277	2,749,282	(397,624)	2,351,658
5	305	Collecting & Impounding Reservoirs	2.50%	-	-	-	-	-	-	-	-	-	-	-	-
6	306	Lake, River, Canal Intakes	2.50%	-	-	-	-	-	-	-	-	-	-	-	-
7	307	Wells & Springs	3.33%	563,511	(160,123)	403,388	(1,518)	-	(1,518)	-	-	18,740	561,993	(178,863)	383,130
8	308	Infiltration Galleries	6.67%	-	-	-	-	-	-	-	-	-	-	-	-
9	309	Raw Water Supply Mains	2.00%	279,153	(26,151)	253,002	-	-	-	-	-	5,583	279,153	(31,735)	247,419
10	310	Power Generation Equipment	5.00%	197,120	(69,734)	127,386	10,000	-	10,000	-	-	10,106	207,120	(79,840)	127,280
11	311	Pumping Equipment	12.50%	2,591,970	(1,882,999)	708,971	224,575	-	224,575	-	-	338,032	2,816,546	(2,221,032)	595,514
12	320	Water Treatment Equipment	3.33%	372,970	(144,799)	228,171	(3,869)	-	(3,869)	-	-	12,355	369,100	(157,154)	211,946
13	320.1	Water Treatment Plants	3.33%	-	-	-	-	-	-	-	-	-	-	-	-
14	320.2	Solution Chemical Feeders	20.00%	-	-	-	-	-	-	-	-	-	-	-	-
15	330	Distribution Reservoirs & Standpipes	2.22%	759,861	(138,279)	621,581	-	-	-	-	-	16,869	759,861	(155,148)	604,713
16	330.1	Storage Tanks	2.22%	-	-	-	-	-	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	5.00%	-	-	-	-	-	-	-	-	-	-	-	-
18	331	Transmission & Distribution Mains	2.00%	22,089,150	(8,163,798)	13,925,353	40,046	-	40,046	-	-	442,183	22,129,197	(8,605,981)	13,523,216
19	333	Services	3.33%	2,209,274	(805,963)	1,403,311	123,799	-	123,799	(4,394)	-	75,557	2,328,679	(877,126)	1,451,553
20	334	Meters	8.33%	956,605	(319,684)	636,921	1,871	-	1,871	(5,402)	-	79,538	953,075	(393,820)	559,254
21	335	Hydrants	2.00%	568,577	(148,744)	419,834	-	-	-	-	-	11,372	568,577	(160,115)	408,462
22	336	Backflow Prevention Devices	6.67%	3,848	(385)	3,463	-	-	-	-	-	257	3,848	(642)	3,206
23	339	Other Plant & Misc Equipment	6.67%	121,843	(4,647)	117,197	-	-	-	-	-	8,127	121,843	(12,774)	109,070
24	340	Office Furniture & Equipment	6.67%	22,986	(17,954)	5,032	-	-	-	-	-	1,533	22,986	(19,487)	3,499
25	340.1	Computers & Software	20.00%	76,919	(76,919)	-	-	-	-	-	-	-	76,919	(76,919)	-
26	341	Transportation Equipment	20.00%	218,945	(25,112)	193,833	(78,957)	-	(78,957)	-	-	35,893	139,988	(61,005)	78,983
27	342	Stores Equipment	4.00%	-	-	-	-	-	-	-	-	-	-	-	-
28	343	Tools, Shop & Garage Equipment	5.00%	15,035	(9,301)	5,734	-	-	-	-	-	752	15,035	(10,053)	4,982
29	344	Laboratory Equipment	10.00%	3,061	(2,893)	168	-	-	-	-	-	168	3,061	(3,061)	-
30	345	Power Operated Equipment	5.00%	-	-	-	-	-	-	-	-	-	-	-	-
31	346	Communication Equipment	10.00%	218,040	(113,464)	104,577	-	-	-	-	-	21,804	218,040	(135,268)	82,773
32	347	Miscellaneous Equipment	10.00%	7,701	(6,641)	1,060	480	-	480	-	-	794	8,181	(7,435)	746
33	348	Other Tangible Plant	4.00%	-	-	-	-	-	-	-	-	-	-	-	-
34		Plant Held for Future Use		-	-	-	-	-	-	-	-	-	-	-	-
35															
36		RUCO TOTALS		$ 34,059,801	$(12,423,937)	$21,635,864	$ 332,877	$ -	$332,877	$ (9,796)	$ -	$1,170,940	$ 34,382,881	$ (13,585,081)	$ 20,797,800

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012

Rio Rico - Water Division
Direct Schedule TJC-5(c)

PLANT RECONSTRUCTION SCHEDULE

Line No.	NARUC Account No.	Description	2010 Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	301	Organization Cost			$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	302	Franchise Cost			-	-	-	-	417	-	417
3	303	Land and Land Rights			-	-	-	-	44,194	-	44,194
4	304	Structures & Improvements	2,367		2,367	-	-	91,591	2,751,649	(489,214)	2,262,435
5	305	Collecting & Impounding Reservoirs			-	-	-	-	-	-	-
6	306	Lake, River, Canal Intakes			-	-	-	-	-	-	-
7	307	Wells & Springs	897		897	-	-	18,729	562,890	(197,592)	365,298
8	308	Infiltration Galleries			-	-	-	-	-	-	-
9	309	Raw Water Supply Mains			-	-	-	5,583	279,153	(37,318)	241,836
10	310	Power Generation Equipment	10,472		10,472	-	-	10,618	217,592	(90,458)	127,134
11	311	Pumping Equipment	23,210		23,210	-	-	353,519	2,839,756	(2,574,551)	265,205
12	320	Water Treatment Equipment			-	-	-	12,291	369,100	(169,445)	199,655
13	320.1	Water Treatment Plants			-	-	-	-	-	-	-
14	320.2	Solution Chemical Feeders			-	-	-	-	-	-	-
15	330	Distribution Reservoirs & Standpipes			-	-	-	16,869	759,861	(172,017)	587,844
16	330.1	Storage Tanks			-	-	-	-	-	-	-
17	330.2	Pressure Tanks			-	-	-	-	-	-	-
18	331	Transmission & Distribution Mains	20,635		20,635	-	-	442,790	22,149,832	(9,048,771)	13,101,060
19	333	Services	251,427		251,427	(84,388)	-	80,326	2,495,718	(873,064)	1,622,654
20	334	Meters	12,184		12,184	(4,967)	-	79,692	960,292	(468,545)	491,747
21	335	Hydrants			-	-	-	11,372	568,577	(171,487)	397,091
22	336	Backflow Prevention Devices	9,513		9,513	-	-	574	13,361	(1,216)	12,146
23	339	Other Plant & Misc Equipment			-	-	-	8,127	121,843	(20,901)	100,943
24	340	Office Furniture & Equipment			-	-	-	1,533	22,986	(21,020)	1,966
25	340.1	Computers & Software			-	-	-	-	76,919	(76,919)	-
26	341	Transportation Equipment	381		381	-	-	28,036	140,369	(89,041)	51,328
27	342	Stores Equipment			-	-	-	-	-	-	-
28	343	Tools, Shop & Garage Equipment			-	-	-	752	15,035	(10,805)	4,230
29	344	Laboratory Equipment			-	-	-	-	3,061	(3,061)	-
30	345	Power Operated Equipment			-	-	-	-	-	-	-
31	346	Communication Equipment	3,230		3,230	-	-	21,966	221,270	(157,233)	64,037
32	347	Miscellaneous Equipment	4,947		4,947	-	-	1,065	13,128	(8,501)	4,628
33	348	Other Tangible Plant			-	-	-	-	-	-	-
34		Plant Held for Future Use			-	-	-	-	-	-	-
35											
36		RUCO TOTALS	$ 339,262	$ -	$339,262	$ (89,355)	$ -	$ 1,185,432	$ 34,632,789	$(14,681,158)	$ 19,951,631

Rio Rico Utilities, Inc
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Rio Rico - Water Division
Direct Schedule TJC-5(c)

PLANT RECONSTRUCTION SCHEDULE

Line No.	NARUC Account No.	Description	2011 Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	302	Franchise Cost	-	-	-	-	-	-	417	-	417
3	303	Land and Land Rights	-	-	-	-	-	-	44,194	-	44,194
4	304	Structures & Improvements	41,525	-	41,525	-	-	92,321	2,793,174	(581,536)	2,211,638
5	305	Collecting & Impounding Reservoirs	-	-	-	-	-	-	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-	-	-	-	-	-	-
7	307	Wells & Springs	632	-	632	-	-	18,755	563,522	(216,347)	347,175
8	308	Infiltration Galleries	-	-	-	-	-	-	-	-	-
9	309	Raw Water Supply Mains	-	-	-	-	-	5,583	279,153	(42,901)	236,253
10	310	Power Generation Equipment	1,023	-	1,023	-	-	10,905	218,615	(101,363)	117,252
11	311	Pumping Equipment	67,261	-	67,261	-	-	269,409	2,907,017	(2,843,960)	63,057
12	320	Water Treatment Equipment	-	-	-	-	-	12,291	369,100	(181,736)	187,364
13	320.1	Water Treatment Plants	-	-	-	-	-	-	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-	-	-	-	-	-	-
15	330	Distribution Reservoirs & Standpipes	-	-	-	-	-	16,869	759,861	(188,886)	570,975
16	330.1	Storage Tanks	-	-	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-	-	-	-
18	331	Transmission & Distribution Mains	76,932	-	76,932	-	-	443,766	22,226,764	(9,492,537)	12,734,227
19	333	Services	307,904	-	307,904	(105,260)	-	86,481	2,698,362	(854,285)	1,844,076
20	334	Meters	61,930	-	61,930	(27,767)	-	81,415	994,455	(522,193)	472,262
21	335	Hydrants	3,684	-	3,684	-	-	11,408	572,261	(182,895)	389,366
22	336	Backflow Prevention Devices	2,494	-	2,494	-	-	974	15,855	(2,190)	13,666
23	339	Other Plant & Misc Equipment	3,443	-	3,443	-	-	8,242	125,286	(29,142)	96,144
24	340	Office Furniture & Equipment	554	-	554	-	-	1,552	23,540	(22,572)	969
25	340.1	Computers & Software	-	-	-	-	-	-	76,919	(76,919)	-
26	341	Transportation Equipment	-	-	-	-	-	28,074	140,369	(117,115)	23,254
27	342	Stores Equipment	-	-	-	-	-	-	-	-	-
28	343	Tools, Shop & Garage Equipment	2,437	-	2,437	-	-	813	17,472	(11,618)	5,855
29	344	Laboratory Equipment	-	-	-	-	-	-	3,061	(3,061)	-
30	345	Power Operated Equipment	-	-	-	-	-	-	-	-	-
31	346	Communication Equipment	381	-	381	(33,249)	-	20,484	188,402	(144,468)	43,934
32	347	Miscellaneous Equipment	-	-	-	-	-	1,313	13,128	(9,813)	3,315
33	348	Other Tangible Plant	-	-	-	-	-	-	-	-	-
34		Plant Held for Future Use	-	-	-	-	-	-	-	-	-
35											
36		RUCO TOTALS	$ 570,201	$ -	$ 570,201	$ (166,276)	$ -	$ 1,110,655	$ 35,036,714	$ (15,625,537)	$ 19,411,177

Rio Rico Utilities, Inc
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Rio Rico - Water Division
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PLANT RECONSTRUCTION SCHEDULE

			2012 (2 Months - January 1 through February 29, 2012)								
Line No.	NARUC Account No.	Description	Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	301	Organization Cost	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	302	Franchise Cost	-	-	-	-	-	-	417	-	417
3	303	Land and Land Rights	-	-	-	-	-	-	44,194	-	44,194
4	304	Structures & Improvements	639,756	-	639,756	-	-	17,277	3,432,930	(598,813)	2,834,117
5	305	Collecting & Impounding Reservoirs	-	-	-	-	-	-	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-	-	-	-	-	-	-
7	307	Wells & Springs	3,794	(4,372)	(578)	-	-	3,126	562,944	(219,473)	343,471
8	308	Infiltration Galleries	-	-	-	-	-	-	-	-	-
9	309	Raw Water Supply Mains	4	-	4	-	-	931	279,157	(43,831)	235,326
10	310	Power Generation Equipment	745	-	745	-	-	1,825	219,360	(103,188)	116,172
11	311	Pumping Equipment	351,006	(170)	350,836	(110,842)	-	13,009	3,147,011	(2,746,127)	400,884
12	320	Water Treatment Equipment	-	-	-	-	-	2,049	369,100	(183,785)	185,316
13	320.1	Water Treatment Plants	-	-	-	-	-	-	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-	-	-	-	-	-	-
15	330	Distribution Reservoirs & Standpipes	-	-	-	-	-	2,811	759,861	(191,697)	568,163
16	330.1	Storage Tanks	-	-	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	-	-	-	-	-	-	-	-	-
18	331	Transmission & Distribution Mains	118,060	(5,568)	112,492	-	-	74,277	22,339,256	(9,566,814)	12,772,442
19	333	Services	69,760	-	69,760	-	-	15,169	2,768,122	(869,455)	1,898,667
20	334	Meters	15,911	-	15,911	-	-	13,917	1,010,366	(536,110)	474,256
21	335	Hydrants	60	-	60	-	-	1,908	572,321	(184,803)	387,519
22	336	Backflow Prevention Devices	-	-	-	-	-	176	15,855	(2,366)	13,489
23	339	Other Plant & Misc Equipment	6,878	(8,386)	(1,508)	-	-	1,384	123,778	(30,527)	93,252
24	340	Office Furniture & Equipment	5,725	-	5,725	-	-	193	29,265	(22,765)	6,500
25	340.1	Computers & Software	-	-	-	-	-	-	76,919	(76,919)	-
26	341	Transportation Equipment	1,819	-	1,819	-	-	3,906	142,188	(121,021)	21,167
27	342	Stores Equipment	-	-	-	-	-	-	-	-	-
28	343	Tools, Shop & Garage Equipment	731	-	731	-	-	149	18,203	(11,766)	6,437
29	344	Laboratory Equipment	-	-	-	-	-	-	3,061	(3,061)	-
30	345	Power Operated Equipment	-	-	-	-	-	-	-	-	-
31	346	Communication Equipment	24,594	-	24,594	-	-	3,345	212,996	(147,813)	65,183
32	347	Miscellaneous Equipment	-	-	-	-	-	219	13,128	(10,032)	3,096
33	348	Other Tangible Plant	-	-	-	-	-	-	-	-	-
34		Plant Held for Future Use	-	-	-	-	-	-	-	-	-
35											
36		RUCO TOTALS	$1,238,843	$ (18,496)	$ 1,220,347	$ (110,842)	$ -	$ 155,671	$36,146,219	$(15,670,367)	$20,475,853
37		Company Plant in Service as Filed							36,146,219		
38		RUCO Increase/(Decrease) Plant in Service Adjustment							$ -		
39		Company Accumulated Depreciation as Filed								(15,784,381)	
40		RUCO (Increase)/Decrease Accumulated Depreciation Adjustment								$ 114,014	

Rio Rico Utilities, Inc
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RUCO RATE BASE ADJUSTMENT NO. 2(a)
RECLASSIFY WATER & WASTEWATER PLANT ACCOUNTS TO NWWTP

Line No.	NARUC Account No.	Description	Company Plant in Service As Filed	RUCO Adjustments	Note	RUCO As Adjusted
1	301	Organization Cost	$ 5,785	$ -		$ 5,785
2	302	Franchise Cost	417	-		417
3	303	Land and Land Rights	44,194	-		44,194
4	304	Structures & Improvements	3,432,930	-		3,432,930
5	305	Collecting & Impounding Reservoirs	-	-		-
6	306	Lake, River, Canal Intakes	-	-		-
7	307	Wells & Springs	562,944	-		562,944
8	308	Infiltration Galleries	-	-		-
9	309	Raw Water Supply Mains	279,157	-		279,157
10	310	Power Generation Equipment	219,360	-		219,360
11	311	Pumping Equipment	3,147,011	-		3,147,011
12	320	Water Treatment Equipment	369,100	(5,658)	WP's	363,442
13	320.1	Water Treatment Plants	-	-		-
14	320.2	Solution Chemical Feeders	-	-		-
15	330	Distribution Reservoirs & Standpipes	759,861	-		759,861
16	330.1	Storage Tanks	-	-		-
17	330.2	Pressure Tanks	-	-		-
18	331	Transmission & Distribution Mains	22,339,256	-		22,339,256
19	333	Services	2,768,122	-		2,768,122
20	334	Meters	1,010,366	-		1,010,366
21	335	Hydrants	572,321	-		572,321
22	336	Backflow Prevention Devices	15,855	(9,704)	WP's	6,151
23	339	Other Plant & Misc Equipment	123,778	-		123,778
24	340	Office Furniture & Equipment	29,265	-		29,265
25	340.1	Computers & Software	76,919	-		76,919
26	341	Transportation Equipment	142,188	-		142,188
27	342	Stores Equipment	-	-		-
28	343	Tools, Shop & Garage Equipment	18,203	-		18,203
29	344	Laboratory Equipment	3,061	-		3,061
30	345	Power Operated Equipment	-	-		-
31	346	Communication Equipment	212,996	-		212,996
32	347	Miscellaneous Equipment	13,128	-		13,128
33	348	Other Tangible Plant	-	-		-
34		Plant Held for Future Use	-	-		-
35		TOTALS	$ 36,146,219	$ (15,362)		$ 36,130,857
36		Company As Calculated & Filed				36,146,219
37		RUCO Adjustment				$ (15,362)

References: Company B-2 Plant Schedules, Schedules TJC-4 2009 Through 2012, and RUCO NWWTP Reclassification Calculation Adjustme

RUCO RATE BASE ADJUSTMENT NO. 2(b)
RECLASSIFY WATER ACCUMULATED DEPRECIATION TO NWWTP

Line No.	NARUC Account No.	Description	Company Accum. Depre. As Filed	RUCO Adjustments	Note	RUCO As Adjusted
1	301	Organization Cost	$ -	$ -		$ -
2	302	Franchise Cost	-	-		-
3	303	Land and Land Rights	-	-		-
4	304	Structures & Improvements	(598,813)	-		(598,813)
5	305	Collecting & Impounding Reservoirs	-	-		-
6	306	Lake, River, Canal Intakes	-	-		-
7	307	Wells & Springs	(219,473)	-		(219,473)
8	308	Infiltration Galleries	-	-		-
9	309	Raw Water Supply Mains	(43,831)	-		(43,831)
10	310	Power Generation Equipment	(103,188)	-		(103,188)
11	311	Pumping Equipment	(2,859,238)	-		(2,859,238)
12	320	Water Treatment Equipment	(183,785)	94	WP's	(183,690)
13	320.1	Water Treatment Plants	-	-		-
14	320.2	Solution Chemical Feeders	-	-		-
15	330	Distribution Reservoirs & Standpipes	(191,697)	-		(191,697)
16	330.1	Storage Tanks	-	-		-
17	330.2	Pressure Tanks	-	-		-
18	331	Transmission & Distribution Mains	(9,566,814)	-		(9,566,814)
19	333	Services	(869,455)	-		(869,455)
20	334	Meters	(536,110)	-		(536,110)
21	335	Hydrants	(184,803)	-		(184,803)
22	336	Backflow Prevention Devices	(2,366)	324	WP's	(2,043)
23	339	Other Plant & Misc Equipment	(30,527)	-		(30,527)
24	340	Office Furniture & Equipment	(22,865)	-		(22,865)
25	340.1	Computers & Software	(76,919)	-		(76,919)
26	341	Transportation Equipment	(121,824)	-		(121,824)
27	342	Stores Equipment	-	-		-
28	343	Tools, Shop & Garage Equipment	(11,766)	-		(11,766)
29	344	Laboratory Equipment	(3,061)	-		(3,061)
30	345	Power Operated Equipment	-	-		-
31	346	Communication Equipment	(147,813)	-		(147,813)
32	347	Miscellaneous Equipment	(10,032)	-		(10,032)
33	348	Other Tangible Plant	-	-		-
34		Plant Held for Future Use	-	-		-
35		TOTALS	$ (15,784,381)	$ 418		$ (15,783,963)
36		Company As Calculated & Filed				(15,784,381)
37		RUCO Adjustment				$ 418

References: Company B-2 Plant Schedules, Schedules TJC-4 2009 Through 2012, and RUCO NWWTP Reclassification Calculation Adjustment WP

RUCO RATE BASE ADJUSTMENT NO. 3(a)
INTENTIONALLY LEFT BLANK - FOR USE OF WASTEWATER DIVISION

RUCO RATE BASE ADJUSTMENT NO. 3(b)
INTENTIONALLY LEFT BLANK - FOR USE OF WASTEWATER DIVISION

RUCO RATE BASE ADJUSTMENT NO. 4(a)
REMOVE AFFILIATE PLANT IN SERVICE PROFITS

Line No.	NARUC Account No.	Description	Company Plant in Service As Filed	RUCO Adjustments	RUCO As Adjusted
1	301	Organization Cost	$ 5,785	$ -	$ 5,785
2	302	Franchise Cost	417	-	417
3	303	Land and Land Rights	44,194	-	44,194
4	304	Structures & Improvements	3,432,930	(35)	3,432,895
5	305	Collecting & Impounding Reservoirs	-	-	-
6	306	Lake, River, Canal Intakes	-	-	-
7	307	Wells & Springs	562,944	(7)	562,937
8	308	Infiltration Galleries	-	-	-
9	309	Raw Water Supply Mains	279,157	-	279,157
10	310	Power Generation Equipment	219,360	-	219,360
11	311	Pumping Equipment	3,147,011	(303)	3,146,708
12	320	Water Treatment Equipment	369,100	-	369,100
13	320.1	Water Treatment Plants	-	-	-
14	320.2	Solution Chemical Feeders	-	-	-
15	330	Distribution Reservoirs & Standpipes	759,861	-	759,861
16	330.1	Storage Tanks	-	-	-
17	330.2	Pressure Tanks	-	-	-
18	331	Transmission & Distribution Mains	22,339,256	(1,363)	22,337,894
19	333	Services	2,768,122	-	2,768,122
20	334	Meters	1,010,366	-	1,010,366
21	335	Hydrants	572,321	-	572,321
22	336	Backflow Prevention Devices	15,855	-	15,855
23	339	Other Plant & Misc Equipment	123,778	-	123,778
24	340	Office Furniture & Equipment	29,265	-	29,265
25	340.1	Computers & Software	76,919	-	76,919
26	341	Transportation Equipment	142,188	-	142,188
27	342	Stores Equipment	-	-	-
28	343	Tools, Shop & Garage Equipment	18,203	-	18,203
29	344	Laboratory Equipment	3,061	-	3,061
30	345	Power Operated Equipment	-	-	-
31	346	Communication Equipment	212,996	-	212,996
32	347	Miscellaneous Equipment	13,128	-	13,128
33	348	Other Tangible Plant	-	-	-
34		Plant Held for Future Use	-	-	-
35		TOTALS	$ 36,146,219	$ (1,708)	$ 36,144,511
36		Company As Calculated & Filed			36,146,219
37		RUCO Adjustment			$ (1,708)

