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Docket #(s): W-02500A-10-0382

Exhibit # : RUC02, RUC03, RUC05 - RUC08

Arizona Corporation Commission
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To: Docket Control

Date: November 17, 2011

Re: Goodman Water Company / Rates
W-02500A-10-0382
Volumes I through V, Concluded
July 26 through November 1, 2011

STATUS OF ORIGINAL EXHIBITS

EXHIBITS FILED WITH DOCKET CONTROL

Goodman Water Company (A Exhibits)

1 through 23

James Schoemperlen (JS Exhibits)

8, 9, 21, 41 through 44, 51, 52

Lawrence Wawrzyniak (LW Exhibits)

1 through 6, 8, 9

Staff (S Exhibits)

1 through 4, 7 through 15

Residential Utility Consumer Office (RUCO Exhibits)

1 through 3, 5 through 14

EXHIBITS RETURNED TO PARTIES

James Schoemperlen (JS Exhibits)

1-2	Not utilized
3-4	Not offered [by design or oversight]
4a	Not utilized
4b	Not offered [by design or oversight]
5	Not offered [by design or oversight]
5a	Not utilized
6	Not utilized
7	Not offered [by design or oversight]
10	Not offered [by design or oversight]
12-14	Not offered [by design or oversight]
15	Not utilized
16	Not offered [by design or oversight]
17	Not utilized
20	Not utilized
20b	Not utilized
22-23	Not utilized
25-38	Not utilized
38a	Not utilized
39a-c	Not utilized
40	Not utilized
46a	Not offered [by design or oversight]

Lawrence Wawrzyniak (LW Exhibits)

7	Not utilized

Residential Utility Consumer Office (RUCO Exhibits)

4	Withdrawn

EXHIBITS TO BE PROVIDED

Staff (S Exhibits)

5	Marlin Scott's Calculation of the 1,800 customers; to be provided by Staff (see page 600 of transcript)
6	Third step of Marlin Scott's calculation from MSJ-1; to be provided by Staff (see page 600 of transcript)

EXHIBITS NOT UTILIZED
Not given to court reporter

James Schoemperlen (JS Exhibits)

11, 18, 19, 20a, 24, 45, 47-50

Copy to:

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Ms. Bridget A. Humphrey, Staff
Mr. Daniel Pozefsky, RUCO
Mr. Lawrence Wawrzyniak, Intervenor
Mr. James Schoemperlen, Intervenor

EXHIBIT
RUCO-2
ADMITTED

GOODMAN WATER COMPANY

DOCKET NO. W-02500A-10-0382

SURREBUTTAL TESTIMONY

OF

JODI A. JERICH

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 13, 2011

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Q. Please state your name, occupation and business address for the record.

A. My name is Jodi Jerich. I am the Director of the Arizona Residential Utility Consumer Office (RUCO). My business address is 1110 W. Washington Street, Suite 220, Phoenix, Arizona 85007.

Q. Please state your educational background and qualifications in the utility regulation field.

A. Governor Brewer appointed me to serve as the Director of RUCO in February 2009. The Arizona State Senate found my qualifications met the statutory requirements found in Arizona Revised Statutes §40-462 and confirmed my appointment. As Director, I oversee and approve all testimony and briefs filed by RUCO. In consultation with my staff, I direct the public policy decisions of the office.

From 2003 through 2005, I was employed at the Arizona Corporation Commission as the Policy Advisor to Corporation Commissioner Mike Gleason. In that role, I advised the Commissioner on matters coming before the Commission. I was actively involved in the utility policy-making decisions of that Commissioner's office.

Except for the time I was employed by the Commission, from 1997 through 2008, I was employed at the Arizona House of Representatives. I held several positions during my tenure, eventually becoming Chief of Staff and Counsel to the Majority Caucus. Relevant to the question at hand, I advised Legislators on matters involving water, energy, Commission jurisdiction and utility security.

In 2006, when Governor Janet Napolitano appointed Barry Wong to fill the Commission seat vacated by Commissioner Marc Spitzer's appointment to the Federal Energy Regulatory Commission (FERC), I took a leave of absence from the Legislature for a short time in order to assist Commissioner Wong establish his office.

Finally, I am a Phi Beta Kappa graduate of Indiana University. I also have a law degree from Indiana University and am a member of the Arizona and Tennessee bars.

Q. Have you filed testimony previously in this docket?

A. No.

Q. What is the purpose of your surrebuttal testimony?

A. I will provide testimony on two issues. First, I will explain RUCO's objection to the Company's position on rate case expense. Notably, that the Company in its rebuttal testimony, now requests the Commission ***double*** its rate case expense amount because of RUCO's participation in this matter.

Second, I will discuss RUCO's policy position on excess capacity. Specifically, I will testify why RUCO believes "prudent" expenditures and "used and useful" plant are two distinct concepts in utility ratemaking. My testimony on the policy considerations of excess capacity are meant to complement the technical calculations made of the amount of excess capacity of Goodman's system by RUCO's witness, Mr. Coley.

RATE CASE EXPENSE

Q. Have you, in your position as Director of RUCO, ever filed testimony on rate case expense before?

A. No.

Q. What compels you to address this matter, which is typically a routine, albeit disputed, issue in virtually every rate case?

A. Mr. Bourassa claims that RUCO's intervention in this rate case is a direct cause of the doubling of rate case expense.

> "First, RUCO has intervened in this case which was not anticipated. In my experience, RUCO typically does not get involved in Class C and smaller company rate cases. Whatever the reason RUCO chose to intervene in the instant case ***RUCO's intervention has and will cause a significant increase in costs.***" (emphasis added)
>
> (Bourassa Rebuttal Testimony, p. 33, lines 7-10)

Q. Does Mr. Bourassa's assertion that RUCO's involvement justifies a 100% spike in rate case expense have any merit?

A. None. Mr. Bourassa's rebuttal testimony is both specious and inflammatory. His rebuttal testimony suggests that RUCO's intervention actually injures customers because our participation will result in higher rates. This position infers that RUCO's participation only serves to punish the ratepayers. If not conclusively repudiated now, the Commission can expect this message to be repeated in testimony for other utilities.

Q. Is RUCO allowed to intervene in rate cases of small utility companies?

A. Yes. In A.R.S. §40-462, the Legislature directs RUCO to represent the interests of residential utility consumers before the Corporation

Commission. A.R.S. §40-464 authorizes RUCO to intervene, ***at the discretion of the Director***, in any rate case of a "public service corporation" as a party in interest no matter what the size of the Company. While RUCO does not have the resources to intervene in every rate case, we do our best to provide support to Arizonans who need a voice before the Commission.

Q. So why did RUCO intervene in this matter?

A. RUCO intervened for several reasons.

First, Congresswoman Gabrielle Giffords' office contacted RUCO and brought this rate case to our attention. A copy of the email from Ron Barber, Congresswoman Giffords' District Director, to me is attached as Exhibit A.

Second, State Senator Al Melvin contacted RUCO regarding this rate increase. Like Congresswoman Giffords, State Senator Melvin represents the residents served by Goodman Water.

Third, several residents of Eagle Crest Ranch approached RUCO asking for our intervention in the rate case.

Fourth, the glaring issue of excess capacity of Goodman Water's system is a matter of concern for RUCO.

Q. Isn't it true that the Company could not have foreseen the issue of excess capacity raised in this rate case and that this justifies doubling rate case expense?

A. Absolutely not. The Company had ample notice that excess capacity was going to be an issue in its rate case at the time it filed its Application. And it was in its Application that the Company provided its original estimated rate case expense. The Company has failed to provide any legitimate reason for increasing rate case expense beyond its original estimate filed in its Application.

Q. What support does RUCO have for claiming Goodman Water was on notice that excess capacity was "on the table" for this rate case?

A. Prior to the filing of the Application, Commission Staff issued a Staff Report regarding Goodman Water's system. In that Report, Staff noted the following:

> "Based on these plant capacities, ***this system can currently serve approximately 1,800 customers***...In addition, Staff concludes that the water system has sufficient capacity to meet the customer growth through 2019." (emphasis added)
>
> September 2, 2010 Staff Report, p. 2

The service list shows that the Report was mailed to Goodman Water and to its attorney of record. Additionally, the Report was docketed and publicly available.

Q. And how many customers did Goodman Water have during the Test Year?

A. 626 customers.[1] This customer count is well below the 1,800 customers that the system can accommodate as calculated by Staff.

Q. Even if the Company could reasonably foresee Staff raising the excess capacity argument, isn't it fair to say that it could not have foreseen (1) RUCO's intervention and (2) RUCO's analysis of excess capacity?

A. Not really. The level of customer discontent was so high that RUCO's participation should not have come as a surprise.

Furthermore, Mr. Bourassa is familiar with RUCO's excess capacity argument. After all, it is the same excess capacity argument RUCO made

[1] See Bourassa Schedule H-2, p. 4.

in Gold Canyon.[2] (Docket No. SW-02519A-06-0015) In fact, Mr. Bourassa was the expert witness for Gold Canyon in that matter. As Mr. Bourassa notes in his rebuttal testimony, "I am very familiar with that case, because I was both a consultant and witness for the Company." (Bourassa Rebuttal Testimony, p. 19, lines 9-10)

Q. Do you have any concluding remarks regarding rate case expense?

A. Yes. The Company has failed to provide any legitimate reasons why the Commission should allow rate case expense over and above the Company's original request of $80,000. $80,000 is a reasonable amount of rate case expense for several reasons. First, it is a rational amount of compensation when requesting a $262,717 rate increase.[3] A $160,000 rate case expense is blatantly unreasonable when compared to the size of the requested overall revenue increase. A rate case expense that is roughly 2/3 of the total increase is not only unreasonable, but offensive. The Company should know better than to make a request that in essence punishes its ratepayers through unreasonable and meritless rate case expense. Second, $80,000 is a reasonable amount because it is the amount requested by the Company in its Application. The Company is in the best

[2] RUCO's excess capacity argument is the same although its calculations and methodology are different. For example, in Gold Canyon, RUCO did not recommend an extra 10% margin when calculating the amount of excess capacity. However, RUCO did recommend a reserve margin calculated in a different way applicable to the facts and circumstances of that case. The reserve margin benefits the utility in both cases.
[3] See Bourassa Rebuttal Testimony, p. 2, lines 1-4.

position to make an informed cost estimate. At the time of its Application, it had notice that excess capacity was going to be a litigated issue. Furthermore, it knew that there was a significant amount of discontent among its ratepayers and RUCO's intervention was certainly possible.

In essence, Mr. Bourassa's excessive and unsupported inflation of rate case expense sends the wrong message to customers, to elected officials, RUCO and to the Commission.

To customers, Mr. Bourassa's testimony states that customers should not request RUCO intervene in their rates cases. For if they do, the utility will only ask for more rate case expense and, in the end, RUCO's participation will only end up hurting the customers' wallets. Another way of looking at this is that any success RUCO's participation would have in reducing a rate increase would only be wiped out by an alleged increase in rate case expense.

To elected officials, Mr. Bourassa's testimony signals that these officials should not get involved in matters involving their constituents. For if they do, they run the risk of elevating rate case expense.

To RUCO, Mr. Bourassa's testimony attempts to provide a chilling effect on the decision making of the Director.

To the Commission, Mr. Bourassa's testimony impedes on the necessary balancing of interests between ratepayers and the utility. For Mr. Bourassa, the Company can hire him and other high priced experts to advocate on its behalf. But customers deserve no similar advocate.

It is true that RUCO does not typically intervene in cases involving smaller utilities. RUCO simply does not have the financial and staff resources to intervene in every rate case. However, that does not mean that RUCO will not get involved in a smaller case if there is a good reason. RUCO chooses to intervene in cases where RUCO's participation can have the greatest impact on the largest number of ratepayers or in cases where there is an important issue of public policy or law in question in dispute. In this rate case, where rates are already well above the rates of neighboring water utilities and the case involves a sizeable amount of excess capacity, RUCO's participation is lawful, appropriate and helpful to the discussion. The claim that RUCO's participation doubles rate case expense, if left unchecked, effectively impedes RUCO's legal obligation to fulfill its mandate to represent the interests of Arizona families and individuals before the Corporation Commission.

EXCESS CAPACITY

Q. **What is the purpose of your testimony on excess capacity?**

A. The purpose of my testimony is to explain the policy reasons in support of RUCO's position on excess capacity and its concept of a "reserve margin". Specifically, I will discuss why it is so important that excess capacity be removed from rate base. Furthermore, I will provide detail why RUCO believes that even if a utility made a "prudent" decision to build out its system, the Commission must and should refuse to allow recovery of that prudently incurred cost until that plant is "used and useful". "Prudent" and "used and useful" are not synonymous terms. Each requires its own analysis. This is evident after looking at several factors:

1. The plain language of the Commission's Rules.
2. Past Commission decisions.
3. Arizona case law and US Supreme Court case law.
4. Public policy.

The Theory of Excess Capacity and Its Exclusion from Rate Base

Q. What is excess capacity?

A. The concept of excess capacity is not new to utility ratemaking. Nonetheless, the term "excess capacity" is not defined in Commission Rule.

However, the Commission, in its ***Gold Canyon*** Order states that excess capacity is "available plant capacity that exceeded the amount necessary to serve its existing customers."[4]

Q. Why does RUCO believe it is important that excess capacity be removed from ratebase?

A. Since excess capacity is plant that exceeds the amount necessary to serve its existing customers, it is plant that will serve future customers and should not be paid for by current customers. To allow excess plant into ratebase is to allow a utility to recover costs from existing customers for plant that will serve future customers. It is completely contrary to basic tenets of utility ratemaking. It shifts the entire risk of growth on current ratepayers resulting in unfair and inflated rates that effectively leave the utility with little incentive to self-police itself when determining plant requirements. Furthermore, it obliterates any sense that customers are paying a fair cost for the service provided.

Q. **Isn't RUCO being unrealistic in prohibiting a utility from recovering any amount of plant that does not precisely match up to the exact customer count in an historical test year? More bluntly, isn't RUCO totally naïve about real world business practices and if RUCO's**

[4] Decision No. 69664, p. 5, lines 20-23.

position is adopted it would restrict utilities from making prudent business decisions?

A. Absolutely not. RUCO readily admits that it is a typical business practice to plan ahead for growth. If an enterprise expects to grow and expand it must plan for such growth.

Furthermore, it is because of this reality that RUCO is not recommending that ALL excess plant be removed from ratebase. Under Mr. Coley's methodology, RUCO recommends a "reserve margin" to reflect this real world dilemma that utilities face in balancing the need to accommodate for growth without overbuilding.

Q. Explain RUCO's "reserve margin" theory.

A. RUCO acknowledges that a water system cannot be designed to serve the exact number of current customers in any sort of economically feasible manner. The planning of future capacity requirements is not an exact science. But the negative impact of such an inexact calculation should not be entirely borne by either the ratepayer or the shareholder. For this reason, RUCO's recommends a "reserve margin". This "reserve margin" provides the balance that assures that risk is equitably shared by both parties. To balance these considerations in this case, RUCO recommends a reserve margin that exceeds the Company's six percent (6%) customer

growth rate from year 2009-2010. The reserve margin allows ample time for the Company to make any necessary service line connections and meter installations.

Adoption of RUCO's "reserve margin" allows the Commission to balance risk of anticipated growth among both the investors and the ratepayers in a manner that is fair to both. The reserve margin benefits the utility because it allows some amount of plant that is available for future customers to be included into ratebase now. It also benefits the utility because it provides the Company the ability to address plans for growth without fear of being unable to precisely estimate the number of customers during the test year for their next rate case. Finally, it takes away any perceived disincentive that might make a utility under-build its plant.

Q. Why is RUCO's "reserve margin" approach different than Staff's "engineering analysis"?

A. As I stated earlier, RUCO believes it is appropriate that the Commission accept the reality that plant cannot be built to the precise customer count in the test year. And that in the short run, there will possibly be plant that can

accommodate more customers than those served by the utility in the historical test year. [5]

Staff and the Company proposes an "engineering approach" that provides recovery for costs that meet a 5-year planning horizon. Under this engineering approach, as long as the Company's growth projections were reasonable at the time they were made, then the plant that was built to meet this 5-year planning horizon is prudent. And because it is prudent it is inherently used and useful. RUCO respectfully contends that this logic is strained – that these two concepts are separate and discrete considerations. The finding of "prudent costs" cannot bootstrap a finding of "used and useful".

RUCO believes that its "reserve margin" approach is a better balance of ratepayer and utility considerations than Staff's 5-year engineering analysis. First, a five year period places the entire risk of that five year projection on current ratepayers. Second, RUCO finds that a five year look ahead is too long of a time period. Arizona residents are witnesses to Arizona's rapidly-changing economic environment and our state's habitual boom/bust cycles that began in the Wild West days of Tombstone, Arizona and continue

[5] Perhaps there has been no time more evident than in today's current real estate crisis to recognize the dilemma faced by both ratepayers and utilities. Utilities that designed plant during the real estate "boom" days of a few years ago are now facing the "bust" of that cycle. So, too are the ratepayers who are facing high unemployment levels, mortgage foreclosures, substantial losses of equity in their homes and sharply rising utility rates. The result is excess capacity that does not serve existing customers. RUCO believes this issue is likely to repeat in other rate cases. A clearly defined policy on excess capacity that is fair to both the ratepayers and the utility and its shareholders is needed.

through to today's mortgage meltdown crisis. Third, the 5-year rule of thumb does not provide the Commission any flexibility based on the specific situation of any particular case. Each rate case present unique facts and the Commission should have a flexible guideline to balance the interests of those ratepayers while still giving the industry a stable and easily understandable guideline to follow. Fourth, the engineering analysis relies almost entirely on the uncensored projections of the Company. It is my understanding that there is little oversight on the utility's 5-year projections. Finally, as I will discuss in greater detail below, RUCO disagrees strongly that the Commission should allow all prudently incurred costs regardless of whether the plant is used and useful.

Q. So, while RUCO is recommending a 10% reserve margin in this case, could RUCO recommend a different percentage of reserve margin in a future case?

A. Yes. Mr. Coley's testimony defends how RUCO came to find that 10% is appropriate in this case. The point of my testimony is to explain why the concept of a "reserve margin" provides an equitable balance between the interests of ratepayers and shareholders.

Q. **Staff and every intervenor in this rate case makes the argument that the Company has excess capacity on its system. Does exclusion of**

plant that is not being used to service existing customers in this rate case mean that the Company would be left unwhole for its investment in that plant?

A. No. Exclusion of the excess capacity merely changes from whom the costs are recovered and when. When growth actually occurs, the full amount of the investment at that time would receive rate base treatment and rate recovery. The Company can elect to file another rate case at a time of their choosing.

Prudence and Used and Useful are Two Distinct Ratemaking Concepts, are Not Synonymous and Both Criteria Must be Met For Rate Recovery

Q. Mr. Bourassa comments that the Company's decision to invest $3.1 million in plant expansions was prudent at the time and these costs are, therefore, must be considered used and useful. (Bourassa rebuttal testimony, pp. 10-11) Does RUCO believe that prudent costs should be recovered if the plant is not used and useful?

A. No. RUCO contends that costs must be **both** "prudent" and "used and useful" in order to be placed into ratebase. Each term has its own meaning and requires a different analysis. RUCO's position is supported by:

1. The plain language of the Commission's Rules.
2. Past Commission Decisions.

3. Sound public policy.

I explain each supporting argument in detail below.

1. The Plain Language of the Commission's Rules.

Q. What is a prudently incurred expense?

A. Commission Rule R14-2-103 defines "Prudently Invested" as:

> "Investments which under ordinary circumstances would be deemed reasonable and not dishonest or obviously wasteful. All investments shall be presumed to have been prudently made, and such presumptions may be set aside only by clear and convincing evidence that such investments were imprudent, when viewed in the light of all relevant conditions known or which in the exercise of reasonable judgment should have been known, at the time such investments were made." (R14-2-103(I))

For further guidance, the National Regulatory Research Institute (NRRI) defines "prudence review" as follows:

> "The process by which a regulator determines the prudence of utility resource decisions goes to the heart of the goal of aligning private and public interests For utility-built resources, utilities often seek this approval many years ***prior to the resource being determined "used and useful" and available for service***..." (emphasis added) (http://communities.nrri.org/web/mutli-utility-diversity-in-utility-contracts/glossary) (Exhibit B)

Q. Does Commission Rule define "used and useful"?

A. No. However, Commission Rule defines "Original Cost Rate Base" as:

> An amount consisting of the depreciated original cost, ***prudently invested***, of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, ***used or useful***, plus a proper allowance for working capital and including all applicable pro forma adjustments." (R14-2-103(h))
>
> A similar definition exists for "Reconstructed Cost New Rate Base"

Q. In your opinion, what does these definitions tell you?

A. It tells me that in order to be placed into ratebase, the Commission's own rules require the cost be both prudent and used and useful. In other words, the Commission requires in its own Rules that the two concepts have different considerations.

Q. Why?

A. To begin, it is informative that the definition of "prudently invested" makes no mention of used and useful. "Used and useful" is not a factor in the definition of "prudently invested". Furthermore, the definitions of OCRB and RCND include both "prudent" and "used and useful" as elements in consideration of its calculation. If "prudent" and "used and useful" mean the same thing, then there would be no reason to mention both concepts in the definitions of OCRB or RCND.

The plain language of the Commission's own rules tell me that these two concepts have separate meanings. Second, the basic rules of statutory

construction requires that each word must be given its own meaning.[6] Again, basic statutory construction and interpretation lead me to the conclusion that these two terms do not have the same meaning.

2. Past Commission Decisions.

Q. Has the Commission agreed with your assertion that "prudent" and "used and useful" are two distinct ratemaking concepts and that *both* criteria must be met before the Commission authorizes rate recovery?

A. Yes. Commission Decisions support RUCO's position that "prudent" and "used and useful" are two separate ratemaking concepts and that both criteria must be met before costs may be recovered in rates. Furthermore, the Commission has consistently required plant to be used and useful before allowing it to be placed into rate base.

In a 2001 ***Arizona Water*** rate case for its Northern Group, the Company asked for recovery of costs to install a steel casing during planned ADOT highway construction with an open trench. This casing would be used to

[6] "In construing statute or rule, court presumes that promulgating body did not intend to do futile act by including provision that is not operative or that is inert and trivial, and thus must give every word, phrase, clause and sentence meaning so that no part of the rule is rendered superfluous, void, insignificant, redundant or contradictory. (Patterson v. Maricopa County Sheriff's Office, 177 Ariz. 153, 156 (App. 1993).

replace an existing water line in 2003. Arizona Water claimed the cost was prudent because it would have cost much more if the utility had not taken advantage of ADOT's open trench. In rejecting this argument, the Commission stated:

> "We agree that the Company's decision to take advantage of the ADOT project was prudent. However, we disagree that the Company is entitled to recover the cost of placing the steel casing in this proceeding since the plant is not used and useful at this time. After the project to the subdivision is completed the Company may seek inclusion in rate base. Until the plant is being used for provision of utility service the costs are not includable in the Company's rate base." (Decision No. 64282, p. 9, lines 13-17)

Of course, the most recent, and most contentious case involving the debate over the scope of these two terms came in ***Gold Canyon.*** Upon rehearing, the Commission agreed with RUCO that although Gold Canyon's costs were prudent, they were not permitted into rate base because they were not used and useful. (Decision No. 70624 at p. 9)

Q. What other Commission Decisions support RUCO's assertion that plant must be used and useful prior to being placed into rate base?

A. Commission Decisions in ***Pima Utility*** (Decision No. 58743), ***LPSCO*** (Decision Nos. 57944 and 50273), provide further support that plant must be used and useful. Furthermore, through these Decisions, we see that the Commission does not commingle the terms "used and useful" and "prudent". They are separate and discrete considerations.

In ***Pima Utility***, the Commission stated:

"In the instant case, the CWIP has been completed by the additional plant is not serving any customers. The Company is asking current customers to pay for plant that is not used and useful and will be used to serve only future customers. Although there was evidence presented that a small percentage of this additional plant may be considered used and useful from an engineering standpoint, as of the date of the hearing, for ratemaking purposes this additional plant is not used and useful under the circumstances." (Id at 5)

In ***LPSCO*** Decision No. 50273, The Commission stated:

"For ratemaking purposes 50% of the total installed cost of the new treatment plant shall be considered used and useful property for inclusion in rate base on the in service date. The remaining 50% shall be included in rate base proportionate to the percentage of utilization in any given test year." (Id. at 2)

The Decision is highly illustrative of the difference between "prudent" and "used and useful". Here, the Commission has impliedly made a prudency determination that 100% of the plant is "prudent". However, only when the remaining plant is "used and useful" will it be included in rate based in any given test year.

In ***LPSCO*** Decision No. 56362, the Commission excluded excess capacity from rate base.

"Staff excluded from rate base a sludge concentrator that is no longer used and useful and continued to disallow approximately 50% of the sewage treatment plant found to be excess capacity in Decision No. 50273." (Id. at 7)

Q. Any other regulatory support for RUCO's position that "prudent" and "used and useful" are two different concepts?

A. Yes. The 2004 NARUC Ad Hoc Committee on Critical Infrastructure issued a paper on cost recovery for critical infrastructure protection measures. In it, NARUC discusses the dilemma of how to allow recovery of costs to protect critical infrastructure if no attack occurs.

> "Under traditional regulation, utilities may recover costs that are both "prudent" and "used and useful" **It is the role of a commission to review costs and ensure that recovery is based on prudently incurred costs that are both used and useful.** (Emphasis in the original) How that review occurs is a product of state statute, administrative rules, and traditions of practice." (Exhibit C, p. 20)

In support of this statement, the NARUC paper cites to Duquesne Light Company v. Barasch, 488 US 299 (1989). I will discuss Duquesne and other cases later in my testimony.

3. Sound Public Policy

Q. **Earlier in this testimony, you stated that the third reason why "prudent" and "used and useful" are two separate ratemaking concepts is grounded in sound public policy. Can you explain your reasoning for this statement?**

A. Yes. Sound public policy requires these two terms to have different meanings and different applications in ratemaking. This assertion is best articulated in the amicus brief filed by the Industrial Energy Consumers of Pennsylvania in the United States Supreme Court case Duquesne.[7] Although long winded, it hits the policy bulls-eye. It reads in part:

> "The Fifth and Fourteenth amendments to the United State Constitution do not require states to allow recovery of or on prudently incurred investments by regulated utilities without any consideration of whether those investments produced used and useful utility property...
>
> By creating a constitutional entitlement to utility investor recovery which does not produce used and useful public service, this Court would upset the long-established principle of public utility regulation that should mirror the competitive private marketplace in an otherwise monopolistic business...In the private unregulated economy, the invisible hand of the market usually does not provide a return or, or on, investments, however prudent, which turn out to be wrong by not producing property which is used and useful in making products or service consumers wish to purchase...The visible hand of public regulation should not provide an affirmative constitutional entitlement to the recovery of such prudent, yet uneconomic, investments. Such an entitlement would create an undue preference for the utility investor over the investor in the private competitive marketplace. It would not only shift the balance in favor of the utility investor over the ratepayer and the private investor, but would also upset the balance inherent in the American economy between regulated entities and nonregulated entities. The former would recover any prudent investment, with the cost of prudent but uneconomic investment borne by their customers and not by their shareholders. Competitive private enterprises have no such guarantee and the cost of their prudent, yet uneconomic investments are usually borne entirely by their shareholders. No rational reading of this Court's teaching in the Hope and Permian

[7] In Duquesne, the US Supreme Court upheld Pennsylvania statute that precluded inclusion of plant in rate base until it was used and useful. This case stemmed from the issue of whether Pennsylvania utilities that invested funds in the construction of nuclear power plants that were later abandoned or cancelled could recover their prudently invested costs.

Basin cases would conclude that this Court intended the former as a result." (Amicus Brief of Industrial Energy Consumer of Pennsylvania, 1987 WL 880084)

Q. Does that conclude your testimony on this subject?

A. Yes.

EXHIBIT A

Jodi Jerich

From: Barber, Ron [Ron.Barber@mail.house.gov]
Sent: Thursday, November 04, 2010 11:54 AM
To: Jodi Jerich
Subject: Goodman Water Company issue
Attachments: Congresswoman Giffords letter to ACC.pdf

Dear Ms. Jerich,

Congresswoman Gabrielle Giffords has asked me to contact you to request that you review the proposed Goodman Water Company rate increase. The Congresswoman recently received a copy of an email (copy below) that was sent to you in which residents of Eagle Crest Ranch requested an opportunity to discuss their concerns with you. She is hopeful that you will meet with the residents as they have requested.

The Congresswoman has received 35 complaints from constituents who would be affected by another water rate increase. We understand that more than 300 additional complaints have been send directly to the Arizona Corporation Commission. I have attached a copy of Congresswoman Giffords' letter to the ACC regarding this matter.