References: Company B-2 Plant Schedules and RRUI's Revised DR Response to Staff MJR 3-13

RUCO RATE BASE ADJUSTMENT NO. 4(b)
REMOVE AFFILIATE ACCUMULATED DEPRECIATION PROFITS

Line No.	NARUC Account No.	Description	Company Plant in Service As Filed	RUCO Adjustments	Note	RUCO As Adjusted
1	301	Organization Cost	$ -	$ -		$ -
2	302	Franchise Cost	-	-		-
3	303	Land and Land Rights	-	-		-
4	304	Structures & Improvements	(598,813)	1	WP's	(598,813)
5	305	Collecting & Impounding Reservoirs	-	-		-
6	306	Lake, River, Canal Intakes	-	-		-
7	307	Wells & Springs	(219,473)	0	WP's	(219,473)
8	308	Infiltration Galleries	-	-		-
9	309	Raw Water Supply Mains	(43,831)	-		(43,831)
10	310	Power Generation Equipment	(103,188)	-		(103,188)
11	311	Pumping Equipment	(2,859,238)	19	WP's	(2,859,219)
12	320	Water Treatment Equipment	(183,785)	-		(183,785)
13	320.1	Water Treatment Plants	-	-		-
14	320.2	Solution Chemical Feeders	-	-		-
15	330	Distribution Reservoirs & Standpipes	(191,697)	-		(191,697)
16	330.1	Storage Tanks	-	-		-
17	330.2	Pressure Tanks	-	-		-
18	331	Transmission & Distribution Mains	(9,566,814)	14	WP's	(9,566,800)
19	333	Services	(869,455)	-		(869,455)
20	334	Meters	(536,110)	-		(536,110)
21	335	Hydrants	(184,803)	-		(184,803)
22	336	Backflow Prevention Devices	(2,366)	-		(2,366)
23	339	Other Plant & Misc Equipment	(30,527)	-		(30,527)
24	340	Office Furniture & Equipment	(22,865)	-		(22,865)
25	340.1	Computers & Software	(76,919)	-		(76,919)
26	341	Transportation Equipment	(121,824)	-		(121,824)
27	342	Stores Equipment	-	-		-
28	343	Tools, Shop & Garage Equipment	(11,766)	-		(11,766)
29	344	Laboratory Equipment	(3,061)	-		(3,061)
30	345	Power Operated Equipment	-	-		-
31	346	Communication Equipment	(147,813)	-		(147,813)
32	347	Miscellaneous Equipment	(10,032)	-		(10,032)
33	348	Other Tangible Plant	-	-		-
34		Plant Held for Future Use	-	-		-
35		TOTALS	$ (15,784,381)	$ 33		$(15,784,347)
36		Company As Calculated & Filed				(15,784,381)
37		RUCO Adjustment				$ 33

References: Company B-2 Plant Schedules and RRUI's Revised DR Response to Staff MJR 3-13

RUCO RATE BASE ADJUSTMENT NO. 5
ACCUMULATED DEFERRED INCOME TAX ("ADIT")

Line No.			Water & Sewer Adjusted Book Value	Water & Sewer Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Effective Tax Rate	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
1		Deferred Income Tax as of February 29, 2012									
2											
3											
4											
5											
6		Plant-in-Service	$ 50,385,286 [1]								
7		Accum. Deprec.	(22,029,373) [1]								
8		CIAC - Net	(14,692,881) [3]								
9	Fed.	Fixed Assets	$ 13,663,032	$ 8,955,829 [2]	100.0%	$ (4,707,203)	31.63%		-		(1,488,930)
10											
11	State	Fixed Assets	$ 13,663,032	$ 23,646,536 [2]	100.0%	$ 9,983,504	6.97%		695,651		-
12											
13	Fed &State	AIAC		593,411 [4]	30.0%	$ 178,023 [4]	38.60%		$ 68,715		
14											
15								$ -	$ 764,366	$ -	$ (1,488,930)
16											
17		Net Asset (Liability)						$ (724,564)			
18											
19		Allocation Factor - Water-Division (based on rate base before ADIT)						0.62224			
20											
21		Net Asset (Liability) Water Division						$ (450,850)			
22											
23		DIT Asset (Liability) per Books						$ -			
24											
25		RUCO's Calculated Amount of ADIT						$ (450,850)			
26											
27		Company's Calculated Amount of ADIT						(405,395)			
28											
29		RUCO Adjustment to ADIT						$ (45,456)			
30											
31											
32		Footnotes - See Schedule TJC-9, page 2 of 2									

RUCO RATE BASE ADJUSTMENT NO. 5
ACCUMULATED DEFERRED INCOME TAX ("ADIT")

Line No.		FEDERAL			STATE	
1	[1] **Adjusted per B-2, page 2**					
2	[2] **Computation of Net Tax Value February 29, 2012**					
3	Based on 2011 Tax Depreciation report (December 31, 2011)					
4	Unadjusted Cost per 2011 Tax Depr. Report	$ 28,328,799			$ 28,328,799	
5	Reconciling Items not on tax report:					
6	KPMG CIAC related adjustments (see page 7.2)	(3,942,541)			-	
7	Plant added after 12/31/2011 (see B-2 page 3.4)	3,039,772			3,039,772	
8	Land costs not on tax, on books (see B-2 page 3.4)	51,739			51,739	
9	Reconciling Difference Book vs. Tax (timing) (see page 7.2)	(120,225)			(120,225)	
10					-	
11	Net Unadjusted Cost tax Basis			$ 27,357,544		$ 31,300,085
12						
13	Reductions					
14	Basis Reduction 2011 and Prior Years (from 2011 Tax Depr. Report)	$ (3,066,507)			$ -	
15	KPMG CIAC related adjustments (see workpapers)	1,166,545			-	
16	Accumulated Depreciation 2010 and prior (2011 Tax Depr Report)	(14,334,173)			(6,381,079)	
17	2011 Tax Depreciation (2011 Tax Depr Report)	(1,751,690)			(1,109,895)	
18	2012 Bonus Depreciation Estimate (50% - 2 months)(estimate)	(253,314)			-	
19	2012 Tax Depreciation Estimate (2 months)(estimate)	(162,575)			(162,575)	
20					-	
21	Net Reductions through February 2012			(18,401,715)		(7,653,549)
22	Net tax value of plant-in-service at February 29, 2012			$ 8,955,829		$ 23,646,536
23						
24	[3] **CIAC (including impact of change to probability of realization)**					
25						
26	Gross CIAC per B-2 (Water & Sewer)		$ 25,331,792			
27	CIAC reductions/addtions					
28	A.A per B-2 (Water and Sewer)	$ (11,307,236)				
29	A.A. reductions/addtions	-				
30			(11,307,236)			
31	Net CIAC before unrealized AIAC			$ 14,024,556		
32						
33	Unrealized AIAC Component (Water and Sewer)					
34	Adjusted Net AIAC (see footnote 5 below)		$ 954,749			
35	Unrealized AIAC Component % (1-Realized AIAC Component)		70.0%			
36				$ 668,325		
37	Total realizable CIAC			$ 14,692,881		
38						
39	[4] **AIAC (including impact of change in probability of realization)**					
40	AIAC per B-2 (Water and Sewer)		$ 954,749			
41	AIAC reductions/additions		-			
42	Net AIAC before unrealized portion			$ 954,749		
43	Less: Unrealized AIAC (from Note 4, above)			$ (668,325)		
44	Net realizable AIAC			$ 286,425		
45	Meter and Service Line Installation Charges			306,987		
46	Total AIAC			$ 593,411		

0

2012 Tax Estimate	
Tax Plant	$ 28,328,799
Less: KPMG adjustment	(3,942,541)
Net Tax Plant	$ 24,386,258
25 Year Tax Life	4%
Annual Tax Epense	$ 975,450.32
2 Months Tax Expense	$ 162,575
2012 Adds	$ 3,039,772
Less: Bonus Depr	$ (3,039,772)
Net Adds	$ -
25 Year Tax Life	4%
2012 Tax Expnese (hlf-yr conv.)	0.00
2 Months Tax Expense	$ 0
Total 2012 Tax Depr Estimate	$ 162,575

Rio Rico Utilities, Inc
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Test Year Ended February 29, 2012

Rio Rico - Water Division
Direct Schedule TJC-10

OPERATING INCOME SUMMARY

LINE NO.		[A] COMPANY AS FILED	[B] RUCO TEST YEAR ADJM'TS	[C] RUCO TEST YEAR AS ADJ'TED	[D] RUCO PROP'D CHANGES	[E] RUCO AS RECOMM'D
1	**Operating Revenues**					
2	Metered Water Revenues	$ 2,811,949	$ 41,797	$ 2,853,746	$ 90,894	$ 2,944,640
3	Unmetered Revenues	-	-	-	-	-
4	Other Water Revenues	42,889	-	42,889	-	42,889
5	Total Water Revenues (L2 thru L4)	$ 2,854,838	$ 41,797	$ 2,896,635	$ 90,894	$ 2,987,529
6						
7	**Operating Expenses**					
8	Salaries and Wages	$ 426,012	$ -	$ 426,012	$ -	$ 426,012
9	Purchased Water	-	-	-	-	-
10	Purchased Power	371,378	351	371,729	-	371,729
11	Fuel For Power Production	-	-	-	-	-
12	Chemicals	3,884	4	3,888	-	3,888
13	Materials and Supplies	27,517	-	27,517	-	27,517
14	Management Services - US Liberty Water	257,367	(2,350)	255,017	-	255,017
15	Management Services - Corporate	133,975	(51,243)	82,732	-	82,732
16	Management Services - Other	15,903	-	15,903	-	15,903
17	Outside Services - Accounting	167	-	167	-	167
18	Outside Services - Engineering	-	-	-	-	-
19	Outside Services- Other	14,205	-	14,205	-	14,205
20	Outside Services- Legal	4,690	-	4,690	-	4,690
21	Water Testing	28,231	-	28,231	-	28,231
22	Rents - Building	-	-	-	-	-
23	Rents - Equipment	3,208	-	3,208	-	3,208
24	Transportation Expenses	89,305	-	89,305	-	89,305
25	Insurance - General Liability	34,100	-	34,100	-	34,100
26	Insurance - Vehicle	7,733	-	7,733	-	7,733
27	Reg. Comm. Exp. - Other	-	-	-	-	-
28	Reg. Comm. Exp. - Rate Case	87,500	(21,875)	65,625	-	65,625
29	Miscellaneous Expense	85,057	(1,802)	83,255	-	83,255
30	Bad Debt Expense	-	-	-	-	-
31	Depreciation and Amortization Expense	551,222	(198,500)	352,722	-	352,722
32	Taxes Other Than Income	-	-	-	-	-
33	Property Taxes	155,805	(148)	155,656	1,634	157,290
34	Income Tax	181,647	131,579	313,226	34,453	347,680
35						
36	Total Operationing Expenses (L8 thru L34)	$ 2,478,906	$ (143,985)	$ 2,334,921	$ 36,088	$ 2,371,008
37						
38	**Operating Income (L5 less L36)**	$ 375,933	$ 185,781	$ 561,714	$ 54,807	$ 616,521

REFERENCES:
Column [A]: Company Schedule C-1
Column [B]: Summation of RUCO's Recommended Adjustment on Schedule TJC-11
Column [C]: Col. A + Col. B
Column [D]: RUCO Proposed Increases/(Decreases) to Revenues & Expenses
Column [E]: Column [C] + Column [D]

OPERATING INCOME

Line No.		[A] Company Adjusted Test Year As Filed	[B] Operating Income Adjustment No. 1 Depreciation Exp.	[C] Operating Income Adjustment No. 2 Property Tax Exp.	[D] Operating Income Adjustment No. 3 Rate Case Exp.	[E] Operating Income Adjustment No. 4 6-Inch Bulk Water Sales Revenue Annualization	[F] Operating Income Adjustment No. 5 Intentionally Left Blank	[G] Operating Income Adjustment No. 6 6-Inch Bulk Water Sales Revenue Accrual	[H] Operating Income Adjustment No. 7 Intentionally Left Blank	[I] Operating Income Adjustment No. 8 Expense Annualization	[J] Operating Income Adjustment No. 9 Intentionally Left Blank	[K] Operating Income Adjustment No. 10 Miscellaneous Expenses	[L] Operating Income Adjustment No. 11 Achievement / Incentive Pay
1	Operating Revenues												
2	Metered Water Revenues	$ 2,811,949	$ -	$ -	$ -	$ 20,898	$ -	$ 20,898	$ -	$ -	$ -	$ -	$ -
3	Unmetered Revenues	-	-	-	-	-	-	-	-	-	-	-	-
4	Other Water Revenues	42,889	-	-	-	-	-	-	-	-	-	-	-
5	Total Water Revenues (L2 thru L4)	$ 2,854,838	$ -	$ -	$ -	$ 20,898	$ -	$ 20,898	$ -	$ -	$ -	$ -	$ -
6													
7	Operating Expenses												
8	Salaries and Wages	$ 426,012	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Purchased Water	-	-	-	-	-	-	-	-	-	-	-	-
10	Purchased Power	371,378	-	-	-	-	-	-	-	351	-	-	-
11	Fuel For Power Production	-	-	-	-	-	-	-	-	-	-	-	-
12	Chemicals	3,884	-	-	-	-	-	-	-	4	-	-	-
13	Materials and Supplies	27,517	-	-	-	-	-	-	-	-	-	-	-
14	Management Services - US Liberty Wate	257,367	-	-	-	-	-	-	-	-	-	-	-
15	Management Services - Corporate	133,975	-	-	-	-	-	-	-	-	-	-	(19,977)
16	Management Services - Other	15,903	-	-	-	-	-	-	-	-	-	-	-
17	Outside Services - Accounting	167	-	-	-	-	-	-	-	-	-	-	-
18	Outside Services - Engineering	-	-	-	-	-	-	-	-	-	-	-	-
19	Outside Services- Other	14,205	-	-	-	-	-	-	-	-	-	-	-
20	Outside Services- Legal	4,690	-	-	-	-	-	-	-	-	-	-	-
21	Water Testing	28,231	-	-	-	-	-	-	-	-	-	-	-
22	Rents - Building	-	-	-	-	-	-	-	-	-	-	-	-
23	Rents - Equipment	3,208	-	-	-	-	-	-	-	-	-	-	-
24	Transportation Expenses	89,305	-	-	-	-	-	-	-	-	-	-	-
25	Insurance - General Liability	34,100	-	-	-	-	-	-	-	-	-	-	-
26	Insurance - Vehicle	7,733	-	-	-	-	-	-	-	-	-	-	-
27	Reg. Comm. Exp. - Other	-	-	-	-	-	-	-	-	-	-	-	-
28	Reg. Comm. Exp. - Rate Case	87,500	-	-	(21,875)	-	-	-	-	-	-	-	-
29	Miscellaneous Expense	85,057	-	-	-	-	-	-	-	-	-	(1,802)	-
30	Bad Debt Expense	-	-	-	-	-	-	-	-	-	-	-	-
31	Depreciation and Amortization Expense	551,222	(198,500)	-	-	-	-	-	-	-	-	-	-
32	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
33	Property Taxes	155,805	-	(148)	-	-	-	-	-	-	-	-	-
34	Income Tax	181,647	-	-	-	-	-	-	-	-	-	-	-
35													
36	Total Operationing Expenses (L8 thru L34)	$ 2,478,906	$ (198,500)	$ (148)	$ (21,875)	$ -	$ -	$ -	$ -	$ 355	$ -	$ (1,802)	$ (19,977)
37													
38	Operating Income (L5 less L36)	$ 375,933	$ 198,500	$ 148	$ 21,875	$ 20,898	$ -	$ 20,898	$ -	$ (355)	$ -	$ 1,802	$ 19,977

REFERENCES:
Adjustment No. 1 - Company Schedule C-1
Adjustment No. 2 - Depreciation Expense Schedule TJC-12
Adjustment No. 3 - Property Tax Expense Schedule TJC-13
Adjustment No. 4 - Rate Case Expense Schedule TJC-14
Adjustment No. 5 - Revenue Annualization of 6" Meter Bulk Water Sales for Known and Measurable Sales Sch. TJC-15
Adjustment No. 6 - Intentionally Left Blank for Water Division Schedule TJC-16
Adjustment No. 7 - Revenue Accrual of 6" Meter Bulk Water Sales for Known and Measurable Sales Schedule TJC-17
Adjustment No. 8 - Intentionally Left Blank for Water Division Schedule TJC-18
Adjustment No. 9 - Expense Annualization Related to RUCO's Revenue Annualization Adjustment No. 4- Schedule TJC-19
Adjustment No. 10 - Intentionally Left Blank Schedule TJC-20
Adjustment No. 11 - Miscellaneous Expense Schedule TJC-21
Adjustment No. 12 - Achievement/Incentive Pay per Company Response to RUCO DR 1.15 Schedule TJC-22

Rio Rico Utilities, Inc
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Test Year Ended February 29, 2012

OPERATING INCOME

Line No.		[M] Operating Income Adjustment No. 12 Merit Pay Expense	[N] Operating Income Adjustment No. 13 Intentionally Left Blank	[O] Operating Income Adjustment No. 14 Intentionally Left Blank	[P] Operating Income Adjustment No. 15 APUC Corporate Allocations	[Q] Operating Income Adjustment No. 16 Income Tax Expense	[R] Operating Income Adjustment No. 17 Not Used	[S] Operating Income Adjustment No. 18 Not Used	[T] Operating Income Adjustment No. 19 Not Used	[U] Operating Income Adjustment No. 20 Not Used	[V] Operating Income Adjustment No. 21 Not Used	[W] RUCO Total Pro Forma Adjustments	[X] Test Year Adjusted Results
1	**Operating Revenues**												
2	Metered Water Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,797	$ 2,853,746
3	Unmetered Revenues	-	-	-	-	-	-	-	-	-	-	-	-
4	Other Water Revenues	-	-	-	-	-	-	-	-	-	-	-	42,889
5	Total Water Revenues (L2 thru L4)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,797	$ 2,896,635
6													
7	**Operating Expenses**												
8	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 426,012
9	Purchased Water	-	-	-	-	-	-	-	-	-	-	-	-
10	Purchased Power	-	-	-	-	-	-	-	-	-	-	351	371,729
11	Fuel For Power Production	-	-	-	-	-	-	-	-	-	-	-	-
12	Chemicals	-	-	-	-	-	-	-	-	-	-	4	3,888
13	Materials and Supplies	-	-	-	-	-	-	-	-	-	-	-	27,517
14	Management Services - US Liberty Wate	(2,350)	-	-	-	-	-	-	-	-	-	(2,350)	255,017
15	Management Services - Corporate	-	-	-	(31,266)	-	-	-	-	-	-	(51,243)	82,732
16	Management Services - Other	-	-	-	-	-	-	-	-	-	-	-	15,903
17	Outside Services - Accounting	-	-	-	-	-	-	-	-	-	-	-	167
18	Outside Services - Engineering	-	-	-	-	-	-	-	-	-	-	-	-
19	Outside Services- Other	-	-	-	-	-	-	-	-	-	-	-	14,205
20	Outside Services- Legal	-	-	-	-	-	-	-	-	-	-	-	4,690
21	Water Testing	-	-	-	-	-	-	-	-	-	-	-	28,231
22	Rents - Building	-	-	-	-	-	-	-	-	-	-	-	-
23	Rents - Equipment	-	-	-	-	-	-	-	-	-	-	-	3,208
24	Transportation Expenses	-	-	-	-	-	-	-	-	-	-	-	89,305
25	Insurance - General Liability	-	-	-	-	-	-	-	-	-	-	-	34,100
26	Insurance - Vehicle	-	-	-	-	-	-	-	-	-	-	-	7,733
27	Reg. Comm. Exp. - Other	-	-	-	-	-	-	-	-	-	-	-	-
28	Reg. Comm. Exp.. - Rate Case	-	-	-	-	-	-	-	-	-	-	(21,875)	65,625
29	Miscellaneous Expense	-	-	-	-	-	-	-	-	-	-	(1,802)	83,255
30	Bad Debt Expense	-	-	-	-	-	-	-	-	-	-	-	-
31	Depreciation and Amortization Expense	-	-	-	-	-	-	-	-	-	-	(198,500)	362,722
32	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
33	Property Taxes	-	-	-	-	-	-	-	-	-	-	(148)	155,656
34	Income Tax	-	-	-	-	131,579	-	-	-	-	-	131,579	313,226
35													
36	Total Operationing Expenses (L8 thru L34)	$ (2,350)	$ -	$ -	$ (31,266)	$ 131,579	$ -	$ -	$ -	$ -	$ -	$ (143,985)	$ 2,334,921
37													
38	Operating Income (L5 less L36)	$ 2,350	$ -	$ -	$ 31,266	$ (131,579)	$ -	$ -	$ -	$ -	$ -	$ 185,781	$ 561,714

REFERENCES:
Adjustment No. 13 - Intentionally Left Blank Schedule TJC-23
Adjustment No. 14 - APUC Cost Allocations Adjustment Schedule TJC-24
Adjustment No. 15 - Income Tax Expense Adjustments Schedules TJC-15 and TJC-1, page 2
Adjustment No. 16 - Not Used
Adjustment No. 17 - Not Used
Adjustment No. 18 - Not Used
Adjustment No. 19 - Not Used
Adjustment No. 20 - Not Used
Adjustment No. 21 - Not Used
Column [W] - RUCO Total Adjustments
Column [X] - RUCO Recommended Adjusted Test Year Level of Expenses
Column [X] - RUCO Adjusted Test Year Operating Income Recommendations (Col. [A] + Col. [W])

Rio Rico Utilities, Inc.
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Rio Rico - Water Division
Direct Schedule TJC-12

OPERATING INCOME ADJUSTMENT NO. 1
DEPRECIATION EXPENSE

Line No.	NARUC Account	Description	Company Adjusted Gross Plant Balance	RUCO Depreciable Plant Adjustments	RUCO Rate Base Adjustments 1(a) - 4(a)	RUCO Recommended Depreciable Balance	Depreciation Rate	RUCO Depreciation Expense Going Forward
1	301	Organization Cost	$ 5,795	$ -	$ -	$ 5,785	0.00%	$ -
2	302	Franchise Cost	417	-	-	417	0.00%	-
3	303	Land and Land Rights	44,194	-	-	44,194	0.00%	-
4	304	Structures & Improvements	3,432,930	-	(35)	3,432,895	3.33%	114,315
5	305	Collecting & Impounding Reservoirs	-	-	-	-	2.50%	-
6	306	Lake, River, Canal Intakes	-	-	-	-	2.50%	-
7	307	Wells & Springs	562,944	-	(7)	562,937	3.33%	18,746
8	308	Infiltration Galleries	-	-	-	-	6.67%	-
9	309	Raw Water Supply Mains	279,157	-	-	279,157	2.00%	5,583
10	310	Power Generation Equipment	219,360	-	-	219,360	5.00%	10,968
11	311	Pumping Equipment	3,147,011	(2,733,118)	(303)	413,590	12.50%	51,699
12	320	Water Treatment Equipment	369,100	-	(5,658)	363,442	3.33%	12,103
13	320.1	Water Treatment Plants	-	-	-	-	3.33%	-
14	320.2	Solution Chemical Feeders	-	-	-	-	20.00%	-
15	330	Distribution Reservoirs & Standpipes	759,861	-	-	759,861	2.22%	16,869
16	330.1	Storage Tanks	-	-	-	-	2.22%	-
17	330.2	Pressure Tanks	-	-	-	-	5.00%	-
18	331	Transmission & Distribution Mains	22,339,255	-	(1,363)	22,337,894	2.00%	446,758
19	333	Services	2,768,122	-	-	2,768,122	3.33%	92,178
20	334	Meters	1,010,366	-	-	1,010,366	8.33%	84,163
21	335	Hydrants	572,321	-	-	572,321	2.00%	11,446
22	336	Backflow Prevention Devices	15,855	-	(9,704)	6,151	6.67%	410
23	339	Other Plant & Misc Equipment	123,778	-	-	123,778	6.67%	8,256
24	340	Office Furniture & Equipment	29,265	(22,572)	-	6,694	6.67%	446
25	340.1	Computers & Software	78,919	(78,919)	-	-	20.00%	-
26	341	Transportation Equipment	142,188	(117,115)	-	25,073	20.00%	5,015
27	342	Stores Equipment	-	-	-	-	4.00%	-
28	343	Tools, Shop & Garage Equipment	18,203	-	-	18,203	5.00%	910
29	344	Laboratory Equipment	3,061	(3,061)	-	-	10.00%	-
30	345	Power Operated Equipment	-	-	-	-	5.00%	-
31	346	Communication Equipment	212,996	-	-	212,996	10.00%	21,300
32	347	Miscellaneous Equipment	13,128	-	-	13,128	10.00%	1,313
33	348	Other Tangible Plant	-	-	-	-	10.00%	-
34								
35								
36			$ 36,115,219	$ (2,952,784)	$ (17,070)	$ 33,176,365		$ 902,479
37								
38								
39		Less: Amortization of Contributions				Gross CIAC $ (20,179,119)	Amortization Rate 2.7244%	
40								(549,757)
41		RUCO Total Depreciation Expense						
42								$ 352,722
43		Company Adjusted Depreciation Expense As Filed						
44								551,222
45		RUCO Increase/(Decrease) Expense Adjustment						$ (198,500)

References:
Company B-2 and C-1 Schedules, RUCO Schedule TJC-5 on Pages 5-6, and RUCO Schedule 4(a)

OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAXES

LINE NO.	Property Tax Calculation	(A) RUCO AS ADJUSTED	(B) RUCO RECOMMENDED
1	RUCO Adjusted Test Year Revenues - Ended February 29, 2012 Per RUCO Schedule TJC-10	$ 2,896,635	$ 2,896,635
2	Multiplied by 2	2	2
3	Subtotal (Line 1 * Line 2)	$ 5,793,270	$ 5,793,270
4a	RUCO Adjusted Test Year Revenues - Ended February 29, 2012 Per RUCO Schedule TJC-10	2,896,635	
4b	RUCO Recommended Revenue Per RUCO Schedule TJC-9		2,987,529
5	Subtotal (Line 3 + Line 4a)	$ 8,689,904	$ 8,780,799
6	Number of Years	3	3
7	Three Year Average (Line 5 / Line 6)	$ 2,896,635	$ 2,926,933
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (Line 7 * Line 8)	$ 5,793,270	$ 5,853,866
10	Plus: 10% of CWIP Per Company As Filed	-	-
11	Less: Net Book Value of Licensed Vehicles	21,167	21,167
12	Full Cash Value (Line 9 + Line 10 - Line 11)	$ 5,772,102	$ 5,832,699
13	Assessment Ratio	20.0%	20.0%
14	Assessed Value (Line 12 * Line 13)	$ 1,154,420	$ 1,166,540
15	Composite Property Tax Rate (Per RUCO Effective Property Tax Calculation)	13.4835%	13.4835%
16	RUCO Adjusted Test Year Property Tax Expense (Line 14 * Line 15)	$ 155,656	
17	Company Adjusted Test Year Property Tax Expense (Per Company Schedule C-1)	155,805	
18	RUCO Test Year Adjustment (Line 16-Line 17)	$ (148)	
19	Property Tax - RUCO Recommended Revenue (Line 14 * Line 15)		$ 157,290
20	RUCO Test Year Adjusted Property Tax Expense (Line 16)		155,656
21	Increase/(Decrease) to Property Tax Expense		$ 1,634
22	Increase/(Decrease) to Property Tax Expense		$ 1,634
23	Increase in Revenue Requirement		90,894
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (Line 22 / Line 23)		1.7978%

OPERATING INCOME ADJUSTMENT NO. 3
RATE CASE EXPENSE

Line No.			Amount
1	Company Requested Total Amount of Rate Case Expense	$	262,500
2			
3	Company Requested the Expense be Amortized Over a 3-Year Period		3
4			
5	Company's Annual Amortization Expense (L1 / L3)	$	87,500
6			
7	RUCO's Recommended Normalization is Over a 4-Year Period		4
8			
9	RUCO's Recommended Annual Normalization of Rate Case Expense (L1 / L7)	$	65,625
10			
11	RUCO's Recommended Expense Adjustment		(21,875)

OPERATING INCOME ADJUSTMENT NO. 4
REVENUE ANNUALIZATION

Line No.	Meter Size	Class	Company Annualization Present Revenues	RUCO Annualization Adjustments	RUCO Annualization Present Revenues	Additional Bills	Additional Gallons to be Pumped (In 1,000's)
1	5/8X3/4 Inch	Residential	$ (6,796)	$ -	$ (6,796)	(328)	(1,648)
2	5/8X3/4 Inch	Residential (Low Income)	11,550	-	11,550	520	3,196
3	3/4 Inch	Residential	(461)	-	(461)	(16)	(68)
4	1 Inch	Residential	(191)	-	(191)	(4)	(28)
5	1 Inch	Residential (Low Income)	70	-	70	3	-
6	1 1/2 Inch	Residential	1,219	-	1,219	9	235
7	2 Inch	Residential	(260)	-	(260)	(2)	(29)
8		Subtotal	$ 5,132	$ -	$ 5,132	182	1,659
9							
10	5/8X3/4 Inch	Commercial	$ 1,582	$ -	$ 1,582	35	425
11	1 Inch	Commercial	417	-	417	5	92
12	1 1/2 Inch	Commercial	(79)	-	(79)	-	(22)
13	2 Inch	Commercial	(779)	-	(779)	(4)	(147)
14	3 Inch	Commercial	(9,576)	-	(9,576)	(13)	(2,150)
15	4 Inch	Commercial	(1,321)	-	(1,321)	-	(363)
16	6 Inch	Commercial	-	-	-	-	-
17		Subtotal	$ (9,757)	$ -	$ (9,757)	23	(2,164)
18							
19	5/8X3/4 Inch	Industrial	$ 28	$ -	$ 28	-	10
20	2 Inch	Industrial	(13,917)	-	(13,917)	(22)	(3,531)
21		Subtotal	$ (13,889)	$ -	$ (13,889)	(22)	(3,521)
22							
23	5/8X3/4 Inch	Multi-family	$ (35)	$ -	$ (35)	(2)	(9)
24	1 1/2 Inch	Multi-family	-	-	-	-	-
25		Subtotal	$ (35)	$ -	$ (35)	(2)	(9)
26							
27	6 Inch	Bulk	$ -	$ 20,898	$ 20,898	8	4,676
28		Fire Lines up to 8 Inch	318	-	318	58	-
29			$ 318	$ 20,898	$ 21,217	66	4,676
30							
31							
32	Total Revenue Annualization		$ (18,231)	$ 20,898	$ 2,668		
33							
34	RUCO Total Revenue Annualization						$ 2,668
35							
36	Company Revenue Annualization						(18,231)
37							
38							
39	RUCO Increase/(Decrease) Adjustment to Revenue and/or Expense						$ 20,898
40							
41							
42							
43	Total Increase/(Decrease) Gallons to be Produced						641

SUPPORTING SCHEDULES
RUCO Schedules TJC-15, pages 2 thru 21 and Company Schedule C-1, page 2.1

Rio Rico Utilities, Inc.
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Residential 5/8 x 3/4 Inch Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	5,875	5,875	5,875	5,875	5,875	5,875	5,875	5,875	5,875	5,875	5,875	5,875	70,500
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	5,960	5,935	5,934	5,932	5,444	6,308	5,891	5,895	5,874	5,880	5,900	5,875	70,828
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(85)	(60)	(59)	(57)	431	(433)	(16)	(20)	1	(5)	(25)	-	(328)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 27.34	$ 31.40	$ 30.65	$ 36.41	$ 37.30	$ 29.90	$ 31.39	$ 29.56	$ 29.11	$ 25.41	$ 25.56	$ 24.82	
5	INCREASE/(DECREASE) IN REVENUES	$ (2,324)	$ (1,884)	$ (1,809)	$ (2,075)	$ 16,075	$ (12,948)	$ (502)	$ (591)	$ 29	$ (127)	$ (639)	$ -	$ (6,796)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(6,796)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	(6,796)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	6,968	8,361	8,104	9,863	10,106	7,847	8,356	7,729	7,576	6,307	6,361	6,108	
10	INCREASE IN CUSTOMERS	(85)	(60)	(59)	(57)	431	(433)	(16)	(20)	1	(5)	(25)	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(592,262)	(501,665)	(478,135)	(562,178)	4,355,760	(3,397,760)	(133,701)	(154,589)	7,576	(31,533)	(159,017)	-	(1,647,503)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(1,647,503)												(1,647,503)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Residential 5/8 x 3/4 Inch Meter - Low Income

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	139	139	139	139	139	139	139	139	139	139	139	139	1,668
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	54	65	79	62	127	112	117	126	132	135	139	1,148
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	139	85	74	60	77	12	27	22	13	7	4	-	520
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 9.33	$ 24.46	$ 25.03	$ 30.28	$ 30.38	$ 27.03	$ 27.10	$ 24.19	$ 25.86	$ 21.25	$ 23.00	$ 21.64	
5	INCREASE/(DECREASE) IN REVENUES	$ 1,297	$ 2,079	$ 1,853	$ 1,817	$ 2,339	$ 324	$ 732	$ 532	$ 336	$ 149	$ 92	$ -	$ 11,550
6	RUCO INCREASE/(DECREASE) IN REVENUE	11,550												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	11,550												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	7,463	7,692	9,646	9,677	8,496	8,527	7,350	8,024	6,167	6,874	6,324	
10	INCREASE IN CUSTOMERS	139	85	74	60	77	12	27	22	13	7	4	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	634,352	569,231	578,734	745,161	101,953	230,223	161,709	104,310	43,167	27,496	-	3,196,336
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	3,196,336												3,196,336

Rio Rico Utilities, Inc.
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Residential 3/4" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	10	10	10	10	10	10	10	10	10	10	10	10	120
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	12	11	12	12	13	11	11	10	11	11	12	10	136
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(2)	(1)	(2)	(2)	(3)	(1)	(1)	-	(1)	(1)	(2)	-	(16)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 23.77	$28.68	$27.18	$ 31.80	$ 29.50	$ 30.01	$ 30.27	$ 29.32	$ 30.54	$ 29.48	$ 28.88	$ 29.90	
5	INCREASE/(DECREASE) IN REVENUES	$ (48)	$ (29)	$ (54)	$ (64)	$ (88)	$ (30)	$ (30)	$ -	$ (31)	$ (29)	$ (58)	$ -	$ (461)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(461)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (461)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	2,500	4,182	3,667	5,250	4,462	4,636	4,727	4,400	4,818	4,455	4,250	4,600	
10	INCREASE IN CUSTOMERS	(2)	(1)	(2)	(2)	(3)	(1)	(1)	-	(1)	(1)	(2)	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(5,000)	(4,182)	(7,333)	(10,500)	(13,385)	(4,636)	(4,727)	-	(4,818)	(4,455)	(8,500)	-	(67,536)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(67,536)												(67,536)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	35	35	35	35	35	35	35	35	35	35	35	35	420
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	38	37	36	36	35	34	35	35	35	35	33	35	424
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(3)	(2)	(1)	(1)	-	1	-	-	-	-	2	-	(4)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 37.44	$ 60.83	$ 64.44	$ 65.57	$73.33	$ 58.37	$ 61.24	$ 61.74	$ 62.66	$ 53.06	$ 57.36	$ 50.14	
5	INCREASE/(DECREASE) IN REVENUES	$ (112)	$ (122)	$ (64)	$ (66)	$ -	$ 58	$ -	$ -	$ -	$ -	$ 115	$ -	$ (191)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(191)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (191)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	3,421	11,432	12,667	13,056	15,571	10,588	11,571	11,743	12,057	8,771	10,242	7,771	
10	INCREASE IN CUSTOMERS	(3)	(2)	(1)	(1)	-	1	-	-	-	-	2	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(10,263)	(22,865)	(12,667)	(13,056)	-	10,588	-	-	-	-	20,485	-	(27,777)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(27,777)												(27,777)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	-	-	1	1	1	1	1	1	1	1	1	9
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	1	1	-	-	-	-	-	-	-	-	-	3
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 23.33	$23.33	$23.33	$38.22	$33.26	$ 40.71	$ 43.19	$ 40.71	$ 40.71	$ 40.71	$ 40.71	$ 40.71	
5	INCREASE/(DECREASE) IN REVENUES	$ 23	$ 23	$ 23	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 70
6	RUCO INCREASE/(DECREASE) IN REVENUE	70												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ 70												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	6,000	4,000	7,000	8,000	7,000	7,000	7,000	7,000	7,000	
10	INCREASE IN CUSTOMERS	1	1	1	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	4	4	4	4	4	4	4	4	4	4	4	4	48
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	3	3	3	3	3	3	3	3	3	4	4	4	39
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	1	1	1	1	1	1	1	1	-	-	-	9
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$135.14	$161.83	$144.85	$130.29	$124.22	$118.15	$ 156.98	$ 126.65	$ 120.58	$ 157.89	$ 136.05	$ 174.27	
5	INCREASE/(DECREASE) IN REVENUES	$ 135	$ 162	$ 145	$ 130	$ 124	$ 118	$ 157	$ 127	$ 121	$ -	$ -	$ -	$ 1,219
6	RUCO INCREASE/(DECREASE) IN REVENUE	1,219												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ 1,219												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	26,000	33,333	28,667	24,667	23,000	21,333	32,000	23,667	22,000	32,250	26,250	36,750	
10	INCREASE IN CUSTOMERS	1	1	1	1	1	1	1	1	1	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	26,000	33,333	28,667	24,667	23,000	21,333	32,000	23,667	22,000	-	-	-	234,667
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{234,667}$												234,667

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	3	3	3	3	3	3	3	3	3	3	3	3	36
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	5	3	3	3	3	3	3	3	3	3	3	3	38
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(2)	-	-	-	-	-	-	-	-	-	-	-	(2)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$129.89	$159.87	$145.27	$151.11	$151.11	$179.33	$ 164.73	$ 146.24	$ 139.43	$ 125.80	$ 120.93	$ 126.77	
5	INCREASE/(DECREASE) IN REVENUES	$ (260)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (260)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(260)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (260)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	14,400	24,667	19,667	21,667	21,667	31,333	26,333	20,000	17,667	13,000	11,333	13,333	
10	INCREASE IN CUSTOMERS	(2)	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(28,800)	-	-	-	-	-	-	-	-	-	-	-	(28,800)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(28,800)												(28,800)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	83	83	83	83	83	83	83	83	83	83	83	83	996
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	79	78	79	79	47	111	80	80	81	81	83	83	961
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	4	5	4	4	36	(28)	3	3	2	2	-	-	35
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 29.06	$28.25	$27.73	$34.97	$ 46.20	$ 34.32	$ 37.00	$ 37.91	$ 32.12	$ 41.13	$ 29.12	$ 31.44	
5	INCREASE/(DECREASE) IN REVENUES	$ 116	$ 141	$ 111	$ 140	$ 1,663	$ (961)	$ 111	$ 114	$ 64	$ 82	$ -	$ -	$ 1,582
6	RUCO INCREASE/(DECREASE) IN REVENUE	1,582												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ 1,582												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	7,557	7,282	7,101	9,468	12,553	9,288	10,025	10,275	8,605	11,160	7,578	8,373	
10	INCREASE IN CUSTOMERS	4	5	4	4	36	(28)	3	3	2	2	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	30,228	36,410	28,405	37,873	451,915	(260,072)	30,075	30,825	17,210	22,321	-	-	425,190
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	425,190												425,190

Rio Rico Utilities, Inc.
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 1" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	49	49	49	49	49	49	49	49	49	49	49	49	588
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	50	47	47	47	43	55	49	49	49	49	49	49	583
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(1)	2	2	2	6	(6)	-	-	-	-	-	-	5
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 68.10	$73.34	$80.31	$119.96	$ 84.79	$ 95.21	$ 62.91	$ 62.25	$ 65.89	$ 60.17	$ 60.76	$ 61.24	
5	INCREASE/(DECREASE) IN REVENUES	$ (68)	$ 147	$ 161	$ 240	$ 509	$ (571)	$ -	$ -	$ -	$ -	$ -	$ -	$ 417
6	RUCO INCREASE/(DECREASE) IN REVENUE	417												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ 417												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	13,920	15,574	17,489	28,383	18,721	21,582	12,143	11,918	13,163	11,204	11,408	11,571	
10	INCREASE IN CUSTOMERS	(1)	2	2	2	6	(6)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(13,920)	31,149	34,979	56,766	112,326	(129,491)	-	-	-	-	-	-	91,808
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	91,808												91,808

Rio Rico Utilities, Inc.
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 1.5" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	10	10	10	10	10	10	10	10	10	10	10	10	120
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	10	10	10	10	8	12	10	10	10	10	10	10	120
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	2	(2)	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 130.77	$130.04	$129.32	$164.62	$160.17	$199.75	$ 122.40	$ 97.24	$ 107.75	$ 104.54	$ 116.94	$ 96.66	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ 320	$ (400)	$ -	$ -	$ -	$ -	$ -	$ -	$ (79)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(79)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (79)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	24,800	24,600	24,400	34,100	32,875	43,750	22,500	14,500	18,100	17,000	21,000	14,300	
10	INCREASE IN CUSTOMERS	-	-	-	-	2	(2)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	65,750	(87,500)	-	-	-	-	-	-	(21,750)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(21,750)												(21,750)

Rio Rico Utilities, Inc.
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 2" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	43	43	43	43	43	43	43	43	43	43	43	43	516
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	43	44	44	43	42	44	43	43	43	44	44	43	520
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	(1)	(1)	-	1	(1)	-	-	-	(1)	(1)	-	(4)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 200.16	$219.44	$210.28	$226.37	$202.76	$193.82	$ 248.58	$ 189.29	$ 194.93	$ 177.10	$ 181.27	$ 186.58	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ (219)	$ (210)	$ -	$ 203	$ (194)	$ -	$ -	$ -	$ (177)	$ (181)	$ -	$ (779)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(779)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (779)												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	38,465	45,068	41,932	47,442	39,357	36,295	55,047	34,744	36,674	30,568	31,998	33,814	
10	INCREASE IN CUSTOMERS	-	(1)	(1)	-	1	(1)	-	-	-	(1)	(1)	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	(45,068)	(41,932)	-	39,357	(36,295)	-	-	-	(30,568)	(31,998)	-	(146,505)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{(146,505)}$												(146,505)

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Commercial 3" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	11	11	11	11	11	11	11	11	11	11	11	11	132
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	14	11	12	12	14	11	12	11	14	12	11	11	145
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(3)	-	(1)	(1)	(3)	-	(1)	-	(3)	(1)	-	-	(13)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 621.62	$955.29	$ 1,102.58	$ 1,120.17	$ 960.14	$747.15	$ 687.92	$ 907.97	$ 503.58	$ 408.85	$ 605.85	$ 590.63	
5	INCREASE/(DECREASE) IN REVENUES	$ (1,865)	$ -	$ (1,103)	$ (1,120)	$ (2,880)	$ -	$ (688)	$ -	$ (1,511)	$ (409)	$ -	$ -	$ (9,576)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(9,576)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (9,576)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	133,786	225,455	265,917	270,750	226,786	168,273	152,000	212,455	101,357	75,333	129,455	125,273	
10	INCREASE IN CUSTOMERS	(3)	-	(1)	(1)	(3)	-	(1)	-	(3)	(1)	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(401,357)	-	(265,917)	(270,750)	(680,357)	-	(152,000)	-	(304,071)	(75,333)	-	-	(2,149,786)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(2,149,786)												(2,149,786)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	6	6	6	6	6	6	6	6	6	6	6	6	72
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	6	6	6	6	4	8	6	6	6	6	6	6	72
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	2	(2)	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 1,171.97	$ 1,339.41	$ 1,154.99	$ 1,508.07	$ 871.37	$ 1,532.03	$ 1,119.19	$ 1,110.70	$ 1,078.55	$ 785.53	$ 956.61	$ 1,022.73	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ 1,743	$ (3,064)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,321)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(1,321)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (1,321)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	257,833	303,833	253,167	350,167	175,250	356,750	243,333	241,000	232,167	151,667	198,667	216,833	
10	INCREASE IN CUSTOMERS	-	-	-	-	2	(2)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	350,500	(713,500)	-	-	-	-	-	-	(363,000)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(363,000)												(363,000)

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Commercial 6" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1	1	1	1	1	1	1	1	1	1	1	1	12
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$2,006.00	$1,547.36	$549.00	$5,292.92	$2,999.72	$2,766.76	$ 820.56	$1,605.60	$ 2,202.56	$ 2,006.00	$1,620.16	$ 2,206.20	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	RUCO INCREASE/(DECREASE) IN REVENUE	-												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ -												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	425,000	299,000	-	1,328,000	698,000	634,000	93,000	315,000	479,000	425,000	319,000	480,000	
10	INCREASE IN CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	17	17	17	17	17	17	17	17	17	17	17	17	204
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	17	17	17	17	13	21	17	17	17	17	17	17	204
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	4	(4)	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 26.74	$ 14.53	$ 15.75	$ 21.42	$ 24.51	$ 17.42	$ 19.70	$ 19.36	$ 21.93	$ 23.31	$ 18.67	$ 18.15	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ 98	$ (70)	$ -	$ -	$ -	$ -	$ -	$ -	$ 28
6	RUCO INCREASE/(DECREASE) IN REVENUE	28												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ 28												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	6,765	2,235	3,000	4,941	6,000	3,571	4,353	4,235	5,118	5,588	4,000	3,824	
10	INCREASE IN CUSTOMERS	-	-	-	-	4	(4)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	24,000	(14,286)	-	-	-	-	-	-	9,714
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{9,714}$												9,714