Thank you for your consideration of this rate increase issue that would have a dramatic and adverse impact on the residents of Eagle Crest Ranch.

-----Original Message-----
From: Larry Wawrzyniak <larrywaw@hotmail.com>
To: Jodi Jerich <jjerich@azruco.gov>
Cc: Bill Rigsby <brigsby@azruco.gov>; Bill Daniels <bildaniels@aol.com>; JimSchoemperlen <jscho@sargentcontrols.com>
Sent: Wed, Oct 13, 2010 10:53 pm
Subject: Goodman Water Co. Rate Increase

To: Jodi Jerich, Director RUCO

Re: Docket No. W-02500A-10-0382 Goodman Water Co. Rate Increase

The residents of Eagle Crest Ranch are the only customers of the Goodman Water Company (GWC). GWC has submitted a rate increase that is unjustified and based on speculative infrastructure costs.

Here are our talking points:

GWC built a water plant with capacity for 1,800 homes but we only have 650 homes built. This is approximately 200 more homes since our last rate increase in 2007. See Docket No. W-02500A-06-0281: Decision #69404. The total development build out is 920 homes. This is almost a 100% over capacity. See Document No. 116091, dated 9/2/10 attached. We should not have to pay bailout for any speculative capacity built by GWC though rate increases.

Our current water rate is approximately 250-300% more than adjacent communities (SaddleBrooke $23, Catalina $27, Goodman $70) and GWC appears to have no concern on the effects on future homes sales but rather sink money into infrastructure as a means to a guaranteed return on investment better than the general financial market.

The depreciation of capital plan they are using is flawed. We have a CPA, Jim Shoemperlen, on our committee who has documented this issue and can discuss this with you.

We have concurrently discussed these topics with State Senator Al Melvin, Senatorial Candidate Cheryl

Cage and Congresswomen Gabrielle Giffords', District Director Ron Barber. All have indicated that there is cause to investigate this further and they offered to support this issue.

We also had a very informative discussion with Bill Rigsby who has been most helpful in assisting us and recommended that we contact you.

We would like to schedule a conference call with you to discuss a request for your staff to act as Intervener for our case.

Looking forward to your reply,

Larry Wawrzyniak, Chairman, Concerned Citizens Committee
Bill Daniels, Chairman, Homeowners Executive Advisory Committee
Jim Schoemperlen, CPA

Ron Barber
District Director
Congresswoman Gabrielle Giffords
520.881.3588

Sign-up* for e-updates from Congresswoman Giffords at *www.giffords.house.gov

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SUBCOMMITTEE ON ENERGY AND ENVIRONMENT

FOREIGN AFFAIRS
SUBCOMMITTEE ON THE WESTERN HEMISPHERE

October 29, 2010

Chairwoman Kris Mayes
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Dear Chairwoman Mayes,

I am writing on behalf of 35 residents of Eagle Crest Ranch who have contacted my office with serious concerns about Goodman Water Company's proposed water rate increase. As you know, I have been sending you the residents' concerns as they have come into my office. Thank you for your receptivity to this information. I understand that you have also directly received hundreds of other letters on this issue.

I have reviewed the letters and information presented to my staff by representatives of the residents of Eagle Crest Ranch when they met to discuss the community's concerns. The drastic jump in water rates for the customers of Goodman Water Company that would result from an approval of their application is most alarming. Many of my constituents must make difficult decisions about household costs and family expenditures. A large jump in their monthly utility bills will only add to the financial challenges they are facing.

Given the large volume of comments submitted by the residents of Eagle Crest Ranch opposing this rate increase, it is clear that the impact of Goodman Water Company's actions will not be small. Thank you for giving thorough consideration to the residents' concerns and for seeking ways to minimize the hardships this rate increase would impose. I have copied your colleagues on the Arizona Corporation Commission and ask the same of them.

Sincerely yours,

Gabrielle Giffords
Member of Congress

cc: Sandra Kennedy, Commissioner, Arizona Corporation Commission
Paul Newman, Commissioner, Arizona Corporation Commission
Gary Pierce, Commissioner, Arizona Corporation Commission
Bob Stump, Commissioner, Arizona Corporation Commission

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EXHIBIT B

GLOSSARY

(Redirected from FrontPage)

Below are electric industry glossary terms. Some of these definitions come from Spectra Energy's website. Please augment definitions or add additional terms, though do so in alphabetical order. Please note that some of these definitions come from other sources like the EIA, Spectra Energy, and ISO New England.

Accumulated deferred income taxes (ADIT): An adjustment to rate base reflecting timing differences in taxes for book and ratemaking purposes. Accelerated tax depreciation is one of the drivers of ADIT.

Accelerated depreciation: A regulatory (not tax) treatment that allows the utility to recover asset capital costs more rapidly than through conventional straight-line depreciation, through which the utility recovers costs evenly over each asset's useful life.

Adjustment clauses: Allowing for recovery of specified costs as incurred, e.g., on a monthly or annual basis.

Advanced metering infrastructure: Meters and data systems that facilitate two-way communication between customer meters and the utility. Information can be transmitted at intervals ranging from five minutes to an hour. Advanced meters can use radio or fiber optic technology to communicate information.

Ad valorem tax: A state or local tax based on the assessed value of the real or personal property.

Air Conditioning Cycling Program: A demand-side management program in which the utility remotely controls customers' cooling equipment and periodically interrupts power to the equipment during times of high power system demands.

Allocation: The assignment of property functionalized and classified utility costs to customers, customer groups, or unbundled services based on cost causation principles.

Allowance for funds used during construction (AFUDC): A non-cash accounting convention of regulatory utilities that represents the estimated composite interest costs of debt and a return on equity funds used to finance construction. The allowance is capitalized in the property accounts and included in income.

Alternating Current (AC): A periodic current, the average value of which over a period is zero. Unless distinctly specified otherwise, the term refers to a current that reverses its direction at regularly recurring intervals of time and that has alternately positive and negative values. Almost all electric utilities generate AC electricity because it can easily be transformed to higher or lower voltages.

Ancillary services: Ancillary services are those services necessary to support the transmission of energy from generation to loads while maintaining reliable operation of the Transmission Provider's transmission system in accordance with Good Utility Practice. These include including regulation and frequency response (regulation or automatic generator control), spinning reserve, nonspinning reserve, replacement reserve, and reactive supply and voltage control.

Annualization: An adjustment to a cost of service study to reflect a full 12 months effect of a rate base, income, or expense item that is only if effect for a part of the year.

Arbitrage: Trading the same security, currency or commodity in two or more markets in order to profit from differences in prices. Economic theory states that arbitrage eliminates inefficiencies in markets.

Auction revenue rights (ARR): Entitlements in regional transmission organizations to receive revenues generated by the sale of Financial Transmission Rights in a specific auction.
Available transfer capability (ATC): The amount of energy above "base case" conditions that can be transferred reliably from one area to another over all transmission facilities without violating any pre- or post-contingency criteria for the facilities in a control area under specified system conditions.
Average cost: The revenue requirement divided by the quantity of utility service.
Average Cost Pricing: A pricing mechanism based on dividing the total cost of providing electricity incurred in a period by the number MWh (wholesale) and kWh (retail) sold in the same period.
Asset retirement obligation (ARO): A liability for the legal obligation associated with the retirement of a tangible long-lived asset that a company is required to settle as a result of existing or enacted law, statute, ordinance or written oral contract. AROs are amortized over the remaining life of the asset.
Baseload capacity: The generation normally operated at all times to serve load. Typically, this includes units with low marginal costs such as hydro and nuclear generators.
Baseload Plant: A plant, usually housing high-efficiency steam-electric units, which is normally operated to take all or part of the minimum load of a system, and which consequently produces electricity at an essentially constant rate and runs continuously. These units are operated to maximize system mechanical and thermal efficiency and minimize system operating costs.
Basis point: As applied to the return on equity and rate of return, each basis point is one one-hundredth of a percent.
Bilateral Contract: A direct contract two parties centralized power pool or RTO auction. Examples include contracts between independent power producers a utilities and contracts between two utilities selling energy, ancillary services, capacity, or fuel.
Black start capability: The ability to rapidly start an off-line, idle, non-spinning electric generation source. Such abilities enhance grid reliability and are considered ancillary services.
Btu (British Thermal Unit): A standard unit for measuring the quantity of heat energy equal to the quantity of heat required to raise the temperature of 1 pound of water by 1 degree Fahrenheit.
Capacity factor: The ratio of total energy produced by a generator for a specified period to the maximum it could have produced if it ran at nameplate capacity through the entire period, expressed as a percent.
Capacity market: Markets found in certain RTOs including PJM and ISO New England where generators receive compensation for investing in generating capacity. Load-serving entities, the market participants that secure electric energy, transmission service, and related services to serve the demand of their customers, make capacity payments to generators to ensure the long-term availability of sufficient generation capacity for the reliable operation of the bulk power grid.
Coefficient of correlation: A measure of how well trend in one variable follows trend in another variable. The correlation coefficient is a number between 0 and 1. If there is no relationship between the two variables the correlation coefficient is close to 0. The stronger the relationship, the higher the correlation coefficient. Cluster analysis - a technique that is used in different disciplines to assign a set of observations (data points) into subsets (clusters), such that observations in the same cluster are similar in some characteristics, but have different characteristics between the clusters.

Coincidental Demand: The sum of two or more demands that occur in the same time interval. Utilities sometimes allocate certain costs to customers on this basis.

Combined Cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Billing cycle: The period of time or the dates of occurrence for issuing periodic bills for service to customers. The billing cycle is also used loosely to refer to the customer's meter read cycle, i.e., the reading of the billing meter as opposed to the calculation of the bill.

Capacity: The ability of a utility to have the resources available to meet the needs of its customers.

Capacity, base load: Capacity used to serve an essentially constant level of customer demand. Base load generators typically operated whenever they are available, and they usually have a capacity factor above 60%.

Capacity, intermediate: Capacity intended to operate fewer hours per year than base load capacity but more hours than peaking capacity. Typically, such units have a capacity factor of 20%-60%.

Capacity, peaking: Capacity used to serve peak demand. Peaking generators operate a limited number of hours per year and normally feature capacity factors of less than 20%.

Capacity factor: The ratio of the total energy generated by a unit for a specified period to the maximum possible energy it could have generated if operated at the maximum capacity rating for the same specified period, expressed as a percentage.

Capitalized costs: Costs are capitalized when they are expected to provide benefits over a period longer than one year.

Carbon intensity: The amount of carbon by weight emitted per unit of energy consumed. A common measure of carbon intensity is weight of carbon per British thermal unit (Btu) of energy. When there is only one fossil fuel under consideration, the carbon intensity and the emissions coefficient are identical. When there are several fuels, carbon intensity is based on their combined emissions coefficients weighted by their energy consumption levels. Also see Emissions coefficient and Carbon output rate.

Cascading: The uncontrolled successive lost of system elements triggered by an incident at any location. Cascading, often caused by changes in voltage, results in widespread service interruption, which cannot be restrained from sequentially spreading beyond an area predetermined by appropriate studies.

Classification: The separation of costs into categories of fixed costs (demand-related), variable costs (energy-related, and customer costs (costs which are proportional to the number of customers and include meter reading, customer accounting and collections).

Coincident peak demand: The maximum demand that a load places on a system at the time the system itself experiences its maximum demand.

Combined cycle: An electric generating technology in which electricity is produced from otherwise lost waste heat exiting from one or more gas (combustion) turbines. The exiting heat is routed to a conventional boiler or to a heat recovery steam generator for utilization by a steam turbine in the production of electricity. This process increases the efficiency of the electric generating unit.

Combined heat and power plant (CHP): A plant designed to produce both heat and electricity from a single heat source. Note: This term is being used in place of the term "cogenerator" that was used by EIA in the past. CHP better describes the facilities because some of the plants included do not produce heat and power in a sequential fashion and, as a result, do not meet the legal definition of cogeneration specified in the Public Utility Regulatory Policies Act (PURPA).

Commodity (volumetric) costs: Costs that tend to vary with the quantity of utility service provided.

Competitive market: A market in which a large number of buyers and sellers trade independently such that no one participant can influence price.

Complementary good (complement good): A good which is consumed together with another good (example, cars and gasoline). If the price for one good increases, the demand for another good decreases.

Congestion: A condition that occurs when insufficient transfer capacity is available to implement all of the preferred schedules for electricity transmission simultaneously. Congestion prevents the economic dispatch of electric energy from serving load.

Connection charge: An amount to be paid by a customer in a lump sum or in installments to the utility for connecting the customer's facilities to the supplier's facilities.

Construction work in progress (CWIP): A regulatory treatment that allows utilities to earn a return on, but not of, investments before they are placed in service. Absent CWIP, utilities bear financing costs during the period prior to project operation and then recover them after projects commence operation. In other words, putting CWIP in rate base does not allow the utility to recover the CWIP costs themselves. The utility instead recovers only the financing costs associated with the CWIP. The CWIP amount earns a return at the utility's Weighted Average Cost of Capital (WACC). Further, where CWIP is put in rate base with an AFUDC offset, the only dollar cost recovery created is CWIP times the excess of the allowed return over the AFUDC rate. This amount is substantial only where the AFUDC rate is based primarily on debt, particularly short-term debt, rather than a measure of the utility's WACC.

Consumer Price Index (CPI): These prices are collected in 85 urban areas selected to represent all urban consumers about 80 percent of the total U.S. population. The service stations are selected initially and on a replacement basis, in such a way that they represent the purchasing habits of the CPI population. Service stations in the current sample include those providing all types of service (i.e., full, mini, and self service).

Contract for Differences: A form of bilateral contract where the electric generation seller receives a fixed payment amount over time which is a combination of the short-term market price and an adjustment which the purchaser for the difference.

Contract path: A specific contiguous electrical path from a point of receipt to a point of delivery for which transfer rights have been contracted. The actual or real path of electricity could differ from the contract path.

Contract Price: Price of fuels marketed on a contract basis covering a period of 1 or more years. Contract prices reflect market conditions at the time the contract was negotiated and therefore remain constant throughout the life of the contract or are adjusted through escalation clauses. Generally, contract prices do not fluctuate widely.

Cooperative Electric Utility: An electric utility legally established to be owned by and operated for the benefit of those using its service. The utility company will generate, transmit, and/or distribute supplies of electric energy to a specified area not being serviced by another utility. Such ventures are generally exempt from Federal income tax laws. Most electric cooperatives have been initially financed by the Rural Electrification Administration, U.S. Department of Agriculture.

Cost of debt: The interest rate paid on new increments of debt capital multiplied by 1 minus the tax rate.

Cost-Based Rates: A ratemaking concept used for the design and development of rate schedules to ensure that the filed rate schedules recover only the cost of providing the service.

Cost of New Entry (CONE): An economic concept depicting the price of capacity in $/kw-month that is needed to attract sufficient new capacity. It is determined using clearing prices in Forward Capacity Auctions as described in the Market Rule.

Cost-of-Service Regulation: Traditional electric utility regulation under which a utility is allowed to set rates based on the cost of providing service to customers and the right to earn a limited profit.

Cost, administrative and general (A&G): A subset of operation and maintenance expenses which are part of a utility company's cost of service (e.g., salaries, office supplies and expenses, outside services, injuries and damages).

Cost, fixed: Costs that (at least in the short run) do not vary with the quantity of utility service.

Cost, net original: Original cost less accumulated depreciation. Also called net book cost.

Cost, operations and maintenance (O&M): A broad class of expenses that are part of a utility company's cost of service (e.g., production, storage, terminaling, processing, transmission, distribution, customer accounts, customer service, sales, administration and general). These are non-tax or depreciation costs of providing service.

Cost, original: The total cost of utility property at the time it came in service.

Cost, variable: Costs varying with a utility's output or a customer's usage; sometimes called user-sensitive rates.

Cost causation: The assignment of costs to utility services and customers that caused those costs to be incurred.

Cost of service: The total cost of providing utility service to a utility system or a subgroup within the system (the latter referred to as cost allocation).

Cost-of-service pricing: A method pricing utility service in strict accordance with the costs that are attributed to it.

Critical peak pricing (CPP): Programs allowing the utility to dramatically increase rates on short notice a predetermined number of times per year.

Cross price elasticity of demand: A percentage change in demand for good A that occurs in response to a percentage change in price of good B.

Curtailability: The right of a transmission provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide that transmission. Transmission service is to be curtailed only in cases where system reliability is threatened or emergency conditions exists.

Customer classification: The grouping of customers into "homogeneous" classes often based on size, interconnection voltage, quality of service, or corporate status.
Customer (base) charge: Also called a flat fee. Costs associated with serving customers, irrespective of the amount of use (e.g. collection, billing, administrative costs).
Day-ahead energy market: Markets in certain regional transmission organizations that produce financially binding schedules for the production and consumption of electricity one day before the operating day
Debt service: The amount of money necessary to pay interest and principal repayment on debt instruments.
Debt service coverage: The ratio of net revenue available for debt service to the average annual debt-service requirements.
Declining Block Rate: A rate structure that prices successive blocks of power use at increasingly lower per-unit prices. The more energy a customer uses, the lower the average price. Such rates often reflect fixed costs in the volumetric component of rates such that the average costs of serving a customer declines with higher consumption.
Deferred Costs: An expenditure not recognized as a cost of operation of the period where they occurred, but carried forward so as to be written off in future periods.
Delivered cost: The cost of fuel, including the invoice price of fuel, transportation charges, taxes, commissions, insurance, and expenses associated with leased or owned equipment used to transport the fuel.
Delta: The rate of change of the theoretical price of an option with respect to a 1 unit move in the price of the underlying instrument. Also referred to as a hedge ratio because the value of Delta represents the ratio of options contracts to underlying instrument contracts required to establish a neutral option hedge.
Demand: The rate at which electric energy or natural gas is delivered to or by a system at a given instant or averaged over a designated period, usually expressed in kilowatts or megawatts (electric); Mcfs or MMBtus (natural gas).
Demand bid: A bid into the power exchange indicating a quantity of energy or an ancillary service that an eligible customer is willing to purchase and, if relevant, the maximum price that the customer is willing to pay.
Demand Charge: The Demand Charge portion of rate design is expected to recover the costs associated with the level of demand for the particular service and will be paid even if no service is taken by the customer; a reservation charge. Included in demand charges are capital-related costs and the cost of operation and maintenance of generation, transmission and distribution.
Demand curve: A graph related the system demand (if kW) over a period of time (e.g. month, day, or hour).
Demand Interval: Time period over which electric billing demand is measured (typically 15, 30 or 60 minute intervals).
Demand-side management (DSM): The planning, implementation, and monitoring of utility activities designed to encourage consumers to modify patterns of electricity usage, including the timing and level of electricity demand. It refers to only energy and load-shape modifying activities that are

undertaken in response to utility-administered programs. It does not refer to energy and load-shaped changes arising from the normal operation of the marketplace or from government-mandated energy-efficiency standards. Demand-Side Management covers the complete range of load-shape objectives, including strategic conservation and load management, as well as strategic load growth.

Dendrogram: A graphical representation of how observations are grouped together at various levels of dissimilarity by a cluster analysis. Price elasticity of demand - a measure of the sensitivity of quantity demanded to changes in price.

Depreciation: The loss of value of assets, such as buildings and transmission lines, due to age and wear. Among the factors considered in determining depreciation are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the technology, changes in demand, requirements of public authorities and salvage value. Depreciation is charged to utility customers as an annual expense.

Derating (Generator): Reduction of a generating unit's net dependable capacity to a point below the manufacturer's nameplate rating.

Direct Billing: A means of recovering costs other than by demand or commodity charge to customers; charges are made directly to identified parties, perhaps regardless of their current status as a customer. Direct billing provides a relatively low risk to the pipeline or utility of non-recovery of costs.

Direct Current (DC): An electric current that flows in one direction with a magnitude that does not vary or that varies only slightly.

Direct load control: Refers to program activities that can interrupt consumer load at the time of annual peak load by direct control of the utility system operator by interrupting power supply to individual appliances or equipment on consumer premises.

Discounted cash flow (DCF): A method for calculating the ROE by combining the estimated current yield, determined by utility's dividend price ratio, with a growth component.

Distribution: The delivery of electricity to end users via low-voltage electric power lines (typically <69 kV) ; the transfer of electricity from high-voltage lines to lower-voltage lines.

Dynamic pricing: Dynamic pricing creates changing prices for electricity which reflect actual wholesale electric market conditions. Examples of dynamic pricing include critical peak pricing and real-time rates.

Eastern Interconnection: One of two major AC power grids in North America that spans from central Canada eastward to the Atlantic coast (excluding Qubec), south to Florida, and west to the foot of the Rocky Mountains (excluding most of Texas). The electric utilities within the Eastern Interconnection are electrically tied together during normal system conditions and operate at a synchronized frequency of 60 Hz average. The Eastern Interconnection is tied to the Western Interconnection, the Texas Interconnection, and the Qubec Interconnection, and other systems in Canada through numerous high-voltage DC transmission lines.

Earnings before interest and taxes: A measure of financial performance. EBIT is a company's revenues minus its cost of doing business. It is a measure of a company's operating profit before interest on debt and income taxes on earnings are deducted.

Economic dispatch: The selection of generating resources to cover load as inexpensively as possible.

Economic efficiency: A term that refers to the optimal production and consumption of goods and services, typically occurring when prices reflect marginal costs. They take into account (1) the cost to society from satisfying the demands of a utility's customers and (2) the value that customers place on utility service.

Economies of scale: Economies of scale exist when, for a given level of technology and set of prices, larger production facilities have lower unit costs than smaller ones.

Elasticity (of demand): A measure of consumer response to price changes.

Energy audit: A program carried out by a utility company in which an auditor inspects a home and suggests ways energy can be saved.

Energy charge: The part of the charge for electric service based upon the electric energy (kWh) consumed or billed.

Energy Information Administration (EIA): An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and does analytical and modeling analyses of energy issues. The Agency must satisfy the requests of Congress, other elements within the Department of Energy, Federal Energy Regulatory Commission, the Executive Branch, its own independent needs, and assist the general public, or other interest groups, without taking a policy position.

Energy intensity: Economy-wide energy intensity measures units of energy to units of gross domestic product (GDP). EIA uses energy consumption (measured in Btu) to the constant dollar value of the GDP. Energy intensity can also be measured at the sector level using sector-specific data. For example, energy intensity in the commercial sector is measured by the ratio of energy consumption measured in millions of Btu to square feet of commercial floor space

Energy management and control system (EMCS): An energy conservation feature that uses mini/microcomputers, instrumentation, control equipment, and software to manage a building's use of energy for heating, ventilation, air conditioning, lighting, and/or business-related processes. These systems can also manage fire control, safety, and security. Not included as EMCS are time-clock thermostats.

Energy reserves: Estimated quantities of energy sources that are demonstrated to exist with reasonable certainty on the basis of geologic and engineering data (proved reserves) or that can reasonably be expected to exist on the basis of geologic evidence that supports projections from proved reserves (probable/indicated reserves). Knowledge of the location, quantity, and grade of probable/indicated reserves is generally incomplete or much less certain than it is for proved energy reserves.

Environmental impact statement: A report that documents the information required to evaluate the environmental impact of a project. It informs decisionmakers and the public of the reasonable alternatives that would avoid or minimize adverse impacts or enhance the quality of the environment.

Exchange, electricity: A type of energy exchange in which one electric utility agrees to supply electricity to another. Electricity received is returned in kind at a later time or is accumulated as an energy balance until the end of a specified period, after which settlement may be made by monetary payment.

Exempt wholesale generator (EWG): Wholesale generators created under the 1992 Energy Policy Act that are exempt from certain financial and legal restrictions stipulated in the Public Utilities Holding Company Act of 1935.

Expense: Cash outflows or incurrence of liabilities that result from the ongoing operation of a company.

Externalities: Also known as external effects, external economies and diseconomies, spillovers and neighborhood effects. A beneficial externality raises the production or utility of the third party (e.g., a beekeeper helping neighboring farmers). An external diseconomy occurs when the externality-generating activity lowers the production or utility of third parties, such as numerous forms of environmental pollution.

Extraordinary Items: An accounting term meaning, significant items of income or loss resulting from events or transactions in the current period that are of unusual nature and infrequent occurrence. Extraordinary storm losses are an example.

Fair market value: The price at which a property would be sold by a willing seller to a willing buyer, neither being under compulsion to buy or sell, and both being competent and having reasonable knowledge of the facts.

Federal Power Act: Enacted in 1920, and amended in 1935, the Act consists of three parts. The first part incorporated the Federal Water Power Act administered by the former Federal Power Commission, whose activities were confined almost entirely to licensing non-Federal hydroelectric projects. Parts II and III were added with the passage of the Public Utility Act. These parts extended the Act's jurisdiction to include regulating the interstate transmission of electrical energy and rates for its sale as wholesale in interstate commerce. The Federal Energy Regulatory Commission is now charged with the administration of this law.

FERC: The Federal Energy Regulatory Commission.

Financial Accounting Standards Board (FASB): An independent board responsible, since 1973, for establishing generally accepted accounting principles. Its official pronouncement are called "Statements of Financial Accounting Standards" and "Interpretations of Financial Accounting Standards."

Financial transmission rights (FTRs): Financial instruments auctioned in certain RTOs. FTRs enable holders to hedge against locational electricity price differences caused by transmission constraints in the day-ahead energy market.

Firm Power: Electric energy or capacity which is intended to have assured availability to the customer to meet an agreed upon portion of his load requirements.

Firm obligation: A commitment to supply electric energy or to make capacity available at any time specified during the period covered by the commitment.

Fixed charge: The charge calculated in rate design to recover all or a portion of the fixed costs of a utility plant, including the generation facility and transmission lines, meters and some taxes.

Fixed costs: Costs that do not change or vary with energy consumption or production.

Fixed operating costs: Cost, other than that associated with capital investment that does not vary with the operation, such as base maintenance and labor.

Forward Capacity Auction (FCA): The "descending-clock" annual auction of the Forward Capacity Market in certain RTOs during which the price for capacity will be decreased until the quantity of capacity remaining in the auction equals the quantity of capacity needed.

Forward Capacity Market (FCM) In certain RTOs, the locational capacity market whereby the RTO will project the needs of the power system three years in advance and then hold an annual auction to purchase power resources to satisfy the region's future needs. The aim of the FCM is to send appropriate price signals to attract new investment and maintain existing resources where and when they are needed, thus ensuring the reliability of the RTO electricity grid.

Forward reserve: The 10-minute nonspinning reserves and 30-minute operating reserves the ISO purchases on a forward basis on behalf of market participants.

Forward Reserve Market (FRM): In certain RTOs, a market used for acquiring the generating resources needed to satisfy the requirements for 10-minute nonspinning reserves and 30-minute operating reserves.

Franchise tax: Taxes levied in associated with states and localities as a condition of utility operation.

Frequency: The rate of oscillation (cycles/second) of the alternating current in an electrical power system, measured in hertz (Hz). In the United States, the rate is 60 Hz.

Formula rates: The traditional test year approach to determining a utility's revenue requirement allows for a consideration of all cost increases and decreases. Regulators have designed a method for preserving the integrity of the test year while expediting analysis of a proposed rate increase necessitated by a capital addition. The approach allows the utility to update its rate base with increments of completed capital investment by filing an annual update of the inputs to a rate formula.

Franchise tax: Tax imposed on a state or municipal chartered corporation (typically a regulated monopoly) for the right to do business. They are usually levied on a number of value bases, such as capital stock, profits, or property.

Fuel expense: These costs include the fuel used in the production of steam or driving another prime mover for the generation of electricity. Other associated expenses including transportation and unloading the shipped fuel and all handling of the fuel up to the point where it enters the first bunker, hopper, bucket, tank, or holder in the boiler-house structure.

Fuel switching capability: The short-term capability of a manufacturing establishment to have used substitute energy sources in place of those actually consumed. Capability to use substitute energy sources means that the establishment's combustors (for example, boilers, furnaces, ovens, and blast furnaces) had the machinery or equipment either in place or available for installation so that substitutions could actually have been introduced within 30 days without extensive modifications. Fuel-switching capability does not depend on the relative prices of energy sources; it depends only on the characteristics of the equipment and certain legal constraints.

Functionalization: The separation of costs among the operating functions, which traditionally include: production, transmission, distribution, customer accounting, customer service and information, sales, and administrative and general.

Functional accounts: Groupings of plant and expense accounts according to the specified part that they play in rendering utility service.

Fully allocated costs or fully distributed costs: A costing procedure that spreads the utility's joint and common costs across various services and customer classes.

Full requirements consumer: A wholesale consumer without other generating resources whose electric energy seller is the sole source of long-term firm power for the consumer's service area. The terms and conditions of sale are equivalent to the seller's obligations to its own retail service, if any.

Genco: The term used for that portion of a functionally disaggregated electric utility's business that involves the production of power which is operated separately from any other power functions which the utility owns or operates.

Generally accepted accounting principles (GAAP): Defined by the FASB as the conventions, rules, and procedures necessary to define accepted accounting practice at a particular time, includes both broad guidelines and relatively detailed practices and procedures.

Good Will: An accounting term meaning, a value in excess of a business' tangible assets, caused by merger by superior future earning power determined by the capitalization at an assumed interest rate of those earnings which exceed the "normal" return in that industry. The actual amount of the good will is negotiated by the buyer and seller.

Greenhouse gases: Those gases, such as water vapor, carbon dioxide, nitrous oxide, methane, hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulfur hexafluoride, that are transparent to solar (short-wave) radiation but opaque to long-wave (infrared) radiation, thus preventing long-wave radiant energy from leaving Earth's atmosphere. The net effect is a trapping of absorbed radiation and a tendency to warm the planet's surface.

Green pricing: In the case of renewable electricity, green pricing represents a market solution to the various problems associated with regulatory valuation of the nonmarket benefits of renewables. Green pricing programs allow electricity customers to express their willingness to pay for renewable energy development through direct payments on their monthly utility bills. Such programs are optional.

Gross receipts taxes: Taxes levied based on utility sales.

Heat rate: A measure of generating station thermal efficiency commonly stated as Btu per kilowatthour. Note: Heat rates can be expressed as either gross or net heat rates, depending whether the electricity output is gross or net generation. Heat rates are typically expressed as net heat rates.

Hedging: To offset a position with the intent of managing risk. The process of protecting the value of an investment from the risk of loss in case the price fluctuates. Hedging is accomplished by protecting one transaction with another. A long position in an underlying instrument can be hedged or protected with an offsetting short position in a related underlying instrument.

Hedging contracts: Contracts which establish future prices and quantities of electricity independent of the short-term market. Derivatives may be used for this purpose.

Herfindahl-Hirschman Index (HHI): A measure of market concentration. It is calculated by squaring the market share of each firm competing in a market, and then summing the resulting numbers. The HHI number can range from close to zero to 10,000. It is frequently used by federal regulators when analyzing mergers and acquisition and has been used by FERC to evaluate market based rate authority requests.

Hourly Peak: The maximum demand for energy from a transmission or distribution system in any hourly period of time.

Hub: A specific set of predefined nodes for which locational marginal prices are calculated and used to establish a reference price for electric energy purchases and the transfer of day-ahead adjusted load obligations and real-time adjusted load obligations and for the designation of Financial Transmission Rights. The current New England hub consists of 32 nodes.

Hypothetical capital structures: Capital structures not based on the actual balance of debt and equity. This regulatory treatment usually creates an equity-to-debt ratio higher than the actual ratio for purposes of calculating the rate of return.

Impaired capital: A negative surplus account due to the corporation's capital stock has been reduced below what it was a t the time the stock was issued, usually recognized at the time of sale of an asset.

Impairment, asset impairment: Impairment or asset impairment occurs when, due to changed circumstances, the previously allowed recovery of costs of a regulatory asset through rates is eliminated or removed by action of a regulatory body.

Inclining block rates: Rates that increase at higher levels of electricity consumption.

Income (or budget) statement: A statement of revenues and expenditures, over a period of time.

Incremental cost: The change in total cost from a change in service provided, such as the cost of an additional customer, kW of demand, or kWh consumed.

Increment offer: A financial offer to sell electric energy at a specified location in the day-ahead energy market; virtual supply not associated with a physical generator. In speaking, sometimes referred to as an "inc" (pronounced "ink".)

Independent power facility: A facility, or portion thereof, that is not in a utility's rate base. Power is usually sold to utilities, though in some cases directly to end-use customers. These facilities or their owners are often referred to as independent power producers.

Interest coverage ratio: The number of times that fixed interest charges were earned. It indicates the margin of safety of interest on fixed debt. The times-interest-earned ratio is calculated using net income before and after income taxes; and the credits of interest charged to construction being treated as other income. The interest charges include interest on long-term debt, interest on debt of associated companies, and other interest expenses.

Inframarginal revenues: The revenues earned by generators through the electric energy market that are in excess of the generators' short-run variable costs for fuel and other operating expenses, which assists in recovering fixed costs, the largest portion being capital costs.

Integrated Resource Planning (IRP): A public planning process and framework within which the costs and benefits of both demand and supply side resources are evaluated to develop the least total cost mix of utility resource options. In many states, IRP includes a means for considering environmental damages caused by electricity supply/transmission and identifying cost effective energy efficiency and renewable energy alternatives. IRP has become a formal process prescribed by law in some states and under some provisions of the Clean Air Act Amendments of 1992.

Intermittent electric generator or intermittent resource: An electric generating plant with output controlled by the natural variability of the energy resource rather than dispatched based on system requirements. Intermittent output usually results from the direct, non-stored conversion of naturally occurring energy fluxes such as solar energy, wind energy, or the energy of free-flowing rivers (that is, run-of-river hydroelectricity).

Interruptible power: Power made available under agreements that permit curtailment or cessation of delivery by the supplier. Customers typically receive a discount for agreeing to for their power to be interruptible.

Inverted block rate design: Sometimes referred to as inclining rates, graduated rates, baseline rates, or block rates. A rate design for a customer class through which the unit charge for electricity increases as usage increases.

Inventories: Raw materials, stocks, capital goods, or finished products kept by firms in order to allow them to meet production requirements or fluctuations in sales.

Investor-owned utility (IOU): A privately-owned electric utility whose stock is publicly traded. It is rate regulated and authorized to achieve an allowed rate of return.

Joint and common costs: Costs incurred by a utility in producing multiple services but cannot be directly assigned to any individual service or customer class; these costs must be assigned according to some rule or formula.

Joint Use Facilities: A facility that is used in common by two or more entities or power generating units. Also know as Common Use Facilities.

Levelized Cost, Life-Cycle Cost: The present value of the cost of a resource, including capital, financing and operating costs, converted into a stream of equal annual payments.

Load Center: A geographical area where large amounts of power are drawn by end-users.

Load control program: A program in which the utility company offers a lower rate in return for having permission to turn off the air conditioner or water heater for short periods of time by remote control. This control allows the utility to reduce peak demand. Such programs fall under the broader heading of demand-side management.

Load curve: The relationship of power supplied to the time of occurrence. Illustrates the varying magnitude of the load during the period covered. The period is often a day, month, or year.

Load factor: The ratio of average load to peak load during a specific period of time, expressed as a percent. The load factor indicates to what degree energy has been consumed compared to maximum demand or the utilization of units relative to total system capability. An electric system's load factor shows the variability in all customers' demands.

Load following: Regulation of the power output of electric generators within a prescribed area in response to changes in system frequency, tieline loading, or the relation of these to each other, so as to maintain the scheduled system frequency and/or established interchange with other areas within predetermined limits. Load following is a type of ancillary service.

Local distribution company (LDC): A legal entity engaged primarily in the retail sale and/or delivery of natural gas through a distribution system that includes mainlines (that is, pipelines designed to carry large volumes of gas, usually located under roads or other major right-of-ways) and laterals (that is, pipelines of smaller diameter that connect the end user to the mainline). Since the restructuring of the gas industry, the sale of gas and/or delivery arrangements may be handled by other agents, such as producers, brokers, and marketers that are referred to as "non-LDC."

Load pockets: Areas of the system where the transmission capability is not adequate to import capacity from other parts of the system and demand is met by relying on local generation.

Load-Serving Entity (LSE): Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers. In restructured states, such entities are not necessarily the utilities that own transmission and distribution assets.

Load shedding: Intentional action by a utility that results in the reduction of more than 100 megawatts (MW) of firm customer load for reasons of maintaining the continuity of service of the reporting entity's bulk electric power supply system. The routine use of load control equipment that reduces firm customer load is not considered to be a reportable action. Examples would be rolling brownouts conducted to preserve reliability in extreme operating conditions.

Load Shifting: Involves moving load from on-peak to off-peak periods. Applications include use of storage water heating, storage space heating, cool storage, and customer load shifts to take advantage of time-of-use or other special rates.

Locational marginal price (LMP): Used in certain organized markets, the LMP is the cost to serve the next MW of load at a specific location, using the lowest production cost of all available generation, while observing all transmission limits.

Long Run Marginal Costs: The long-run costs of the next unit of electricity produced. This includes the cost of future infrastructure development.

Long-term debt: Debt that is payable more than one year from the date it was incurred.

Loss (losses): The energy (kilowatt-hours) and power (kilowatts) lost or unaccounted for in the operation of an electric system. Losses occur primarily as energy transformations from kilowatt-hours to waste heat in electric conductors and apparatus.

Market clearing price: The price at which supply and demand are in balance with respect to a particular commodity at a particular time. This price can be established through specific auctions, as used in organized wholesale markets, or through ongoing markets such as NYMEX and the NYSE.

Market power: The ability of a market participant with a large market share to significantly control or affect price by withholding production from the market, limiting service availability, or reducing purchases.

Merit order: The order that an RTO designates generators to operate based on the lowest to highest cleared offers, until the demand for electric energy is met.

Minimum charge: A rate schedule provision stating that a customer's bill cannot fall below a specified level.

Mothball: To place a generating facility in an inactive state so that it can neither be brought into operation immediately nor counted towards reserve margin.

Must run units: A specific generating unit that has been designated by the system operator to be on line or on the grid to insure the flow of electricity. This must run unit is outside of economic dispatch and may or may not be a system's most efficient unit. A unit may be designated as must run for operating reasons that may include system reliability, voltage control or system stability.

Nameplate Capacity: The maximum rated output of a generator under specific conditions designated by the manufacturer. Generator nameplate capacity is usually indicated in units of kilovolt-amperes (kVA) and in kilowatts (kW) on a nameplate physically attached to the generator.

Native load customers: The wholesale and retail customers on whose behalf the Transmission Provider, by statute, franchise, regulatory requirements, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

Natural Monopoly: An economic term connoting a situation where one firm can produce a given level of output at a lower total cost than can any combination of multiple firms. Natural monopolies occur in industries, which exhibit decreasing average long run costs due to size (economies of scale). According to economic theory, a public monopoly governed by regulation is justified when an industry exhibits natural monopoly characteristics.

The North American Electric Reliability Corporation (NERC): Organization who's mission is to ensure the reliability of the bulk power system in North America. They develop and enforce reliability standards; assess reliability annually via 10-year and seasonal forecasts; monitor the bulk power system; evaluate users, owners, and operators for preparedness; and educate, train, and certify industry personnel. NERC is a self-regulatory organization, subject to oversight by the U.S. Federal Energy Regulatory Commission and governmental authorities in Canada

Net income: Operating income plus other income and extraordinary income less operating expenses, taxes, interest charges, other deductions, and extraordinary deductions.

Network: A system of interconnected circuit components. In power system usage, a system of transmission (or distribution) lines interconnected and operated so that any principal point has multiple sources of power.

Network Resource: In certain organized markets, any designated generating resource owned or purchased by a Network Customer under the Network Integration Transmission Service Tariff. Network Resources do not include any resource or any portion that is committed for sale to third parties or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

Network Upgrade: Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

Nominal price: The price paid for a product or service at the time of the transaction. Nominal prices are those that have not been adjusted to remove the effect of changes in the purchasing power of the dollar; they reflect buying power in the year in which the transaction occurred.

Non-coincident Demand (NCD) or Non-coincident Peak Load: A customer's maximum energy demand during any stated period. Customers who use large quantities of electricity may pay a monthly demand charge based on their maximum electric demand during each month. This maximum demand in the electric industry can also be called a customer's monthly non-coincident demand. This demand can establish demand charges in rates, though is typically not used for cost allocation purposes.

Non-firm electricity transaction: These transactions are typically for short periods and subject to curtailment or cessation of delivery by the supplier or purchaser in accordance with prior agreements or under specified conditions. Non-firm sales are sometimes called economy or interruptible sales.

Non-operating expenses: Expenses other than operating expenses (e.g., debt service, working capital, cash funding of capital projects).

Non-operating revenues: Sometimes referred to as other operating revenues, there are revenues that are incidental to a utility's revenues received for primary service activities (e.g., investment income, provision for bad debt, land leases, rental of electric towers for telecommunications.) These revenues are a credit against the revenue requirement.

Non-requirements consumer: A wholesale consumer (unlike a full or partial requirements consumer) that purchases economic or coordination power to supplement their own or another system's energy needs.

Non-spinning reserve: Generating units that are not connected to the system but are capable of coming on line within a specified time, or interruptible load that can be removed from the system in a specified time.

Normalization: An adjustment of costs and revenues to conform to a typical year. Separate from tax normalization used to calculate accumulated deferred income taxes.

Notice of Proposed Rule Making (NOPR): A draft generic policy change promulgated by regulatory agencies

Obligation to serve: The concept embodied in the statutes of most states governing the retail or end-use provision of electric service where a utility is required to serve all customers who request service at non-discriminatory prices. This obligation is rendered in return for granting of a geographic retail service monopoly.

Open transmission access: Enables all participants in the wholesale market equal access to transmission service, as long as capacity is available, with the objective of creating a more competitive wholesale power market.

Operating expenses: Expenses related to maintaining day-to-day utility functions, including operation and maintenance expenses.

Operating revenues: Revenues directly related to the utility's primary service activities.

Ordinance: A document listing the terms and conditions, including a schedule of prices, under which utility services will be provided.

Other operating revenue: Operating revenues received from sources other than electricity sales. These include forfeited discounts, miscellaneous service revenues, sales of water and water power, rent from electric property, interdepartmental rents, and other revenues. In some cases, all such revenues are credited to customers while in other cases the utility and ratepayers split such revenues.

Out-of-merit cost: A payment to a generator for operating when it is more expensive for it to do so than the price-setting generator.

Own price elasticity of demand: A percentage change in quantity demanded in response to a percentage change in price of the same good or service.

Parallel Flow: Electricity flow on a utility's transmission system resulting from electricity flows scheduled on any other system. Electricity flows on parallel paths in amounts inversely proportional to each path's impedance. Due to parallel flows, point-to-point transmission sales between two utilities could lead to increased transmission congestion for a third utility.

Partial requirements consumer: A wholesale consumer with generating resources insufficient to carry all its load and whose energy seller is a long-term firm power source supplemental to the

consumer's own generation or energy received from others. The terms and conditions of sale are similar to those for a full requirements consumer.

Pay-as-you-go ("PAYG"): Refers to financing a capital project with existing cash flows, thus avoiding debt obligations..

Payback period: The amount of time required fro the net revenues of an investment to return its costs. This metric is often employed for energy efficiency measures.

Payroll taxes: Taxes, such as FICA, Social Security taxes, and federal and local unemployment taxes, that are levied on the basis of employee salaries.

Peak period: Any period of time when the system operates at maximum capacity.

Peak shaving: Employment of supplemental power supply, demand side resources, or rate designs to reduce peak demand.

Plant held for future use: Plant held in reserve for use in the future. Such plant is usually included in rate base.

Point of delivery: A point on the electric system where a power supplier or wheeling entity delivers electricity to the recipient. This point could include an interconnection with another system or a substation where the transmission provider's transmission and distribution systems connect to another system.

Point of receipt: A point on the electrical system where an entity receives electricity from a power supplier of wheeling entity.

Post-retirement benefits other than pensions (PBOP): Sometimes called other post employment benefits (OPEBs). These include healthcare, life insurance, and other non-pension benefits.

Power factor: The fraction of power actually used by a customer's electrical equipment compared to the total apparent power supplied, usually expressed as a percentage. Power factors apply only to alternating current circuits; direct current circuits always exhibit a power factor of 100 percent. A power factor indicates how far a customer's electrical equipment causes the electric current delivered at the customer's site to be out of phase with the voltage.

Power factor adjustment: A calculation or charge on industrial or commercial customers' bills reflecting an adjustment in billing demand based on customer's actual metered power factor. If the power factor stays within a specified range, there is no adjustment.

Power transfer distribution factor: A measure of the responsiveness or change in electric loading on system facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer. The PTDF applies only for the pre-contingency configurations of the system under study.

Prepayment: Expenditure for future benefit, which is recorded on a balance sheet asset account called a deferred charge, then written off in a period when the benefit is enjoyed. An example is prepaid rent.

Present value: The present value of a payment (PMT) received n years hence equals: PMT / (1+i)^n, where i equals the interest rate.

Price cap: A method of setting a utility distribution company's rates whereby regulators establish a maximum allowable price level. Flexibility in individual pricing is allowed in some cases, and where efficiency gains can be encouraged and captured by the company.

Prudence Review: The process by which a regulator determines the prudence of utility resource decisions goes to the heart of the goal of aligning private and public interests. For utility-built resources, utilities often seek this approval many years prior to the resource being determined "used and useful," and available for service. For long-term purchased power contracts, utilities seek a prudence review relatively contemporaneously with availability of the resource, assuming the facilities for the purchase are in operation. If the power purchase is for a project not yet completed, utilities may seek prior approval of the purchase agreement as they would for a utility-built plant.

Purchased power adjustment: A clause in a rate schedule that provides for adjustments to the bill when energy from another electric system is acquired and it varies from a specified unit base amount.

Public Utility Regulatory Policies Act of 1978 (PURPA): This statute requires States to implement utility conservation programs and create special markets for co-generators and small producers who meet certain standards, including the requirement that States set the prices and quantities of power the utilities must buy from such facilities.

Qualifying Facility (QF): A cogeneration facility or small power production facility which 1) is a qualifying facility under PURPA and FERC's Regulations, 2) is permitted to sell electric energy and capacity to the host utility at the host utility's avoided cost rate, 3) is not owned by an entity primarily engaged in the sale or generation of electric power, and 4) in the case of cogeneration facilities, and small power production facilities under 30 megawatts in size (80 megawatts for geothermal generators), is largely exempt from the provisions of the Federal Power Act and the Public Utility Holding Company Act.

Radial: A transmission or distribution system that is not networked and does not provide multiple parallel flow paths. Radials often connect remote generation to the rest of the transmission grid.

Rate base: The value, specified by a regulatory authority, upon which a utility (usually an investor owned utility) is permitted to earn a specified rate of return. The rate base generally represents the value of property used by the utility in providing service and may be calculated by any one or a combination of the following accounting methods: fair value, prudent investment, reproduction cost or original cost. The rate base may include a working capital allowance covering such elements as cash, working capital, materials and supplies, prepayments, minimum bank balances and tax offsets. The rate base may be adjusted by deductions for accumulated provision for depreciation, contributions in aid of construction, accumulated deferred income taxes and accumulated deferred investment tax credits.

Rate case: A proceeding, usually before a regulatory commission, involving the rates to be charged for a public utility service.

Rate design: The design and organization of billing charges by customer class to distribute the costs allocated to the different classes.

Rate of return: The overall rate of return, pre-tax, return, weighting the cost of debt and the return on equity with the capital structure.

Real-time load obligation (RTLO): For each hour, the requirement that each market participant (in organized wholesale markets) has for providing electric energy (megawatt-hours) at each node, external node, load zone, or the Hub equal to the megawatt-hours of load, including external transaction sales and internal bilateral transactions that transfer these obligations.

Real-time pricing: Rates that adjust in real-time based on wholesale electricity costs.
Real-time reserve market: An ISO market where resources capable of providing 10-minute and 30-minute reserves are designated in real time, for which they are paid the reserve market clearing price.
Reactive power: The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive power must be supplied to most types of magnetic equipment, such as motors and transformers. Reactive power is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors and directly influences electric system voltage. It is a derived value equal to the vector difference between the apparent power and the real power. It is usually expressed as kilovolt-amperes reactive (kVAR) or megavolt-ampere reactive (MVAR). Reactive power is an ancillary service, sold through some RTO markets.
Rebate program: A utility company-sponsored conservation program whereby the utility funds or provides a bill credit equal to a portion of the purchase price cost when a more energy-efficient refrigerator, water heater, air conditioner, or other appliance is purchased.
Regional Transmission Organization (RTO): An independent regional transmission operator and service provider established by FERC and that meets FERC's RTO criteria, including those related to independence and market size. The RTO controls and manages the high-voltage flow of electricity over an area generally larger than the typical power company's service territory for its distribution system. Most RTOs also operate day-ahead, real-time, ancillary services, and capacity markets and conduct system planning. RTOs include PJM, ISO-New England, the Midwest Independent System Operator, the Southwest Power Pool, the New York ISO, and the California ISO (CAISO).
Regulation: The capability of specially equipped generating resources to increase or decrease their generation output every four seconds in response to signals they receive from the ISO to control slight changes on the system. This capability is necessary to balance supply levels with the second-to-second variations in demand.
Regulatory Asset: A promise of collection of a cost at a future point. Regulatory assets are added to rate base.
Regulatory Lag: The laps of time between a petition for a rate increase and the formal action by a regulatory body.
Regulatory Liability: A credit against rate base due usually to a timing difference between when costs, including depreciation, are incurred and recovered through rates.
Reliability adequacy: A measure of the reliability of the bulk power system to meet demand and the sufficiency of the system's generating resources.
Reliability Agreement: - An agreement made between the ISO and a generation owner whereby an approved generator continues to operate, even when it is not economical to do so, to ensure system reliability, and whereby the generation owner recovers the fixed costs for operation; sometimes termed Reliability Must-Run (RMR) Agreement.
Reserve capacity/ Reserve margin: The amount of capacity a system can supply greater than what is required to meet demand. Typically 15-20 percent reserve capacity is needed for good reliability.
Restructuring: The process of replacing a monopoly system of electric utilities with competing sellers, allowing individual retail customers to choose their electricity supplier but still receive delivery over the power lines of the local utility. It includes the reconfiguration of the vertically-integrated electric utility.

Resource adequacy: The ability of a bulk electric power system to supply the aggregate electrical demand and energy requirements (i.e., the electrical loads of all the customers at all times plus external transaction sales to other control areas), taking into account scheduled and reasonably expected unscheduled outages of system devices (e.g., generators, transformers, circuits, circuit breakers, or bus sections). Annual expected system resource adequacy is calculated in terms of system loss-of-load expectation, accounting for load forecast uncertainty caused by weather and resource availability and reflecting assumed forced and scheduled outages.

Retail wheeling: The process of moving electric power from a point of generation across third-party-owned transmission and distribution systems to a retail customer. Owners of power must pay transmission fees to system that they wheel through in most cases.

Retirement: The permanent removal from service of a facility, which cannot return to service without major refurbishment or relicensing.

Return on equity: Compensation for the investment of capital; i.e., earnings. Regulated public utilities statutorily entitled to charge rates that permit them to earn a fair return on their equity invested.

Revenue requirement: the annual revenues that the utility is entitled to collect (as modified by automatic adjustment clauses). it is the sum of operation and maintenance expenses, depreciation, taxes, and a return on rate base.

Run-of-river hydro: A hydroelectric plant which depends chiefly on the flow of a stream as it occurs for generation, as opposed to a storage project, which has space available to store water from one season to another. Some run-of-river projects have a limited storage capacity (pondage) which permits them to regulate streamflow on a daily or weekly basis.

Revenue requirement: The sum total of the revenues required to pay all operating and other costs of providing service.

Seasonal rates: Rates that vary by season Time-of-use rates: Rates that vary by time of day and day of the week.

Securitization: A rock-solid, often statute-based, government guarantee of cost recovery, which is intended to reduce financing costs by eliminating the risk of non-recovery.

Self-Generation: A generation facility dedicated to serving a particular retail customer, usually located on the customer's premises. The facility may either be owned directly by the retail customer or owned by a third party with a contractual arrangement to provide electricity to meet some or all of the customer's load.

Sensitivity analysis: A procedure that determines how sensitive the analysis's outcomes are to changes in assumptions. If a small change in the assumption results in relatively large changes in the outcomes, the outcomes are said to be sensitive to that assumption.

Shaping: The scheduling and operation of generating resources to meet changing load levels. Load shaping on a hydroelectric system usually involves the adjustment of water releases from reservoirs so that generation and load are continuously in balance. Natural gas plants can also adjust to meet load. Intermittent generation, such as wind and solar, require shaping by other generation resources.

Short Run Marginal Cost: All variable production costs including fuel and operations and maintenance costs.

Short-term debt: Debt that is payable less than one year from the date it was incurred.

Spinning Reserve: Unused capacity available from units connected to and synchronized with the grid to serve additional demand. The spinning reserve must be under automatic governor control to instantly respond to system requirements.

Split-the-Savings: A method of pricing where the buyer and the seller agree to divide the difference between the seller's costs of producing power and the buyer's otherwise available purchase price of power. Such arrangements can also take place between utilities and ratepayers for energy efficiency programs.

Spot Market: Commodity transactions in which the transaction commencement is near term (e.g., within 10 days) and the contract duration is relatively short (e.g., 30 days). Such markets include those run by RTOs and ISOs as well as over-the-counter markets like NYMEX.

Spot Purchases: A short-term single shipment sale of a commodity, including electricity or gas, purchased for delivery within one year, generally on an interruptible or best efforts basis. Spot purchases are often made to fulfill a certain portion of energy requirements, to meet unanticipated energy needs, or to take advantage of low prices.

Spread: The difference between two prices, amounts or numbers such as the bid/ask prices in a commodity trading. In the futures and options markets a spread is the simultaneous purchase and sale of two different contracts in the expectation of a favorable change in their relative prices.

Standard Deviation: A measure of the volatility of an underlying instrument. It is a statistical quantity that measures the magnitude of the daily price change of that asset.

Standards of Conduct: Requirements under FERC's marketing affiliate rule, which prohibit discrimination in favor of the pipeline's own marketing affiliates and which require pipelines to submit reports detailing compliance with the rules.

Standby Service: Support service that is available, as needed, to supplement a consumer, a utility system or to another utility to replace normally scheduled power that becomes unavailable.

Straight Fixed Variable (SFV) Rate Design: A rate design method applied by the FERC on gas pipelines which allocates all fixed costs to the demand component and all variable costs to the commodity, or usage component.

Stranded costs: Fixed or sunk costs to be paid by the incumbents utility. Such costs become stranded when they cannot be recovered through the rates after the introduction of competition. An example would be the difference between the non-depreciated value of a generator and the book remaining depreciation when the utility sells the plant as part of restructuring. In some states, utilities could subsequently recover such costs from ratepayers despite the asset's sale.

Substitute good: A good which is to some extent interchangeable with another good (example, petroleum and natural gas). When the price of one good increases, the demand for another good increases.

Subsidization: The imposition of costs on one customer or class of customers that are attributable to services provided to other customers or classes of customers, who therefore pay less than the appropriate actual costs for the services they receive.

Substation: Facility equipment that switches, changes or regulates electric voltage. An electric power station which serves as a control and transfer point on an electrical transmission system. Substations

route and control electrical power flow, transform voltage levels, and serve as delivery points to industrial customers.

Sunk Cost: In economics, a sunk cost is a cost that has already been incurred, and therefore cannot be avoided by any strategy going forward.

Supplemental Regulation Service: A method of providing regulation service in which the control area providing the regulation service receives a signal representing all or a portion of the other control area's ACE.

Supply-Side: Activities conducted on the utility's side of the customer meter. Activities designed to supply electric power to customers, rather than meeting load though energy efficiency measures or on site generation on the customer side of the meter.

Take-or-pay clause: A contract provision obligating the buyer to pay for a certain minimum quantity of product, whether or not the buyer actually takes that quantity during the stated period. Utilities often have take-or-pay clauses with fuel suppliers.

Test year: A specific period chosen to demonstrate a utility's need for a rate increase. Data for a rate case or hearing comes from this period. It may or may not include adjustments to reflect known and measurable changes in operating revenues, expenses and rate base. A test year can be either historical or projected.

Tie line: A circuit connecting two or more Control Areas or systems of an electric system.

Tiered Rates: A rate design which divides customer use into different tiers, or blocks, with different prices charged for each. Inclining block rates, seasonal rates, and time-of-use rates contain such tiers.

Total Transfer Capability (TTC): TTC is the capacity of a transmission path taking into account ATC and all of the complex transmission network operating factors.

Tracker: A rate schedule provision giving the utility company the ability to change its rates at different points in time to recognize changes in specific cost of service items without the usual suspension period of a rate filing.

Transmission Loss: The power lost in transmission between one point and another. It is measured as the difference between the net power passing the first point and the net power passing the second point.

Transmission Only Company (TransCo): The term for that portion of a functionally disaggregated electric utility's business that involves the bulk transmission of power that is operated separately from any other power functions the utility might own or operate. Transcos can also be wholly unaffiliated with any other utility business.

Undergrounding: The act or program for placing the overhead transmission or distribution system underground.

Used and useful: A regulatory concept for determining whether utility plant is eligible for inclusion in a utility's rate base. Often defined as when plant is energized.