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Industrial 2" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	4	4	4	4	4	4	4	4	4	4	4	4	48
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	7	7	7	7	6	8	7	5	4	4	4	4	70
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(3)	(3)	(3)	(3)	(2)	(4)	(3)	(1)	-	-	-	-	(22)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 360.36	$ 818.48	$ 538.20	$ 731.12	$ 183.23	$ 969.09	$ 526.24	$ 751.50	$ 855.79	$ 530.01	$ 570.96	$ 1,189.76	
5	INCREASE/(DECREASE) IN REVENUES	$ (1,081)	$ (2,455)	$ (1,615)	$ (2,193)	$ (366)	$ (3,876)	$ (1,579)	$ (752)	$ -	$ -	$ -	$ -	$ (13,917)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(13,917)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (13,917)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	86,143	212,000	135,000	188,000	32,667	253,375	131,714	193,600	222,250	132,750	144,000	314,000	
10	INCREASE IN CUSTOMERS	(3)	(3)	(3)	(3)	(2)	(4)	(3)	(1)	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	(258,429)	(636,000)	(405,000)	(564,000)	(65,333)	(1,013,500)	(395,143)	(193,600)	-	-	-	-	(3,531,005)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(3,531,005)												(3,531,005)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	7	7	7	7	7	7	7	7	7	7	7	7	84
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	6	8	8	8	5	9	7	7	7	7	7	7	86
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	(1)	(1)	(1)	2	(2)	-	-	-	-	-	-	(2)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 32.30	$31.81	$32.18	$31.08	$44.19	$ 30.35	$ 31.60	$ 29.52	$ 26.60	$ 26.60	$ 32.44	$ 64.99	
5	INCREASE/(DECREASE) IN REVENUES	$ 32	$ (32)	$ (32)	$ (31)	$ 88	$ (61)	$ -	$ -	$ -	$ -	$ -	$ -	$ (35)
6	RUCO INCREASE/(DECREASE) IN REVENUE	(35)												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ (35)												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	8,667	8,500	8,625	8,250	12,000	8,000	8,429	7,714	6,714	6,714	8,714	17,714	
10	INCREASE IN CUSTOMERS	1	(1)	(1)	(1)	2	(2)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	8,667	(8,500)	(8,625)	(8,250)	24,000	(16,000)	-	-	-	-	-	-	(8,708)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{(8,708)}$												(8,708)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1	1	1	1	1	1	1	1	1	1	1	1	12
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 78.26	$ 78.26	$ 78.26	$ 78.26	$101.62	$110.38	$ 98.70	$ 89.94	$ 98.70	$ 87.02	$ 87.02	$ 84.10	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	RUCO INCREASE/(DECREASE) IN REVENUE	-												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ -												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	8,000	8,000	8,000	8,000	16,000	19,000	15,000	12,000	15,000	11,000	11,000	10,000	
10	INCREASE IN CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{-}$												-

Rio Rico Utilities, Inc.
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Bulk Water Sales 6" Meter

LINE NO.	DESCRIPTION	MARCH 2011	APRIL 2011	MAY 2011	JUNE 2011	JULY 2011	AUGUST 2011	SEPTEMBER 2011	OCTOBER 2011	NOVEMBER 2011	DECEMBER 2011	JANUARY 2012	FEBRUARY 2012	TOTAL YEAR	
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12	
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	-	-	-	-	-	-	-	1	1	1	1	4	
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	1	1	1	1	1	1	1	-	-	-	-	8	
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	$ 12,348.56	$ 9,478.92	$ 4,397.48	$ 3,400.12		$29,625.08
5	INCREASE/(DECREASE) IN REVENUES	$ 2,180	$ 1,520	$ 2,589	$ 3,052	$ 4,139	$ 2,505	$ 2,190	$ 2,723	$ -	$ -	$ -	$ -	$ 20,898	
6	RUCO INCREASE/(DECREASE) IN REVENUE	20,898													
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ -													
8	RUCO REVENUE ADJUSTMENT	$\boxed{20,898}$													
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	462,000	275,000	578,000	709,000	1,017,000	554,000	465,000	616,000	3,266,364	2,478,000	1,082,000	808,000		7,634,364
10	INCREASE IN CUSTOMERS	1	1	1	1	1	1	1	1	-	-	-	-		
11	RUCO INCREASE/(DECREASE) IN GALLONS	462,000	275,000	578,000	709,000	1,017,000	554,000	465,000	616,000	-	-	-	-	4,676,000	584,500
12	COMPANY INCREASE IN GALLONS													-	
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{4,676,000}$												4,676,000	

Note:
[redacted]

Rio Rico Utilities, Inc.
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Fire Lines Up to 8 Inch

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	:EPTEMBE	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	24	24	24	24	24	24	24	24	24	24	24	24	288
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	17	17	18	18	18	19	19	20	20	20	20	24	230
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	7	7	6	6	6	5	5	4	4	4	4	-	58
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	$ 5.49	
5	INCREASE/(DECREASE) IN REVENUES	$ 38	$ 38	$ 33	$ 33	$ 33	$ 27	$ 27	$ 22	$ 22	$ 22	$ 22	$ -	$ 318
6	RUCO INCREASE/(DECREASE) IN REVENUE	318												
7	COMPANY INCREASE/(DECREASE) IN REVENUE	$ -												
8	RUCO REVENUE ADJUSTMENT	318												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	7	7	6	6	6	5	5	4	4	4	4	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

OPERATING INCOME ADJUSTMENT NO. 5
INTENTIONALLY LEFT BLANK USED FOR WASTEWATER DIVISION

Line No.
1
2
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20

OPERATING INCOME ADJUSTMENT NO. 6
REVENUE ACCRUAL

Line No.		
1	Revenue Accrual	
2		
3	Company Revenue Accrual Adjustment	$ 10,308
4		
5	RUCO Revenue Annualialization/Accrual Amount	20,898
6		
7		
8	RUCO Recommended Accrual Amount	$ 31,206
9		
10	RUCO Adjustment to Revenue and/or Expense	$\boxed{\$ 20,898}$
11		
12		
13		
14		
15		
16		
17		
18		
19		
20		

OPERATING INCOME ADJUSTMENT NO. 7
INTENTIONALLY LEFT BLANK USED FOR WASTEWATER DIVISION

Line
No.

OPERATING INCOME ADJUSTMENT NO. 8
EXPENSE ANNUALIZATION

Line No.	Expense Annualization	
1	Total Cost of Purchased Power Expense (Company Schedule C-1)	$ 371,729
2		
3	Total Cost of Chemical Expense (Company Schedule C-1)	$ 3,884
4		
5	Total Gallons Sold (In 1,000 Gallons) Per Company Schedule H-2, Page 3.2	678,936
6		
7	Cost of Purchased Power Expense Per 1,000 Gallons (L1 / L5)	0.5475
8		
9	Cost of Chemical Expense Per 1,000 Gallons (L3 / L5)	0.0057
10		
11	Total Revenue Annualization Increase/(Decrease) Gallons to be Produced (RUCO Schedule TJC-15, Page 1 of 21 and Company Schedule H-1, Pa	641
12		
13		
14	RUCO Adjustment to Purchased Power Expense (L7 X L11)	$ 351
15		
16	RUCO Adjustment to Chemical Expense (L9 X L11)	$ 4

OPERATING INCOME ADJUSTMENT NO. 9
INTENTIONALLY LEFT BLANK - FOR FUTURE USE

Line
No.

OPERATING INCOME ADJUSTMENT NO. 10
MISCELLANEOUS EXPENSE

Line No.	Description	Company Water Division	Company Wastewater Division	RUCO Water Adjustments	RUCO Wastewater Adjustments
1	**Caritable Donations and Sponsorships:**				
2	Rio Rico Little League Per MJR 2-7	$ 1,000	$ -	$ (1,000)	
3	RRUI's 2011 Christmas Party Expenses Per MJR 2-7	802		(802)	
4					
5		$ 1,802	$ -		
6					
7					
8	RUCO Miscellaneous Expense Water Adjustment			(1,802)	
9					
10	RUCO Miscellaneous Expense Wastewater Adjustment				-
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

OPERATING INCOME ADJUSTMENT NO. 11
ACHIEVEMENT / INCENTIVE PAY

Line No.	Description	Total RRUI Amount	Amount Allocated to RRUI Water	Amount Allocated to RRUI Wastewater
1				
2				
3				
4				
5				
6				
7	CONFIDENTIAL			
8				
9				
10				
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12				
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21				
22				
23				
24				
25				
26				
27	References:			
28	Company's Response to RUCO Data Request 2.13			

OPERATING INCOME ADJUSTMENT NO. 12
MERIT PAY ADJUSTMENT - 50/50 SHARING

Line No.	Description	[A] Company Water Amount	[B] Company Wastewater Amount	[C] RUCO Water Amount	[D] RUCO Wastewater Amount
1					
2					
3					
4					
5					
6					
7					
8					
9					
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16					
17					
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19					
20					
21					

CONFIDENTIAL

OPERATING INCOME ADJUSTMENT NO. 13
INTENTIONALLY LEFT BLANK

Line
No.

OPERATING INCOME ADJUSTMENT NO. 14
INTENTIONALLY LEFT BLANK

Line
No.

OPERATING INCOME ADJUSTMENT NO. 15
APUC COST ALLOCATIONS

Line No.	Description	[A] Company Requested Cost	[B] Currency Conversion 1.05 CSD -> USD	[C] Company Allocation 9.21% RRUI Water	[D] Company Allocation 3.01% RRUI Sewer	[E] Percentage Amount Allowed	[F] RUCO Recommended Allocations RRUI Water	[G] Company Recommended Allocations RRUI Sewer
1	Audit	$ 136,866	$ 130,348	$ 11,999	$ 3,924	100%	$ 11,999	$ 3,924
2	Tax Services	37,197	35,426	3,261	1,067	100%	3,261	1,067
3	Legal	179,072	170,545	15,699	5,134	100%	15,699	5,134
4	Other Professional Services	86,163	82,060	7,554	2,470	0%	-	-
5	Unit Holder Communications	100,802	96,002	8,837	2,890	0%	-	-
6	Trustee Fees	97,290	92,657	8,529	2,789	0%	-	-
7	Computer	54,904	52,290	4,813	1,574	100%	4,813	1,574
8	Office Expenses	48,404	46,099	4,244	1,388	100%	4,244	1,388
9	Capital Tax	29,167	27,778	2,557	836	0%	-	-
10	Insurance	26,554	25,289	2,328	761	50%	1,164	381
11	Travel	17,146	16,330	1,503	492	100%	1,503	492
12	Vehicle Rental Expense	3,162	3,012	277	91	100%	277	91
13	Accommodation	11,469	10,923	1,005	329	100%	1,005	329
14	Meals and Entertainment	18,516	17,634	1,623	531	100%	1,623	531
15	Parking Mileage	4,284	4,080	376	123	100%	376	123
16	Escrow & Transfer Agent Fees	17,505	16,671	1,535	502	0%	-	-
17	Training	5,450	5,190	478	156	100%	478	156
18	HR Recruitment	6,374	6,070	559	183	100%	559	183
19	Rent	38,137	36,321	3,343	1,093	100%	3,343	1,093
20	Donations	1,638	1,560	144	47	0%	-	-
21	Communications	20,389	19,418	1,788	585	100%	1,788	585
22	Dues and Memberships	10,796	10,282	947	310	0%	-	-
23	Licenses/Fees & Permits	150,573	143,402	13,201	4,317	100%	13,201	4,317
24	APS Overhead Allocation	(8,066)	(7,682)	(707)	(231)	100%	(707)	(231)
25								
26	Total APUC Allocations Per Company and RUCO	$1,093,791	$1,041,705	$ 95,892	$ 31,361		$ 64,626	$ 21,135
27								
28								
29	RUCO Water and Wastewater Division's APUC Cost Allocation Recommendation						64,626	21,135
30								
31	Company Water Division's APUC Cost Allocation Requested						95,892	31,361
32								
33								
34	RUCO Water and Wastewater Division's APUC Cost Allocation Adjustment						$ (31,266)	$ (10,225)
35								
36								
37								
38								
39								
40	Variance by Company Per Response to RUCO DR 3.7			$ (540)	$ (177)			

OPERATING INCOME ADJUSTMENT NO. 15
ADJUSTED TEST YEAR INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT			
	FEDERAL INCOME TAX PER RUCO:					
1	Operating Income Before Taxes	Sch. TJC-9, Col. (C), L38 + L34	$ 874,941			
	LESS:					
2	Arizona State Tax	Line 16	56,545			
3	Interest Expense	Note (A) Line 27	63,450			
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ 754,946			
5	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%		$ 7,500			
6	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%		6,250			
7	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%		8,500			
8	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%		91,650	$ 285,472	$ 285,472	
9	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%		142,782			
10	Total Federal Income Tax Expense (L5 + L6 + L7 + L8 + L9)		$ 256,682	34.00%	34.00%	
11	Effective Federal Income Tax Rate	Line 10 / Line 4	34.00%	$ 256,682	$ 256,682	$ -
	STATE INCOME TAX PER RUCO:					
12	Operating Income Before Taxes	Line 1	$ 874,941			
	LESS:					
13	Interest Expense	Note (A) Line 27	63,450			
14	State Taxable Income	Line 12 - Line 13	$ 811,491			
15	State Tax Rate	Sch. TJC-1, pg. 2, Col. [A] L10	6.968%			
16	State Income Tax Expense	Line 14 X Line 15	$ 56,545			
	RUCO TOTAL INCOME TAX EXPENSE:					
17	Federal Income Tax Expense	Line 10	$ 256,682			
18	State Income Tax Expense	Line 16	56,545			
19	Total Income Tax Expense Per RUCO	Line17 + Line 18	$ 313,226	$ 313,226		
20	Total Federal Income Tax Expense Per Company (Company Sch. GRCF, Col. (C), L53		148,856			
21	Total State Income Tax Expense Per Company (Company Sch. GRCF, Col. (C), L44)		32,792	$ 181,647		
22	RUCO Federal Income Tax Adjustment	Line 10 - Line 20	$ 107,826			
23	RUCO State Income Tax Adjustment	Line 16 - Line 21	$ 23,753			
24	RUCO Total Federal & State Income Tax Adjustment		$ 131,579	$ 131,579		

NOTE (A):

24	Interest Synchronization:	
25	Adjusted Rate Base (Sch. TJC-2, Col. (C), L23)	$ 7,681,547
26	Weighted Cost Of Debt (Sch. TJC-28 Col. [C], L1)	0.83%
27	Interest Expense (L25 X L26)	$ 63,450

COST OF CAPITAL

LINE NO.	DESCRIPTION	[A] CAPITAL RATIO	[B] COST RATE	[C] WEIGHTED COST RATE
1	Long-Term Debt	20.00%	4.13%	0.83%
2				
3	Common Equity	80.00%	9.00%	7.20%
4				
5	Total Capitalization			
6				
7				
8	WEIGHTED AVERAGE COST OF CAPITAL			8.03%

References:
Columns [A] Thru [C]: WAR Testimony

TABLE OF CONTENTS TO TJC SCHEDULES

Rio Rico Utilities, Inc
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REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	[A] COMPANY OCRB/FVRB COST	[B] RUCO OCRB/FVRB COST
1	Adjusted Original Cost/Fair Value Rate Base	$ 4,600,012	$ 4,663,510
2			
3	Adjusted Operating Income (Loss)	$ 213,826	$ 372,448
4			
5	Current Rate of Return (L3 / L1)	4.65%	7.99%
6			
7	Required Operating Income (L9 X L1)	$ 446,201	$ 374,293
8			
9	Required Rate of Return on Fair Value Rate Base	9.70%	8.03%
10			
11	Operating Income Deficiency (L7 - L3)	$ 232,375	$ 1,845
12			
13	Gross Revenue Conversion Factor (TJC-1, Page 2 of 2)	1.6939	1.6585
14			
15	Required Increase in Gross Revenue Requirement (L11 X L13)	$ 393,612	$ 3,060
16			
17	Adjusted Test Year Revenue	$ 1,360,583	$ 1,402,212
18			
19	Proposed Annual Revenue (L15 + L17)	$ 1,754,195	$ 1,405,272
20			
21	Required Percentage Increase in Revenue (L15 / L17)	28.93%	0.22%
22			
23			
24	Rate of Return on Common Equity	10.70%	9.00%

References:
Column [A]: Company Schedules A-1, B-1 and C-1
Column [B]: RUCO Schedules TJC-2, TJC-3, TJC-9 and TJC-10

GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	[A]	[B]	[C]	[D]
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	100.0000%			
2	Proposed Bad Debt Expense (Per Co. Workpapers)	-			
3	Subtotal (L1 thru L2)	100.0000%			
4	Combined Federal, State, Property Tax Rate (L22)	39.7027%			
5	Subtotal (L3 - L4)	60.2973%			
6	Gross Revenue Conversion Factor (L1 / L5)	1.6585			
7					
8	CALCULATION OF EFFECTIVE TAX RATE:				
9	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
10	Arizona State Income Tax Rate	6.9680%			
11	Federal Taxable Income (L9 - L10)	93.0320%			
12	Applicable Federal Income Tax Rate (L58)	34.0000%			
13	Effective Federal Income Tax Rate (L11 X L12)	31.6309%			
14	Combined Federal and State Income Tax Rate (L10 + L13)	38.5989%			
15					
16	CALCULATION OF EFFECTIVE PRPERTY TAX FACTOR:				
17	Unity	100.0000%			
18	Combined Federal and State Tax Rate	38.5989%			
19	1 Minus Combined Income Tax Rate	61.4011%			
20	Property Tax Factor	1.7978%			
21	Effective Property Tax Factor (L19 x L 20)	1.1039%			
22	Combined Federal, State & Property Tax RateTax Rate (L14 + L21)	39.7027%			
23					
24	RUCO Required Operating Income (Sch. TJC-1, Col. [B], L7)	$ 374,293			
25	RUCO Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Col. [B], L3)	372,448			
26	Required Increase In Operating Income (L24 - L25)		$ 1,845		
27					
28	Income Taxes On Recommended Revenue (Col. [D], L53)	$ 211,078			
29	Income Taxes On Test Year Revenue (Col. [D], L55)	209,919			
30	Required Increase In Revenue To Provide For Income Taxes (L28 - L29)		$ 1,160		
31					
32	Property Tax with Recommended Revenue (Sch. TJC-10, Col. [E], L33)	75,679			
33	Propertry Tax on Test Year Revenue (Sch. TJC-10, Col. [C], L33)	75,624			
34	Increase in Property Tax Due to Increase in Revenue (L32 - L33)		$ 55		
35					
36	Total Required Increase In Revenue (L26 + L30 + L34)		$ 3,060		
37				RUCO	
38	RUCO's CALCULATION OF INCOME TAX:			Recommended	
39	RUCO Proposed Revenue (Sch. TJC-1, Col. [B], L19)			$ 1,405,272	
40	Less:				
41	Operating Expense Excluding Income Tax (Sch. TJC-10, Col. [E], L36 - L34)			819,900	
42	Synchronized Interest (Col. [C], L63)			38,521	
43	Arizona Taxable Income (L39 - L41 - L42)			$ 546,851	
44	Arizona State Income Tax Rate			6.9680%	
45	Arizona Income Tax (L43 X L44)				$ 38,105
46	Fed. Taxable Income (L43 - L45)			$ 508,747	
47	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
48	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			$ 6,250	
49	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			$ 8,500	
50	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%			$ 91,650	
51	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%			$ 59,074	
52	Total Federal Income Tax (L47 thru L 51)				$ 172,974
53	Combined Federal And State Income Tax (L45+ L52)				$ 211,078
54					
55	RUCO Adj'd Test Year Combined Federal and State Income Tax (TJC-10, Col. [C], L34)				$ 209,919
56	RUCO Proposed Income Tax Adjustment (L53 - L55)				$ 1,160
57					
58	Applicable Federal Income Tax Rate				34.00%
59					
60	NOTE (A): Interest Synchronization				
61	Adjusted Rate Base TJC-2, Col. (C), L23			$ 4,663,510	
62	Weighted Cost Of Debt TJC-28, Col. [C], L1			0.83%	
63	Interest Expense (L61 X L62)			$ 38,521	

RATE BASE - ORIGINAL COST/FAIR VALUE

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED OCRB/FVRB	[B] RUCO OCRB/FVRB ADJUSTMENTS	[C] RUCO ADJ'TED OCRB/FVRB
1				
2	Gross Utility Plant in Service	$ 14,241,191	$ 14,947	$ 14,256,137
3				
4	Accumulated Depreciation	(6,437,304)	77,847	(6,359,458)
5	Net Utility Plant In Service (L2 + L4)	$ 7,803,886	$ 92,793	$ 7,896,679
6				
7	**Less:**			
8	Advances In Aid Of Construction (AIAC)	$ (293,794)	$ -	$ (293,794)
9				
10	Contribution In Aid Of Construction (CIAC)	(5,152,673)	-	(5,152,673)
11	Accumulated Amortization of CIAC	2,509,975	-	2,509,975
12	NET CIAC (L10 + L11)	$ (2,642,698)	$ -	$ (2,642,698)
13				
14	Deferred Income Tax	$ (244,419)	$ (29,295)	$ (273,714)
15				
16	Customer Deposits	(22,963)	-	(22,963)
17				
18				
19				
20				
21				
22				
23	TOTAL RATE BASE (L5+L8+L12+L14+L16)	$ 4,600,012	$ 63,498	$ 4,663,510

References:
Column [A]: Company Schedule B-1
Column [B]: Schedule TJC-3 Column [H]
Column [C]: Column [A] + Column [B]

Rio Rico Utilities, Inc
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ORIGINAL COST/FAIR VALUE RATE BASE - RUCO ADJUSTMENTS

LINE NO.	DESCRIPTION	[A] COMPANY AS FILED OCRB/FVRB	[B] RUCO ADJUSTMENT NO. 1(a) RECONSTRUCT PLANT BALANCES	[C] RUCO ADJUSTMENT NO. 1(b) ACCUM. DEPRE. BALANCE	[D] RUCO ADJUSTMENT NO. 2 RECLASSIFY NWWTP PLANT ACCOUNTS	[E] RUCO ADJUSTMENT NO. 3 RECLASSIFY ACCT. 380 CAPACITY CHRGS. TO NWWTP	[F] RUCO ADJUSTMENT NO. 4 REMOVE AFFILIATE PROFITS PER MJR 1-15	[G] RUCO ADJUSTMENT NO. 5 ADIT BALANCE	[H] RUCO Total Pro Forma Adjustments	[I] RUCO ADJ'TED OCRB/FVRB
1										
2	Gross Utility Plant in Service	$ 14,241,191	$ -	$ -	$ 15,362	$ -	$ (415)	$ -	$ 14,947	$ 14,256,137
3										
4	Accumulated Depreciation	(6,437,304)	-	78,260	(418)	-	4	-	77,847	(6,359,458)
5	Net Utility Plant in Service (L2 + L4)	$ 7,803,886	$ -	$ 78,260	$ 14,944	$ -	$ (411)	$ -	$ 92,793	$ 7,896,679
6										
7	**Less:**									
8	Advances in Aid Of Construction (AIAC)	$ (293,794)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (293,794)
9										
10	Contribution in Aid Of Construction (CIAC)	(5,152,673)	-	-	-	-	-	-	-	(5,152,673)
11	Accumulated Amortization of CIAC	2,509,975	-	-	-	-	-	-	-	2,509,975
12	NET CIAC (L10 + L11)	$ (2,642,698)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (2,642,698)
13										
14	Deferred Income Tax	(244,419)	-	-	-	-	-	(29,295)	(29,295)	(273,714)
15										
16	Customer Deposits	(22,963)	-	-	-	-	-	-	-	(22,963)
17										
18										
19										
20										
21										
22										
23	TOTAL RATE BASE (L5+L8+L12+L14+L16)	$ 4,600,012	$ -	$ 78,260	$ 14,944	$ -	$ (411)	$ (29,295)	$ 63,498	$ 4,663,510