Utility plant: All equipment used fro the generation, transmission, and distribution of electricity, or an account which record is kept of this equipment. This includes plant in service, purchased or sold, in process of reclassification, leased to others, held for future use, and under construction, and acquisition adjustments and adjustment accounts, without deduction of accumulated provision for depreciation and amortization.

Variable operating costs: Those expenses that vary with the amount of business done or volume of goods produced. For most utilities these costs include fuel and certain operations and maintenance costs.

Vertical Integration: An arrangement whereby the same company owns all the different aspects of making, selling and delivering a product or service. In the electric industry, it refers to the historically common arrangement whereby a utility would own its own generating plants, transmission system and distribution lines to provide all aspects of electric service.

Volatility: A measurement of the price fluctuation of an underlying instrument that takes place over a certain period of time. Utilities must manage the volatility in the organized wholesale markets.

Volt: The unit of measurement of electromotive force. It is equivalent to the force required to produce a current of one ampere through a resistance of one ohm. The unit of measure for electrical potential. Generally measured in kilovolts or kV. Typical transmission level voltages are 115 kV, 230 kV and 500 kV.

Voltage Control: The control of transmission voltage adjustments in generator reactive output and transformer taps, and by switching capacitors and inductors on the transmission and distribution systems.

Voltage Support: A small remote generator located on a transmission system to provide voltage within tolerance limits to the customer. If the voltage delivered is outside of the tolerance levels, appliances will not run efficiently.

Wholesale electric power market: The purchase and sale of electricity from generators to resellers (retailers), along with the ancillary services needed to maintain reliability and power quality at the transmission level. RTOs operate such markets in much of the country.

Volumetric Rate: A rate or charge for a commodity or service that is calculated and charged on the basis of the amount or volume actually received by the purchaser.

Weatherization: A process or program for increasing a building's thermal efficiency. Examples include caulking of windows, weather stripping, and adding insulation to the wall, ceilings, and floors.

Wholesale sales: Energy supplied to other electric utilities, cooperatives, municipals, and Federal and State electric agencies for resale to ultimate consumers

Wholesale transmission services: The transmission of electric energy sold, or to be sold, in the wholesale electric power market. FERC has jurisdiction over such services.

Wires charge: A broad term referring to fees levied on power suppliers or their customers for the use of the transmission or distribution wires. The fixed or demand component of bills often includes these charges where they are not explicitly stated on electric bills.

Working capital: Amount of cash or other liquid assets that a utility must have on hand to meet the current costs of operations until such time as it is reimbursed by its customers. Working Capital includes fuel stock the utility must keep on hand in the event of a shortage or emergency, materials and supplies, prepayments, and cash working capital, which covers ongoing costs.**

EXHIBIT C

Model State Protocols for Critical Infrastructure Protection Cost Recovery

Prepared for the
NARUC Ad Hoc Committee on Critical Infrastructure

by

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The views and opinions expressed herein are not necessarily those of the National Regulatory Research Institute (NRRI), the National Association of Regulatory Utility Commissioners (NARUC), the U.S. Department of Energy (DOE), or any particular state or federal regulatory commission.

FOREWORD

The cost recovery of expenses associated with protecting critical electric, natural gas, telecommunications and water infrastructures is one of the most important issues to be addressed by the NARUC Ad Hoc Committee on Critical Infrastructure. This report synthesizes the work of the Committee to date and identifies cost recovery protocols successfully used by State regulatory commissions to address infrastructure security cost recovery requests. These cost recovery protocols can serve as models for States and will provide an essential means to help ensure that our Nation's critical utility infrastructure is protected. The impressive amount of effort by State commissions shows a bedrock commitment for ensuring that utility infrastructure protection efforts are adequately funded in order that our Nation's consumers can continue to receive an uninterrupted supply of utility services.

Much of the Nation's critical infrastructure is subject to regulation through an administrative hearing process that is carried out through State public utility commissioners. The regulatory processes for recovering investment costs in utility infrastructures in many States are handled through rate of return regulation and other cost recovery mechanisms. This paper examines the manner in which investments to protect critical utility infrastructures can be effectively accommodated within these existing regulatory frameworks. The first part of the report provides an overview summary, and the subsequent parts provide a more detailed discussion.

I gratefully acknowledge the assistance provided by the U.S. Department of Energy's Office of Energy Assurance to support this important effort.

The Honorable Connie O. Hughes, Chair
NARUC Ad Hoc Critical Infrastructure Committee and
Commissioner, New Jersey Board of Public Utilities

EXECUTIVE SUMMARY

State regulators and energy utilities have focused a considerable amount of attention on protecting the critical infrastructure of America's electric and natural gas utilities. One example of this is the cost recovery work done by the NARUC Ad Hoc Committee on Critical Infrastructure. This report draws upon the extensive work of the Committee, most notably its two cost recovery workshops, and several critical infrastructure surveys of state commissions conducted by NRRI. The objective of the report is to provide state regulators with information about the variety of workable cost recovery protocols that exist for energy utilities.

This report to the Ad Hoc Committee on Critical Infrastructure identifies cost recovery protocols used by state commissions. ***In some states, new legislation or regulatory proceedings were developed to deal with cost recovery.*** In most instances, existing regulatory cost recovery mechanisms were used. Many of the cost recovery protocols involve some form of a rate case proceeding. In most states, commissions have not received a security-specific cost recovery request. It may be that incremental security costs did not reach a materiality threshold in some states, or that security costs were not discussed explicitly in rate case filings. Of the states that have directly addressed security costs, all have done so in a rate case context. Generally, either a separate protocol path was followed that was then paired with a rate case, or the whole cost recovery request was entirely made in a specific general rate case proceeding. ***In all instances, the rate case requirement that a recoverable cost be prudent, or just and reasonable, was a central concern.***

The different protocols are specific attempts to smooth out any bumps on the road to the recovery of prudently incurred costs. Some cost recovery examples include:

- **A Kansas Act providing for confidentiality of the amount requested and allowed.** (See 2003 Kansas HB 2374, codified as Kansas Statute Nos. 66-1234, 66-1235, and 66-1236.)
- **The Florida Commission's use of two adjustment clauses.** (See Florida Public Service Commission, Order No. PSC-02-1761-FOF-El and Florida Public Service Commission, Order No. PSC-01-2516-FOF-El.)
- **A Michigan Act allowing use of deferral accounts and a security recovery factor.** (See Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d.)
- **The New Jersey Board's establishing an ongoing dialogue.**
- **The Oklahoma Corporation Commission's use of a Notice of Inquiry process.** (See Oklahoma Corporation Commission, Case No. PUD 200300624.)

OUR SURVEY OF THE STATES FOUND THAT:

- **State regulators are committed to allowing cost recovery of critical infrastructure costs that are prudently incurred.**
- **Regulators generally felt that they did not have to reinvent the wheel; finding that their existing inventory of cost recovery protocols and cost recovery mechanisms is sufficient for energy utilities.**
- **In restructured states, state legislatures have sometimes acted to reaffirm that post 9/11 security costs are eligible for recovery, as long as the costs are reasonable or prudently incurred.**
- **Insurance should be a part of a utility's cost recovery efforts.**

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PART I

INTRODUCTION AND OVERVIEW

INTRODUCTION AND OVERVIEW

An important new concern for utility industries and regulators alike is the need for cost recovery of security-related expenditures. Utilities expect that state commissions will approve recovery of appropriate critical infrastructure protection costs. The NARUC Ad Hoc Committee on Critical Infrastructure has conducted several surveys, undertaken a series of cost recovery workshops and commissioned this study in order to assist state regulators in developing model cost recovery protocols that address this need.

An important issue raised during the NARUC/DOE cost recovery workshops and by many state commissions in general, was the need for a practical examination and documentation regarding the best ways to handle cost recovery for security related expenses.[1] The nation's utilities have clearly made post 9/11 security investments in both restructured and non-restructured states. This report identifies and discusses critical infrastructure protection cost recovery protocols that are appropriate for energy utilities in a variety of regulatory frameworks. It also includes the existing cost recovery mechanisms successfully used by state commissions associated with each protocol.

What is a Cost Recovery Protocol?
What is a Cost Recovery Mechanism?

Cost recovery protocols, like much of regulation, are about process.

- A **cost recovery protocol** is the identifiable process that a commission uses to address a request by a utility in order to determine whether requested monies will be recovered.
- A **cost recovery mechanism** is the specific technique used for cost recovery. The protocol underlies the logic path for cost recovery for a rate regulated utility and the cost recovery mechanism, say, an adjustment clause, is how the commission authorizes the actual cost recovery.

Many Cost Recovery Protocols Exist

Since 9/11, a number of state commissions have responded to utility cost recovery requests.[2] The cost recovery protocols and mechanisms examined in this report are all reasonable approaches and no one protocol or cost recovery mechanism is recommended over another as the circumstances in different states may make one protocol more appropriate than another. As will be seen later, the actual cost recovery mechanisms — such as a deferral account — can be used in more than one protocol.

In some instances, new legislation or regulatory proceedings were developed to deal with critical infrastructure cost recovery. In most cases, existing regulatory cost recovery mechanisms were used. ***Nearly all of the protocols include a path to some form of a rate case proceeding.*** This

level of activity seems to indicate that the Ad Hoc Committee on Critical Infrastructure's efforts to develop critical infrastructure cost recovery protocols are well timed and will be helpful to a number of state regulatory commissions.

State commissions have reacted in a positive and timely way to address the cost recovery requests of their energy utilities. The protocols and cost recovery methods examined in this report provide a benchmark guide for best practices that all regulatory commissions can use.

1. COST RECOVERY ACTIVITIES, PROTOCOLS AND MECHANISMS

Cost recovery protocols mirror the regulatory reforms that states have undertaken in the past decade. In the energy arena a mix of rate base regulated and competitive market regulatory frameworks exist, with cost recovery requests occurring only in the regulated portions of each sector. In addition to energy utilities, water utilities have made a significant number of recovery requests, all of which have been handled under a rate base regulatory process. Some form of price caps is the dominant type of regulation for telecommunications utilities. Accordingly, it is not unexpected that no security cost recovery requests were reported in our survey for telecommunications utilities or providers.

Figure 1 provides a general framework for the discussion of cost recovery protocols and identifies three protocols (administrative, traditional, and restructured) along with a set of cost recovery mechanisms.[3] While any state regulatory commission may have important variations, the protocols can be applied to different regulatory regimes and specific cost recovery situations. Because the cost recovery mechanisms available are the same for all three protocols, the real regulatory differences in Figure 1 are driven by three considerations:

1. ***Do pre-existing critical infrastructure cost recovery mechanisms already exist?*** If the answer is "Yes", then it is appropriate to use the administrative protocol for those pre-existing mechanisms.
2. ***Is the energy market in the state subject to traditional rate-based regulation?*** If the answer is "Yes", then the traditional regulatory protocol is the correct protocol.
3. ***Has the energy market in the state been restructured?*** If the answer is "Yes", then the restructured protocol is the one to use.

The three protocols shown in Figure 1 arise because of the differences in the underlying logic within each. All states have administrative processes that occur on the front end of a cost recovery issue. Depending on the circumstances, this may lead directly to a cost recovery mechanism, or down one of the other protocol paths (traditional or restructured).

In a restructured environment, the protocol logic says cost reimbursement requests are examined differently than in a traditionally regulated market. Regulatory standards such as used and useful, just and reasonable, and prudence tests are similarly applied in each protocol, except that a competitive market perspective is also employed in the restructured regulatory environment. In most states, security investments have been initiated by utilities and not necessarily solely in response to governmental directives (see Figure 2). Interestingly, the utilities in most states have not filed for recovery security costs (see Figure 3).

Figure 1: Security-Related Cost Recovery Protocols and Mechanisms

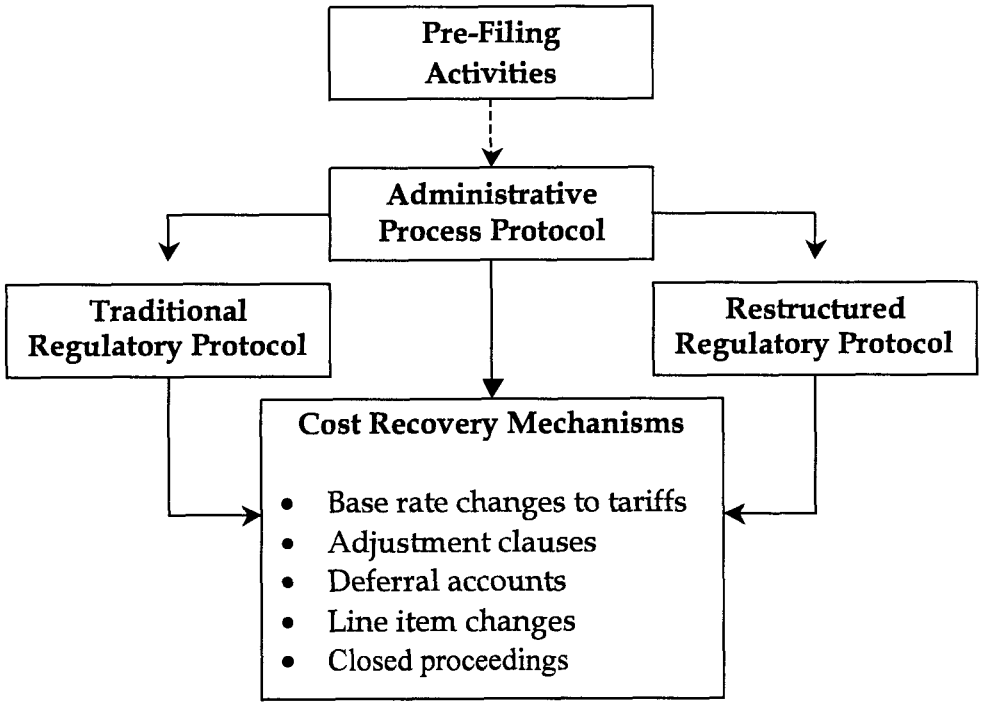
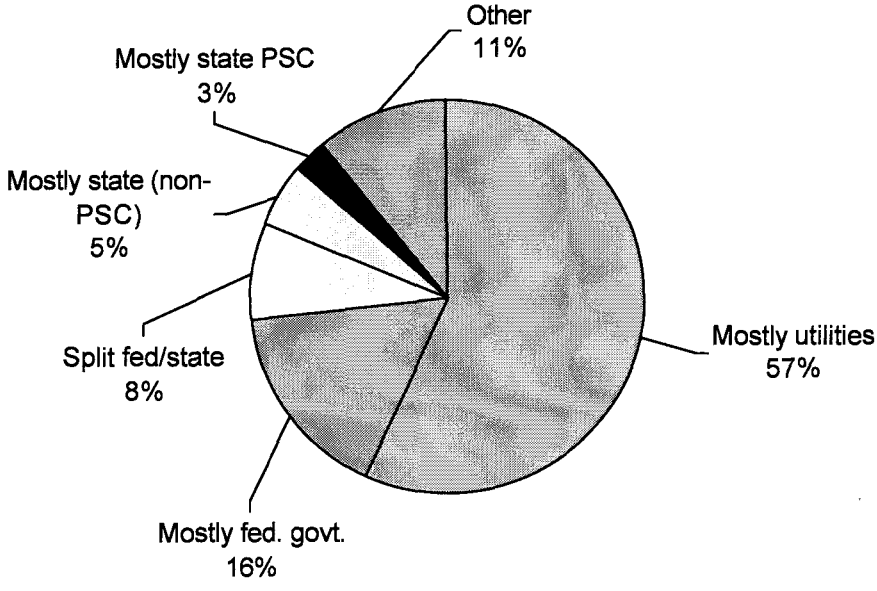


Figure 2: Who is driving security-related investments?



According to state public service commissions (PSCs) - It is mostly the utilities.

Source: Authors' construct from McGarvey and Wilhelm (2003), n=37 (10 other states reported no investments).

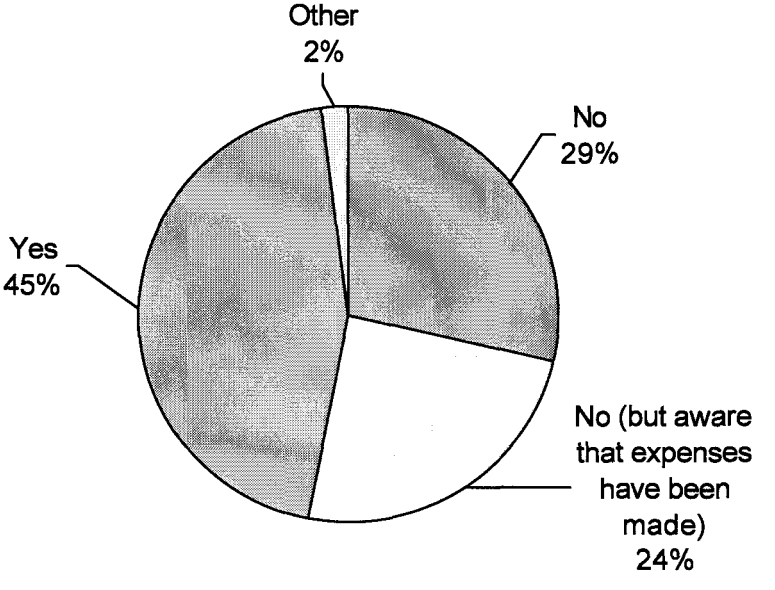
2. PRE-FILING ACTIVITIES AND ADMINISTRATIVE PROCESS PROTOCOL

Prior to the filing of a formal rate case, state rules may permit a utility to discuss issues with the state commission. Two types of preliminary activities identified are pre-filing discussions and ongoing dialogues. While significant differences exist between states,

- Some state rules allow for discussions between utility and regulator prior to filing. This can serve to brief regulators about security cost considerations.
- Another activity is to promote an ongoing dialogue, such as New Jersey has done, that allows regulators and utilities to discuss infrastructure security issues, including cost recovery.[4]

Commissions clearly have a well-formed set of administrative processes for addressing cost recovery issues. These processes serve as filters. The administrative protocol for security-related costs is applicable if and when a legislative act or commission rule specifies a particular cost recovery mechanism, such as Connecticut's Special Infrastructure Cost Recovery Hearing. This allows the commission to have a more focused cost recovery process, and not to have to rely on the traditional regulatory protocol.

Figure 3. Are utilities filing for security-related cost recovery?



Most states still have not had filings even though they are aware that security-related expenses have been made.

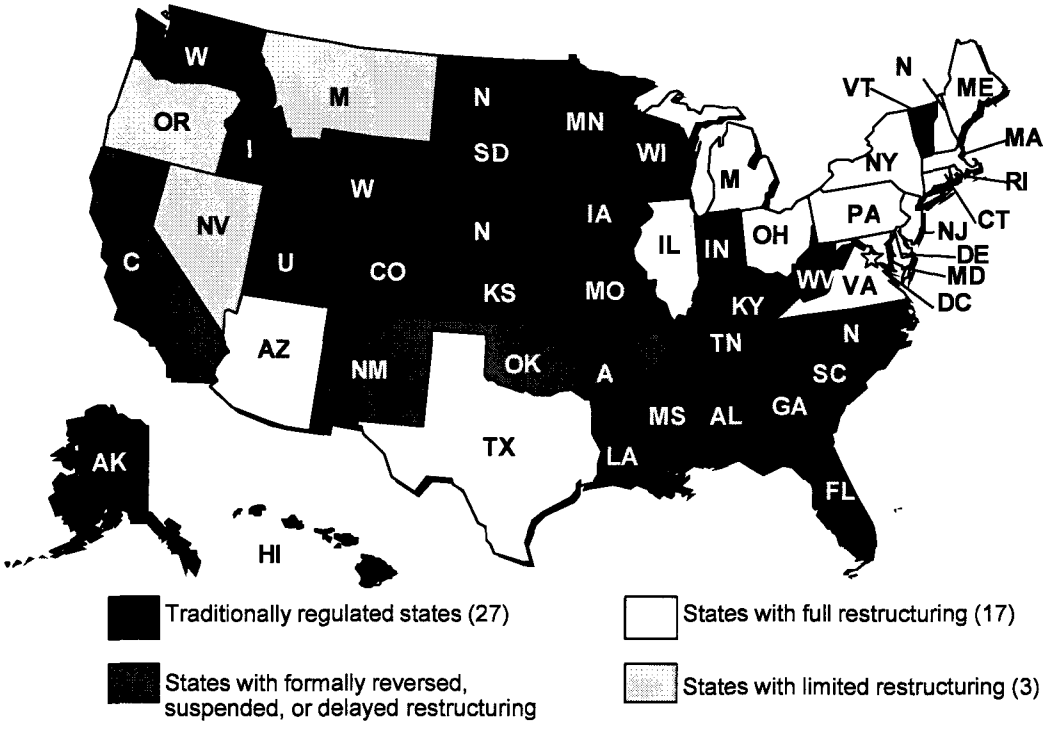
Source: Authors' construct from McGarvey and Wilhelm (2003), n=49.

3. REGULATORY PROTOCOLS

Regulatory protocols guide the processes state commissions use to make cost recovery decisions. In states with vertically integrated, rate base regulated electric and natural gas utilities (see Figure 4), rate cases are the primary way that critical infrastructure costs are addressed. Iowa, for example, examined and allowed specifically identified critical infrastructure costs in several rate cases. In some other states, rate cases were pending but not resolved. Most states surveyed by NRRI indicated that they had not seen a specific critical infrastructure protection cost recovery request.

In states with restructured electricity markets, generally a base case exists that deals with cost recovery. The logic underlying a utility cost recovery request is that the increase in security costs was not known at the time of restructuring and that a filing to recover these costs is appropriate. In Connecticut, as noted above, and in Michigan the legislature acted to allow the regulator to consider cost recovery for electric utilities. In restructured markets, cost recovery is more risky than in traditionally regulated markets.

Figure 4. Map of state electricity markets



Source: Authors' construct from Potter (2003), updated to June 2004.

In each of the cost recovery protocols and cost recovery mechanisms, regulators consider all cost changes before determining what security costs are authorized for recovery, although cost recovery is not guaranteed, just allowed. A utility may present valid and well-documented critical infrastructure protection cost information, but not be allowed the opportunity for cost recovery because an equal offsetting cost savings has occurred. It may be that the cost-of-capital has decreased and these documented savings necessarily reduce some portion of the security costs allowed for recovery. Equally, significant cost offsets may not exist, or may be dealt with in a subsequent proceeding. These cost recovery considerations also apply to regulated water and telecommunications utilities.

4. COST RECOVERY MECHANISMS AND OPTIONS

NRRI's survey of the states identified eight main cost recovery mechanisms (see Table 1) that have been successfully implemented in various states. Utilities have been allowed the opportunity to recover their critical infrastructure protection costs in restructured as well as traditional regulatory environments. All of the mechanisms are described in detail in Section 3, Detailed Discussion of Security Related Cost Recovery, but the outlines of each cost recovery mechanism can be seen in Table 1, and additional cost recovery options are noted in Table 2.

Table 1: Key Cost Recovery Mechanisms and State Examples

Cost Recovery Mechanism	Highlights	State Example
Base Rate Changes to Tariffs	• Rate base adjustment for nuclear power plant security • Operations and Maintenance (O&M) security expenses requested	Iowa (page 33)
Adjustment Clauses	• Fuel adjustment and capacity cost recovery clauses used • Focus on incremental post 9/11 security costs	Florida (page 33 and 34)
Closed Proceedings	• Legislative act provides confidential treatment of security costs • Consumer group may review documents	Kansas (page 35)
Deferral (Balancing) Accounts	• Costs must be reasonable and prudent • Costs deferred while rate cap in effect	Michigan (page 36)
Security Recovery Factor Charges	• Enhanced security costs eligible for recovery • Recovery is net of insurance or government funds	Michigan (page 37)

Base Rate Changes to Tariffs

A rate case is the standard way regulated utilities recover costs through a change to the existing, or base tariff, in which prices are authorized to increase to cover allowable and needed increases in capital, O&M, and other costs. While all of the mechanisms listed in Table 1 serve distinct purposes, they all have a common origin in a rate case where utility requests to change tariffs are resolved. In a traditional regulatory environment protocol, other types of cost recovery mechanisms are possible—most notably an adjustment clause—but each mechanism is either authorized in or reconciled to the rates previously approved in a rate case, although a significant time lag may exist. In a restructured environment protocol, commissions are able to consider rate changes for distribution rates, or retail customers, or standard offer customers, but these are generally tied to an initial rate case. NRRI found:

- States with pending utility rate case filings for critical infrastructure cost recovery, but as no action had been taken, no trend lines can be drawn.
- States with rate cases filed, but which do not have specific security costs identified.
- Instances where utilities have indicated that they do not intend to file for cost recovery.
- Iowa's consideration and approval of security costs.

Adjustment Clauses

In many states, adjustment clauses may be used to recover extraordinary costs that occur between rate cases. The Florida Public Service Commission used two different adjustment clauses to allow, in part, three Florida utilities to recover security costs due to compliance with a Nuclear Regulatory Commission order and for security, actions taken that were consistent with Presidential Homeland Security directives and North American Electric Reliability Council actions.[5] Some of the costs authorized for recovery were costs that would normally be classified as capital items.

Closed Proceedings

Except for proprietary information, commission proceedings are generally open. Due to security concerns, the Kansas Legislature acted to provide a confidential proceeding where the amount of recovery requested, the amount allowed, and the method of cost recovery were kept confidential.[6] Its focus was on post-9/11 security costs and provides for a cost recovery period within half of the useable lifetime of the investment. The Act also allowed the Citizen's Utility Ratepayer Board access within a protective order.

Deferral (Balancing) Accounts

Deferral accounts allow a utility to accumulate critical infrastructure protection expenditures that may be recovered in a rate case or other proceeding. This may be the cost recovery mechanism

most commonly used in conjunction with other cost recovery mechanisms. The Michigan legislature specifically authorized such an account so that costs could be accrued and deferred until rate caps are removed.[7]

Security Recovery Charges

In addition to general costs, a commission may allow a specific cost to be recovered through a security factor that can be included in rates. In Michigan, enhanced security costs can be recouped through a security recovery factor. In authorizing recovery, the commission must determine if costs are reasonable and prudent and are jurisdictionally assigned to retail customers.

Table 2. Other Cost Recovery Options and State Examples

Cost Recovery Options	Highlights	State Example
Notice of Inquiry	• Comprehensive regulatory forum to address a wide range of issues, including cost recovery	Oklahoma
Ongoing Dialogue	• Best practices identified	New Jersey
Special Cost Recovery Proceeding	• Ensures that ratemaking includes consideration of reasonable security costs	Connecticut

Notice of Inquiry

Rather than using a rate case, a commission may initiate a special proceeding or notice of inquiry (NOI) to establish a cost recovery framework (see Table 2). Cost recovery, confidentiality of data, and other critical infrastructure protection issues have been approached by Oklahoma through the NOI process.[8] Cost recovery was a central issue covered. Formal commission action is still pending, however.

Ongoing Dialogue

New Jersey, and Ohio told NRRI that they had a dialogue with their utilities. In New Jersey dialogue occurred through the New Jersey Infrastructure Advisory Committee. In Ohio, utilities are informally polled as they file rate cases.

Special Cost Recovery Proceeding

The Connecticut legislature acted to ensure ratemaking consideration of security costs. Connecticut regulators must examine the costs and find them reasonable. Connecticut has accepted some costs, but not others.

Concluding Observations

State regulatory commissions have acted in a number of ways to address the infrastructure cost recovery concerns of utilities, legislatures, consumers, and other stakeholders. ***In the majority of instances, state commissions have not received a specific cost recovery request (see Figure 3).*** It may also be that incremental security costs did not reach a materiality threshold and were not discussed explicitly in rate case filings. Of the states that have directly addressed security costs, all have done so in some form of a rate case context. Often, either a cost recovery mechanism was followed that was then paired with a rate case, or the whole cost recovery request was entirely made in a general rate case proceeding. In all instances, the rate case requirement that a recoverable cost be prudent, or just and reasonable was a central concern.

The cost recovery mechanisms that were paired with the rate cases are interesting and reflect attempts to work out key issues in advance. The Kansas closed rate case focused rate case and appears to be an expedited approach. The adjustment clauses and the focused issue hearings expedite recovery by producing, in effect, a commission-approved cost pre-approval that would be confirmed in a subsequent rate case. A number of rate cases used various forms of stipulation, or agreements between the parties, that also had the effect of looking like a pre-approval of costs, although commissions were not necessarily bound by a stipulation among the parties. The general rate case was without a doubt the most common critical infrastructure protection cost recovery approach.

5. COST RECOVERY CONSIDERATIONS

Subsequent to a determination that there is a need for recovery of costs, how closely a state commission might want to exercise its prudence review should be influenced in part by the type of regulation to which the particular utility is subject. In other words, which protocol path is most appropriate?

If the anticipated expenditures on security are relatively small and the utility is over-earning, then a utility might be reluctant to bring a rate case to recover its additional cost. Some utilities might be uncertain about expending money or investing in security if they are subject to a price cap or a rate freeze. In such a situation, all other things being equal, there might be an incentive for the utility to under-invest in security measures. This can be particularly troublesome as many security-related expenditures have positive externalities and they might have the effect of making the utility network more secure. Equally, state commissioners are also sensitive to not creating an incentive for carte blanche expenditures on security, which in turn end up directly in higher

rates. State and federal commissions have been sensitive to any possible incentive for a utility to cut expenditures to suboptimal levels under price cap or rate freezes, unless other mechanisms for cost recovery are created.

The policy implications are that:

- State commissions regulating utilities subject to either a price cap or rate freeze might mandate security measures (which would be difficult to the extent that asymmetry of information would tend to favor the utility having expertise over the commission).
- The commission might try to isolate prudently incurred security-related expenditures, or investments and provide for a special rate adjustment or rate supplement mechanism to allow these costs to be recovered.

At the federal level, as of June 2004, the FERC had approved at least five cost recovery surcharges.[9] And, as stated in the *FERC's FY 2005 Congressional Performance Budget Request*, the FERC plans to give its highest priority to processing any filing made for the recovery of extraordinary expenditures to safeguard the reliability of our energy transportation systems and energy supply infrastructure. The FERC has set as its performance target of timely processing of such filings: within 30 days for gas and oil rate filings and within 60 days for electric filings.[10]

The FERC, in its Statement of Policy on Extraordinary Expenditures Necessary to Safeguard National Energy Supplies, indicated its awareness that:

> *"...there may be uncertainty about companies' ability to recover the expenses necessary to further safeguard our energy infrastructure, especially if they are operating under frozen or indexed rates. In order to alleviate this uncertainty, the (FERC) assure[d] its jurisdictional companies that it will approve applications to recover prudently incurred costs necessary to further safeguard the reliability and security of our energy supply infrastructure in response to the heightened state of alert. Companies may propose a separate rate recovery mechanism, such as a surcharge to currently existing rates or some other cost recovery method."* (FERC, Docket No. PL 01-6-000, 96 FERC ¶ 61,299 (2001)

6. OTHER IMPLICATIONS

Other implications for states when considering critical infrastructure cost recovery requests include:

- **A need exists for critical infrastructure protection standards or guidelines** that regulators and utilities can use in ensuring that critical infrastructure is protected and that can be used in a cost recovery proceeding, which may be used in a pre-approval or other regulatory proceeding. State commissions can and have made cost recovery decisions without guidelines, but having guidelines is especially helpful for resolving prudence, reasonableness, and used and useful concerns.

- Commissions should **examine existing guidelines** issued by the North American Electric Reliability Council (NERC), the Network Reliability and Interoperability Council (NRIC), and the Department of Transportation's Office of Pipeline Safety (OPS) as a baseline for determining the guidelines or standards that they will use in their proceedings.

- Standards are more prescriptive than guidelines, but **standards may make cost recovery less problematic**. Guidelines, however, may offer greater flexibility that accounts for regional differences.

- **Critical infrastructure investments also need to be thought of as investments that increase shareholder value**. Both commissions and utilities have a common interest in ensuring continuity of service, but utility shareholders have the added interest in ensuring that net future revenue streams are not disrupted by terrorist attacks.

- Providers of utility services may be fully or partially regulated, or not regulated at all. Cost recovery for a vertically integrated regulated utility raises a different set of issues than a partially regulated utility in a price cap setting. **To date, all identified security cost recovery has occurred directly or indirectly in a rate case proceeding.**

- Whether or not standards or guidelines are used, **the state regulatory commission remains the final decision maker** (within constraints set by legislation and court decisions) regarding the timing, amount, and items eligible for cost recovery. A finding of prudence or reasonableness by a commission was a common part of all proceedings.

- **Pre-approval mechanisms exist,** but all identified have been eventually integrated in a larger rate case proceeding.

- **Utilities felt a strong need to have an informal dialogue with regulators** about their critical infrastructure plans. Protocols and rate case proceedings may need to have this flexibility.

- **Insurance** may be difficult to acquire, but regulators may wish to see that insurance was considered as an option.

PART II

DETAILED DISCUSSION

7. SECURITY RELATED COST RECOVERY – DETAILED DISCUSSION

This section describes in detail the cost recovery protocols and mechanisms identified in our survey of the states. Determining issues related to cost recovery of utility expenditures is a central role of federal and state public utility commissions. One way to look at security costs is through a framework like the one developed by the Battelle Memorial Institute that identifies the key elements of an effective security program. Battelle's framework includes (in no particular order):[11]

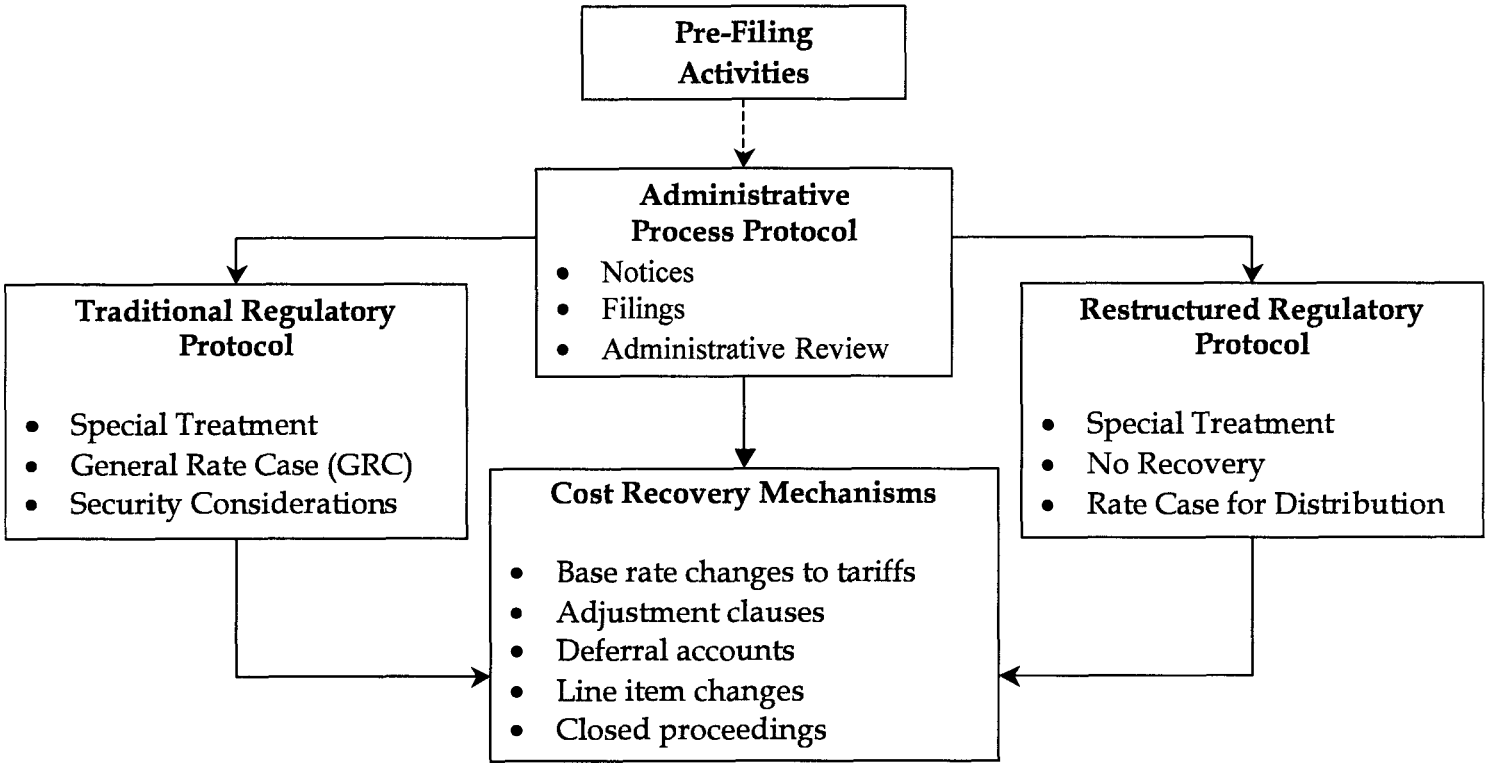
- Vulnerability assessments;
- Information management and intelligence;
- Threat detection;
- Physical security and deterrence;
- Cyber-security;
- Consequence management;
- Event mitigation; and
- Counter-terrorism.

With the exception of counter-terrorism, state and federal public utility commissions may expect a utility to undertake some or all of these functions. The level of effort and the decision on what to focus are a concern that can be somewhat alleviated by the development of standards or guidelines. ***Responding to governmental directives, such as a Nuclear Regulatory Commission directive, is an authoritative and governmentally sanctioned way of determining on which aspects of security a utility should focus.*** Carrying out these functions comes at a cost, whether the cost is a one-time non-capital expenditure (such as a vulnerability assessment), ongoing security expenditures, or capital investments.

This section discusses the protocols, and the underlying rationale, that state commissions can use in their cost recovery decisions. Figure 5 provides a detailed view of the entire security-related cost recovery process – from preliminary activities through various cost recovery protocols, and to the cost recovery mechanisms themselves.

By design, a generic framework that applies to most, if not all, commissions will have many exceptions. Certain steps may be rearranged, or be known by different names in different states. At nearly any point in the process, a state commission can redefine the issues involved and modify the process accordingly. However, even with these caveats, the main outline of the three cost recovery protocols holds for most states. Further, the security-related cost recovery protocol process diagram allows state commissions to visualize and modify their protocols as appropriate.

Figure 5: Detailed Security-Related Cost Recovery Protocols Process Diagram



8. PRE-FILING ACTIVITIES AND INFORMAL DISCUSSIONS

Cost recovery discussions may occur between the utility and the commission prior to an official critical infrastructure cost recovery filing. State laws and administrative rules differ significantly between states regarding the ability to talk to utilities. In some states, utilities are allowed to discuss issues with the commission, but only prior to any formal notice being filed for a proceeding. In these situations, a utility may brief the commission, say, about its security concerns, plans, and costs, but the commission is under no obligation to respond or pre-approve.

In some states, a commission may establish a working group, task force, or committee to look into an issue, such as cost recovery, or protection of confidential information. New Jersey is a good example of a state with an ongoing working group focusing on critical infrastructure. The idea of a dialogue was a central component of the NARUC Cost Recovery Workshop dialogue. While a commission is under no obligation to bind itself in any critical infrastructure dialogue, such a setting could allow the utility to share information and raise issues in a non-adversarial setting. Other groups and stakeholders may need to be included, depending on the state's rules. These dialogues could also take place in public conferences convened by a third-party.

Figure 6: Pre-filing Activities and Administrative Processes

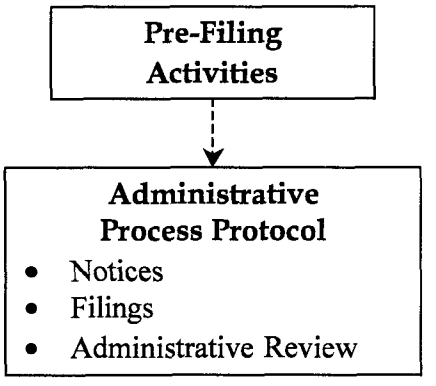
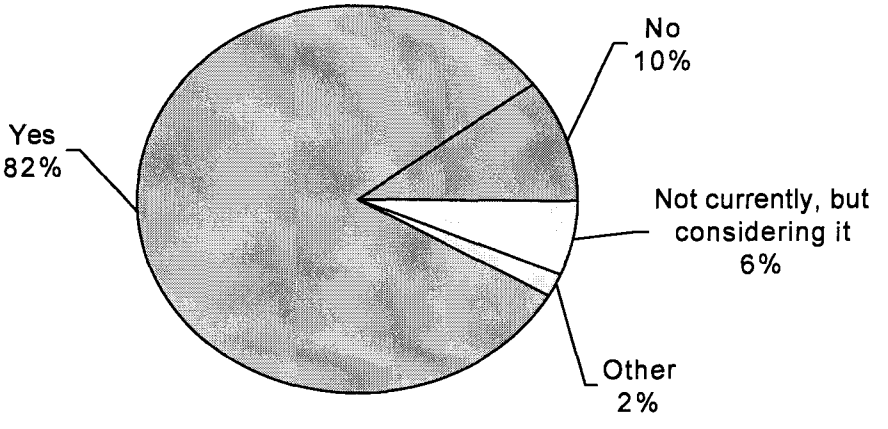


Figure 7: Do states offer utilities protections from disclosure of security-related information?



***Yes - Most do.* And this number has increased significantly since 2002.**
Source: Authors' construct from McGarvey and Wilhelm (2003), n=49.

9. ADMINISTRATIVE PROCESS PROTOCOL

In general, there are three main components to commissions' administrative proceedings for cost recovery. As shown in Figures 6 and 8, these include notices, filings and administrative reviews. A brief discussion of these follows.

Notices and Filings

Oftentimes, the administrative process starts with a pre-filing notice, followed by the formal filing. A commission examines the filing and makes a determination about the issues in the filing and whether the administrative remedy requested is appropriate. This could happen when the commission concludes that the relief being requested is no longer jurisdictional due to changes in regulatory structure. A commission may also examine the filing to see if it is intended as a rate case or for a previously approved proceeding, such as a fuel adjustment or capacity clause.

Administrative Reviews

While done somewhat differently in each state, all filings are initially administratively examined or reviewed to determine their appropriateness. There are several security related issues that may be considered during an administrative review. These include the issue of jurisdiction, whether cost have been pre-approved or not, and the appropriate regulatory framework for cost recovery (traditional, restructured or hybrid) for the utility in question. Figure 8 highlights these issues.

Commission Jurisdiction

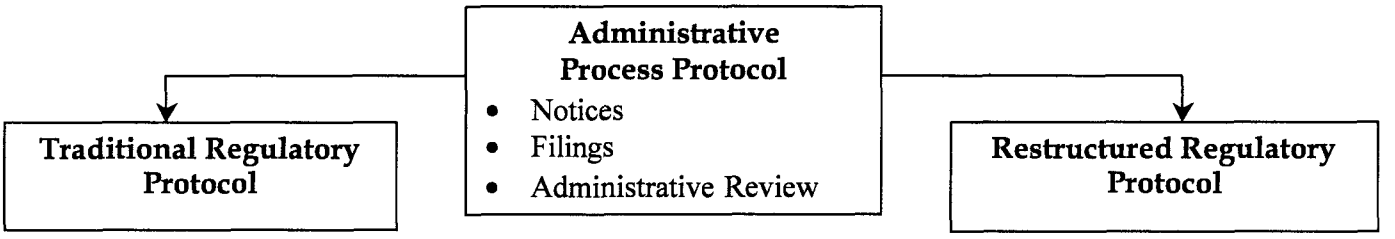
An important step that state commissions need to take when considering a request for recovery of security-related costs is whether or not the costs are jurisdictional or non-jurisdictional, or state or federal. Nearly all telecommunications utilities, most electric utilities, and some gas and water utilities have complex corporate structures that include both jurisdictional and non-jurisdictional entities and activities. ***Only the state commission may consider the security-related costs that are associated with the jurisdictional utility service.*** In order to determine whether security-related expenditures are joint or common costs, the state commission must use established cost allocation methods to divide the security-related costs between the jurisdictional and non-jurisdictional entity or activity. In other words, only those security-related costs related to the regulated activities of a jurisdictional entity should be considered. [12]

In the case of security-related cost recovery for telecommunications network equipment, which is a joint and common cost between state and federal jurisdictions, the telecommunications separations system provides the initial starting point for cost allocation. Currently there is a separation freeze, which means that the allocators used in the separations process are frozen.

Unless utility requests an exception, 76 percent of all increased expenditures that are joint and common costs are state jurisdictional, while 24 percent are federal.

If an inappropriate regulatory remedy is requested, the commission may reject the filing. It may or may not suggest the appropriate regulatory remedy. This procedure essentially involves a shortened staff review and commission concurrence and signing.

Figure 8: Security-Related Considerations in an Administrative Review



Pre-approved expenditure determination

In some instances, such as a previously established deferral or holding account, or adjustment clause, the utility is simply filing or registering expenditures that will be recovered later in a manner previously established by the commission. This protocol approach has been used in critical infrastructure cost recovery requests.

Applicable regulatory framework

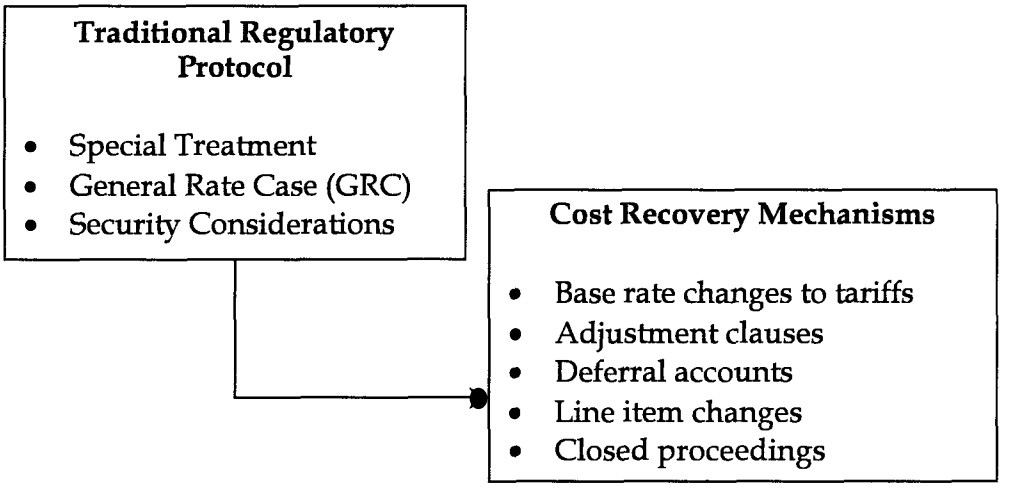
Many decisions are made in rate cases and are discussed in detail in a subsequent section. Commissions decide whether utility customers or utility shareholders are to pay for security costs. Traditionally security costs have not generally received a lot of regulatory attention. In the cost recovery protocols examined in this report, the existing level of security costs were accepted as a given and any regulatory review centered on the incremental post-9/11 security costs. The most visible example of this being utilities filing for cost recovery requests due (in part) to complying with post-9/11 Nuclear Regulatory Commission directives.

The "last mile" is generally still regulated in states that have competitive or restructured utility markets. This "last mile" may provide a common platform for incumbent and competitive providers that is still regulated and subject to commission oversight. The issue of concern to regulators is whether in a mixed regulatory regime — one partially regulated—that costs are properly assigned. ***Captive ratepayers and competitive providers of utility services can be disadvantaged if costs are wrongly assigned.*** For the portion of the utility still under state jurisdiction, most of the same cost recovery protocols already in use by the commission are appropriate.

Prior regulatory hearings or legislative acts may have established an adjustment clause, line item charge, or special proceeding that a state may use in an administrative protocol, even in a traditionally regulated state. This administrative protocol allows a pre-existing cost recovery mechanism to be used for critical infrastructure protection cost recovery requests. The Florida Public Service Commission, as part of its annual proceeding on fuel and purchased power expenses, approved certain security-related costs. These costs, incremental to costs recovered through base rates, were recovered through the fuel cost recovery clause and the capacity cost recovery clause.[13] These costs, once approved, would flow through and be a base rate tariff charge. In a restructured state, such as Connecticut, a legislative act allowed the Connecticut Department of Public Utility Control to examine and authorize critical infrastructure costs to be included in base tariff rates.[14] Within the administrative protocol, then, the commission may examine the costs according to its rules and determines the amount to be recovered.

10. TRADITIONAL REGULATORY PROTOCOL

Figure 9: Traditional Regulatory Protocol and Cost Recovery Mechanism



Well-established cost recovery procedures exist in all states that regulate utility services. Whether the state's utility markets are served by single provider or are open to competition, states have a long history of experience with traditional cost recovery of the jurisdictional wholesale and retail portions of a utility operation. Traditional cost recovery mechanisms for specific items can take many forms, including previously approved rate adjustment clauses, retail bill line-item charges, simple tariff changes, and all the way up to a large general rate case. These cost recovery mechanisms have been variously applied by commissions in their response to critical infrastructure cost recovery reimbursement requests. Figure 9 highlights key components that might be encountered when the administrative review dictates following the traditional regulatory path. Figure 9 also outlines the potential cost recovery mechanisms that might be appropriate.

The first step down the traditional path is to determine whether the applicant's filing falls within a pre-defined set of special treatment protocols such as a pre-existing approval to issue a line-item charge or an adjustment clause that might have been pre-approved in a previous case. If such treatment is warranted the case would proceed to be reviewed for allowance or disallowance using that specific cost recovery mechanism. If such treatment is not appropriate, the recovery request would proceed into the general rate case (GRC) process. Within the GRC process, the commission would undertake the evaluation of the critical infrastructure expenditures. Ultimately, the GRC would conclude with a determination of recovery, allowance or disallowance, within a well defined, traditional ratemaking process.

Traditionally regulated utilities are given an opportunity to recover jurisdictional service costs that are at the same time prudent, used and useful. ***Once costs are determined to be associated with jurisdictional utility service, a state commission must determine whether the security-related costs are used and useful, as well as whether they are prudent.*** It is the utility's responsibility to identify and make the link between an expenditure and its security function for the commission.

Security-related expenditures and investments mandated by either state or federal agency may be considered prudent. To date, most security-related investment or expenditures have necessarily been driven by the utilities themselves and not by state or federal mandates. In the NARUC Cost Recovery Workshops, it was noted by several participants that state commissions should consider a collaborative dialogue to discuss what actions are necessary to meet the security needs of the utility. Such commission-utility discussions would, it was felt, be general in nature and details would need to be kept confidential. Traditionally, cost recovery and reasonable access to information associated with utility expenditures have gone hand-in-hand. Developing appropriate policies, practices and procedures for the disclosure and handling of security sensitive information is a fundamental necessity for cost recovery.

If it is determined that security-related costs are used, useful and prudent, there are a variety of cost recovery protocols that might be appropriate. In choosing a cost recovery mechanism state commissions may also consider the relative size of the security-related expenditures.

A cost recovery mechanism can be used in a traditional rate case, or other regulatory proceeding, such as an adjustment clause. It can also be used, to a much lesser extent, for restructured utilities, and mainly for the distribution utility. A cost recovery mechanism is the final administrative tool that the commission uses to allow cost recovery.

Special Considerations and Treatment

When a utility seeks recovery for critical infrastructure investments, the filing may provide the commission with cause to apply special considerations or treatment outside of the larger parameters of a traditional review. An example of special consideration might be an expedited review process. It might be that the recovery sought was for expenditures on critical

infrastructure that fell into a certain previously approved, reviewed, or generally accepted category of expenditures. Depending upon the regulations, statutes, and practices of the state, a commission may need to consider special confidentiality treatment for the sensitive security information portion of the pleading and proceeding. The NARUC/NRRI 2003 Survey on Critical Infrastructure found that 84% of the states have exemptions to Freedom of Information Acts or other protection mechanisms in place to guard against the disclosure of sensitive security information that applicants share with the state commission.[15] In part due to the commission experience with Y2K, and in dealing with confidential information with competitive implications, and because of the clear consensus to prevent information from being revealed to terrorists, state commissions overwhelmingly acted to modify their disclosure rules and sought legislative authority when needed.

If the nature of the pleading was so overwhelmingly sensitive that attempting to protect the sensitive information, as part of a general rate case would prove too difficult, a commission might conduct a special entirely closed proceeding. Generally, parties to rate case proceedings have recognized the need to protect data and developed reasonable ways to handle confidential data. When confidentiality issues have been important issues in regulatory proceedings, the issue appeared to center on financial data. Commissions generally resolved this through the use of stipulations and by approving rates that did not specifically identify the security cost component.

General Rate Case (GRC) Considerations

Absent a previously established specific cost recovery mechanism, a showing for special consideration in terms of expedited recovery, or other special treatment, the merits of a critical infrastructure cost recovery pleading have been resolved in the course of a traditional general rate case proceeding. However, even a GRC from the start may have to consider and implement mechanisms for the protection of confidential security-related information.

A "prudence review" is a common activity that occurs during a GRC. Various aspects of security-related costs can be evaluated through this process. Within the prudence review is the *prudence test* and the *used and useful test*. The consideration of insurance may also be necessary. The existence (or lack of) of security guidelines will drive the scope and scale of the prudence review tests. The review will culminate in a determination of the allowance of the claimed expenditures. If recovery is allowed, the process will proceed to the appropriate cost recovery mechanism.

Prudence and used and useful reviews

Under traditional regulation, utilities may recover costs that are both "prudent" and "used and useful."[16] ***It is the role of a commission to review costs and ensure that recovery is based on prudently incurred costs that are both used and useful.*** How that review occurs is a product of state statute, administrative rules, and traditions of practice. There are some general guidelines

that a typical state prudence review would follow to determine whether a critical infrastructure expenditure was prudent and used and useful.

Critical infrastructure protection may have special characteristics that do not neatly fit into the established prudence and reasonable standards used by commissions. In the NARUC Cost Recovery Workshops, participants expressed several concerns. The first was that the utilities felt that they were going to incur significant costs when the U.S. Department of Homeland Security (DHS) changed its color alert levels in response to a threat. If no attack occurs, the issue was whether an after-the-fact review in a rate proceeding would disallow some or all of these expenditures as not being "used and useful", however prudence guidelines prevent hindsight. A second concern, that follows the same line of reasoning, is whether capital investments and other expenses may be ruled to be non-recoverable after the fact. Some also felt that normal requirements to have construction projects competitively bid might result in some costs being disallowed if the utility felt it had to respond quickly.

Examining prudence first, expenditures must be prudent to be subject to cost recovery. There are **four widely accepted guidelines** that can be used to determine whether an investment or expenditure is prudent.

1. The first guideline is the presumption that the investment and expenditure decisions of a utility are prudent. Unless the presumption of prudence is overcome, there is no need for further examination of the investment or expenditure. The existence of standards or guidelines, or governmental security protection requirements would be important in reinforcing a presumption of prudence. However, an allegation of imprudence that is backed by substantive evidence creating a serious doubt about the prudence of the investment or expenditure decision would require a commission to apply the prudence test to determine whether or not the expenditure or investment qualifies for full or partial cost recovery or no cost recovery at all. ***There is no presumption of prudence for affiliate transactions, whether they are for expenditures or investments.***
2. The second guideline is that, to be prudent, a utility decision resulting in expenditures or investments must have been reasonable under the circumstances that were known or knowable at the time the decision was made.
3. A corollary to this is the third guideline: the proscription against hindsight. The proscription against hindsight means that one cannot supplement reasonableness under the circumstances at the time of the investment decision with other standards that first look at the final outcome of the decision. How this proscription against hindsight is applied will greatly resolve the dilemmas posed at the Cost Recovery Workshops. Nevertheless, consideration of the outcome may legitimately be used to overcome the presumption of prudence.
4. The fourth guideline is that prudence is determined in a retrospective, factual inquiry, which should exemplify the proscription against hindsight.[17]

In addition to being prudent, expenditures must be used and useful. State commissions may consider security-related expenses to be used and useful so long as they are directly related to jurisdictional critical infrastructure or linked to the critical infrastructure through processes that support the critical infrastructure. For example, if electricity or telecommunications distribution systems are considered to be critical infrastructure, then the distribution service restoration processes may be found to be critical to supporting that infrastructure. Consequently, assets and expenditures that support the service restoration process might, therefore, be considered to be security-related costs. As noted above, security-related costs can be classified as serving one or more of the following functions: vulnerability assessment; information management and intelligence; threat detection; physical security and deterrence; cyber-security; consequence management; and event mitigation.

Michigan has defined security costs for recovery purposes as those costs that are reasonable and prudent costs of new and enhanced security measures mandated by government or found necessary by the commission. [18] The statute goes on to include applicable insurance and service restoration costs.