References:
Column [A]: Company Schedule B-1 as Filed
Column [B] Thru [G]: RUCO Recommended Adjustments
Column [H]: Sum of Columns [B] Thru [G]
Column [I]: Column [A] + Column[H]

Rio Rico Utilities, Inc
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TOTAL UTILITY PLANT IN SERVICE SUMMARY SCHEDULE

Line No.	NARUC Account	Description	Company Plant in Service Balance As Filed	RUCO Adjustment No. 1(a) Plant In Service Reconstruction Adjustment	RUCO Adjustment No. 2(a) Reclassify NWWTP Accounts Per RUCO DR 2.1	RUCO Adjustment No. 3(a) Reclassify Acct. 380 Acct. 380 Capacity Chrgs. To NWWTP Account	RUCO Adjustment No. 4(a) Remove Affiliate Profits Per Staff DR MJR 1.15	RUCO Total Adjustments	RUCO Total Plant In Service Balance
1	351	Organization	$ 5,785	$ -	$ -	$ -	$ -	$ -	$ 5,785
2	352	Franchise	417	-	-	-	-	-	417
3	353	Land	7,545	-	-	-	-	-	7,545
4	354	Structures & Improvements	150,294	-	-	-	-	-	150,294
5	355	Power Generation	-	-	-	-	-	-	-
6	360	Collection Sewer Forced	636,023	-	-	-	-	-	636,023
7	361	Collection Sewers Gravity	5,991,654	-	-	-	(415)	(415)	5,991,239
8	362	Special Collecting Structures	-	-	-	-	-	-	-
9	363	Customer Services	1,204,113	-	-	-	-	-	1,204,113
10	364	Flow Measuring Devices	66,339	-	-	-	-	-	66,339
11	366	Reuse Services	-	-	-	-	-	-	-
12	367	Reuse Meters And Installation	-	-	-	-	-	-	-
13	370	Receiving Wells	867,120	-	-	-	-	-	867,120
14	371	Pumping Equipment	1,712,940	-	-	-	-	-	1,712,940
15	374	Reuse Distribution Reservoirs	-	-	-	-	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-	-	-	-	-
17	380	Treatment & Disposal Equipment	1,128,675	-	(153,642)	(1,008,000)	-	(1,161,642)	(32,967)
18	381	Plant Sewers	13,690	-	-	-	-	-	13,690
19	382	Outfall Sewer Lines	-	-	-	-	-	-	-
20	389	Other Sewer Plant & Equipment	64,928	-	-	-	-	-	64,928
21	390	Office Furniture & Equipment	116,937	-	-	-	-	-	116,937
22	390.1	Computers and Software	4,025	-	-	-	-	-	4,025
23	391	Transportation Equipment	117	-	-	-	-	-	117
24	392	Stores Equipment	-	-	-	-	-	-	-
25	393	Tools, Shop And Garage Equip	5,139	-	-	-	-	-	5,139
26	394	Laboratory Equip	-	-	-	-	-	-	-
27	396	Communication Equip	5,936	-	-	-	-	-	5,936
28	398	Other Tangible Plant	3,913	-	-	-	-	-	3,913
29		Nogales WWTP	2,255,600	-	169,004	1,008,000	-	1,177,004	3,432,604
30									
31		RUCO Increase/(Decrease) Adj.	$ 14,241,191	$ -	$ 15,362	$ -	$ (415)	$ 14,947	$ 14,256,137

References:
Adjustment No. 1(a) - Schedule TJC-5(c), pages 1-4
Adjustment No. 2(a) - Schedule TJC-6(a)
Adjustment No. 3(a) - Schedule TJC-7(a)
Adjustment No. 4(a) - Schedule TJC-8(a)

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Rio Rico - Wastewater Division
Schedule TJC-4(b)
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TOTAL ACCUMULATED DEPRECIATION SUMMARY SCHEDULE

Line No.	NARUC Account	Description	Company Accum. Depre. Balance As Filed	RUCO Adjustment No. 1(b) Accumulated Depreciation Adjustment	RUCO Adjustment No. 2(b) Reclassify NWWTP Accounts Per RUCO DR 2.1	RUCO Adjustment No. 3(b) Reclassify Acct. 380 Acct. 380 Capacity Chrgs. To NWWTP Account	RUCO Adjustment No. 4(b) Remove Affiliate Profits Per Staff DR MJR 1.15	RUCO Total Adjustments	RUCO Total Accum. Depre. Balance
1	351	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	352	Franchise	-	-	-	-	-	-	-
3	353	Land	-	-	-	-	-	-	-
4	354	Structures & Improvements	(29,339)	160	-	-	-	160	(29,179)
5	355	Power Generation	-	-	-	-	-	-	-
6	360	Collection Sewer Forced	(1,910)	0	-	-	-	0	(1,910)
7	361	Collection Sewers Gravity	(2,596,939)	-	-	-	4	4	(2,596,935)
8	362	Special Collecting Structures	-	-	-	-	-	-	-
9	363	Customer Services	(669,901)	-	-	-	-	-	(669,901)
10	364	Flow Measuring Devices	(51,174)	-	-	-	-	-	(51,174)
11	366	Reuse Services	-	-	-	-	-	-	-
12	367	Reuse Meters And Installation	-	-	-	-	-	-	-
13	370	Receiving Wells	(330,148)	-	-	-	-	-	(330,148)
14	371	Pumping Equipment	(1,687,580)	78,311	-	-	-	78,311	(1,609,269)
15	374	Reuse Distribution Reservoirs	-	-	-	-	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-	-	-	-	-
17	380	Treatment & Disposal Equipment	(827,041)	-	3,841	623,352	-	627,193	(199,847)
18	381	Plant Sewers	(57)	-	-	-	-	-	(57)
19	382	Outfall Sewer Lines	-	-	-	-	-	-	-
20	389	Other Sewer Plant & Equipment	(68,869)	22	-	-	-	22	(68,847)
21	390	Office Furniture & Equipment	(31,386)	-	-	-	-	-	(31,386)
22	390.1	Computers and Software	(4,025)	-	-	-	-	-	(4,025)
23	391	Transportation Equipment	(10)	-	-	-	-	-	(10)
24	392	Stores Equipment	-	-	-	-	-	-	-
25	393	Tools, Shop And Garage Equip	(4,937)	18	-	-	-	18	(4,918)
26	394	Laboratory Equip	-	-	-	-	-	-	-
27	396	Communication Equip	(5,936)	-	-	-	-	-	(5,936)
28	398	Other Tangible Plant	(3,662)	(251)	-	-	-	(251)	(3,913)
29		Nogales WWTP	(124,390)	-	(4,259)	(623,352)	-	(627,611)	(752,001)
30									
31		RUCO Increase/(Decrease) Adj.	$ (6,437,304)	$ 78,260	$ (418)	$ -	$ 4	$ 77,847	$ (6,359,458)

References:
Adjustment No. 1(b) - Schedule TJC-5(c), pages 1-4
Adjustment No. 2(b) - Schedule TJC-6(b)
Adjustment No. 3(b) - Schedule TJC-7(b)
Adjustment No. 4(b) - Schedule TJC-8(b)

RUCO RATE BASE ADJUSTMENT NO. 1(a)
RECONSTRUCTION OF UTILITY PLANT IN SERVICE ("UPIS")

Line No.	NARUC Account No.	Description	Company Plant in Service Balance As Filed	RUCO Adjustments	RUCO As Calculated
1	351	Organization	$ 5,785	$ -	$ 5,785
2	352	Franchise	417	-	417
3	353	Land	7,545	-	7,545
4	354	Structures & Improvements	150,294	-	150,294
5	355	Power Generation	-	-	-
6	360	Collection Sewer Forced	636,023	-	636,023
7	361	Collection Sewers Gravity	5,991,654	-	5,991,654
8	362	Special Collecting Structures	-	-	-
9	363	Customer Services	1,204,113	-	1,204,113
10	364	Flow Measuring Devices	66,339	-	66,339
11	366	Reuse Services	-	-	-
12	367	Reuse Meters And Installation	-	-	-
13	370	Receiving Wells	867,120	-	867,120
14	371	Pumping Equipment	1,712,940	-	1,712,940
15	374	Reuse Distribution Reservoirs	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-
17	380	Treatment & Disposal Equipment	1,128,675	-	1,128,675
18	381	Plant Sewers	13,690	-	13,690
19	382	Outfall Sewer Lines	-	-	-
20	389	Other Sewer Plant & Equipment	64,928	-	64,928
21	390	Office Furniture & Equipment	116,937	-	116,937
22	390.1	Computers and Software	4,025	-	4,025
23	391	Transportation Equipment	117	-	117
24	392	Stores Equipment	-	-	-
25	393	Tools, Shop And Garage Equip	5,139	-	5,139
26	394	Laboratory Equip	-	-	-
27	396	Communication Equip	5,936	-	5,936
28	398	Other Tangible Plant	3,913	-	3,913
29		Nogales WWTP	2,255,600	-	2,255,600
30		Plant Held for Future Use	-	-	-
31		RUCO TOTALS	$ 14,241,191	$ -	$ 14,241,191
32		Company As Calculated & Filed			14,241,191
33		RUCO Increase/(Decrease) Adj.			$ -

References: Schedules TJC-5, Pages 3-6, Plant Reconstruction Schedules - Years 2009 Through 2012

RUCO RATE BASE ADJUSTMENT NO. 1(b)
RECONSTRUCTION OF ACCUMULATED DEPRECIATION

Line No.	NARUC Account No.	Description	Company Accum. Depre. Balance As Filed	RUCO Adjustments	RUCO As Adjusted
1	351	Organization	$ -	$ -	$ -
2	352	Franchise	-	-	-
3	353	Land	-	-	-
4	354	Structures & Improvements	(29,339)	160	(29,179)
5	355	Power Generation	-	-	-
6	360	Collection Sewer Forced	(1,910)	0	(1,910)
7	361	Collection Sewers Gravity	(2,596,939)	-	(2,596,939)
8	362	Special Collecting Structures	-	-	-
9	363	Customer Services	(669,901)	-	(669,901)
10	364	Flow Measuring Devices	(51,174)	-	(51,174)
11	366	Reuse Services	-	-	-
12	367	Reuse Meters And Installation	-	-	-
13	370	Receiving Wells	(330,148)	-	(330,148)
14	371	Pumping Equipment	(1,687,580)	78,311	(1,609,269)
15	374	Reuse Distribution Reservoirs	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-
17	380	Treatment & Disposal Equipment	(827,041)	-	(827,041)
18	381	Plant Sewers	(57)	-	(57)
19	382	Outfall Sewer Lines	-	-	-
20	389	Other Sewer Plant & Equipment	(68,869)	22	(68,847)
21	390	Office Furniture & Equipment	(31,386)	-	(31,386)
22	390.1	Computers and Software	(4,025)	-	(4,025)
23	391	Transportation Equipment	(10)	-	(10)
24	392	Stores Equipment	-	-	-
25	393	Tools, Shop And Garage Equip	(4,937)	18	(4,918)
26	394	Laboratory Equip	-	-	-
27	396	Communication Equip	(5,936)	-	(5,936)
28	398	Other Tangible Plant	(3,662)	(251)	(3,913)
29		Nogales WWTP	(124,390)	-	(124,390)
30		Plant Held for Future Use	-	-	-
31		RUCO TOTALS	$ (6,437,304)	$ 78,260	$ (6,359,044)
32		Company As Calculated & Filed			(6,437,304)
33		RUCO (Increase)/Decrease Adj.			$ 78,260

References: Schedules TJC-5, Pages 3-6, Plant Reconstruction Schedules - Years 2009 Through Feb. 20

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PLANT RECONSTRUCTION SCHEDULE

				Per Decision 72059			2009								
Line No.	NARUC Account No.	Description	Allowed Deprec. Rate	Plant at 12/31/2008	Accum. Deprec. At 12/31/2008	Net Plant at 12/31/2008	Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	351	Organization	0.00%	$ 5,785	$ -	$ 5,785	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	352	Franchise	0.00%	417	-	417	-	-	-	-	-	-	417	-	417
3	353	Land	0.00%	7,545	-	7,545	-	-	-	-	-	-	7,545	-	7,545
4	354	Structures & Improvements	3.33%	28,548	(27,203)	1,345	294	-	294	-	-	956	28,842	(28,159)	683
5	355	Power Generation	5.00%	-	-	-	-	-	-	-	-	-	-	-	-
6	360	Collection Sewer Forced	2.00%	636,023	38,371	674,394	-	-	-	-	-	12,720	636,023	25,651	661,674
7	361	Collection Sewers Gravity	2.00%	5,945,962	(2,213,553)	3,732,409	130,091	-	130,091	-	-	120,220	6,076,053	(2,333,773)	3,742,280
8	362	Special Collecting Structures	2.00%	-	-	-	-	-	-	-	-	-	-	-	-
9	363	Customer Services	2.00%	1,145,530	(595,856)	549,674	7,994	-	7,994	(245)	-	22,988	1,153,279	(618,599)	534,680
10	364	Flow Measuring Devices	10.00%	55,988	(31,043)	24,946	8,964	-	8,964	-	-	6,047	64,952	(37,090)	27,863
11	366	Reuse Services	2.00%	-	-	-	-	-	-	-	-	-	-	-	-
12	367	Reuse Meters And Installation	8.33%	-	-	-	-	-	-	-	-	-	-	-	-
13	370	Receiving Wells	3.33%	867,120	(238,710)	628,410	-	-	-	-	-	28,875	867,120	(267,585)	599,535
14	371	Pumping Equipment	12.50%	1,504,181	(1,232,681)	271,499	112	-	112	-	-	188,030	1,504,292	(1,420,711)	83,582
15	374	Reuse Distribution Reservoirs	2.50%	-	-	-	-	-	-	-	-	-	-	-	-
16	375	Reuse Trans. and Dist. System	2.50%	-	-	-	-	-	-	-	-	-	-	-	-
17	380	Treatment & Disposal Equipment	5.00%	1,006,848	(665,783)	341,066	14,462	-	14,462	-	-	50,704	1,021,310	(716,486)	304,824
18	381	Plant Sewers	5.00%	-	-	-	-	-	-	-	-	-	-	-	-
19	382	Outfall Sewer Lines	3.33%	-	-	-	-	-	-	-	-	-	-	-	-
20	389	Other Sewer Plant & Equipment	6.67%	68,869	(65,244)	3,625	-	-	-	-	-	3,625	68,869	(68,869)	-
21	390	Office Furniture & Equipment	6.67%	110,454	(8,021)	102,433	-	-	-	-	-	7,367	110,454	(15,388)	95,066
22	390.1	Computers and Software	20.00%	4,025	(4,025)	-	-	-	-	-	-	-	4,025	(4,025)	-
23	391	Transportation Equipment	20.00%	-	-	-	-	-	-	-	-	-	-	-	-
24	392	Stores Equipment	4.00%	-	-	-	-	-	-	-	-	-	-	-	-
25	393	Tools, Shop And Garage Equip	5.00%	4,897	(4,156)	741	-	-	-	-	-	245	4,897	(4,401)	496
26	394	Laboratory Equip	10.00%	-	-	-	-	-	-	-	-	-	-	-	-
27	396	Communication Equip	10.00%	5,936	(5,936)	-	-	-	-	-	-	-	5,936	(5,936)	-
28	398	Other Tangible Plant	10.00%	3,913	(2,815)	1,099	-	-	-	-	-	391	3,913	(3,206)	707
29		Nogales WWTP	4.72%	427,000	(53,375)	373,625	-	-	-	-	-	20,154	427,000	(73,529)	353,471
30															
31															
32															
33															
34		Rounding		-	-	-	-	-	-	-	-	-	-	-	-
35															
36		RUCO TOTALS		$ 11,829,042	$ (5,110,028)	$ 6,719,013	$ 161,917	$ -	$ 161,917	$ (245)	$ -	$ 462,323	$ 11,990,714	$ (5,572,107)	$ 6,418,607

PLANT RECONSTRUCTION SCHEDULE

Line No.	NARUC Account No.	Description	2010 Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	351	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	352	Franchise	-	-	-	-	-	-	417	-	417
3	353	Land	-	-	-	-	-	-	7,545	-	7,545
4	354	Structures & Improvements	-	-	-	-	-	683	28,842	(28,842)	-
5	355	Power Generation	-	-	-	-	-	-	-	-	-
6	360	Collection Sewer Forced	-	-	-	-	-	12,720	636,023	12,930	648,953
7	361	Collection Sewers Gravity	108	-	108	-	-	121,522	6,076,161	(2,455,296)	3,620,866
8	362	Special Collecting Structures	-	-	-	-	-	-	-	-	-
9	363	Customer Services	36,522	-	36,522	-	-	23,431	1,189,801	(642,030)	547,771
10	364	Flow Measuring Devices	-	-	-	-	-	6,495	64,952	(43,585)	21,368
11	366	Reuse Services	-	-	-	-	-	-	-	-	-
12	367	Reuse Meters And Installation	-	-	-	-	-	-	-	-	-
13	370	Receiving Wells	-	-	-	-	-	28,875	867,120	(296,460)	570,660
14	371	Pumping Equipment	84,064	-	84,064	-	-	88,836	1,588,356	(1,509,546)	78,810
15	374	Reuse Distribution Reservoirs	-	-	-	-	-	-	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-	-	-	-	-	-	-
17	380	Treatment & Disposal Equipment	609	-	609	-	-	51,081	1,021,920	(767,567)	254,352
18	381	Plant Sewers	-	-	-	-	-	-	-	-	-
19	382	Outfall Sewer Lines	-	-	-	-	-	-	-	-	-
20	389	Other Sewer Plant & Equipment	-	-	-	-	-	-	68,869	(68,869)	-
21	390	Office Furniture & Equipment	-	-	-	-	-	7,367	110,454	(22,755)	87,699
22	390.1	Computers and Software	-	-	-	-	-	-	4,025	(4,025)	-
23	391	Transportation Equipment	-	-	-	-	-	-	-	-	-
24	392	Stores Equipment	-	-	-	-	-	-	-	-	-
25	393	Tools, Shop And Garage Equip	-	-	-	-	-	245	4,897	(4,646)	251
26	394	Laboratory Equip	-	-	-	-	-	-	-	-	-
27	396	Communication Equip	-	-	-	-	-	-	5,936	(5,936)	-
28	398	Other Tangible Plant	-	-	-	-	-	391	3,913	(3,597)	316
29		Nogales WWTP	-	-	-	-	-	20,154	427,000	(93,684)	333,316
30											
31											
32											
33											
34		Rounding	-	-	-	-	-	-	-	-	-
35											
36		RUCO TOTALS	$ 121,303	$ -	$121,303	$ -	$ -	$ 361,801	$ 12,112,017	$(5,933,908)	$ 6,178,109

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PLANT RECONSTRUCTION SCHEDULE

Line No.	NARUC Account No.	Description	2011 Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	351	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	352	Franchise	-	-	-	-	-	-	417	-	417
3	353	Land	-	-	-	-	-	-	7,545	-	7,545
4	354	Structures & Improvements	-	-	-	-	-	-	28,842	(28,842)	-
5	355	Power Generation	-	-	-	-	-	-	-	-	-
6	360	Collection Sewer Forced	-	-	-	-	-	12,720	636,023	210	636,233
7	361	Collection Sewers Gravity	652	-	652	-	-	121,530	6,076,813	(2,576,825)	3,499,988
8	362	Special Collecting Structures	-	-	-	-	-	-	-	-	-
9	363	Customer Services	7,319	-	7,319	-	-	23,869	1,197,120	(665,899)	531,221
10	364	Flow Measuring Devices	-	-	-	-	-	6,495	64,952	(50,080)	14,872
11	366	Reuse Services	-	-	-	-	-	-	-	-	-
12	367	Reuse Meters And Installation	-	-	-	-	-	-	-	-	-
13	370	Receiving Wells	-	-	-	-	-	28,875	867,120	(325,335)	541,785
14	371	Pumping Equipment	94,151	-	94,151	-	-	84,694	1,682,507	(1,594,241)	88,267
15	374	Reuse Distribution Reservoirs	-	-	-	-	-	-	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-	-	-	-	-	-	-
17	380	Treatment & Disposal Equipment	99,979	-	99,979	(3,400)	-	53,510	1,118,499	(817,678)	300,821
18	381	Plant Sewers	-	-	-	-	-	-	-	-	-
19	382	Outfall Sewer Lines	-	-	-	-	-	-	-	-	-
20	389	Other Sewer Plant & Equipment	-	-	-	-	-	-	68,869	(68,869)	-
21	390	Office Furniture & Equipment	-	-	-	-	-	7,367	110,454	(30,122)	80,332
22	390.1	Computers and Software	-	-	-	-	-	-	4,025	(4,025)	-
23	391	Transportation Equipment	67	-	67	-	-	7	67	(7)	61
24	392	Stores Equipment	-	-	-	-	-	-	-	-	-
25	393	Tools, Shop And Garage Equip	139	-	139	-	-	248	5,036	(4,894)	142
26	394	Laboratory Equip	-	-	-	-	-	-	-	-	-
27	396	Communication Equip	-	-	-	-	-	-	5,936	(5,936)	-
28	398	Other Tangible Plant	-	-	-	-	-	316	3,913	(3,913)	-
29		Nogales WWTP	-	-	-	-	-	20,154	427,000	(113,838)	313,162
30											
31											
32											
33											
34		Rounding	-	-	-	-	-	-	-	-	-
35											
36		RUCO TOTALS	$ 202,307	$ -	$ 202,307	$ (3,400)	$ -	$ 359,787	$ 12,310,924	$ (6,290,295)	$ 6,020,629