***In the NARUC Cost Recovery Workshops** it was noted that security expenditures can be:*

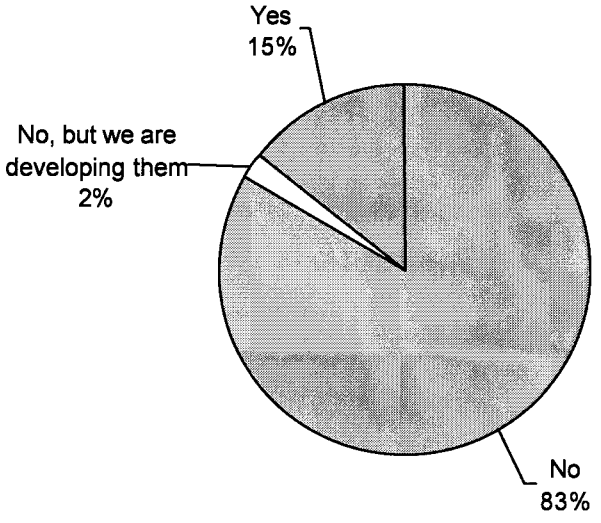
- ***One-time, non-capital expenditures;***
- ***Ongoing security expenditures; and***
- ***Capital expenditures.***

They can be the same as or different than pre-9/11 costs. In some cases, there will be a one-time expenditure that might properly be amortized over several years. There might be new facilities and equipment (including additions to spare equipment in inventory), or additional ongoing expenditures, such as the hiring of personnel or the purchase and ongoing training of security dogs. There are wide arrays of additional expenditures that may be considered security-related, and as long as they serve one of the above security functions for critical infrastructure or its support, the expenditure should be considered used and useful. It is the utility's responsibility to identify and make the link between an expenditure and its security function for the commission to be satisfied that the expenditure is used and useful.

As part of a prudence review, a commission may need to consider the role that contracted insurance plays in the applicant's critical infrastructure plans and expenditures. ***Insurance can provide both an incentive and a risk management tool for utilities.*** Insurance companies can require that certain actions be undertaken by utilities if they wish to purchase insurance. Second, utilities can minimize their risk by purchasing insurance. Michigan explicitly requires that the reimbursement of security recovery costs must be net of any insurance proceeds.[19]

Independently of the shared concerns of both regulators and utilities about service availability, utility shareholders have an unmistakable interest in preserving net future revenue streams. Losing customers through an inability to provide needed services due to terrorist attacks affects the utilities' revenues and bottom line profitability. Utilities have a clear interest in insurance coverage, as well as preventative and service restoration planning and investment.
The existence of security investment guidelines (or standards or rules)[20] will have significant impact on the review process of critical infrastructure expenditure recovery sought in the context of a GRC. If a state commission has security investment guidelines the application of the prudence review and used and useful tests will be faster and less arguable. If the guidelines are specific enough, it may be that prudence review steps can be by-passed for items that fall within the security guidelines. A commission's guidelines may go so far as to establish a list of critical infrastructure expenditures that will receive approval *prima facie*. If a state has security

Figure 10. Are there separate prudence guidelines for security costs?



No **– most states plan to use their existing prudence review process for handling security-related expenses. However, a few state commissions are developing them or have some modifications in place.**

Source: Authors' construct from McGarvey and Wilhelm (2003), n=48.

guidelines and an applicant's request for recovery is not within the parameters of those guidelines, the commission could review the request through a detailed prudence review as described above. The presumption of prudence seems to have been the prevailing regulatory perspective in the cost recovery protocols identified in our survey. If the security guidelines are written such that any security expenditure outside the guidelines is by definition non-recoverable, the commission would simply deny the recovery in its order for the GRC.

In contrast to other expenditures where standards have been developed and refined over many years, state commissions do not have well-established, security-specific, standards by which to evaluate the appropriateness of utilities' efforts to protect their critical infrastructure. Without standards, commissions would have to rely on witnesses in a proceeding in order to make a determination on cost recovery. Both the gas and electric industries now operate under some level of security guidelines. In the electric industry, the North American Electric Reliability Council (NERC), an intra-industry organization, has compiled the most extensive set of guidelines for both physical and cyber security.[21] Originally developed in June 2002, the physical guidelines are arranged by security topic and are periodically updated with the understanding that the guidelines are intended to evolve along with the threats to the electric industry. The existence of the NERC physical security standards is beneficial, but they leave room for differences in protection.

The gas industry largely relies upon the Security Practices Guidelines developed by the Department of Transportation's Office of Pipeline Safety (OPS) and issued in September 2002.[22] These guidelines were developed with the assistance of state pipeline agencies and pipeline industry representatives. The guidelines are not publicly available, but a review by the Oklahoma Corporation Commission (OCC) found the guidelines to be methodical and comprehensive. In addition to on-site follow-up by OPS, compliance with the guidelines is subject to review by state pipeline agencies.[23]

In its review of the status of state and federal security standards and guidelines, the OCC noted full agreement among the commission and industry participants that any measures passed by the state commission should be consistent with the requirements of other states and the federal government since companies should be held to conflicting requirements. The OCC found the NERC and the OPS guidelines to be the most authoritative and extensive guidelines available for their respective industries.

Within the telecommunications sector, the Network Reliability & Interoperability Council (NRIC) is an intra-industry organization that has developed an extensive list of best practices for the telecommunication industry.[24] Although the telecommunication industry participants in the OCC's review supported the commission's use of the NRIC guidelines, NRIC states that the guidelines are not intended to be imposed as government regulations. More to the point, the nearly 800 highly technical items in the list would be impractical to adopt as regulations; in order to make use of the NRIC guidelines, it would be necessary for a commission to identify those best practices that were relevant for the companies under the commission's jurisdiction.

The Environmental Protection Agency (EPA) is the lead federal agency for the security of drinking water and wastewater. In February 2004, the EPA's National Drinking Water Advisory Council formed the Water Security Working Group in order to establish and disseminate best practices for drinking water and wastewater utilities by 2005.[25] Under the Public Health Security and Bioterrorism Preparedness and Response Act, the EPA requires water operators serving populations larger than 3,300 people to certify to EPA that they have conducted a vulnerability assessment, and revise their emergency response plan correspondingly.[26] EPA provides grants of up to $115,000 to defray the costs of assessments. Smaller water companies (i.e., those serving fewer than 3,300 people) are not required to conduct assessments partly out of concern that they could not recoup the relatively high costs, although grants and other assistance for voluntary assessments and low-cost security strategies may be offered by state agencies. In addition, intra-industry organizations such as the American Water Works Association (AWWA) and the National Association of Water Companies (NAWC) support members with vulnerability assessments.

Commissions must decide whether to employ mandatory security standards or a set of official voluntary security guidelines. In the NARUC Cost Recovery Workshops the distinction between standards and guidelines was drawn. Mandatory standards make questions of cost recovery easier to resolve since the mandate would usually imply the prudence of the corresponding expenditure. Mandatory standards also offer greater assurance against certain companies under-investing in security. However, voluntary guidelines (possibly including a method of self-certification) would allow a commission greater flexibility in dealing with the cost burden on companies of different sizes and criticality and would allow companies more flexibility to develop security plans specific to their needs. Commissions must also resolve whether imposing equal standards on all companies would require openly publishing what those specific standards are, thereby serving notice to potential attackers.

The four prudence guidelines discussed earlier can raise a more fundamental question: how does one determine what is reasonable under the circumstances for the purpose of determining the prudence of security-related expenditures or investments? The NARUC/NRRI 2003 Survey on Critical Infrastructure Security found that a large majority (83 percent) of commissions do not have different guidelines for determining the prudence of security investments and only a few are developing them at present.[27] So, what can be said about a prudence standard for security-related expenditures or investments? Certainly, security-related expenditures and investments that are mandated by either a state or federal agency are considered prudent (so long as no gold-plating takes place). However, the NRRI survey shows that most security-related investment or expenditure has been driven by the utilities themselves and not by state or federal mandates. In such cases, it might behoove state commissions to begin a collaborative dialogue, similar to that undertaken for Y2K expenditures, to discuss generally, what actions are necessary to meet the security needs of the utility.

These discussions could focus on both short-run actions that the utility can take to protect its existing system as well as long-term planning solutions that might provide for event mitigation or produce a self-healing or redundant utility system, which inherently mitigates the damage of any attack. Such discussions could deal with issues of resource allocation and the level of costs for security-related expenditures, and could allow both the commission and the utility to wrestle together with issues of whether the benefits of increased security are worth the costs as well as potentially prioritizing alternative or complementary projects by cost-benefit ratios. This would lead to the lowest cost expenditures being made on the most vulnerable part of the utility system first, something noted in the NARUC Cost Recovery Workshops. Another alternative might be to provide for outage risk insurance for ratepayers and/or shareholders. Such commission - utility discussions would necessarily be general in nature and details would need to be kept confidential.

Such collaborative dialogue might strongly appeal to state commissions and be worthwhile, particularly given the "obligation to serve" standard that state commissions still have and enforce regardless of whether their network utilities have restructured. Nevertheless, the utility needs to fulfill its obligation to provide safe, reliable, and adequate service. Further, it is the utility itself that has the expertise and knowledge of its own system, which is necessary to do a proper cost-benefit analysis. While commissions can review utility decisions, care must be taken not to substitute the commission and commissioners in place of utility management and their responsibilities. Indeed, if the commission's level of involvement becomes too great, the commission will have essentially pre-approved the decision of the utility to make its security-related expenditures. The commission would be left only to decide how well the utility had executed its security plans.

Security Considerations - Information Handling

Traditionally, cost recovery and reasonable access to information associated with utility expenditures have gone hand-in-hand. ***Prior to Sept. 11, 2001, the trend in regulation, as in most segments of our society, was to move more and more information into the public domain.*** The Freedom of Information Act (FOIA), public records laws, open meetings, sunshine requirements, and *ex parte* communication rules all served to increase both the types and amount of information that was available to a broad-based set of stakeholders affected by utilities and their operations.

In light of the new developments concerning critical infrastructure security, the "right-to-know" proposition is being challenged or at least tempered by the more limiting proposition of "need-to-know." Developing appropriate policies, practices, and procedures for the disclosure and handling of security sensitive information is a fundamental necessity for cost recovery.

The recent NARUC/ NRRI 2003 Survey on Critical Infrastructure Security found that 82 percent of commissions offer FOIA protection for sensitive utility security information.[28] This is a substantial increase from the 2002 survey, which found that only 42 percent of states offered

protection of sensitive information (shown in Figure 7). Nonetheless, the 2003 survey also found that most commissions (54 percent) still believe that utilities are either somewhat or very reluctant to share their security information with the commission. However, this level represents a decrease from the previous year, when 74 percent of respondents reported that utilities were reluctant to share information.

Although considerations regarding the sensitivity of security-related data clearly go beyond the cost recovery issue, a commission's access to pertinent information is at the heart of traditional cost recovery determinations. It is, perhaps, reasonable to begin with the assumption that, at a minimum, summarized expenditure data on security can be shared with regulators.

The NARUC Resolution on Guidelines for State Commission Procedures Involving the Handling of Security Sensitive Documents and the Recovery of Prudently Incurred Security-Related Costs encourages commissions to:

- ***Review appropriate treatments of security sensitive information** that are available to the public.*
- ***Work with utilities** and other appropriate government agencies to establish procedures for cost recovery.*
- ***Share information handling procedures** among themselves as this issue evolves over time.*

(Resolution available at http://www.naruc.org/associations/1773/files/security.pdf.)

It may be appropriate for regulated utilities to share only generalized cost increase information with regulators. To the extent that any details in the information are sensitive due to national security concerns, state commissions should make that information confidential and not subject to state sunshine acts or FOIA disclosure. Indeed, some states have already specifically excluded information about critical infrastructure from their FOIA procedures. Other state commissions might wish to consider promulgating or proposing similar measures to their legislatures.

As noted in Appendix B, the FERC has issued Final Order No. 630 and Order No. 630-A, both of which deal with the protection of critical energy infrastructure information. Order No. 630 covers only information submitted to or prepared by the FERC. "*Critical energy infrastructure information*" is information about proposed or existing critical infrastructure that relates to the production, generation, transmission, or distribution of energy that could be useful to a person in planning an attack on critical infrastructure; is exempt from mandatory disclosure under FOIA;

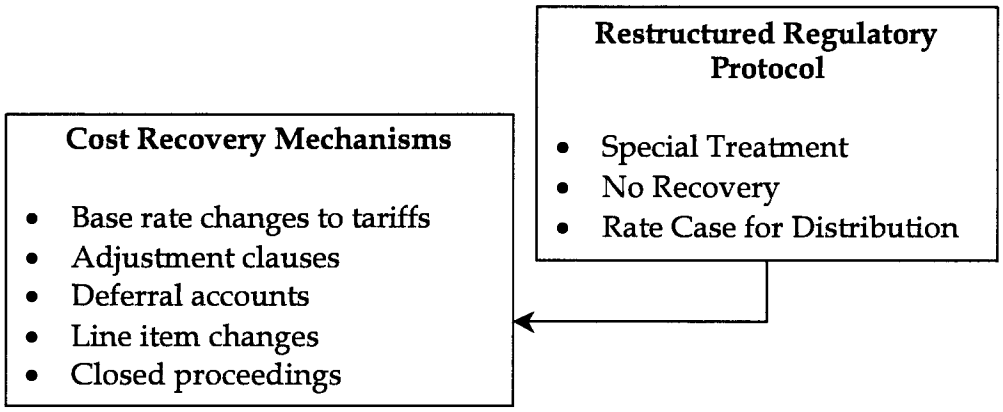
and does not simply give the location of the critical infrastructure. The applicability of FOIA requests is still to be processed on an individual case-by-case basis. Critical energy infrastructure information may or may not include information that would be useful in determining cost recovery for FERC jurisdictional costs. Nothing in Order No. 630 or 630-A prevents state commissions from independently seeking information that they might need to make a cost recovery determination; however, these orders highlight the need for state commissions to consider confidentiality concerns and to have protective order guidelines when handling cost recovery information that may have security implications.

11. RESTRUCTURED REGULATORY PROTOCOL

The filing of an application for critical infrastructure expenditure cost recovery in a state with open utility markets and/or competition may require a state commission to engage in special or additional considerations beyond that of a general rate case. An important part of the administrative review (Figure 8) is to determine if a path other than a traditional cost recovery path is required. For simplicity, this other path is referred to as the restructured regulatory protocol. Important elements of this protocol are highlighted in Figure 11.

The restructured path would necessarily be a consideration for electricity and gas utility services in open-market states, but it might also be a consideration in competitive telecommunications environments. If the restructured path is chosen, ***the first step is to determine if any cost recovery treatment is allowed under the new regulatory regime.*** If not, the protocol process ends at that point. The principle in effect here applies to all recovery cost requests in restructured states. If a further review for cost recovery treatment is appropriate, the next step is to determine if the review should happen in the context of a pre-existing cost recovery mechanism, or through a more general rate case type of proceeding.

Figure 11: Restructured Regulatory Protocol and Cost Recovery Mechanisms



Special Considerations and Treatment

The existence of a restructured market in and of itself does not necessarily change the principle issues and considerations of critical infrastructure expenditure cost recovery. There are a variety of cost recovery protocols that might be appropriate for the recovery of security-related costs. In making an initial choice among cost-recovery protocols, regulators should consider whether the entity is subject in any service or organizational structure to rate base, cost-of-service regulation. The answer might be "no" for a variety of reasons. Most, if not all, of a utility's services might be considered to be competitive in nature. In the telecommunications sector many of these competitive services are subject to price cap or other alternative forms of regulation. In other cases, particularly in states that have undergone retail electric industry restructuring, the rates might be subject to a price cap or a rate freeze. Allowable expenditures will still need to meet some pre-authorized qualifications, or pass tests of prudence and used and usefulness.

However, in a restructured environment, a commission may need to take into account special conditions and consider additional factors in its cost recovery review. Among those special condition and factors might be:

- Existing rate freezes or caps.
- The existence of provider-of-last-resort requirements.
- Applicant specific restructuring plan requirements.
- Existing laws, rules, or guidelines that address recovery of excess costs in the restructured environment.
- Effect of recovery mechanisms on market development or competitive neutrality.
- Policy considerations of guaranteed cost recovery in an open market.

No Recovery Allowed

In a fully competitive market, where the requirements for retail service tariffs have been removed, or where rates are now market-based, it may be as simple as saying that ***security-related critical infrastructure expenditures are (like other expenditures) business decisions subject to recovery only as the market will bear*** and not subject to guaranteed recovery through a commission order. For example, if local telecommunications services were deemed to be fully competitive by a state commission, and all providers were subject to the same service standards, even if some basic local rates are still fully regulated, a commission might deny allowance of a guaranteed specific recovery for critical infrastructure investments since all providers would be equally burdened in the competitive market.

Other considerations as discussed below notwithstanding, a similar conclusion might also be reached in a restructured energy market. Generally speaking, in a restructured energy market traditional retail rate controls are replaced with market-based rates. As detailed in a recent report on electric restructuring transition periods, exactly when the market-based rates did or will take

over varies from state-to-state.[29] However, if market-based rates have replaced the traditional non-market rates, a commission might deny recovery allowance of a claimed critical infrastructure expenditures made without a specific government mandate, based on the finding that the expenditure was a competitive marketplace business decision.

Rate Case for Distribution

The utility markets in most states may not be at a level of competition that would give state commissions enough comfort to simply deny cost recovery based on the above arguments – that the investments are equal burdens for all providers or competitive business decisions not eligible for guaranteed cost recovery. A possible scenario in a restructured environment may be the need for state commissions to consider security cost recovery from still regulated services with a mix of rate types (e.g., market-based, capped, frozen, and standard cost-based) and a mix of regulatory scenarios (e.g., negotiated rate settlements, statutorily restricted rates, and alternative or incentive plans).

Assuming a state commission has not issued a *prime facie* dismissal of an applicant's request for cost recovery, the commission will proceed to review that request. If the filing is by an electric utility service provider in a state with electric retail competition, the commission must consider the conditions of that restructuring in its review of the request. We can assume that since most restructuring was in place (or well on its way to being so) prior to September 11, 2001, that recovery of critical infrastructure expenditures was not specifically addressed in most restructuring rules and regulations. While some states have subsequently specifically addressed the recovery of critical infrastructure related costs, according to the NARUC/NRRI survey, 83% of the states do not have specific rules or guidelines.[30] Consequently, a state may likely have to develop guidelines, practices, and precedents as they examine the filings and consider the restructuring conditions.

The easiest review of a security-related cost recovery request will likely be for those expenditures that were to comply with a government mandate to enhance critical infrastructure or security. A state or federally mandated security investment would only require the commission to determine that the investment was made according to the mandate to approve the recovery. How that recovery was implemented could depend on the amount of the recovery and the restructuring conditions. It may be possible for a state to treat the recovery of the expenditure through the traditional process of regulating and setting regulated service rates. ***However, restructuring conditions may have placed caps or freezes on the retail rates.[31] In which case, a commission may need to consider other treatment and recovery protocols such as special line item charges and/or deferred recovery after a rate freeze.*** For example, Michigan statute has placed a cap (for large electric utilities) on retail rates that could extend until the end of 2013, depending upon a market test. The statute mandates that excess or new expenses shall be accrued and deferred. Such deferrals will be subject to commission determination of the amount of reasonable and prudent costs, if any, to be recovered after the rate cap is removed.[32]

In addition to recovery of the approved costs from an applicant's retail customers, a commission may need to consider the market neutrality of cost recovery in a competitive market. In some states, recovery rules for restructured markets may clearly define from whom a covered utility service provider can recover security-related costs. In Michigan allowable security-related expenses can only be recovered from the retail customers of the "covered utility."[33] However, if existing regulations or laws do not specify from whom these costs can be recovered, the question must be considered. If a local distribution company incurs an allowable critical infrastructure expense, it may be appropriate for the commission to implement recovery of that expense from not only the retail customers of that distribution company, but also from any competitive providers that sell service to customers over the applicant's distribution system.

Finally, the existence of ***provider-of-last-resort (POLR) requirements may also be a factor in a commission's review of a security related investment.*** An applicant that has the burden of an explicit POLR requirement may be able to justify more robust critical infrastructure investments, if such investments are prudently incurred to assure that it can provide service to all customers in a market – including, if necessary, those that are now served by other competitive providers.

12. COST RECOVERY MECHANISMS AND CASE STUDIES

The three cost recovery protocols use different logic to implement cost recovery mechanisms. The protocols establish the process and regulatory framework needed to use the cost recovery mechanisms examined below. A cost recovery mechanism is the actual technique state regulators use to authorize a utility to recover some, all, or none of the monies they have requested. A variety of cost recovery methods exist, ranging from ones that make this determination through automatic adjustment clauses to more elaborate mechanisms, such as a rate case. Since 9/11, a number of state commissions have responded to utility cost recovery requests. The cost recovery mechanisms examined below are all reasonable approaches these states have used and no one is recommended over another as the circumstances in different states may make one method more appropriate. Figure 12 highlights the five main cost recovery mechanisms identified by commissions as being useful with respect to security related expenses.

Figure 12: Cost Recovery Mechanisms

Cost Recovery Mechanisms

- Base rate changes to tariffs
- Adjustment clauses
- Deferral accounts
- Line item changes
- Closed proceedings

Base Rate Changes to Tariffs

The clear majority of the critical infrastructure cost recovery activities identified in our survey of the states was either immediately or ultimately part of a rate case proceeding that resulted in base rate tariff changes. Even the adjustment clauses described below are actually part of a base rate tariff settlement process.

A number of states surveyed indicated that they had rate cases in process, ones where utilities had security costs identified, but that since the commission had not made a final decision or issued an order, nothing definitive could be said.[34] Other states said that they had rate filings from utilities, but that their initial review of the filing did not reveal any distinctly identified critical infrastructure protection costs. Incremental security costs may or may not be subsequently revealed in the course of these rate cases.

Some states surveyed have reportedly learned from their jurisdictional electric and natural gas utilities that the utilities do not intend to file for critical infrastructure cost recovery for a variety of reasons. These reasons include:

- A concern about the confidentiality of the data.
- The desire to avoid having to develop and share detailed cost data on a facility-by-facility basis.

States have addressed these issues in several ways.[35] In New York, a restructured state with a future test year, existing rate processes are used to deal with security cost recovery issues. The New York Public Service Commission has used a variety of cost recovery mechanisms that include:

- Consideration of settlements;
- Forecast reconciliations; and
- Deferral of carrying charges.

Furthermore, utilities that are under-earning can file for deferral under Commission rules. Respondents in some states noted that some utilities said that the security costs were not sufficient to warrant initiating a regulatory proceeding. In California, Pennsylvania, and perhaps in other states, it was felt that the lessons learned and institutionalized from Y2K, earthquakes, fire, and other natural disasters made critical infrastructure protection more of an incremental cost. In other words, ***many utilities already have considerable experience planning and responding to significant service protection and service restoration scenarios***. Incremental security costs could occur, but it was thought these costs would be much lower than if utilities were starting from scratch in their disaster planning.

Other states have reported that they have not established separate or special efforts to recover security-related expenses. Generally, states in this situation report no current security cost recovery requests before them. While their treatment is speculative, these states tend to say that security expenses would be treated and evaluated like any other operating expense in order to verify costs, assess reasonableness, and to determine whether all or part of the costs would be recovered. Maine noted that it would refer to NARUC's preliminary cost recovery guidelines. Other states in a similar situation include Arkansas and Iowa. Iowa has had regulated utilities seek Iowa Board approval for at least $1.6 million in rate base and $982,000 in operations and maintenance for post 9/11 security-related expenses. In a MidAmerican Energy gas rate case, the company requested and was granted an increase in rate base of $780,375.[36] In an Interstate Power & Light electric rate case, the company requested and was granted an additional $938,000 in rate base adjustment for increased security at its nuclear power plant.[37]

The rate case implications for other states include the following considerations:

- No critical infrastructure-only or security-only tariffs, or riders, or surcharges were identified in these cases.
- Approved security costs were included in adjustments to the general tariff.
- Utilities often do not make identifiable infrastructure protection cost recovery requests.
- Security costs specifically under consideration and approved are incremental costs attributed to responses to the post 9/11 threat environment. Base or existing security costs do not appear to have been examined.
- A number of states had cases pending that addressed cost recovery in the context of a general rate case and no conclusions can be drawn about these cases until the commissions act.
- Water utilities have made a number of filings.
- Commissions appear to tend to grant the requested rate base increases attributed to increased security costs.
- While there is not a lot of information, what data that does exist suggests that the incremental post 9/11 critical infrastructure security costs have a modest rate impact.

Adjustment Clauses

The Florida Public Service Commission (FPSC) initially used its fuel adjustment clause and now uses its capacity cost recovery clause to allow recovery of incremental security costs incurred in response to 9/11.[38] In its first order the FPSC responded to the following stipulation:

> The commission should continue to monitor the nature and longevity of incremental security costs being recovered through a cost recovery clause to determine whether and to what extent such costs should be recovered through base rates. Security costs have traditionally been recovered through base rates, although in Order No. PSC-01-2516-FOF-El, issued Dec. 26, 2001, the commission authorized Florida Power & Light Company to recover incremental

security costs due to recent national security concerns through the fuel adjustment clause.[39]

The FPSC approved the stipulation and said that the Florida Power & Light Company and the Florida Power Corporation's incremental security costs shall be reassessed at the conclusion of settlements in their most recent base rate proceedings.[40] The FPSC then acted to address company-specific cost recovery issues.

For incremental 2002 and 2003 security costs, Florida Power & Light Company (FP&L) requested $12.7 million for costs incurred to comply with directives in Nuclear Regulatory Commission Order No. EA-02-26. Two parties opposed the request based on an earlier settlement and order that said, "FP&L will not use the various cost recovery clauses to recover new capital items which traditionally and historically would be recoverable through base rates."[41] Approximately $1.3 million of the cost recovery request included items that would normally be classified as capital items.

FP&L's 2001 security costs had been approved for recovery using the fuel adjustment clause because of the "...nexus between the protection of nuclear generation facilities and the fuel cost savings that result from the continued operation of those facilities." Further, recognizing that the costs were not clearly defined, the FPSC stated it retained the ability to consider an alternative cost recovery mechanism at a later time.[42] For FP&L's 2002 and 2003 security costs the FPSC found that these costs do not clearly fall within the classification of "items which traditionally and historically would be recoverable through base rates" and approved recovery through a cost recovery clause. Because these costs were seen as extraordinary, recovery (without distinction between capital and expensed items) these costs are treated as current year expenses, and accounted for separately.

The FPSC concluded by stating: "We find that these costs shall be reassessed at the conclusion of the term of the Settlement and Stipulation approved in Order No. PSC-02-0501-AS-EI to determine whether these costs should continue to be recovered through a cost recovery clause or would more appropriately be recovered through base rates."[43] The $12.7 million was authorized for cost recovery. Additional information about Florida's use of the adjustment clause approach is found in Appendix B.

Several implications from the Florida adjustment clause example for other state commissions are readily apparent:

- Only incremental security costs were addressed.
- The company-specific proceedings were initially guided by a stipulation in an earlier proceeding.
- The FPSC accepted one cost recovery mechanism at one point in time, but felt another mechanism (the cost recovery clause) to be more appropriate later.
- While capital costs were identified, all security costs were recovered in the current year.
- Cost recovery requests were documented by reference to federal directives and orders.

- The commission required that incremental security costs be accounted for separately, allowing for auditing.
- The specific utility filings had to consider other relevant regulatory proceedings and orders.

Closed Proceedings

With the exception of Kansas, no closed cost recovery proceedings *per se* were identified. State commissions occasionally used a stipulation process to address security issues. Sometimes commissions approved final rates without specifying what portion of the increase was attributable to existing or post 9/11 security costs. Most states have addressed the issue of confidentiality, as noted elsewhere in this report.

In 2002, Kansas passed a statute requiring the commission to allow utilities to recover expenses that the commission deemed appropriate to secure electric generation or transmission assets or natural gas production and transportation assets.[44] The costs are to be passed through to utility customers' bills. ***The statute directed that the applications for security cost recovery be reviewed in an expedited and confidential manner.***

The Kansas Corporation Commission (KCC) subsequently investigated how to handle requests for security cost recovery and issued an order adopting rules on January 31, 2003.[45] The commission set a target of a 60-day review period on applications, and specified how applications should be identified so as to receive immediate confidential treatment. The commission said it will allow for recovery through its usual manner of depreciation and approved rate of return.

In 2003, Kansas passed the Energy Security Act.[46] The act is specifically intended to address the recovery of enhanced security expenses incurred after the attacks of Sept. 11, 2001. It stated further that:

- The recovery period must be within half of the usable lifetime of the investment.
- Confidentiality exists as to the amount of recovery requested and allowed, as well as the method of recovery requested and allowed.
- The commission must provide protective orders on all filings so that a public watchdog group, the Citizens' Utility Ratepayer Board, may review documents if the board intervenes.
- The security cost recovery charge applies to both retail and wholesale rates, and shall not be identifiable on customers' bills.

With reference to the finding that the threat of terrorism require the government to take extra measures to protect the public welfare, the act notes that the commission's decision on the prudence of a security expenditure should, "not be based on standard regulatory principles and methods of recovery and shall take fully into account the findings and intent of the legislature."[47]

The implications for other state commissions considering a closed proceeding include:

- How procedures may be designed to allow consumer groups access to information.
- That authority may be established that allows a commission to use nonstandard regulatory principles due to critical infrastructure protection concerns.
- That confidentiality may be awarded regarding the amount requested and allowed to a utility for critical infrastructure protection costs.