PLANT RECONSTRUCTION SCHEDULE

Line No.	NARUC Account No.	Description	2012 (2 Months - January 1 through February 29, 2012) Plant Additions (Per Books)	Plant Adjustments	Adjusted Plant Additions	Plant Retirements	Salvage A/D Only	Depreciation (Calculated)	Plant Balance	Accum. Deprec.	Net Plant
1	351	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ 5,785	$ -	$ 5,785
2	352	Franchise	-	-	-	-	-	-	417	-	417
3	353	Land	-	-	-	-	-	-	7,545	-	7,545
4	354	Structures & Improvements	14	121,438	121,452	-	-	337	150,294	(29,179)	121,115
5	355	Power Generation	-	-	-	-	-	-	-	-	-
6	360	Collection Sewer Forced	-	-	-	-	-	2,120	636,023	(1,910)	634,113
7	361	Collection Sewers Gravity	(85,159)	-	(85,159)	-	-	20,114	5,991,654	(2,596,939)	3,394,715
8	362	Special Collecting Structures	-	-	-	-	-	-	-	-	-
9	363	Customer Services	7,009	(16)	6,993	-	-	4,002	1,204,113	(669,901)	534,212
10	364	Flow Measuring Devices	1,387	-	1,387	-	-	1,094	66,339	(51,174)	15,165
11	366	Reuse Services	-	-	-	-	-	-	-	-	-
12	367	Reuse Meters And Installation	-	-	-	-	-	-	-	-	-
13	370	Receiving Wells	-	-	-	-	-	4,813	867,120	(330,148)	536,972
14	371	Pumping Equipment	30,433	-	30,433	-	-	15,028	1,712,940	(1,609,269)	103,671
15	374	Reuse Distribution Reservoirs	-	-	-	-	-	-	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-	-	-	-	-	-	-
17	380	Treatment & Disposal Equipment	10,176	-	10,176	-	-	9,363	1,128,675	(827,041)	301,634
18	381	Plant Sewers	13,690	-	13,690	-	-	57	13,690	(57)	13,633
19	382	Outfall Sewer Lines	-	-	-	-	-	-	-	-	-
20	389	Other Sewer Plant & Equipment	280	(4,221)	(3,941)	-	-	(22)	64,928	(68,847)	(3,919)
21	390	Office Furniture & Equipment	6,483	-	6,483	-	-	1,264	116,937	(31,386)	85,551
22	390.1	Computers and Software	-	-	-	-	-	-	4,025	(4,025)	-
23	391	Transportation Equipment	50	-	50	-	-	3	117	(10)	108
24	392	Stores Equipment	-	-	-	-	-	-	-	-	-
25	393	Tools, Shop And Garage Equip	103	-	103	-	-	24	5,139	(4,918)	221
26	394	Laboratory Equip	-	-	-	-	-	-	-	-	-
27	396	Communication Equip	-	-	-	-	-	-	5,936	(5,936)	-
28	398	Other Tangible Plant	-	-	-	-	-	-	3,913	(3,913)	-
29		Nogales WWTP	1,828,600	-	1,828,600	-	-	10,552	2,255,600	(124,390)	2,131,210
30											
31											
32											
33											
34		Rounding	-	-	-	-	-	-	-	-	-
35											
36		RUCO TOTALS	$ 1,813,066	$ 117,201	$ 1,930,267	$ -	$ -	$ 68,749	$ 14,241,191	$ (6,359,044)	$ 7,882,147
37		Company Plant in Service as Filed							14,241,191		
38		RUCO Increase/(Decrease) Plant in Service Adjustment							$ -		
39		Company Accumulated Depreciation as Filed								(6,437,304)	
40		RUCO (Increase)/Decrease Accumulated Depreciation Adjustment								$ 78,260	

RUCO RATE BASE ADJUSTMENT NO. 2(a)
RECLASSIFY WATER & WASTEWATER PLANT ACCOUNTS TO NWWTP

Line No.	NARUC Account No.	Description	Company Plant In Service As Filed	RUCO Adjustments	RUCO As Calculated
1	351	Organization	$ 5,785	$ -	$ 5,785
2	352	Franchise	417	-	417
3	353	Land	7,545	-	7,545
4	354	Structures & Improvements	150,294	-	150,294
5	355	Power Generation	-	-	-
6	360	Collection Sewer Forced	636,023	-	636,023
7	361	Collection Sewers Gravity	5,991,654	-	5,991,654
8	362	Special Collecting Structures	-	-	-
9	363	Customer Services	1,204,113	-	1,204,113
10	364	Flow Measuring Devices	66,339	-	66,339
11	366	Reuse Services	-	-	-
12	367	Reuse Meters And Installation	-	-	-
13	370	Receiving Wells	867,120	-	867,120
14	371	Pumping Equipment	1,712,940	-	1,712,940
15	374	Reuse Distribution Reservoirs	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-
17	380	Treatment & Disposal Equipment	1,128,675	(153,642)	975,033
18	381	Plant Sewers	13,690	-	13,690
19	382	Outfall Sewer Lines	-	-	-
20	389	Other Sewer Plant & Equipment	64,928	-	64,928
21	390	Office Furniture & Equipment	116,937	-	116,937
22	390.1	Computers and Software	4,025	-	4,025
23	391	Transportation Equipment	117	-	117
24	392	Stores Equipment	-	-	-
25	393	Tools, Shop And Garage Equip	5,139	-	5,139
26	394	Laboratory Equip	-	-	-
27	396	Communication Equip	5,936	-	5,936
28	398	Other Tangible Plant	3,913	-	3,913
29		Nogales WWTP	2,255,600	169,004	2,424,604
30		Plant Held for Future Use	-	-	-
31		TOTALS	$ 14,241,191	$ 15,362	$ 14,256,553
32		Company As Calculated & Filed			14,241,191
33		RUCO Adjustment			$ 15,362

References: Company B-2 Plant Schedules, Schedules TJC-4 2009 Through 2012, and RUCO NWWTP Reclassification Calculation Adjustment WP

RUCO RATE BASE ADJUSTMENT NO. 2(b)
RECLASSIFY WATER & WASTEWATER ACCUMULATED DEPRECIATION TO NWWTP

Line No.	NARUC Account No.	Description	Company Accum. Depre. As Filed	RUCO Adjustments	Note	RUCO As Adjusted
1	351	Organization	$ -	$ -		$ -
2	352	Franchise	-	-		-
3	353	Land	-	-		-
4	354	Structures & Improvements	(29,339)	-		(29,339)
5	355	Power Generation	-	-		-
6	360	Collection Sewer Forced	(1,910)	-		(1,910)
7	361	Collection Sewers Gravity	(2,596,939)	-		(2,596,939)
8	362	Special Collecting Structures	-	-		-
9	363	Customer Services	(669,901)	-		(669,901)
10	364	Flow Measuring Devices	(51,174)	-		(51,174)
11	366	Reuse Services	-	-		-
12	367	Reuse Meters And Installation	-	-		-
13	370	Receiving Wells	(330,148)	-		(330,148)
14	371	Pumping Equipment	(1,687,580)	-		(1,687,580)
15	374	Reuse Distribution Reservoirs	-	-		-
16	375	Reuse Trans. and Dist. System	-	-		-
17	380	Treatment & Disposal Equipment	(827,041)	3,841	WP's	(823,200)
18	381	Plant Sewers	(57)	-		(57)
19	382	Outfall Sewer Lines	-	-		-
20	389	Other Sewer Plant & Equipment	(68,869)	-		(68,869)
21	390	Office Furniture & Equipment	(31,386)	-		(31,386)
22	390.1	Computers and Software	(4,025)	-		(4,025)
23	391	Transportation Equipment	(10)	-		(10)
24	392	Stores Equipment	-	-		-
25	393	Tools, Shop And Garage Equip	(4,937)	-		(4,937)
26	394	Laboratory Equip	-	-		-
27	396	Communication Equip	(5,936)	-		(5,936)
28	398	Other Tangible Plant	(3,662)	-		(3,662)
29		Nogales WWTP	(124,390)	(4,259)	WP's	(128,649)
30		Plant Held for Future Use	-	-		-
31		TOTALS	$ (6,437,304)	$ (418)		$ (6,437,722)
32		Company As Calculated & Filed				(6,437,304)
33		RUCO Adjustment				$ (418)

References: Company B-2 Plant Schedules, Schedules TJC-4 2009 Through 2012, and RUCO NWWTP Reclassification Calculation Adjustment WP

RUCO RATE BASE ADJUSTMENT NO. 3(a)
RECLASSIFY ACCOUNT 380 UPIS CAPACITY CHARGES TO NWWTP

Line No.	NARUC Account No.	Description	Company Plant In Service As Filed	RUCO Adjustments	RUCO As Calculated
1	351	Organization	$ 5,785	$ -	$ 5,785
2	352	Franchise	417	-	417
3	353	Land	7,545	-	7,545
4	354	Structures & Improvements	150,294	-	150,294
5	355	Power Generation	-	-	-
6	360	Collection Sewer Forced	636,023	-	636,023
7	361	Collection Sewers Gravity	5,991,654	-	5,991,654
8	362	Special Collecting Structures	-	-	-
9	363	Customer Services	1,204,113	-	1,204,113
10	364	Flow Measuring Devices	66,339	-	66,339
11	366	Reuse Services	-	-	-
12	367	Reuse Meters And Installation	-	-	-
13	370	Receiving Wells	867,120	-	867,120
14	371	Pumping Equipment	1,712,940	-	1,712,940
15	374	Reuse Distribution Reservoirs	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-
17	380	Treatment & Disposal Equipment	1,128,675	(1,008,000)	120,675
18	381	Plant Sewers	13,690	-	13,690
19	382	Outfall Sewer Lines	-	-	-
20	389	Other Sewer Plant & Equipment	64,928	-	64,928
21	390	Office Furniture & Equipment	116,937	-	116,937
22	390.1	Computers and Software	4,025	-	4,025
23	391	Transportation Equipment	117	-	117
24	392	Stores Equipment	-	-	-
25	393	Tools, Shop And Garage Equip	5,139	-	5,139
26	394	Laboratory Equip	-	-	-
27	396	Communication Equip	5,936	-	5,936
28	398	Other Tangible Plant	3,913	-	3,913
29		Nogales WWTP	2,255,600	1,008,000	3,263,600
30		Plant Held for Future Use	-	-	-
31		TOTALS	$ 14,241,191	$ -	$ 14,241,191
32		Company As Calculated & Filed			14,241,191
33		RUCO Adjustment			$ -

References: Company B-2 Plant Schedules, Schedules TJC-4 2009 Through 2012, and RUCO NWWTP Reclassify WW Acct. 380 to NWWTP WP and Company Data Response to RUCO DR 5.7.

RUCO RATE BASE ADJUSTMENT NO. 3(b)
RECLASSIFY ACCOUNT 380 ACCUMULATED DEPRECIATION CAPACITY CHARGES TO NWWTP

Line No.	NARUC Account No.	Description	Company Accum. Depre. As Filed	RUCO Adjustments	Note	RUCO As Adjusted
1	351	Organization	$ -	$ -		$ -
2	352	Franchise	-	-		-
3	353	Land	-	-		-
4	354	Structures & Improvements	(29,339)	-		(29,339)
5	355	Power Generation	-	-		-
6	360	Collection Sewer Forced	(1,910)	-		(1,910)
7	361	Collection Sewers Gravity	(2,596,939)	-		(2,596,939)
8	362	Special Collecting Structures	-	-		-
9	363	Customer Services	(669,901)	-		(669,901)
10	364	Flow Measuring Devices	(51,174)	-		(51,174)
11	366	Reuse Services	-	-		-
12	367	Reuse Meters And Installation	-	-		-
13	370	Receiving Wells	(330,148)	-		(330,148)
14	371	Pumping Equipment	(1,687,580)	-		(1,687,580)
15	374	Reuse Distribution Reservoirs	-	-		-
16	375	Reuse Trans. and Dist. System	-	-		-
17	380	Treatment & Disposal Equipment	(827,041)	623,352	WP's	(203,688)
18	381	Plant Sewers	(57)	-		(57)
19	382	Outfall Sewer Lines	-	-		-
20	389	Other Sewer Plant & Equipment	(68,869)	-		(68,869)
21	390	Office Furniture & Equipment	(31,386)	-		(31,386)
22	390.1	Computers and Software	(4,025)	-		(4,025)
23	391	Transportation Equipment	(10)	-		(10)
24	392	Stores Equipment	-	-		-
25	393	Tools, Shop And Garage Equip	(4,937)	-		(4,937)
26	394	Laboratory Equip	-	-		-
27	396	Communication Equip	(5,936)	-		(5,936)
28	398	Other Tangible Plant	(3,662)	-		(3,662)
29		Nogales WWTP	(124,390)	(623,352)	WP's	(747,742)
30		Plant Held for Future Use	-	-		-
31		TOTALS	$ (6,437,304)	$ -		$ (6,437,304)
32		Company As Calculated & Filed				(6,437,304)
33		RUCO Adjustment				$ -

References: Company B-2 Plant Schedules, Schedules TJC-4 2009 Through 2012, and RUCO NWWTP Reclassify WW Acct. 380 to NWWTP WP and Company Data Response to RUCO DR 5.7.

Rio Rico Utilities, Inc
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Rio Rico - Wastewater Division
Schedule TJC-8(a)

RUCO RATE BASE ADJUSTMENT NO. 4(a)
REMOVE AFFILIATE PROFITS FROM PLANT IN SERVICE

Line No.	NARUC Account No.	Description	Company Plant In Service As Filed	RUCO Adjustments	RUCO As Calculated
1	351	Organization	$ 5,785	$ -	$ 5,785
2	352	Franchise	417	-	417
3	353	Land	7,545	-	7,545
4	354	Structures & Improvements	150,294	-	150,294
5	355	Power Generation	-	-	-
6	360	Collection Sewer Forced	636,023	-	636,023
7	361	Collection Sewers Gravity	5,991,654	(415)	5,991,239
8	362	Special Collecting Structures	-	-	-
9	363	Customer Services	1,204,113	-	1,204,113
10	364	Flow Measuring Devices	66,339	-	66,339
11	366	Reuse Services	-	-	-
12	367	Reuse Meters And Installation	-	-	-
13	370	Receiving Wells	867,120	-	867,120
14	371	Pumping Equipment	1,712,940	-	1,712,940
15	374	Reuse Distribution Reservoirs	-	-	-
16	375	Reuse Trans. and Dist. System	-	-	-
17	380	Treatment & Disposal Equipment	1,128,675	-	1,128,675
18	381	Plant Sewers	13,690	-	13,690
19	382	Outfall Sewer Lines	-	-	-
20	389	Other Sewer Plant & Equipment	64,928	-	64,928
21	390	Office Furniture & Equipment	116,937	-	116,937
22	390.1	Computers and Software	4,025	-	4,025
23	391	Transportation Equipment	117	-	117
24	392	Stores Equipment	-	-	-
25	393	Tools, Shop And Garage Equip	5,139	-	5,139
26	394	Laboratory Equip	-	-	-
27	396	Communication Equip	5,936	-	5,936
28	398	Other Tangible Plant	3,913	-	3,913
29		Nogales WWTP	2,255,600	-	2,255,600
30		Plant Held for Future Use	-	-	-
31		TOTALS	$ 14,241,191	$ (415)	$ 14,240,775
32		Company As Calculated & Filed			14,241,191
33		RUCO Adjustment			$ (415)

References: Company B-2 Plant Schedules and RRUI's Revised DR Response to Staff MJR-3.13

RUCO RATE BASE ADJUSTMENT NO. 4(b)
REMOVE ACCUMULATED DEPRECIATION RELATED TO REMOVAL OF AFFILIATE PLANT PROFITS

Line No.	NARUC Account No.	Description	Company Accum. Depre. As Filed	RUCO Adjustments	Note	RUCO As Adjusted
1	351	Organization	$ -	$ -		$ -
2	352	Franchise	-	-		-
3	353	Land	-	-		-
4	354	Structures & Improvements	(29,339)	-		(29,339)
5	355	Power Generation	-	-		-
6	360	Collection Sewer Forced	(1,910)	-		(1,910)
7	361	Collection Sewers Gravity	(2,596,939)	4	WP's	(2,596,935)
8	362	Special Collecting Structures	-	-		-
9	363	Customer Services	(669,901)	-		(669,901)
10	364	Flow Measuring Devices	(51,174)	-		(51,174)
11	366	Reuse Services	-	-		-
12	367	Reuse Meters And Installation	-	-		-
13	370	Receiving Wells	(330,148)	-		(330,148)
14	371	Pumping Equipment	(1,687,580)	-		(1,687,580)
15	374	Reuse Distribution Reservoirs	-	-		-
16	375	Reuse Trans. and Dist. System	-	-		-
17	380	Treatment & Disposal Equipment	(827,041)	-		(827,041)
18	381	Plant Sewers	(57)	-		(57)
19	382	Outfall Sewer Lines	-	-		-
20	389	Other Sewer Plant & Equipment	(68,869)	-		(68,869)
21	390	Office Furniture & Equipment	(31,386)	-		(31,386)
22	390.1	Computers and Software	(4,025)	-		(4,025)
23	391	Transportation Equipment	(10)	-		(10)
24	392	Stores Equipment	-	-		-
25	393	Tools, Shop And Garage Equip	(4,937)	-		(4,937)
26	394	Laboratory Equip	-	-		-
27	396	Communication Equip	(5,936)	-		(5,936)
28	398	Other Tangible Plant	(3,662)	-		(3,662)
29		Nogales WWTP	(124,390)	-		(124,390)
30		Plant Held for Future Use	-	-		-
31		TOTALS	$ (6,437,304)	$ 4		$ (6,437,300)
32		Company As Calculated & Filed				(6,437,304)
33		RUCO Adjustment				$ 4

References: Company B-2 Plant Schedules and RRUI's Revised DR Response to Staff MJR-3.13

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Rio Rico - Wastewater Division
Schedule TJC-9

RUCO RATE BASE ADJUSTMENT NO. 5
ACCUMULATED DEFERRED INCOME TAX ("ADIT")

Line No.			Water & Sewer Adjusted Book Value	Water & Sewer Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Effective Tax Rate	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
1	Deferred Income Tax as of February 29, 2012										
6		Plant-in-Service	$ 50,385,286 [1]								
7		Accum. Deprec.	(22,029,373) [1]								
8		CIAC	(14,692,881) [3]								
9	Fed.	Fixed Assets	$ 13,663,032	$ 8,955,829 [2]	100.0%	$ (4,707,203)	31.63%		-		(1,488,930)
11	State	Fixed Assets	$ 13,663,032	$ 23,646,536 [2]	100.0%	$ 9,983,504	6.97%		695,651		-
13	Fed &State	AIAC		593,411 [4]	30.0%	$ 178,023 [4]	38.60%		$ 68,715		
16								$ -	$ 764,366	$ -	$ (1,488,930)
17		Net Asset (Liability)						$ (724,564)			
19		Allocation Factor - Water-Division (based on rate base before ADIT)						0.3778			
21		Net Asset (Liability) Water Division						$ (273,714)			
23		Company's Calculated Amount of ADIT						$ (244,419)			
25		Adjustment to DIT						$ (29,295)			

Footnotes - See Schedule TJC-9, page 2 of 2

Rio Rico Utilities, Inc
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Rio Rico - Wastewater Division
Schedule TJC-9

RUCO RATE BASE ADJUSTMENT NO. 5
ACCUMULATED DEFERRED INCOME TAX ("ADIT")

Line No.		FEDERAL			STATE	
1	[1] Adjusted per B-2, page 2					
2	[2] Computation of Net Tax Value February 29, 2012					
3	Based on 2011 Tax Depreciation report (December 31, 2011)					
4	Unadjusted Cost per 2011 Tax Depr. Report	$ 28,328,799			$28,328,799	
5	Reconciling Items not on tax report:					
6	KPMG CIAC related adjustments (see page 7.2)	(3,942,541)			-	
7	Plant added after 12/31/2011 (see B-2 page 3.4)	3,039,772			3,039,772	
8	Land costs not on tax, on books (see B-2 page 3.4)	51,739			51,739	
9	*Reconciling Difference Book vs. Tax (timing)* (see page 7.2)	(120,225)			(120,225)	
10					-	
11	Net Unadjusted Cost tax Basis			$ 27,357,544		########
12						
13	Reductions					
14	Basis Reduction 2011 and Prior Years (from 2011 Tax Depr. Report)	$ (3,066,507)			$ -	
15	KPMG CIAC related adjustments (see workpapers)	1,166,545			-	
16	Accumulated Depreciation 2010 and prior (2011 Tax Depr Report)	(14,334,173)			(6,381,079)	
17	2011 Tax Depreciation (2011 Tax Depr Report)	(1,751,690)			(1,109,895)	
18	2012 Bonus Depreciation Estimate (50% - 2 months)(estimate)	(253,314)			-	
19	2012 Tax Depreciation Estimate (2 months)(estimate)	(162,575)			(162,575)	
20					-	
21	Net Reductions through February 2012			(18,401,715)		(7,653,549)
22	Net tax value of plant-in-service at February 29. 2012			$ 8,955,829		########
23						
24	[3] CIAC (Including impact of change to probability of realization)					
25						
26	Gross CIAC per B-2 (Water & Sewer)		$ 25,331,792			
27	CIAC reductions/addtions					
28	A.A per B-2 (Water and Sewer)	$ (11,307,236)				
29	A.A. reductions/addtions	-				
30			(11,307,236)			
31	Net CIAC before unrealized AIAC			$ 14,024,556		
32						
33	Unrealized AIAC Component (Water and Sewer)					
34	Adjusted Net AIAC (see footnote 5 below)		$ 954,749			
35	Unrealized AIAC Component % (1-Realized AIAC Component)		70.0%			
36				$ 668,325		
37	Total realizable CIAC			$ 14,692,881		
38						
39	[4] AIAC (Including impact of change in probability of realization)					
40	AIAC per B-2 (Water and Sewer)		$ 954,749			
41	AIAC reductions/additions		-			
42	Net AIAC before unrealized portion			$ 954,749		
43	Less: Unrealized AIAC (from Note 4, above)			$ (668,325)		
44	Net realizable AIAC			$ 286,425		
45	Meter and Service Line Installation Charges			306,987		
46	Total AIAC			$ 593,411		
47						

OPERATING INCOME

LINE NO.		[A] COMPANY AS FILED	[B] RUCO TEST YEAR ADJM'TS	[C] RUCO TEST YEAR AS ADJ'TED	[D] RUCO PROP'D CHANGES	[E] RUCO AS RECOMM'D
1	**Operating Revenues**					
2	Metered Water Revenues	$ 1,360,583	$ 41,629	$ 1,402,212	$ 3,060	$ 1,405,272
3	Unmetered Revenues	-	-	-	-	-
4	Other Water Revenues	-	-	-	-	-
5	Total Water Revenues (L2 thru L4)	$ 1,360,583	$ 41,629	$ 1,402,212	$ 3,060	$ 1,405,272
6						
7	**Operating Expenses**					
8	Salaries and Wages	$ 131,547	$ -	$ 131,547	$ -	$ 131,547
9	Purchased Wastewater Treatment	-	108,999	108,999	-	108,999
10	Sludge Removal Expense	-	-	-	-	-
11	Purchased Power	61,290	505	61,795	-	61,795
12	Fuel for Power Production	-	-	-	-	-
13	Chemicals	4,907	40	4,947	-	4,947
14	Materials and Supplies	4,473	-	4,473	-	4,473
15	Management Services - US Liberty Water	83,038	(783)	82,255	-	82,255
16	Management Services - Corporate	59,292	(19,673)	39,619	-	39,619
17	Management Services - Other	172,270	(165,896)	6,374	-	6,374
18	Contracted Services - Engineering	-	-	-	-	-
19	Contractual Services - Testing	330	-	330	-	330
20	Contractual Services - Other	638	-	638	-	638
21	Contractual Services - Legal	585	-	585	-	585
22	Equipment Rental	400	-	400	-	400
23	Rents - Building	-	-	-	-	-
24	Transportation Expenses	18,066	-	18,066	-	18,066
25	Insurance - General Liability	11,302	-	11,302	-	11,302
26	Insurance - Vehicles	2,516	-	2,516	-	2,516
27	Regulatory Commission Expense	-	-	-	-	-
28	Reg. Comm. Exp. - Rate Case	29,167	(7,292)	21,875	-	21,875
29	Miscellaneous Expense	16,111	-	16,111	-	16,111
30	Bad Debt Expense	23,194	-	23,194	-	23,194
31	Depreciation and Amortization Expense	359,629	(150,435)	209,194	-	209,194
32	Taxes Other Than Income	-	-	-	-	-
33	Property Taxes	74,520	1,103	75,624	55	75,679
34	Income Taxes	93,481	116,437	209,919	1,160	211,078
35						
36	Total Operationing Expenses (L8 thru L44)	$ 1,146,757	$ (116,994)	$ 1,029,764	$ 1,215	$ 1,030,978
37						
38	**Operating Income (L5 less L36)**	$ 213,826	$ 158,622	$ 372,448	$ 1,845	$ 374,293

REFERENCES:

Column [A]: Company Schedule C-1
Column [B]: Summation of RUCO's Recommended Adjustment on Schedule TJC-11
Column [C]: Col. A + Col. B
Column [D]: RUCO Proposed Increases/(Decreases) to Revenues & Expenses
Column [E]: Column [C] + Column [D]

Rio Rico Utilities, Inc
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OPERATING INCOME

Line No.		[A] Company Adjusted Test Year As Filed	[B] Operating Income Adjustment No. 1 Depreciation Exp.	[C] Operating Income Adjustment No. 2 Property Tax Exp.	[D] Operating Income Adjustment No. 3 Rate Case Exp.	[E] Operating Income Adjustment No. 4 6-Inch Commercial WW Revenue Annualization	[F] Operating Income Adjustment No. 5 Missing Bill Counts Per RUCO DR 6.1(d)	[G] Operating Income Adjustment No. 6 6-Inch Commercial WW Revenue Accrual	[H] Operating Income Adjustment No. 7 Missing Bill Counts Revenue Accrual	[I] Operating Income Adjustment No. 8 Expense Annualization	[J] Operating Income Adjustment No. 9 Intentionally Left Blank	[K] Operating Income Adjustment No. 10 Miscellaneous Expenses	[L] Operating Income Adjustment No. 11 Achievement / Incentive Pay
1	**Operating Revenues**												
2	Metered Water Revenues	$ 1,360,583	$ -	$ -	$ -	$ 12,213	$ 4,305	$ 20,805	$ 4,305	$ -	$ -	$ -	$ -
3	Unmetered Revenues	-	-	-	-	-	-	-	-	-	-	-	-
4	Other Water Revenues	-	-	-	-	-	-	-	-	-	-	-	-
5	Total Water Revenues (L2 thru L4)	$ 1,360,583	$ -	$ -	$ -	$ 12,213	$ 4,305	$ 20,805	$ 4,305	$ -	$ -	$ -	$ -
6													
7	**Operating Expenses**												
8	Salaries and Wages	$ 131,547	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Purchased Wastewater Treatment	-	-	-	-	-	-	-	-	-	-	-	-
10	Sludge Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-
11	Purchased Power	61,290	-	-	-	-	-	-	-	-	-	-	-
12	Fuel for Power Production	-	-	-	-	-	-	-	-	-	-	-	-
13	Chemicals	4,907	-	-	-	-	-	-	-	506	-	-	-
14	Materials and Supplies	4,473	-	-	-	-	-	-	-	-	-	-	-
15	Management Services - US Liberty Wa	83,036	-	-	-	-	-	-	-	40	-	-	-
16	Management Services - Corporate	59,292	-	-	-	-	-	-	-	-	-	-	-
17	Management Services - Other	172,270	-	-	-	-	-	-	-	-	-	-	-
18	Contracted Services - Engineering	-	-	-	-	-	-	-	-	-	-	-	(9,448)
19	Contractual Services - Testing	330	-	-	-	-	-	-	-	-	-	-	-
20	Contractual Services - Other	638	-	-	-	-	-	-	-	-	-	-	-
21	Contractual Services - Legal	585	-	-	-	-	-	-	-	-	-	-	-
22	Equipment Rental	-	-	-	-	-	-	-	-	-	-	-	-
23	Rents - Building	400	-	-	-	-	-	-	-	-	-	-	-
24	Transportation Expenses	18,066	-	-	-	-	-	-	-	-	-	-	-
25	Insurance - General Liability	11,302	-	-	-	-	-	-	-	-	-	-	-
26	Insurance - Vehicles	2,516	-	-	-	-	-	-	-	-	-	-	-
27	Regulatory Commission Expense	-	-	-	-	-	-	-	-	-	-	-	-
28	Reg. Comm. Exp. - Rate Case	29,167	-	-	-	-	-	-	-	-	-	-	-
29	Miscellaneous Expense	16,111	-	-	(7,292)	-	-	-	-	-	-	-	-
30	Bad Debt Expense	23,194	-	-	-	-	-	-	-	-	-	-	-
31	Depreciation and Amortization Expense	359,629	(150,435)	-	-	-	-	-	-	-	-	-	-
32	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
33	Property Taxes	74,520	-	1,103	-	-	-	-	-	-	-	-	-
34	Income Taxes	93,481	-	-	-	-	-	-	-	-	-	-	-
35													
36	Total Operationing Expenses (L8 thru L44)	$ 1,146,757	$ (150,435)	$ 1,103	$ (7,292)	$ -	$ -	$ -	$ -	$ 546	$ -	$ -	$ (9,448)
37													
38	Operating Income (L5 less L36)	$ 213,826	$ 150,435	$ (1,103)	$ 7,292	$ 12,213	$ 4,305	$ 20,805	$ 4,305	$ (546)	$ -	$ -	$ 9,448

REFERENCES:
Adjustment No. 1 - Company Schedule C-1
Adjustment No. 2 - Depreciation Expense Schedule TJC-12
Adjustment No. 3 - Property Tax Expense Schedule TJC-13
Adjustment No. 4 - Rate Case Expense Schedule TJC-14
Adjustment No. 5 - Revenue Annualization of 6" Meter Bulk Water Sales for Known and Measurable Sales Sch. TJC-15
Adjustment No. 6 - Intentionally Left Blank for Water Division Schedule TJC-16
Adjustment No. 7 - Revenue Accrual of 6" Meter Bulk Water Sales for Known and Measurable Sales Schedule TJC-17
Adjustment No. 8 - Intentionally Left Blank for Water Division Schedule TJC-18
Adjustment No. 9 - Expense Annualization Related to RUCO's Revenue Annualization Adjustment No. 4- Schedule TJC-19
Adjustment No. 10 - Intentionally Left Blank Schedule TJC-20
Adjustment No. 11 - Miscellaneous Expense Schedule TJC-21
Adjustment No. 12 - Achievement/Incentive Pay per Company Response to RUCO DR 1.15 Schedule TJC-22

Rio Rico Utilities, Inc
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Rio Rico - Wastewater Division
Schedule TJC-11

OPERATING INCOME

Line No.		[M] Operating Income Adjustment No. 12 Merit Pay Expense	[N] Operating Income Adjustment No. 13 Adjust O&M Treatment Expense	[O] Operating Income Adjustment No. 14 Reclassify Treatment Expense	[P] Operating Income Adjustment No. 15 APUC Corporate Allocations	[Q] Operating Income Adjustment No. 16 Income Tax Expense	[R] Operating Income Adjustment No. 17 Not Used	[S] Operating Income Adjustment No. 18 Not Used	[T] Operating Income Adjustment No. 19 Not Used	[U] Operating Income Adjustment No. 20 Not Used	[V] Operating Income Adjustment No. 21 Not Used	[W] RUCO Total Pro Forma Adjustments	[X] Test Year Adjusted Results
1	**Operating Revenues**												
2	Metered Water Revenues	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,629	$ 1,402,212
3	Unmetered Revenues	-	-	-	-	-	-	-	-	-	-	-	-
4	Other Water Revenues	-	-	-	-	-	-	-	-	-	-	-	-
5	Total Water Revenues (L2 thru L4)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 41,629	$ 1,402,212
6													
7	**Operating Expenses**												
8	Salaries and Wages	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 131,547
9	Purchased Wastewater Treatment	-	-	108,999	-	-	-	-	-	-	-	108,999	108,999
10	Sludge Removal Expense	-	-	-	-	-	-	-	-	-	-	-	-
11	Purchased Power	-	-	-	-	-	-	-	-	-	-	505	61,796
12	Fuel for Power Production	-	-	-	-	-	-	-	-	-	-	-	-
13	Chemicals	-	-	-	-	-	-	-	-	-	-	40	4,947
14	Materials and Supplies	-	-	-	-	-	-	-	-	-	-	-	4,473
15	Management Services - US Liberty Wtr	(783)	-	-	-	-	-	-	-	-	-	(783)	82,255
16	Management Services - Corporate	-	-	-	(10,225)	-	-	-	-	-	-	(19,673)	39,619
17	Management Services - Other	-	(56,897)	(108,999)	-	-	-	-	-	-	-	(165,896)	6,374
18	Contracted Services - Engineering	-	-	-	-	-	-	-	-	-	-	-	-
19	Contractual Services - Testing	-	-	-	-	-	-	-	-	-	-	-	330
20	Contractual Services - Other	-	-	-	-	-	-	-	-	-	-	-	638
21	Contractual Services - Legal	-	-	-	-	-	-	-	-	-	-	-	585
22	Equipment Rental	-	-	-	-	-	-	-	-	-	-	-	400
23	Rents - Building	-	-	-	-	-	-	-	-	-	-	-	-
24	Transportation Expenses	-	-	-	-	-	-	-	-	-	-	-	18,068
25	Insurance - General Liability	-	-	-	-	-	-	-	-	-	-	-	11,302
26	Insurance - Vehicles	-	-	-	-	-	-	-	-	-	-	-	2,516
27	Regulatory Commission Expense	-	-	-	-	-	-	-	-	-	-	-	-
28	Reg. Comm. Exp. - Rate Case	-	-	-	-	-	-	-	-	-	-	(7,292)	21,875
29	Miscellaneous Expense	-	-	-	-	-	-	-	-	-	-	-	16,111
30	Bad Debt Expense	-	-	-	-	-	-	-	-	-	-	-	23,194
31	Depreciation and Amortization Expense	-	-	-	-	-	-	-	-	-	-	(150,435)	209,194
32	Taxes Other Than Income	-	-	-	-	-	-	-	-	-	-	-	-
33	Property Taxes	-	-	-	-	-	-	-	-	-	-	1,103	75,624
34	Income Taxes	-	-	-	-	116,437	-	-	-	-	-	116,437	209,919
35													
36	Total Operationing Expenses (L8 thru L44)	$ (783)	$ (56,897)	$ -	$ (10,225)	$ 116,437	$ -	$ -	$ -	$ -	$ -	$ (116,994)	$ 1,029,764
37													
38	Operating Income (L5 less L36)	$ 783	$ 56,897	$ -	$ 10,225	$ (116,437)	$ -	$ -	$ -	$ -	$ -	$ 158,622	$ 372,448

REFERENCES:
Adjustment No. 13 - Intentionally Left Blank Schedule TJC-23
Adjustment No. 14 - APUC Cost Allocations Adjustment Schedule TJC-24
Adjustment No. 15 - Income Tax Expense Adjustments Schedules TJC-15 and TJC-1, page 2
Adjustment No. 16 - Not Used
Adjustment No. 17 - Not Used
Adjustment No. 18 - Not Used
Adjustment No. 19 - Not Used
Adjustment No. 20 - Not Used
Adjustment No. 21 - Not Used
Column [W] - RUCO Total Adjustments
Column [X] - RUCO Recommended Adjusted Test Year Level of Expenses
Column [X] - RUCO Adjusted Test Year Operating Income Recommendations (Col. [A] + Col. [W])

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OPERATING INCOME ADJUSTMENT NO. 1
DEPRECIATION EXPENSE

Line No.	NARUC Account	Description	Company Adjusted Gross Plant Balance	RUCO Depreciable Plant Adjustments	RUCO Rate Base Adjustments 1(a) - 4(a)	RUCO Recommended Depreciable Balance	Depreciation Rate	RUCO Depreciation Expense Going Forward
1	351	Organization	$ 5,785	$ -	$ -	$ 5,785	0.00%	$ -
2	352	Franchise	417	-	-	417	0.00%	-
3	353	Land	7,545	-	-	7,545	0.00%	-
4	354	Structures & Improvements	150,294	28,842	-	121,452	3.33%	4,044
5	355	Power Generation	-	-	-	-	5.00%	-
6	360	Collection Sewer Forced	636,023	-	-	636,023	2.00%	12,720
7	361	Collection Sewers Gravity	5,991,654	415	(415)	5,991,239	2.00%	119,825
8	362	Special Collecting Structures	-	-	-	-	2.00%	-
9	363	Customer Services	1,204,113	-	-	1,204,113	2.00%	24,082
10	364	Flow Measuring Devices	66,339	-	-	66,339	10.00%	6,634
11	366	Reuse Services	-	-	-	-	2.00%	-
12	367	Reuse Meters And Installation	-	-	-	-	8.33%	-
13	370	Receiving Wells	867,120	-	-	867,120	3.33%	28,875
14	371	Pumping Equipment	1,712,940	1,594,241	-	118,700	12.50%	14,837
15	374	Reuse Distribution Reservoirs	-	-	-	-	2.50%	-
16	375	Reuse Trans. and Dist. System	-	-	-	-	2.50%	-
17	380	Treatment & Disposal Equipment	1,128,675	1,161,642	(1,161,642)	(32,967)	5.00%	(1,648)
18	381	Plant Sewers	13,690	-	-	13,690	5.00%	685
19	382	Outfall Sewer Lines	-	-	-	-	3.33%	-
20	389	Other Sewer Plant & Equipment	64,928	64,928	-	-	6.67%	-
21	390	Office Furniture & Equipment	116,937	-	-	116,937	6.67%	7,800
22	390.1	Computers and Software	4,025	4,025	-	-	20.00%	-
23	391	Transportation Equipment	117	-	-	117	20.00%	23
24	392	Stores Equipment	-	-	-	-	4.00%	-
25	393	Tools, Shop And Garage Equip	5,139	4,894	-	245	5.00%	12
26	394	Laboratory Equip	-	-	-	-	10.00%	-
27	396	Communication Equip	5,936	5,936	-	-	10.00%	-
28	398	Other Tangible Plant	3,913	3,913	-	-	10.00%	-
29		Nogales WWTP	2,255,600	(1,177,004)	1,177,004	3,432,604	4.00%	137,304
30			$ 14,241,191	$ 1,691,833	$ 14,947	$ 12,549,358		$ 355,194
31		Less: Amortization of Contributions				Gross CIAC $ (5,152,673)	Amortization Rate 2.8335%	(146,000)
32		RUCO Total Depreciation Expense						$ 209,194
33		Company Adjusted Depreciation Expense As Filed						359,629
34		RUCO Increase/(Decrease) Expense Adjustment						$ (150,435)

References:
Company B-2 and C-1 Schedules, RUCO Schedule TJC-5(c) on Pages 3 and6, and RUCO Schedule 4(a).

OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAXES

LINE NO	Property Tax Calculation	(A) RUCO AS ADJUSTED	(B) RUCO RECOMMENDED
1	RUCO Adjusted Test Year Revenues - Ended February 29, 2012 Per RUCO Schedule TJC-10	$ 1,402,212	$ 1,402,212
2	Multiplied by 2	2	2
3	Subtotal (Line 1 * Line 2)	$ 2,804,424	$ 2,804,424
4a	RUCO Adjusted Test Year Revenues - Ended February 29, 2012 Per RUCO Schedule TJC-10	1,402,212	
4b	RUCO Recommended Revenue Per RUCO Schedule TJC-9		1,405,272
5	Subtotal (Line 3 + Line 4a)	$ 4,206,636	$ 4,209,696
6	Number of Years	3	3
7	Three Year Average (Line 5 / Line 6)	$ 1,402,212	$ 1,403,232
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (Line 7 * Line 8)	$ 2,804,424	$ 2,806,464
10	Plus: 10% of CWIP Per Company As Filed	-	-
11	Less: Net Book Value of Licensed Vehicles	108	108
12	Full Cash Value (Line 9 + Line 10 - Line 11)	$ 2,804,316	$ 2,806,356
13	Assessment Ratio	20.0%	20.0%
14	Assessed Value (Line 12 * Line 13)	$ 560,863	$ 561,271
15	Composite Property Tax Rate (Per RUCO Effective Property Tax Calculation)	13.4835%	13.4835%
16	RUCO Adjusted Test Year Property Tax Expense (Line 14 * Line 15)	75,624	
17	Company Adjusted Test Year Property Tax Expense (Per Company Schedule C-1)	74,520	
18	RUCO Test Year Adjustment (Line 16-Line 17)	$ 1,103	
19	Property Tax - RUCO Recommended Revenue (Line 14 * Line 15)		$ 75,679
20	RUCO Test Year Adjusted Property Tax Expense (Line 16)		75,624
21	Increase/(Decrease) to Property Tax Expense		$ 55
22	Increase/(Decrease) to Property Tax Expense		$ 55
23	Increase in Revenue Requirement		3,060
24	Increase /(Decrease) to Property Tax per Dollar Increase in Revenue (Line 22 / Line 23)		1.7978%

OPERATING INCOME ADJUSTMENT NO. 3
RATE CASE EXPENSE

Line No.			Amount
1	Company Requested Total Amount of Rate Case Expense	$	87,500
2			
3	Company Requested the Expense be Amortized Over a 3-Year Period		3
4			
5	Company's Annual Amortization Expense (L1 / L3)	$	29,167
6			
7	RUCO's Recommended Normalization is Over a 4-Year Period		4
8			
9	RUCO's Recommended Annual Normalization of Rate Case Expense (L1 / L7)	$	21,875
10			
11	RUCO's Recommended Expense Adjustment		(7,292)

OPERATING INCOME ADJUSTMENT NO. 4
REVENUE ANNUALIZATION

Line No.	Meter Size	Class	Company Annualization Present Revenues	RUCO Annualization Adjustments	RUCO Annualization Present Revenues	Additional Bills	Additional Gallons to be Pumped (in 1,000's)
1	5/8X3/4 Inch	Residential	$ (7,478)	$ -	$ (7,478)	(151) 1	-
2	5/8X3/4 Inch	Residential (Low Income)	11,894	-	11,894	305	-
3	3/4 Inch	Residential	(106)	-	(106)	(2)	-
4	1 Inch	Residential	(323)	-	(323)	(5)	-
5	1 Inch	Residential (Low Income)	165	-	165	3	-
6	1 1/2 Inch	Residential	-	-	-	-	-
7	2 Inch	Residential	(132)	-	(132)	(1)	-
8		Subtotal	$ 4,019	$ -	$ 4,019	149	-
9							
10	5/8X3/4 Inch	Commercial	$ 2,592	$ -	$ 2,592	44	432
11	1 Inch	Commercial	1,892	-	1,892	27 2	301
12	1 1/2 Inch	Commercial	25	-	25	-	5
13	2 Inch	Commercial	361	-	361	5 3	54
14	3 Inch	Commercial	-	-	-	4 4	-
15	4 Inch	Commercial	(1,837)	-	(1,837)	-	(393)
16	6 Inch	Commercial	(12,213)	12,213	-	8 5	-
17		Subtotal	$ (9,179)	$ 12,213	$ 3,034	88	399
18							
19	5/8X3/4 Inch	Multi-tenant	$ (47)	$ -	$ (47)	(2)	(5)
20	1 1/2 Inch	Multi-tenant	-	-	-	-	-
21		Subtotal	$ (47)	$ -	$ (47)	(2)	(5)
22							
23	Up to 8 Inch	Fire Lines	-	-	-	-	-
24							
25							
26							
27	Total Revenue Annualization		$ (5,207)	$ 12,213	$ 7,006	235	-
28							
29							
30	RUCO Total Revenue Annualization						$ 7,006
31							
32	Company Revenue Annualization						(5,207)
33							
34							
35	RUCO Increase/(Decrease) Adjustment to Revenue and/or Expense						$ 12,213
36							
37							
38							
39	Total Increase/(Decrease) Gallons to be Produced						394
40							
41							
42	SUPPORTING SCHEDULES						
43	RUCO Schedules TJC-15, pages 2 thru 18 and Company Schedule C-1, page 2.1						

Note
1 Includes 12 Additional Bills Identified in Company's Response to RUCO DR 6.1
2 Includes 12 Additional Bills Identified in Company's Response to RUCO DR 6.1
3 Includes 12 Additional Bills Identified in Company's Response to RUCO DR 6.1
4 Includes 12 Additional Bills Identified in Company's Response to RUCO DR 6.1
5 Includes 12 Additional Bills Identified in Company's Response to RUCO DR 4.2

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Residential 5/8" Meter

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Direct Schedule TJC-15
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LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	1,805	21,660
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1,876	1,837	1,831	1,823	1,378	2,236	1,810	1,816	1,797	1,805	1,809	1,805	21,823
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(71)	(32)	(26)	(18)	427	(431)	(5)	(11)	8	-	(4)	-	(163)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 45.88	$ 45.88	$ 45.88	$45.88	$ 45.88	$ 45.88	$ 45.88	$ 45.88	$ 45.88	$ 45.88	$ 45.88	$ 45.88	
5	INCREASE/(DECREASE) IN REVENUES	$(3,257)	$(1,468)	$(1,193)	$ (826)	$19,591	$(19,774)	$ (229)	$ (505)	$ 367	$ -	$ (184)	$ -	$ (7,478)
6	TOTAL INCREASE/(DECREASE) IN REVENUE	(7,478)												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	(7,478)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	(71)	(32)	(26)	(18)	427	(431)	(5)	(11)	8	-	(4)	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

Rio Rico Utilities, Inc
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Test Year Ended February 29, 2012
Residential 5/8" Meter - Low Income

Rio Rico - Wastewater Division
Direct Schedule TJC-15

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	83	83	83	83	83	83	83	83	83	83	83	83	996
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	36	40	49	33	82	67	69	74	78	80	83	691
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	83	47	43	34	50	1	16	14	9	5	3	-	305
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 39.00	$39.00	$39.00	$39.00	$39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	$ 39.00	
5	INCREASE/(DECREASE) IN REVENUES	$ 3,237	$1,833	$1,677	$1,326	$1,950	$ 39	$ 624	$ 546	$ 351	$ 195	$ 117	$ -	$ 11,894
6	TOTAL INCREASE/(DECREASE) IN REVENUE	11,894												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	11,894												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	83	47	43	34	50	1	16	14	9	5	3	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{-}$												-

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Residential 3/4" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	8	8	8	8	8	8	8	8	8	8	8	8	96
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	8	8	8	9	10	8	8	7	8	8	8	8	98
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	(1)	(2)	-	-	1	-	-	-	-	(2)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 52.88	$52.88	$52.88	$52.88	$52.88	$ 52.88	$ 52.88	$ 52.88	$ 52.88	$ 52.88	$ 52.88	$ 52.88	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ (53)	$ (106)	$ -	$ -	$ 53	$ -	$ -	$ -	$ -	$ (106)
6	TOTAL INCREASE/(DECREASE) IN REVENUE	(106)												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (106)												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	-	-	-	(1)	(2)	-	-	1	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{-}$												-