Deferral (Balancing) Accounts

Deferral accounts were commonly used by state commissions in conjunction with a number of other cost recovery mechanisms in order to allow a utility to accumulate costs that could then be subsequently recovered in a rate case hearing. One interesting example of this occurred in Michigan, where the Michigan legislature amended its Public Utility Chapter that, among other things, defined "enhanced security costs", effectively established deferral accounts, and authorized a security cost recovery factor.[48]

Enhanced security costs include increases in the cost of insurance that are attributable to an increased terror related risk and the costs of maintaining or restoring electric service as the result of an act of terrorism.[49] Michigan's definition allows for costs in response to federal or state requirements.

The Michigan statute defines "enhanced security costs" as reasonable and prudent costs of new and enhanced security measures incurred before January 1, 2006 for an electric generating facility by a covered utility that are required by federal or state regulatory security requirements issued after Sept. 11, 2001 or determined to be necessary by the commission to provide reasonable security from an act of terrorism. (See Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d (17) (c)).

Once these costs have been identified by the utility, the utility may apply to the commission to recover enhanced security costs for an electric generating facility through a security recovery factor. Due to the implementation of a rate cap, allowed cost recovery is to be accrued and deferred until the rate cap is removed. Allowed security costs can only be incurred between Sept. 11, 2001 and January 1, 2006. The Michigan commission then retains the oversight authority to determine which costs in the deferral account are to be recovered, as described in more detail in the following section.

The implications for other states considering using deferral accounts include that:

- Deferral accounts are a well established and widely used regulatory cost recovery method.
- Deferral accounts allow costs to be identified and accounted for, but may not necessarily bind a commission on how the identified costs will be treated.
- Deferral accounts are only appropriate in instances where the commission will consider cost recovery.

Security Recovery Factor Charges

Michigan's security recovery factor allows the commission to decide if identified security costs will be eligible to be included in rates for retail customers. In determining the security recovery factor, the commission shall only include costs that the commission determines are reasonable and prudent and that are jurisdictionally assigned to retail customers of the covered utility in this state. The costs included shall be net of any proceeds that have been or will be received from another source, including, but not limited to, any applicable insurance settlements received by the covered utility or any grants or other emergency relief from federal, state, or local governmental agencies for the purpose of defraying enhanced security costs. In its order, the commission shall designate a period for recovery of enhanced security costs, including a reasonable return on the unamortized balance, over a period not to exceed 5 years. The security recovery factor shall not be less than zero.

The statute allows a "covered utility" utility to seek recovery. A "covered utility" is further defined as an incumbent utility subject to the rate cap provision of the statute amendment.[50] Allowable costs must be recovered through an unbundled "security recovery factor" on retail customers of the covered utility.

The implications for other states relative to line item charges are that:

- Insurance and federal or state governmental funds may need to be considered before a cost request is made.
- A presumption may exist that a utility should have a record that shows that they have examined the use of insurance or governmental funding.
- Commissions apply cost recovery standards that may include various combinations of used and useful, prudence, just and reasonable tests, and compliance with governmental decrees.
- There are no distinctions between capital investments and expense items.
- A recovery time period may be specified.

Other Cost Recovery Mechanisms

Several other cost recovery efforts have been identified. These include the following:

- **Notice of Inquiry.** The Oklahoma Corporation Commission (OCC) initiated a Notice of Inquiry approach to address a number of critical infrastructure issues, including cost recovery.[51] The inquiry covered electric, natural gas, water, and telephone utilities and is now being continued as a Notice of Proposed Rulemaking. While not a unanimous consensus, there appeared among the utilities a preference for rulemaking rather than legislation to address cost recovery. The inquiry approach allowed the OCC to formally and publicly have specific cost recovery questions answered by an array of stakeholders. It did not bind the commission, but provided a forum to hear concerns.

- **Ongoing Dialogue.** New Jersey, through the New Jersey Infrastructure Advisory Committee, has established utility industry working groups that meet regularly and discuss a number of issues, including how utility infrastructure protection is being financed. Through an examination of best practices, New Jersey has created comprehensive guidelines for security, incorporating state and federal standards. Ohio notes it has informally polled utilities as they file rate cases, finding that the smaller companies have not reported doing anything extraordinary regarding security. In two larger utilities security costs were an issue only for one, and the issue centered on disclosure of security sensitive information.

- **Special Infrastructure Cost Recovery Proceeding.** The Connecticut legislature enacted Public Act No. 02-94 to ensure that ratemaking considerations included the "reasonable costs of security assets, facilities and equipment that are incurred solely for the purpose of responding to security needs associated with the terrorist attacks of Sept. 11, 2001, and the continuing war on terrorism."[52] This statute was subsequently amended to include gas and electric utilities rate plans that have earnings sharing mechanisms. Two companies applied to the Connecticut Department of Public Utility Control for cost recovery: Connecticut Natural Gas Corporation (CNG) and The Southern Connecticut Gas Company (CSG).[53] CNG requested recovery of $219,899 in actual and $1,281,078 in forecasted, annualized and on-going expenditures. CSG requested recovery of $137,636 in actual and $564,062 in forecasted, annualized and on-going expenditures.

  The Department found the actual costs to be reasonable and allowed recovery in each company's next rate case proceeding.[54] The Department found that the proposed forecasted costs were not known and measurable at this time. Accordingly, these expenditures could not be deemed reasonable and prudent and further review will be undertaken in the next rate cases. The Department also denied the companies' request to reopen their respective rate case proceedings in order to implement a proposed rate rider to recover post-September 11 security-related enhancements.

Action here by Connecticut has implications for other states that include:

- Affirmation that cost recovery explicitly requires a finding of prudence.
- A single-purpose proceeding on critical infrastructure cost recovery is feasible.
- Reliance on a rate case for actual recovery.
- A cost-recovery approach for utilities with earnings sharing plans can be designed.
- Both a legislative and regulatory focus on critical infrastructure cost recovery.
- Results that seem to indicate that incremental infrastructure costs may be significant but are not overwhelming.

13. SUMMARY

The cost recovery protocols and cost recovery mechanisms identified in this report clearly show that state regulatory commissions have acted to allow cost recovery of prudently incurred critical infrastructure protection costs. Four important summary observations are:

1) Cost recovery activities have occurred and been allowed in both traditionally regulated states as well as in restructured states.
2) Cost recovery mechanisms employed have been nested in rate cases.
3) State legislatures have enacted legislation, but in no case did the legislation override a commission's underlying obligation to ensure that only prudent or reasonable, costs were eligible for cost recovery.
4) An expectation exists that insurance should be part of a utility's cost recovery planning.

In some states, security costs were examined in a regulatory proceeding and allowed without a lot of elaboration. In other instances, commissions had more documentation on their cost recovery rationale. In both approaches, state regulators unmistakably affirmed their support for ensuring that critical utility infrastructure is protected. Unlike other policy debates where cost recovery issues become debating points for opposing sides, no significant regulatory debates were observed, once the reasonableness or prudence of the costs was established. Regulators have a long tradition of examining, selecting, and using the most appropriate cost recovery mechanisms available to them. This report shows that regulators have used a variety of cost recovery mechanisms, both in restructured and traditionally regulated states. While difficult to document, the post 9/11-security costs appear incremental. These cost mechanisms are similar to those identified by the National Conference of State Legislatures (NCSL) shown in Appendix C. They have not been big-ticket expenditures, and state regulators have largely seen them as prudent and eligible for cost recovery.

APPENDIX A

FERC ORDER 630 AND THE PROTECTION OF CRITICAL INFRASTRUCTURE INFORMATION

The Federal Energy Regulatory Commission (FERC) issued a Final Rule in Order 630 on Feb. 20, 2003 on the protection of critical energy infrastructure information. [55] FERC defines critical infrastructure broadly to include "existing and proposed systems and assets, whether physical or virtual, the incapacity or destruction of which would negatively affect security, economic security, public health or safety, or any combination of those matters." ***Though the context of FERC Order 630 is limited to the protection of critical energy infrastructure information in FERC's possession***, FERC's definition of critical energy infrastructure could be a useful basis for creating a definition that states could use to help determine whether an existing system or asset should generally be considered to be critical energy infrastructure.

However, some issues are raised if the broad definition is applied "as is" to cost recovery. The first issue is one of "existing" versus "proposed." The need to protect the sensitive information of a "proposed" critical infrastructure system or assets from unnecessary disclosure is easily understood. However, granting cost recovery for a "proposed" system or asset investment is a larger question and requires more consideration. Under this definition, a commission would be asked to essentially grant pre-approval for "proposed" expenditures to be made in the future. Assuming a state commission wishes to grant approval of the proposed expenditure, it may take one of several approaches. Three common approaches would include the following. It could approve the proposed expenditure as submitted and say nothing further regarding the approval of future similar requests. The commission could approve the expenditure and in its order make clear that the approval was based solely on the merits of the individual rate case and was not precedent setting for future recovery requests of "proposed" systems or assets. Or the commission could approve the expenditure subject to a true-up of the actual recoverable amount following a decision on the type of expenditure in a commission generic proceeding, or following the applicant's submission of actual expenditure records.

Deciding an issue such as recovery of for "proposed" systems or assets in a generic proceeding does offer a commission the opportunity to more broadly examine an issue. However, ***generic cases are generally very open and protracted proceedings***. This may make generic proceedings unsuitable for some critical infrastructure issues. Furthermore, a conditional approval subject to a generic proceeding or future true-up may not provide adequate certainty to an applicant. At best, it would provide a high degree of probability of some recovery, but would tell the applicant it may proceed, but should do so very cautiously.

The second issue with the FERC definition that a state commission must face is one of limiting the definition of what would "negatively affect security." Existing security and protection systems and assets whose loss would negatively affect security are clearly used and useful

critical infrastructure. However, it might be possible to argue that a current or proposed system that does not directly enhance some aspect of security by its operation or addition, will actually have this effect when incapacitated or destroyed. For example, it might be possible for an applicant to argue that a new roof on its executive building, while not directly enhancing security would, if destroyed, negatively affect security. A commission must ask the question: Can a system or asset be considered used and useful or prudent if it does not directly enhance some aspect of security? In a network composed of many joint and common costs, this may be difficult.

A commission must ask the question:

Can an asset be considered used and useful or prudent if it does not directly enhance some aspect of security?

APPENDIX B

RECOVERING CRITICAL INFRASTRUCTURE PROTECTION COSTS THROUGH ADJUSTMENT CLAUSES

The Florida Public Service Commission used the same cost recovery approach, with a few differences, in two cases. In one, the Florida Power Corporation (FPC) requested recovery of approximately $7.8 million for 2002 and 2003 security costs incurred in compliance with Nuclear Regulatory Commission Order No. EA-02-26. Approximately $4.1 million were costs that would normally be classified as capital items. Two parties opposed the request for the same reason noted above. The FPSC concluded stating "Finally we find that these costs shall be reassessed at the conclusion of the term of the Settlement and Stipulation approved in Order No. PSC-02-0655-AS-El to determine whether these costs should continue to be recovered through a cost recovery clause or would more appropriately be recovered through base rates." (See Order No. PSC-02-1761-FOF-El, Docket No. 020001-El, p. 11.) The $7.8 million was authorized for cost recovery.

In another case, Tampa Electric Company (TECO) requested recovery of approximately $1.2 million for incremental operation and maintenance expenses associated with 2001, 2002, and 2003 security costs. TECO's witness noted these costs were not in compliance with any government mandate, but were consistent with guidelines developed by Presidential Homeland Security directives and North American Electric Reliability Council actions. A TECO witness indicated that TECO anticipated moving these costs into base rates at TECO's next traditional rate case. The PSC indicated that it found such treatment reasonable and approved recovery of the $1.2 million through the capacity cost recovery clause. The costs are to be treated as current year expenses and shall be separately accounted for auditing purposes. (See Order No. PSC-02-1761-FOF-EI, Docket No. 020001-EI, p. 15.)

APPENDIX C
NATIONAL COUNCIL OF STATE LEGISLATURES[1]

PAYING FOR ENERGY SECURITY

Energy security may be costly and will require energy companies to make new investments in energy facilities that they had not previously expected. Some of these investments may be for new equipment and others may be for additional employees and security personnel. Some companies –such as oil companies- that operate in competitive markets and are not price-regulated, will make the investments as they see fit and will seek to lower costs and increase efficiency elsewhere in their business or perhaps raise prices to the extent the market allows. Companies that operate in regulated, monopoly markets –including gas, telecommunications, electric and some water companies- operate in a more public environment where state or federal officials oversee the rates they can charge.

How Much Detailed Oversight and Approval Should Utility Commissions Have Over Cost Recovery?

State policymakers, primarily through their utility commissions, must balance the need to oversee the utilities they regulate with the desire to allow them to manage the details of their security measures. Utilities do this with some assurance that the regulatory commissions will approve their prudently incurred costs. Each state will need to develop its own approach to how it allows utilities to recover their security-related costs. In every situation, it may be prudent for the state and the regulated utilities to collaborate and to determine a common strategy for addressing security issues. This common strategy could make utilities more certain that they would later be able to recover their costs.

Table 3. NCSL Solution Menu

Condition	Solution Menu
Regulated utilities, no rate cap or freeze	1. Address security costs in next rate case. 2. Allow commission to allow quick pass-through of security costs through normal regulatory process. 3. Enact legislation to ensure recovery of security-related costs, with specified commission oversight.

[1] The National Conference of State Legislatures is the bipartisan organization that serves the legislators and staffs of the states, commonwealths and territories. The material in this appendix is an except from Matthew H. Brown, Christie Rewey, and Troy Gagliano, *Energy Security* (Washington, D.C., 2003), pp. 48-52.

Regulated utilities with soft rate cap	1. Address security costs in next rate case. 2. Allow commission to allow quick pass-through of security costs through a special surcharge. 3. Enact legislation to ensure recovery of security-related costs, with specified commission oversight.
Regulated utilities with hard cap	1. Enact legislation to ensure recovery of security-related costs, with specified commission oversight. 2. Allow commission, through regulatory process, to set up a "deferral" account for utility to recover prudent costs at a later time.

ENDNOTES

[1] The National Association of Regulatory Utility Commissioners (NARUC) Ad Hoc Committee on Critical Infrastructure's Cost Recovery Workshops took place in Denver, Colorado, June 28, 2003, and in Washington, D.C., October 23-24, 2003.

[2] It may be that September 11 is not the key date for drawing a comparison in utility security expenditures. In 1998 the President's Commission on Critical Infrastructure Protection involved utilities and regulators in its outreach activities. In preparation for Y2K, the Federal Emergency Protection Agency (FEMA) conducted ten regional workshops that included utilities and state regulators.

[3] Price caps generally have an exogenous adjustment factor that allows a utility to request cost recovery for extraordinary expenditures caused by circumstances outside the control of the utility. However, exogenous adjustments are unusual because all costs of a utility (those that have increased and those that have decreased) since base price caps were established would likely have to be examined. Incremental security cost increases, while significant, may not have reached the extraordinary cost threshold.

[4] A working group created by Commissioner Connie Hughes immediately following 9/11 has, for example, continued to function as a workable way to talk about critical infrastructure issues.

[5] See Florida Public Service Commission, Order No. PSC-02-1761-FOF-El and Florida Public Service Commission, Order No. PSC-01-2516-FOF-El.

[6] See 2003 Kansas HB 2374, codified as Kansas Statute Nos. 66-1234, 66-1235, and 66-1236.

[7] Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d (17) (c).

[8] See Oklahoma Corporation Commission, Case No. PUD 200300624.

[9] *FY 2005 Congressional Performance Budget Request*, FERC, February 2004, p. 34. Report is available at http://www.ferc.gov/about/strat-docs/FY05-Budg.pdf.

[10] Ibid., p. 85.

[11] Greg Frank, Frank Cox, Ray Dominquez, "*Homeland Security – Battelle's Capabilities*," presented to The Ohio State University, March 5, 2002, p. 2.

[12] For more information on cost allocation issues, see Robert Burns, et al., *Regulating Electric Utilities with Subsidiaries*, No. 85-16 (Columbus: NRRI, 1986).

[13] See Florida Public Service Commission, Ibid.

[14] State of Connecticut Public Act 02-94, codified as Connecticut General Statute 16-19e(a)(4): subsequently amended to include a new subsection g.

[15] Joe McGarvey and John Wilhelm, *NARUC/NRRI 2003 Survey of Critical Infrastructure Security*, No. 04-01, (Columbus: NRRI, 2004), p. 9-10.

[16] Duquesne Light v. Barash, 488 U.S. 299 (1989).

[17] For more on the prudence test, see Robert Burns, et al., *The Prudent Investment Test in the 1980s*, No. 84-16 (Columbus: NRRI, 1985).

[18] Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d.

[19] Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d (13).

[20] In the NARUC Cost Recovery Workshops the distinction between standards and guidelines was drawn. Standards are mandatory, but increase the probability of cost recovery. Guidelines permit regional flexibility, but as they permit more leeway, may have less cost recovery certainty.

[21] *Security Guidelines for the Electricity Sector*, North American Electric Reliability Council, issued June 14, 2002, available at http://www.esisac.com/publicdocs/Guides/SecurityGuidelinesElectricitySector-Version1.pdf; and *Urgent Action Standard 1200 – Cyber Security*, North American Electric Reliability Council, issued August 13, 2003, available at ftp://ftp.nerc.com/pub/sys/all_updl/standards/Urgent-Req-CyberStnd-3-3121.pdf.

[22] *Pipeline Security Information Circular* and *Pipeline Security Contingency Planning Guidance*, Department of Transportation, Office of Pipeline Safety, issued September 5, 2002; these documents are not publicly available.

[23] In its guidelines, OPS notes that in addition to its *Pipeline Security Information Circular* and *Pipeline Security Contingency Planning Guidance* documents, it also relies on the industry consensus security guidance documents for purposes of evaluating the security plans of pipeline operators. Specifically, the American Petroleum Institute's *Guidelines for Developing and Implementing Security Plans for Petroleum Pipelines,* issued July 2002, are used in reference to hazardous liquid pipelines, and the American Gas Association and Interstate Natural Gas Association of America's *Security Guidelines: Natural Gas Industry, Transmission, and Distribution*, issued September 2002, are used to help evaluate natural gas transmission and distribution lines. The above documents are not publicly available.

[24] *NRIC Best Practices*, The Network Reliability and Interoperability Council, issued various years, available at http://www.bell-labs.com/cgi-user/krauscher/bestp.pl.

[25] See "National Drinking Water Advisory Council's Water Security Working Group Meeting Announcement," *Federal Register*, Vol. 69, No. 118, (June 21, 2004), p. 34351, available at

http://frwebgate.access.gpo.gov/cgi-in/getdoc.cgi?dbname=2004_register&docid=fr21jn04-42.pdf.

[26] Public Law 107-188, 107th Congress, 2nd Session, (June 12, 2002), Sec. 401.

[27] McGarvey and Wilhelm, *NARUC/NRRI 2003 Survey of Critical Infrastructure Security*, p. 3.

[28] Ibid., p. 9-10.

[29] Scott Potter, *After the Freeze: Issues Facing Some State Regulators as Electric Restructuring Transition Periods End*, No. 03-18 (Columbus: NRRI, 2003).

[30] McGarvey and Wilhelm, *NARUC/NRRI 2003 Survey of Critical Infrastructure Security*, p. 3.

[31] Several states have frozen retail service rates during specified periods of transition to competitive markets. A rate freeze or cap may be any or all components of a retail rate. For example, in Ohio a stipulation approved with Dayton Power & Light froze transmission and distribution rates and capped generation rates through 2008; see Public Utilities Commission of Ohio, Case No. 02-2779-EL-ATA. For a summary of electric restructuring transition period details see Scott Potter, *After the Freeze: Issues Facing Some State Regulators as Electric Restructuring Transition Periods End*, No. 03-18 (Columbus: NRRI, 2003).

[32] Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d (4).

[33] That is to say the large utilities subject either to the rate cap and/or a previous orders in Michigan Public Service Commission cases U-11181-R and U-12204. See Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d (17) (b) and (d).

[34] States surveyed reporting pending electric and natural gas rate cases include Arizona, Maine, Ohio, New Hampshire, and Pennsylvania.

[35] In Ohio and New Jersey, water utility rate cases have had a stipulation settlement that effectively made it difficult to link specific security costs to the specific, approved rate items. In a Pennsylvania investor-owned water utility, incremental security costs were approved, but the case is on appeal by the consumer advocate. The Missouri Commission approved a two-year deferral of security costs for a water utility.

[36] See Iowa Utilities Board, Docket No. RPU-02-2.

[37] Ibid., Docket Nos. RPU-02-3 and RPU-02-8. In addition, Iowa American Water Company was granted recovery of $900,781 in operating expenses as part of a rate case, RPU-01-04. The security measures were presented to the Iowa Board at the end of the case and were allowed to constitute a portion of the negotiated settlement only after sufficient notice had been given to customers. The Iowa Board did not receive any comments or objections.

[38] See Florida Public Service Commission, Ibid.

[39] Ibid., Order No. PSC-02-1761-FOF-El, p. 3-4.

[40] Ibid., Docket Nos. 001148-EI and 000824-El.

[41] See Ibid., Order No. PSC-02-0501-AS-El.

[42] See Ibid., Order No. PSC-01-2516-FOF-El.

[43] Ibid., Order No. PSC-02-1761-FOF-El, Docket No. 020001-El, p. 7.

[44] Kansas Statue No. 66-1233.

[45] Kansas Corporation Commission, Docket No. 03-GIMX-431-GIV.

[46] See 2003 Kansas HB 2374, codified as Kansas Statute Nos. 66-1234, 66-1235, and 66-1236.

[47] Ibid., Sec. 3(8)(b).

[48] Michigan Compiled Law, Chapter 460, Act 3 of 1939, Section 460.10d (17) (c).

[49] Ibid., Section 460.10d (17) (c).

[50] Ibid., Section 460.10d (17) (b).

[51] See Oklahoma Corporation Commission, Case No. PUD 200300624.

[52] See State of Connecticut Public Act 02-94, codified as Connecticut General Statute 16-19e(a)(4).

[53] See Connecticut Department of Public Utility Control, Docket No. 03-06-17.

[54] The California Commission rejected a water utility request for a memorandum account for security costs, preferring to address the issue in a general rate case. See California Public Utility Commission Decision D0310070 on Proceeding A0308009.

[55] United States of America Federal Energy Regulatory Commission 18 CFR Parts 375 and 388 (Docket Nos. RM02-4-000, PL02-1-000; Order No. 630), issued February 21, 2003.

EXHIBIT
Ruco 3
ADMITTED

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BEFORE THE ARIZONA CORPORATION COMMISSION

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Arizona Corporation Commission
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COMMISSIONER

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY, AN ARIZONA CORPORATION, FOR (i) A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND (ii) AN INCREASE IN ITS WATER RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. W-02500A-10-0382

NOTICE OF FILING

On June 13, 2011 the Residential Utility Consumer Office ("RUCO") filed the Surrebuttal Testimony of Jodi A. Jerich in the above-referenced matter. RUCO hereby files this Notice of Errata which contains the attached revisions.

RESPECTFULLY SUBMITTED this 22nd day of June, 2011.

Daniel W. Pozefsky
Chief Counsel

AN ORIGINAL AND THIRTEEN COPIES of the foregoing filed this 22nd day of June, 2011 with:

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

COPIES of the foregoing hand delivered/ mailed this 22nd day of June, 2011 to:

Jane L. Rodda
Administrative Law Judge
Hearing Division
Arizona Corporation Commission

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Legal Division
Arizona Corporation Commission

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Utilities Division
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James Schoemperlen
39695 S. Horse Run Dr.
Tucson, AZ 85739
Lawrence Wawrzyniak
39485 S. Mountain Shadow Dr.
Tucson, AZ 85739

By Ernestine Gamble
Ernestine Gamble

On page 15, lines 4-5, after the sentence, "Staff and the Company propose an "engineering approach" that provides recovery for costs that meet a 5-year planning horizon.", **please insert the following new sentences** and a **new footnote 6**.

"Staff and the Company agree that the 5-year planning horizon takes into account actual growth data from the previous 5 years in order to project growth over the next 5 years. However, RUCO finds that Staff and the Company disagree on which 5-year time period to use."[6]

---

[6] "Staff proposes a single 5-year planning horizon time period measured from the end of the 2009 test period that projects customer growth up to 875 customers by 2014. The Company rejects this time period. Mr. Bourassa testifies that a 5-year time period should run for each decision made to expand plant – making the 5-year time period a constantly moving target. For example, the decision to build water storage facilities in 2007 would be based on actual growth from 2002-2007 in order to estimate future growth through 2012. That 5-year planning horizon calculates customer growth to 1,100 by 2012. Furthermore, Mr. Bourassa states that prudency must be determined under the facts at the time the decision was made and any prudently incurred costs simply cannot be excess capacity. (Bourassa Rebuttal, p. 10, lines 5-19).

EXHIBIT
RUCO-5
ADMITTED

System Water Plan

Water Supply Plan

Water system name: Goodman Water
System ID number: 91- 000561.0000

1. Service area lands	
a.	City/town where system is located: Tucson
b.	County where system is located: Pinal
c.	Township/range/section where your system is located (if known): unk
d.	Approximate square miles of service area: unk
e.	Describe or submit a map showing the boundaries of your service area (can be streets, town limits, landmarks, etc.). *Note that a map is not required, but may be submitted in place of a description.* Eagle Crest Ranch
f.	Type of area served (consider majority of area served). Please check all that apply: ☐Rural ☐Suburban ☐Urban ☐Mobile home park ☒Subdivision ☐ Prison ☐Other If other, describe area served:
g.	Typical or predominant landscaping type in residential areas: ☒Low water use landscaping ☐Turf ☐Unlandscaped/unirrigated (dirt or natural desert) ☐No outdoor water use (e.g. mobile homes with no yards) ☐Other Additional description if needed:
h.	Average residential lot size: unk
2. Sources of supply	
a.	Do you serve groundwater? ☒Yes ☐No If so, do you measure water levels? ☐Yes ☒No List well registration numbers, most recent water level measurement and date measured (if applicable):

Well registration number	***Water level***	***Date measured***
55-610541		
55-595278		

(if the number of wells exceeds the space allotted, please continue on a second copy of this page, and attach it for submittal)

b.	Do you serve surface water? ☐Yes ☒No If yes, list name of source(s):

c.	What is your emergency source of water (back-up well number, name of other water provider, etc.)? n/a
3. Interconnections	
a.	Do you have an interconnection with another water system? ☐Yes ☒No If yes, list name of other system(s):
b.	Describe interconnections, including conditions under which water transfer can take place: ***Systems serving more than 1,850 people must provide a map showing interconnections***
4. Water sold and purchased	
a.	Did you sell water to another water system during the past five years? ☐Yes ☒No If yes, list quantities and systems:
b.	Did you purchase water from another water system during the past five years? ☐Yes ☒No If yes, list quantities and systems:
5. Storage and treatment facilities	
a.	Do you have storage facilities? ☒Yes ☐No If yes, what is your total storage capacity? 900,000
b.	Do you treat your potable water? ☒Yes ☐No If yes, describe treatment facilities/methods: chlorine
6. Transmission and distribution facilities	
	Describe your system's transmission and distribution facilities: 2 wells - 2 storage - 1 booster station - distribution lines ***Systems serving more than 1,850 people must provide a map showing transmission and distribution facilities.***
7. System production	
a.	Is your system metered? ☒Yes ☐No Fill out the table below with the following data. If your system is not metered, fill in as much as you are able to estimate (at a minimum, provide estimates for 2006). *Average daily demand – the average daily demand for each of the indicated years (e.g. five average daily demand numbers – one number for each year).* *Maximum monthly demand – the month of highest demand for each of the indicated years. Please identify the months and the total quantity of water used that month.* *Peak day demand – the day of highest demand for each of the indicated years. Please provide the dates and total quantity of water used that day.*

	Avg. daily demand (gallons)	Max monthly demand (gallons)	Estimated peak day demand (gallons)
2002		Month:	Date:
		Quantity:	Quantity:
2003		Month:	Date:

		Quantity:		Quantity:	
2004	unk	Month:	jul	Date:	unk
		Quantity:	2332810	Quantity:	unk
2005	unk	Month:	jul	Date:	unk
		Quantity:	4095020	Quantity:	unk
2006	unk	Month:	aug	Date:	unk
		Quantity:	5658480	Quantity:	unk

b. Do you have difficulty meeting demand during times of peak use?
☐Yes ☒No
If yes, describe:

c. Other important information related to system production and ability to meet current demands:

8. Analysis of projected water demand

a. Fill in the table below with your projected system population and projected demand.