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Residential 1" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	9	9	9	9	9	9	9	9	9	9	9	9	108
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	12	10	10	10	9	9	9	9	9	9	8	9	113
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(3)	(1)	(1)	(1)	-	-	-	-	-	-	1	-	(5)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 64.64	$64.64	$64.64	$64.64	$64.64	$ 64.64	$ 64.64	$ 64.64	$ 64.64	$ 64.64	$ 64.64	$ 64.64	
5	INCREASE/(DECREASE) IN REVENUES	$ (194)	$ (65)	$ (65)	$ (65)	$ -	$ -	$ -	$ -	$ -	$ -	$ 65	$ -	$ (323)
6	TOTAL INCREASE/(DECREASE) IN REVENUE	(323)												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (323)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	(3)	(1)	(1)	(1)	-	-	-	-	-	-	1	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	-	-	1	1	1	1	1	1	1	1	1	9
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	1	1	-	-	-	-	-	-	-	-	-	3
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 54.94	$54.94	$54.94	$54.94	$54.94	$ 54.94	$ 54.94	$ 54.94	$ 54.94	$ 54.94	$ 54.94	$ 54.94	
5	INCREASE/(DECREASE) IN REVENUES	$ 55	$ 55	$ 55	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 165
6	TOTAL INCREASE/(DECREASE) IN REVENUE	165												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ 165												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	1	1	1	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	-
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	-	-	-	-	-	-	-	-	-	-	-	-
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 95.44	$95.44	$95.44	$95.44	$95.44	$ 95.44	$ 95.44	$ 95.44	$ 95.44	$ 95.44	$ 95.44	$ 95.44	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL INCREASE/(DECREASE) IN REVENUE	-												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ -												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

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Test Year Ended February 29, 2012
Residential 2" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	-
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1	-	-	-	-	-	-	-	-	-	-	-	1
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	(1)	-	-	-	-	-	-	-	-	-	-	-	(1)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$132.38	$132.38	$132.38	$132.38	$132.38	$132.38	$ 132.38	$ 132.38	$ 132.38	$ 132.38	$ 132.38	$ 132.38	
5	INCREASE/(DECREASE) IN REVENUES	$ (132)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ (132)
6	TOTAL INCREASE/(DECREASE) IN REVENUE	(132)												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (132)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	-	-	-	-	-	-	-	-	-	-	-	
10	INCREASE IN CUSTOMERS	(1)	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 5/8" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	59	59	59	59	59	59	59	59	59	59	59	59	708
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	54	53	54	54	26	82	55	56	56	56	60	59	664
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	5	6	5	5	33	(23)	4	3	3	3	(1)	-	44
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 52.14	$50.18	$46.56	$58.94	$ 66.54	$ 59.02	$ 55.21	$ 59.14	$ 46.83	$ 47.11	$ 45.88	$ 49.13	
5	INCREASE/(DECREASE) IN REVENUES	$ 275	$ 313	$ 255	$ 295	$ 2,196	$ (1,379)	$ 211	$ 177	$ 144	$ 140	$ (33)	$ -	$ 2,592
6	TOTAL INCREASE/(DECREASE) IN REVENUE	2,592												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ 8,071												
8	RUCO REVENUE ADJUSTMENT	(5,478)												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	8,340	7,921	7,146	9,796	11,423	9,814	8,998	9,839	7,204	7,264	6,965	7,695	
10	INCREASE IN CUSTOMERS	5	6	5	5	33	(23)	4	3	3	3	(1)	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	43,953	49,349	39,069	48,981	376,962	(229,351)	34,461	29,518	22,117	21,574	(5,064)	-	431,569
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	431,569												431,569

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 1" Meter

Rio Rico - Wastewater Division
Direct Schedule TJC-15
Page 10 of 18

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	42	42	42	42	42	42	42	42	42	42	42	42	500
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	41	38	39	39	38	44	41	41	41	41	41	42	485
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	4	3	3	4	(2)	1	1	1	1	1	-	15
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$100.75	$116.13	$105.77	$171.33	$127.96	$ 88.63	$ 85.60	$ 88.10	$ 91.75	$ 89.58	$ 90.15	$ 89.29	
5	INCREASE/(DECREASE) IN REVENUES	$ 68	$ 426	$ 328	$ 457	$ 521	$ (207)	$ 57	$ 59	$ 61	$ 60	$ 60	$ -	$ 1,892
6	TOTAL INCREASE/(DECREASE) IN REVENUE	1,892												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ 7,260												
8	RUCO REVENUE ADJUSTMENT	(5,369)												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	14,732	18,026	15,807	29,846	20,559	12,136	11,488	12,024	12,805	12,341	12,463	12,279	
10	INCREASE IN CUSTOMERS	1	4	3	3	4	(2)	1	1	1	1	1	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	9,870	66,157	49,003	79,689	83,673	(28,278)	7,697	8,056	8,579	8,269	8,350	-	301,066
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	301,066												301,066

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	7	7	7	7	7	7	7	7	7	7	7	7	84
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	7	7	7	7	6	8	7	7	7	7	7	7	84
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	1	(1)	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$208.19	$204.85	$206.19	$267.56	$267.45	$241.96	$ 200.85	$ 152.15	$ 175.50	$ 168.16	$ 195.51	$ 151.48	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ 267	$ (242)	$ -	$ -	$ -	$ -	$ -	$ -	$ 25
6	TOTAL INCREASE/(DECREASE) IN REVENUE	25												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (1,047)												
8	RUCO REVENUE ADJUSTMENT	1,072												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	31,143	30,429	30,714	43,857	43,833	38,375	29,571	19,143	24,143	22,571	28,429	19,000	
10	INCREASE IN CUSTOMERS	-	-	-	-	1	(1)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	43,833	(38,375)	-	-	-	-	-	-	5,458
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	5,458												5,458

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 2" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	27	27	27	27	27	27	27	27	27	27	27	27	324
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	26	27	27	27	26	28	27	27	27	27	27	27	323
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	-	-	-	1	(1)	-	-	-	-	-	-	1
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$330.59	$302.58	$308.28	$313.30	$279.13	$281.49	$ 287.87	$ 267.46	$ 258.64	$ 242.73	$ 262.97	$ 293.41	
5	INCREASE/(DECREASE) IN REVENUES	$ 364	$ -	$ -	$ -	$ 279	$ (281)	$ -	$ -	$ -	$ -	$ -	$ -	$ 361
6	TOTAL INCREASE/(DECREASE) IN REVENUE	361												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ 361												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	49,444	43,444	44,667	45,741	38,423	38,929	40,296	35,926	34,037	30,630	34,963	41,481	
10	INCREASE IN CUSTOMERS	1	-	-	-	1	(1)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	54,388	-	-	-	38,423	(38,929)	-	-	-	-	-	-	53,883
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	53,883												53,883

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Commercial 3" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1	1	1	1	1	1	1	1	1	1	1	1	12
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$230.62	$235.29	$239.96	$310.01	$338.03	$305.34	$ 464.12	$ 529.50	$ 697.62	$ 324.02	$ 324.02	$ 305.34	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL INCREASE/(DECREASE) IN REVENUE	-												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ -												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	-	8,000	9,000	24,000	30,000	23,000	57,000	71,000	107,000	27,000	27,000	23,000	
10	INCREASE IN CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	4	4	4	4	4	4	4	4	4	4	4	4	48
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	4	4	4	4	2	6	4	4	4	4	4	4	48
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	2	(2)	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$1,523.34	$1,877.09	$1,685.62	$2,353.43	$1,434.61	$2,353.04	$ 1,807.04	$1,786.03	$ 1,725.32	$ 1,233.80	$1,499.99	$ 2,749.22	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ 2,869	$ (4,706)	$ -	$ -	$ -	$ -	$ -	$ -	$ (1,837)
6	TOTAL INCREASE/(DECREASE) IN REVENUE	(1,837)												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (1,837)												
8	RUCO REVENUE ADJUSTMENT	$\boxed{-}$												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	260,000	335,750	294,750	437,750	241,000	437,667	320,750	316,250	303,250	198,000	255,000	522,500	
10	INCREASE IN CUSTOMERS	-	-	-	-	2	(2)	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	482,000	(875,333)	-	-	-	-	-	-	(393,333)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	$\boxed{(393,333)}$												(393,333)

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1	1	1	1	1	1	1	1	1	1	1	1	12
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$2,601.64	$2,013.22	$649.58	$6,818.65	$3,876.55	$3,544.98	$ 1,004.50	$2,087.94	$ 2,853.82	$ 2,601.64	$2,106.62	$ 2,858.49	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL INCREASE/(DECREASE) IN REVENUE	-												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (12,213)												
8	RUCO REVENUE ADJUSTMENT	12,213												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	425,000	299,000	-	1,328,000	698,000	627,000	83,000	315,000	479,000	425,000	319,000	480,000	
10	INCREASE IN CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Multi-Family 5/8" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	6	6	6	6	6	6	6	6	6	6	6	6	72
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	5	7	7	7	4	8	6	6	6	6	6	6	74
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	1	(1)	(1)	(1)	2	(2)	-	-	(0)	-	-	-	(2)
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$ 56.94	$56.61	$55.22	$51.88	$77.40	$ 51.72	$ 56.00	$ 49.77	$ 45.88	$ 45.88	$ 55.22	$ 105.03	
5	INCREASE/(DECREASE) IN REVENUES	$ 44	$ (32)	$ (55)	$ (52)	$ 155	$ (103)	$ -	$ -	$ (3)	$ -	$ -	$ -	$ (47)
6	TOTAL INCREASE/(DECREASE) IN REVENUE	(47)												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ (47)												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	9,369	9,297	9,000	8,286	13,750	8,250	9,167	7,833	6,931	7,000	9,000	19,667	
10	INCREASE IN CUSTOMERS	1	(1)	(1)	(1)	2	(2)	-	-	(0)	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	7,214	(5,299)	(9,000)	(8,286)	27,500	(16,500)	-	-	(416)	-	-	-	(4,787)
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(4,787)												(4,787)

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Multi-Family 1.5" Meter

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	1	1	1	1	1	1	1	1	1	1	1	1	12
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	1	1	1	1	1	1	1	1	1	1	1	1	12
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	-	-	-	-	-	-	-	-	-	-	-	-	-
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	$100.11	$100.11	$100.11	$100.11	$137.47	$151.48	$ 132.80	$ 118.79	$ 132.80	$ 114.12	$ 114.12	$ 109.45	
5	INCREASE/(DECREASE) IN REVENUES	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
6	TOTAL INCREASE/(DECREASE) IN REVENUE	-												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ -												
8	RUCO REVENUE ADJUSTMENT	-												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	8,000	8,000	8,000	8,000	16,000	19,000	15,000	12,000	15,000	11,000	11,000	10,000	
10	INCREASE IN CUSTOMERS	-	-	-	-	-	-	-	-	-	-	-	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	-	-	-	-	-	-	-	-	-	-	-	-	-
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	-												-

Rio Rico Utilities, Inc
Docket No. WS-02676A-12-0196
Test Year Ended February 29, 2012
Fire Lines Up to 8 Inch

LINE NO.	DESCRIPTION	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	JANUARY	FEBRUARY	TOTAL YEAR
1	TEST YEAR END CUSTOMERS	4	4	4	4	4	4	4	4	4	4	4	4	48
2	ACTUAL TEST YEAR CUSTOMERS BY MONTH	-	-	-	-	-	-	-	-	-	-	-	4	4
3	INCREASE/(DECREASE) NUMBER OF CUSTOMERS/BILLS	4	4	4	4	4	4	4	4	4	4	4	-	44
4	AVERAGE REVENUE FOR THE MONTH/PRESENT RATES	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ -	
5	INCREASE/(DECREASE) IN REVENUES	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	$ -	#DIV/0!
6	TOTAL INCREASE/(DECREASE) IN REVENUE	#DIV/0!												
7	INCREASE/(DECREASE) IN REVENUE PER COMPANY	$ -												
8	RUCO REVENUE ADJUSTMENT	#DIV/0!												
9	GALLONS SOLD PER AVERAGE CUSTOMER PER MONTH	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	-	
10	INCREASE IN CUSTOMERS	4	4	4	4	4	4	4	4	4	4	4	-	
11	RUCO INCREASE/(DECREASE) IN GALLONS	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	-	#DIV/0!
12	COMPANY INCREASE IN GALLONS													-
13	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	#DIV/0!												#DIV/0!

OPERATING INCOME ADJUSTMENT NO. 5
MISSING BILL COUNTS REVENUE ANNUALIZATIONS

Line No.	Missing Bill Counts:	Amount
1		
2	Nogales Imperial, LLC - ICE	$ 1,072
3	Nogales Imperial, LLC - Fish & Game	1,267
4	Southern Arizona Title Insurance	1,415
5	Sergio Sanchez	551
6	RUCO Adjustment to Revenue and/or Expense	$ 4,305

SUPPORTING SCHEDULES
Per Company Response to RUCO DR 6.1(d)

OPERATING INCOME ADJUSTMENT NO. 6
6 INCH COMMERCIAL METER REVENUE ACCRUAL

Line No.	Revenue Accrual	
1	Company Revenue Accrual Adjustment	$ 41,889
2	RUCO Revenue Accrual Per RRUI Response to RUCO DR 4.2(d)	62,694
3	RUCO Adjustment to Revenue and/or Expense	$ 20,805

SUPPORTING SCHEDULES
Company Schedule C-1, page 2.1 and RRUI Response to RUCO DR 4.2(d)

OPERATING INCOME ADJUSTMENT NO. 7
MISSING METER BILL COUNTS REVENUE ACCRUAL

Line No.	Revenue Accrual:	
1	Company Revenue Accrual Adjustment	$ -
2	Per Company Response to RUCO DR 6.1(d)	4,305
3	RUCO Adjustment to Revenue and/or Expense	$ 4,305

OPERATING INCOME ADJUSTMENT NO. 8
EXPENSE ANNUALIZATION

Line No.	Expense Annualization	
1	Total Cost of Purchased Power Expense (Company Schedule C-1)	$ 61,290
2		
3	Total Cost of Chemical Expense (Company Schedule C-1)	$ 4,907
4		
5	Total Gallons Sold (In 1,000 Gallons) Per Company Schedule H-2, Page 3.2	47,765
6		
7	Cost of Purchased Power Expense Per 1,000 Gallons (L1 / L5)	1.2831
8		
9	Cost of Chemical Expense Per 1,000 Gallons (L3 / L5)	0.1027
10		
11	Total Revenue Annualization Increase/(Decrease) Gallons to be Produced (RUCO Schedule TJC-15, Page 1 of 21 and Company Schedule H-1, Page 2)	394
12		
13		
14	RUCO Adjustment to Purchased Power Expense (L7 X L11)	$ 505
15		
16	RUCO Adjustment to Chemical Expense (L9 X L11)	$ 40

OPERATING INCOME ADJUSTMENT NO. 9
INTENTIONALLY LEFT BLANK - FOR FUTURE USE

Line
No.

OPERATING INCOME ADJUSTMENT NO. 10
MISCELLANEOUS EXPENSE

Line No.	Description	Company Water Division	Company Wastewater Division	RUCO Water Adjustments	RUCO Wastewater Adjustments
	Caritable Donations and Sponsorships:				
1	Rio Rico Little League Per MJR 2-7	$ 1,000	$ -	$ (1,000)	
2	RRUI's 2011 Christmas Party Expenses Per MJR 2-7	802		(802)	
3		$ 1,802	$ -		
4	RUCO Miscellaneous Expense Water Adjustment			(1,802)	
5	RUCO Miscellaneous Expense Wastewater Adjustment				-

OPERATING INCOME ADJUSTMENT NO. 11
ACHIEVEMENT / INCENTIVE PAY

Line No.	Description	Total RRUI Amount	Amount Allocated to RRUI Water	Amount Allocated to RRUI Wastewater
1				
2				
3				
4				
5				
6				
7	CONFIDENTIAL			
8				
9				
10				
11				
12				
13				
14				
15				
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27	References:			
28	Company's Response to RUCO Data Request 2.13			

OPERATING INCOME ADJUSTMENT NO. 12
MERIT PAY ADJUSTMENT - 50/50 SHARING

Line No.	Description	[A] Company Water Amount	[B] Company Wastewater Amount	[C] RUCO Water Amount	[D] RUCO Wastewater Amount
1					
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CONFIDENTIAL

OPERATING INCOME ADJUSTMENT NO. 13
ADJUST TEST YEAR CITY OF NOGALES O&M TREATMENT EXPENSES

Line No.	Adjust Treatment Expenses:		
1	Company Adjusted Test Year City of Nogales Treatment Expenses Per RUCO DR 2.8	$	165,896
2	RUCO Adjustment Per City of Nogales Letter dated May 10, 2012		108,999
3	RUCO Increase/(Decrease) Adjustment to Revenue and Expenses	$	(56,897)

OPERATING INCOME ADJUSTMENT NO. 14
RECLASSIFY THE CITY OF NOGALES TREATMENT O&M EXPENSES

Line No.	Reclassify Treatment Expenses:	
1	Reclassify O&M Treatment Expenses from Management Services - Other Account	$ (108,999)
2	Reclassify O&M Treatment Expenses to Purchased Wastewater Treatment Account	$ 108,999
3	RUCO Increase/(Decrease) Adjustment to Revenue and Expenses	$ -

OPERATING INCOME ADJUSTMENT NO. 14
APUC COST ALLOCATIONS

Line No.	Description	[A] Company Requested Cost	[B] Currency Conversion 1.05 CSD -> USD	[C] Company Allocation 9.21% RRUI Water	[D] Company Allocation 3.01% RRUI Sewer	[E] Percentage Amount Allowed	[F] RUCO Recommended Allocations RRUI Water	[G] Company Recommended Allocations RRUI Sewer
1	Audit	$ 136,866	$ 130,348	$ 11,999	$ 3,924	100%	$ 11,999	$ 3,924
2	Tax Services	37,197	35,426	3,261	1,067	100%	3,261	1,067
3	Legal	179,072	170,545	15,699	5,134	100%	15,699	5,134
4	Other Professional Services	86,163	82,060	7,554	2,470	0%	-	-
5	Unit Holder Communications	100,802	96,002	8,837	2,890	0%	-	-
6	Trustee Fees	97,290	92,657	8,529	2,789	0%	-	-
7	Computer	54,904	52,290	4,813	1,574	100%	4,813	1,574
8	Office Expenses	48,404	46,099	4,244	1,388	100%	4,244	1,388
9	Capital Tax	29,167	27,778	2,557	836	0%	-	-
10	Insurance	26,554	25,289	2,328	761	50%	1,164	381
11	Travel	17,146	16,330	1,503	492	100%	1,503	492
12	Vehicle Rental Expense	3,162	3,012	277	91	100%	277	91
13	Accommodation	11,469	10,923	1,005	329	100%	1,005	329
14	Meals and Entertainment	18,516	17,634	1,623	531	100%	1,623	531
15	Parking Mileage	4,284	4,080	376	123	100%	376	123
16	Escrow & Transfer Agent Fees	17,505	16,671	1,535	502	0%	-	-
17	Training	5,450	5,190	478	156	100%	478	156
18	HR Recruitment	6,374	6,070	559	183	100%	559	183
19	Rent	38,137	36,321	3,343	1,093	100%	3,343	1,093
20	Donations	1,638	1,560	144	47	0%	-	-
21	Communications	20,389	19,418	1,788	585	100%	1,788	585
22	Dues and Memberships	10,796	10,282	947	310	0%	-	-
23	Licenses/Fees & Permits	150,573	143,402	13,201	4,317	100%	13,201	4,317
24	APS Overhead Allocation	(8,066)	(7,682)	(707)	(231)	100%	(707)	(231)
25								
26	Total APUC Allocations Per Company and RUCO	$1,093,791	$1,041,705	$ 95,892	$ 31,361		$ 64,626	$ 21,135
27	RUCO Water and Wastewater Division's APUC Cost Allocation Recommendation						64,626	21,135
28	Company Water Division's APUC Cost Allocation Requested						95,892	31,361
29	RUCO Water and Wastewater Division's APUC Cost Allocation Adjustment						$ (31,266)	$ (10,225)
	Variance by Company Per Response to RUCO DR 3.7			$ (540)	$ (177)			

OPERATING INCOME ADJUSTMENT NO. 15
ADJUSTED TEST YEAR INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAX PER RUCO:		
1	Operating Income Before Taxes	Sch. TJC-10, Col. [C], L38 + L34	$ 582,367
	LESS:		
2	Arizona State Tax	Line 16	37,895
3	Interest Expense	Note (A) Line 27	38,521
4	Federal Taxable Income	Line 1 - Line 2 - Line 3	$ 505,951
5	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%		$ 7,500
6	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%		6,250
7	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%		8,500
8	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%		91,650
9	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%		58,123
10	Total Federal Income Tax Expense (L5 + L6 + L7 + L8 + L9)		$ 172,023
11	Effective Federal Income Tax Rate	Line 10 / Line 4	34.00%
	STATE INCOME TAX PER RUCO:		
12	Operating Income Before Taxes	Line 1	$ 582,367
	LESS:		
13	Interest Expense	Note (A) Line 27	38,521
14	State Taxable Income	Line 12 - Line 13	$ 543,846
15	State Tax Rate	Sch. TJC-1, pg. 2, Col. [A] L10	6.968%
16	State Income Tax Expense	Line 14 X Line 15	$ 37,895
	RUCO TOTAL INCOME TAX EXPENSE:		
17	Federal Income Tax Expense	Line 10	$ 172,023
18	State Income Tax Expense	Line 16	37,895
19	Total Income Tax Expense Per RUCO	Line17 + Line 18	$ 209,919
20	Total Federal Income Tax Expense Per Company (Company Sch. GRCF, Col. (B), L53		75,722
21	Total State Income Tax Expense Per Company (Company Sch. GRCF, Col. (B), L44)		17,759
22	RUCO Federal Income Tax Adjustment	Line 10 - Line 20	$ 96,301
23	RUCO State Income Tax Adjustment	Line 16 - Line 21	$ 20,136
24	RUCO Total Federal & State Income Tax Adjustment		$ 116,437

NOTE (A):

24	Interest Synchronization:	
25	Adjusted Rate Base (Sch. TJC-2, Col. (C), L23)	$ 4,663,510
26	Weighted Cost Of Debt (Sch. TJC-28 Col. [D], L1)	0.83%
27	Interest Expense (L25 X L26)	$ 38,521

COST OF CAPITAL

LINE NO.	DESCRIPTION	[A] CAPITAL RATIO	[B] COST RATE	[C] WEIGHTED COST RATE
1	Long-Term Debt	20.00%	4.13%	0.83%
2	Common Equity	80.00%	9.00%	7.20%
3	Total Capitalization			
4	WEIGHTED AVERAGE COST OF CAPITAL			8.03%

References:
Columns [A] Thru [C]: WAR Testimony