Year	Projected population	Projected average daily demand on system (gallons)
2012	2400	564000
2017	2700	634500
2027	3000	705000

If you have difficulty estimating your projected population, indicate whether you anticipate your population to increase, decrease, or remain stable for the indicated years. If you have difficulty projecting your average daily demand over the next 20 years, consider your current demand with the addition or subtraction of people and provide your best estimate. Projection calculations may be based on information such as gallons per capita per day, gallons per housing unit per day, number of connections and population, historic or expected demands, land use planning/classification, etc.

b. Explain how you arrived at these numbers:
estimated

c. Do you anticipate problems meeting these future demands?
☐Yes ☒No

d. Indicate any changes that may be necessary to meet demands over the next 20 years:
(for example, if demand is expected to greatly increase, options could include more advanced conservation programs, increased storage, additional wells, etc.)
n/a

Water Conservation Plan

Water system name: Goodman Water
System ID number: 91- 000561.0000

Conservation programs

a. *See fact sheet* Conservation and Drought Planning for Community Water Systems: How do they work together? *for conservation tips and suggestions.*

Check and provide a description for all that apply

Currently imple-menting	Planned in next five years	Conservation measures/programs	Description
☒	☐	Metering of source	N/A
☒	☐	Metering of service connections	
☒	☐	Water rate structures that encourage efficient water use (e.g. higher rates for higher use)	
☐	☒	Measures to limit lost and unaccounted for water (e.g. leak detection and repair programs, control evaporation from storage tanks, eliminate illegal connections)	
☐	☒	Programs to encourage low water use landscaping (e.g. low water use/drought tolerant plant list for your area, installation of efficient irrigation systems)	
☐	☒	Describe any education/outreach programs you are implementing *Please include any communication you have with your customers regarding conservation; this can be as simple as conservation tips provided in water bills. Other examples include school education programs, landscape workshops, water festivals, etc.*	
☐	☒	Other programs	

b. Describe any planned changes or additions to your current programs over the next five years:
n/a

Drought Preparedness Plan

Water system name: Goodman Water
System ID number: 91- 000561.0000

Complete the form below, or link to the online drought plan tool at http://droughtplan.arid.arizona.edu.
If you have a curtailment tariff in place, it may be submitted in place of the drought plan if it includes all the information in the pages below.

1. Drought Plan of Action

Drought Stage Name or Number	Management measures *(consider measures for the system and for the customers)*
(Normal conditions)	Implement conservation measures/programs from water conservation plan. *You do not need to repeat them here. However, please include below any non-conservation related activities (such as augmenting water supply) that will be implemented under "normal" conditions.* Other measures:

2. Implementation of drought stages	
a.	How will you determine when to initiate a drought stage for your system? What factors will be considered? *(Indicators to consider include climate conditions, water supply availability, amount of supply in relation to demand, infrastructure of system, well/reservoir levels, and should most likely involve a combination of more than one.)* low water level
b.	Who has the authority to initiate and/or change a drought stage for your system? water company
c.	If you chose to make any of your management measures mandatory for your customers, how will you enforce them? communication
d.	Other important information on implementation of drought stages:
3. Customer communication	
a.	Describe how you plan to educate customers on drought conditions and the need for water conservation: n/a
b.	How will customers be notified of a drought stage declaration and implementation of associated management measures? *Note that different stages of drought may need different notification methods. If the system has reached the point of a water shortage, rapid notification will be necessary.* notice by mail
4. Development of emergency supplies	
a.	Describe how you will get water to your customers in an emergency water shortage situation: *Note that it is the community water system's responsibility to have an emergency source of water and an emergency plan in place.* backup well
5. Contact Information	
a.	Address of water system: PO Box 898
b.	Telephone number of water system: 520-625-1671
c.	Name and number of person(s) responsible for directing emergency operations: Karen Hartwell

ORIGINAL NEW APPLICATION

EXHIBIT
RUCO-6
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMI

MIKE GLEASON
Chairman

WILLIAM A. MUNDELL
Commissioner

JEFF HATCH-MILLER
Commissioner

KRISTIN K. MAYES
Commissioner

GARY PIERCE
Commissioner

Arizona Corporation Commission
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AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY FOR REVIEW AND APPROVAL OF PROPOSED HOOK-UP FEE TARIFF	DOCKET NO. W-02500A-07- W-02500A-07-0452 APPLICATION

In compliance with Decision No. 69404, dated April 16, 2007, Goodman Water Company ("Goodman") submits for Staff's review this proposed Hook-Up Fee Tariff. The proposed Hook-Up Fee Tariff and related hook-up fees would be applicable to new customer connections to Goodman's system. The capital expenditures related to the proposed hook-up fees pertain to Goodman's construction requirements for the 2008-2011 time period. The anticipated new customer growth during this period is 724 new customer connections. The off-site facilities in question include a well #3 and related equipment and engineering. The proportion of anticipated construction costs proposed to be funded by the proposed hook-up fees is 40%.

Attached to this Application as Exhibit "A" is a schedule setting forth the assumptions and estimated future capital expenditures upon which the proposed hook-up fees are based. Exhibit

"A" also sets forth by meter size the amount of proposed hook-up fee applicable to each meter size, as well as the or percentage of anticipated new growth each meter size represents. Attached to this Application as Exhibit "B" is a copy of a proposed Hook-Up Fee Tariff.

Goodman Water Company requests that the Commission review the proposed Hook-Up Fee Tariff and hook-up fees which are the subject of this Application and issue an order approving the tariff and related hook-up fees.

RESPECTFULLY SUBMITTED this 31st day of July, 2007.

By: _____

Michael McNulty
Michael Hallam
Lewis and Roca LLP
One South Church Avenue
Suite 700
Tucson, Arizona 85701-1611
Phone: (520) 629-4453
Fax: (520) 879-4732

Attorneys for Goodman Water Company

ORIGINAL and thirteen (13) copies of the foregoing filed this 31st day of July, 2007, with:

Arizona Corporation Commission
Docket Control – Utilities Division
1200 W. Washington Street
Phoenix, Arizona 85007

COPY of the foregoing hand-delivered
this 31st day of July, 2007, to:

Jane L. Rodda, Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 W. Washington Street
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Christopher C. Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Ernest G. Johnson, Director
Utilities Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Jayne Williams

EXHIBIT A

Goodman Water Company
Computation of Off-Site Facilities Hook-up Fee (HUF)

Exhibit A

Line No.							
1							
2	Off-Site Capital Expenditure Requirements 2008-2011						
3	Well # 3 and related equipment including engineering and contingency					$	940,000
4							
5							
6							
7	Total [1]					$	940,000
8							
9	Anticipated Customer Growth[1]	724					
10							
11	Computation of Equivalent 5/8 Inch Meters						
12				Meter			
13		Portion of	Projected	Flow	Equivalent		
14	Meter Size	Anticipated Growth	Growth	Factor	5/8 Inch Meters		
15	5/8 Inch	98.90%	716	1.0	716		
16	3/4 Inch	0.00%		1.5	-		
17	1 Inch	0.55%	4	2.5	10		
18	1 1/2 Inch	0.00%		5.0	-		
19	2 Inch	0.55%	4	8.0	32		
20	3 inch	0.00%		16.0	-		
21	4 Inch	0.00%		25.0	-		
22	6 Inch	0.00%		30.0	-		
23		100.00%	724		758		
24	Total Equivalent 5/8 Inch Meters [2]						758
25							
26	Construction Costs Expected to be Funded by HUF (Percent times [1] equals [3])				40%	$	376,000
27							
28	HUF for Equivalent 5/8 Inch Metered Customer (rounded down) ([3] divided by [2] equals [4])					$	500
29							
30	Proposed Off-site Facilities Hook-up Fees by Meter Size						
31							
32	Meter Size						
33	5/8 Inch	$	500	[4]			
34	3/4 Inch	$	750	Scaled on 5/8 meter flow			
35	1 Inch	$	1,250	Scaled on 5/8 meter flow			
36	1 1/2 Inch	$	2,500	Scaled on 5/8 meter flow			
37	2 Inch	$	4,000	Scaled on 5/8 meter flow			
38	3 inch	$	8,000	Scaled on 5/8 meter flow			
39	4 Inch	$	12,500	Scaled on 5/8 meter flow			
40	6 Inch	$	15,000	Scaled on 5/8 meter flow			
41							
42	[1] Buildout of current certificated area is 958 customers. There are currently 500 customers. Expected addtions for 70 acres of commericial property						
43	within the existing CC&N is 258 - 5/8 inch metered customers, 4 - 1 inch metered customers, and 4 - 2 inch metered customers.						

EXHIBIT B

TARIFF SCHEDULE

Utility: Goodman Water Company
Docket No.: W-02500A-07
Phone No.: _____

Tariff Sheet No.: Page 1 of 3
Decision No.: _____
Effective: _____

OFF-SITE WATER FACILITIES HOOK-UP FEE

I. Purpose and Applicability

The purpose of the Off-Site Hook-Up Fees payable to Goodman Water Company ("Company") pursuant to this tariff is to equitably apportion the costs of constructing additional facilities to provide water production, storage and appropriate pressure among all new Service Connections.

These fees are applicable to all new Service Connections established after the effective date of this tariff. The fees are one-time charges and are payable as a condition to the Company's establishment of service, as more particularly provided below.

II. Definitions

Unless the context otherwise requires, the definitions set forth in R14-2-401 of the Arizona Corporation Commission's ("Commission") rules and regulations governing water utilities shall apply in interpreting this tariff schedule.

"Applicant" means any party entering into an agreement with Company for the installation of water facilities to serve new service connections.

"Company" means Goodman Water Company.

"Main Extension Agreement" means any agreement in which an Applicant agrees to advance the costs of the installation of water facilities to the Company to serve new service connections, or install water facilities to serve new service connections and transfer ownership of such water facilities to the Company, which agreement shall require the approval of the Commission (same as line extension agreement).

"Off-Site Facilities" means wells, storage tanks and related appurtenances necessary for proper water system operation, including engineering and design costs. Off-Site Facilities may also include booster pumps, pressure tanks, transmission mains and related appurtenances necessary for proper water system operation, if these facilities are not for the exclusive use of an Applicant and these facilities will benefit the entire water system.

"Service Connection" means and includes all service connections for single-family residential, commercial, industrial, or other uses, regardless of meter size.

TARIFF SCHEDULE

Utility: Goodman Water Company
Docket No.: W-02500A-07
Phone No.: _____

Tariff Sheet No.: Page 2 of 3
Decision No.: _____
Effective: _____

III. Off-Site Hook-Up Charges

Each new Service Connection shall pay the total off-site facilities hookup fee, derived from the following table:

OFF-SITE FACILITIES HOOKUP FEE TABLE	
Meter Size	**Total Fee**
5/8"	$500
¾"	$750
1"	$1250
1½ "	$2500
2"	$4000
3"	$8000
4"	$12,500
6" or larger	$15,000

IV. Terms and Conditions

(A) Assessment of One Time Hook-Up Charge: The hook-up fee may be assessed only once per Service Connection, or lot within a platted subdivision (similar to meter and service line installation charges). However, this provision does not exempt from the hook-up fee, any newly created parcel(s) which are the result of further subdivision of a lot or land parcel and which do not have a Service Connection.

(B) Use of Off-Site Hook-Up Fee: Hook-Up Fees may only be used to pay for the capital items of Off-Site Facilities or for repayment of loans obtained for installation of Off-Site Facilities. Off-Site Hook-Up Fees shall not be used for repairs, maintenance, plant replacements, or operational purposes.

(C) Time of Payment:

(1) In the event that an Applicant is required to enter into a Main Extension Agreement, whereby the Applicant agrees to advance the costs of installing mains, valves, fittings, hydrants and other on-site improvements in order to extend service in accordance with R-14-2-406(B), payment of the fee(s) required hereunder shall be made by the Applicant within 15 calendar days after receipt of notification from the Company that the Utilities Division of the Commission has approved the Main Extension Agreement in accordance with R14-2-406(M).

(2) In the event that an Applicant is not required to enter into a Main Extension Agreement, the fee(s) hereunder shall be due and payable at the time the meter and service line installation fee is due and payable.

(D) Failure to Pay Charges; Delinquent Payments: Under no circumstances will the Company set a meter or otherwise allow service to be established if the Applicant has not paid in full all charges as provided by this Off-Site Hook-Up Fee Tariff.

(E) Off-Site Hook-Up Fee Non-refundable: The amounts collected by the Company pursuant to the Off-Site Hook-Up Fee Tariff shall be non-refundable contributions in aid of construction.

(F) Use of Charges Received: All funds collected by the Company as off-site hook-up fees, shall be deposited into a separate interest bearing trust account and used solely for the purposes of paying for the costs of Off-Site Facilities, including repayment of loans obtained for the installation of Off-Site Facilities that will benefit the entire water system.

(G) Off-Site Hook-Up Fees In Addition to Other Charges: The Off-Site Hook-Up Fees shall be in addition to any costs associated with a Main Extension Agreement for on-site facilities, and are in addition to the amounts to be advanced pursuant to charges authorized under other sections of this tariff.

(H) Disposition of Excess Funds: After all necessary and desirable Off-Site Facilities are constructed utilizing funds collected pursuant to the Off-Site Hook-Up Fee Tariff or the Off-Site Hook-Up Fee Tariff has been terminated by order of the Commission, any funds remaining in the trust shall be refunded. The manner of the refund shall be determined by the Commission at the time a refund becomes necessary.

(I) Fire Flow Requirements: In the event an Applicant for service has fire flow requirements that require the construction or installation of additional facilities whose costs are beyond the scope of those facilities costs provided for in the Company's current fees and charges, the Company may require the Applicant to install (as a non-refundable contribution) such additional facilities as are required to meet those fire flow requirements, in addition to the Off-Site Hook-Up Fee.

EXHIBIT
RUCO
7
ADMITTED

GOODMAN WATER COMPANY

DOCKET NO. W-02500A-10-0382

DIRECT TESTIMONY

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

MARCH 21, 2011

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8 Rate Design Summary 10

9 RATE BASE ADJUSTMENTS 11

10 OPERATING EXPENSE ADJUSTMENTS 29

11 RATE DESIGN 38

12 APPENDIX 1 – Qualifications of Timothy J. Coley

13 Exhibit 1 – Golder Ranch Fire District Compliance Letter

14 Exhibit 2 – Compliance Memo from ACC Utilities Division

15 Exhibit 3 – Goodman Water Company Hook-Up Fee Tariff filing

16 Exhibit 4 – Goodman Response to intervenor Wawrzyniak' 3rd set of data

17 requests

18 Exhibit 5 – RUXCO's 2002 – 2010 plant per customer analysis

19 Exhibit 6 – GWC letter sent to customers regarding cold weather conditions

20 REQUIRED REVENUE SCHEDULES TJC-1 through TJC-17

21 RATE DESIGN SCHEDULES

INTRODUCTION

Q. Please state your name, occupation, and business 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 describe your qualifications in the field of utilities regulation and your educational background.

A. From 1985 through 1991, I was employed with the Georgia Public Service Commission as a Junior Auditor, Auditor, and Senior Auditor. I have been involved with utility regulation in Arizona since 2000 with RUCO as a utility rate analyst. I earned a Bachelor of Science degree in business management in 1985 from Troy State University in Troy, Alabama and a Master of Public Administration degree from the University of West Georgia in 1997. I have since taken several accounting classes at Arizona State University – West Campus, which qualifies me to sit for the CPA examination. Appendix I, which is attached to this testimony, further describes my educational background and also includes a list of the rate cases and regulatory matters that I have been involved with.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present recommendations that are based on my analysis of Goodman Water Company's ("GWC" or the

"Company") Application for a permanent rate increase for the Company's operations in Arizona. GWC filed the Application with the Arizona Corporation Commission ("ACC" or "Commission") on September 17, 2010. The Company has chosen the operating period ended December 31, 2009, for the Test Year in this proceeding.

Q. Please describe GWC's organization.

A. GWC is a corporation duly organized and existing under the laws of the State of Arizona. The corporation is owned by the following three shareholders: Alexander Sears, James Shiner, and Amy Shiner. GWC is comprised of a single operating system that provides water utility services in its certificated area in Pinal County, Arizona. During the Test Year, GWC served approximately 625 utility service customers. The Company is seeking additional rate relief in the amount of $291,454. GWC maintains the revenues from its utility operations are presently inadequate to provide the Company a fair rate of return on the fair value of its utility plant and property. The Company's present rates were established and authorized by the Commission in Decision No. 69404, dated April 16, 2007. The rates went into effect on May 1, 2007.

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

A. I reviewed GWC's Application to determine if the rates and charges being requested by the Company are appropriate. RUCO's cost of capital

witness, Mr. William Rigsby, and myself toured GWC's physical plant on December 17, 2010 and was accompanied by Company personnel.

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

A. My direct testimony will cover the rate base issues and levels of operating revenues and expenses, as well as the rate design issues associated with GWC's Application.

Q. What schedules will you be presenting in your direct testimony?

A. I will be presenting RUCO's ratemaking schedules for GWC. The rate base adjustments that I discuss in my direct testimony appear in Schedules TJC-2 through TJC-7. The operating revenue and expense adjustments that I will discuss appear on Schedules TJC-8 through TJC-16. RUCO's rate design will be presented on Schedules TJC RD-1 through TJC RD-6 for the residential and commercial customer classifications and Schedule TJC RD-1 through TJC RD-3 for the construction/standpipe customer classification.

Q. Is RUCO providing testimony on the cost of capital issues associated with the case?

A. Yes. Mr. Rigsby will file cost of capital testimony, under separate cover, for RUCO on the cost of capital issues associated with this case. RUCO's cost of capital analysis is shown on Schedule TJC-17.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your direct testimony is organized.

A. My direct testimony is organized in four sections. First, the introduction I have just presented and second, the summary of my testimony that I am about to give. Third, I will present the findings of my analysis of GWC's Application and will explain the various rate base and operating revenue and expense adjustments that I am recommending. Fourth, and finally, I will discuss my recommendations regarding GWC's rate design.

Summary of RUCO's Revenue Requirement

Q. Please summarize RUCO's revenue requirements.

A. RUCO recommends approximately the same overall revenue requirement that GWC' present rates generate. RUCO finds the Company's total plant capacity far exceeds the needs of its current customer base. This plant is not used and useful and, thus, is unreasonable excess capacity. While the overall requirement remains about the same, RUCO recommends a conservation oriented rate design that places 55.2 percent of the revenue requirement in the fixed monthly bill and 44.8 percent in the variable commodity rate. Residential customers will incur only a small change from their current monthly bill.

Summary of Rate Base Adjustments

Q. Please summarize RUCO's rate base recommendations and adjustments that you will address in your testimony.

A. Based on the results of my analysis of GWC, I am making the following recommendations related to rate base:

Rate Base Adjustment #1 – Test Year Plant & Accumulated Depreciation

This adjustment increases the accumulated depreciation balance for the Test Year by $3,268. The adjustment corrects a depreciation expense formula in the Company's 2007 B-2 Schedules on page 3.3. The Company admitted in response to RUCO Data Request 2.12 that it had "inadvertently used 4 ½ months and 7 ½ months rather than 3 ½ months and 8 ½ months in its computation" for depreciation expense. RUCO still contends that the more correct number of months to be used is 4 months and 8 months rather than 3 ½ months and 8 ½ months because Commission Decision No. 69404 states on page 21 "It is further ordered that the rates and charges approved herein shall be effective for all service provided on and after May 1, 2007."

Rate Base Adjustment #2 – Excess Capacity – This adjustment reduces the Company's plant in service for providing the needs of general water utility service to its customers that meet the Commission standards of 20 pounds per square inch. The adjustment removes a percentage of

general plant that RUCO deems as either not used and useful or more appropriately attributable to fire flow upgrades for a small number of larger homes to meet the fire district's minimum fire flow requirements. The "water development plans" notated in a letter to D. R. Horton Homes, dated September 2003 and attached as RUCO Exhibit 1, specifically states, "The approved Water Development Plans were approved for 1,000 gallons per minute ("gpm") fire flow and have notation that dwelling units exceeding 3,600 square feet in fire area shall have an automatic fire sprinkler system installed."

A Commission Staff engineering compliance report, dated September 2, 2010, indicated that GWC's plant capacity currently can serve approximately 1,800 customers. The Company was presently serving approximately 620 customers at Test Year end or roughly 35 percent of the number of customers that GWC's plant capacity is capable of serving, as identified in Staff's report and attached as RUCO Exhibit 2.

<u>Rate Base Adjustment #3 – Advances in Aid of Construction ("AIAC")</u>

This is a corresponding adjustment to AIAC that is directly related to RUCO Rate Base Adjustment #2 – Excess Capacity Adjustment above. To properly match all methods of financing gross plant (i.e. investor, AIAC, and/or CIAC supplied capital), an adjustment to AIAC is required to recognize a reduced level of AIAC. The same percentage reduction was

used to reduce the AIAC balance as was used in RUCO adjustment number two earlier.

Rate Base Adjustment #4 –Accumulated Deferred Income Taxes ("ADIT") This adjustment is a corresponding adjustment to ADIT that is directly related to RUCO Rate Base Adjustment #2 – Excess Capacity Adjustment above. It reflects the ratemaking/book balances of plant items resulting from RUCO rate base adjustments number two and three. The ADIT balance transforms from the Company's ADIT liability balance to an asset balance, which increases rate base accordingly.

Summary of Operating Income Adjustments

Q. Please summarize RUCO's operating revenue and expense adjustments.

A. Based on the results of my analysis of GWC, I am making the following recommendations related to operating revenues and expenses:

Operating Adjustment #1 – Depreciation Expense – This adjustment calculates depreciation expense based on RUCO's recommended plant levels.

Operating Adjustment #2 – Property Tax Expense – This adjustment calculates property tax expense based on a modified Arizona Department

of Revenue ("ADOR") formula that has been adopted by the Commission in a number of prior rate cases.

Operating Adjustment #3 – Revenue Annualization – This adjustment reverses the Company's negative revenue annualization adjustment to zero.

Operating Adjustment #4 – Salaries & Wages Expense – This adjustment reduces the Company's 25 percent salary and wage expense increase to the Consumer Price Index ("CPI") level of 9.42 percent since the last Test Year of the Company's previous rate case through June 2010. An adjustment to reduce payroll taxes was also necessary to complete the adjustment.

Operating Adjustment #5 – Contractual Services Expense – This adjustment is similar to RUCO operating adjustment number 4 above. The adjustment reduces the Company's 25 percent contractual service expense increase to the Consumer Price Index ("CPI") level of 9.42 percent since the last Test Year of the Company's previous rate case through June 2010.

Operating Adjustment #6 – Remove Meals – This adjustment removes meals/lunches that were identified in the Company's response to Staff data request GTM 4.11.

Operating Adjustment #7 – Income Tax Expense – This adjustment calculates the appropriate level of income tax expense based on RUCO's recommended operating income less income taxes.

REQUIRED REVENUE

Q. Please summarize the results of RUCO's analysis of Goodman Water Company and your recommended revenue requirement.

A. Based on the results of RUCO's analysis of GWC's Application, RUCO's analysis determined that the Company should receive a gross revenue decrease of $36,000, as summarized below:

Fair Value Rate Base	$1,729,190
Adjusted Operating Income (Loss)	$ 160,650
Required Rate of Return	7.85%
Required Operating Income	$ 135,754
Gross Revenue Conversion Factor	1.4460
Gross Revenue Increase (Decrease)	($36,000)

Q. Does RUCO's rate design reflect the $36,000 rate decrease that resulted in RUCO's analysis and shown above?

A. No. RUCO recommends neither a rate decrease, which is reflected in its revenue requirement analysis, nor a revenue increase.

Q. What level of gross revenues will RUCO's recommended rates reflect in its rate design?

A. RUCO's recommended rates will produce approximately the same level of gross revenues that the Company's present rates generate, which will be briefly discussed next.

Rate Design Summary

Q. Is RUCO proposing the same rates that the Company presently has?

A. No. RUCO recommends changing the ratio of the monthly minimum (fixed) and commodity (variable) charges. However, the total gross revenue will remain approximately the same as the Company's present rates produce.

...

Q. Please explain RUCO's recommended rate design that result in approximately the same gross revenue being generated as the Company's present rates but with different fixed and variable charges than the Company presently has?

A. RUCO recommends moving more revenue to the commodity charges and less revenue in the monthly minimum charges while respecting the principle of gradualism.

Q. Did the Company propose moving more revenue to the commodity charges and less revenue in the monthly minimum charges in its proposed rates?

A. Yes. The Company's proposed rate design structure is quite similar to RUCO's recommended structure and will be discussed further at the end of my direct testimony.

RATE BASE ADJUSTMENTS

Rate Base Adjustment #1 – Test Year Plant and Accumulated Depreciation

Q. Please explain RUCO's adjustment to the Company's Test Year plant and accumulated depreciation balances.

A. I recomputed the plant and accumulated depreciation account balances starting at the Commission's last authorized balances that were established in Decision No. 69404, as shown on Schedule TJC-4, page 1 of 5 in columns (C) and (D). All annual plant additions and retirements

were added to and deducted from the Commission's last authorized level of plant and accumulated depreciation established in Decision No. 69404. RUCO's recompilation of plant determined that RUCO and the Company are in agreement on the Test Year end plant balances. However, my Schedule TJC-4, page 5 in column (H) on line 38 shows that the Company calculated $3,268 less of accumulated depreciation than RUCO did.

Q. Were you able to determine the cause of the two different accumulated depreciation balances between RUCO and the Company?

A. Yes.

Q. Briefly explain the difference in RUCO's and the Company's Test Year end accumulated depreciation balances.

A. The difference between the Company and RUCO arises in the 2007 depreciation expense calculation.

Q. What happened in 2007 that caused the two different depreciation expense calculations between the Company and RUCO?

A. The last Commission Decision No. 69404, dated April 16, 2007, authorized new depreciation rates for GWC on a going forward basis. As I stated earlier in my summary section of this testimony, RUCO's "adjustment corrects a depreciation expense formula in the Company's 2007 B-2 Schedules on page 3.3." The Company admitted in response to

RUCO Data Request 2.12 that it had "inadvertently used 4 ½ months and 7 ½ months rather than 3 ½ months and 8 ½ months in its computation" for calculating depreciation expense in that year. RUCO agrees that is what the Company did in its Application. However, RUCO still contends that the more correct number of months to be used for that year is 4 months and 8 months rather than 3 ½ months and 8 ½ months. That is true because Commission Decision No. 69404 states on page 21 "It is further ordered that the rates and charges approved herein shall be effective for all service provided on and after May 1, 2007." There was one set of rates for the first four-months and a second set of rates for the next eight-months. Therefore, depreciation expense should be calculated using four-month/eight-month time frames.

Rate Base Adjustment #2 – Excess Capacity

Q. Did RUCO make an excess capacity adjustment to the Company's Test Year end plant and accumulated depreciation balances?

A. Yes.

Q. Please explain why RUCO believes that excess capacity exists in the Company's Test Year-end plant and accumulated depreciation balances.

A. There are two reasons why RUCO believes excess capacity exists in GWC's system.

Q. What is the first reason why RUCO believes excess capacity exists in GWC's system?

A. RUCO believes the Company over-anticipated GWC's build out date and constructed plant that would be necessary to serve the projected number of customers at build out.

Q. How many customers can GWC serve?

A. RUCO finds GWC's current total capacity can serve 1,288 customers. However, GWC actually serves approximately 625 customers[1] in the Test Year.

Q. What is RUCO's rationale for its belief that the Company over-anticipated GWC's build out date and constructed plant that would be necessary to serve the projected number of customers at build out.

A. In the Company's last rate case[2], which utilized a Test Year ended September 30, 2005, GWC had $2.4 million in plant and served 479 customers. That is approximately $5,010 of plant per customer ($2.4 million of Plant / 479 Customers = $5,010). Since the last Test Year, the Company has added approximately $3.1 million in new plant additions and serves only an additional 142 customers. To serve the additional 142 customers, GWC constructed plant that cost each of the 142 customers

[1] Per GWC's 2009 Annual Report filed with the ACC, GWC served up to 630 customers during a one-month period.
[2] Commission Docket No. W-02500A-06-0281

roughly $22,000 per customer ($3.1 million / 142 = $21,831 per additional customer). Nearly 60 percent of the $3.1 million in plant additions were added in year 2007. What the Company could not have anticipated is the recent great recession and real estate collapse.

Another way to analyze the additional $3.1 million in plant additions is to compare the additions to GWC's customer growth from the end of 2005 thru Test Year end 2009. The $3.1 million of new plant additions since the last rate case represent an approximate 130 percent increase over the $2.4 million that was approved in the last Commission Decision No. 69404. On the other hand, customer growth has grown only 30 percent over the same time period. The ratio of GWC's customer growth to the plant additions over the same period of time is 0.23:1 or roughly 23 percent. Given these facts, RUCO believes that roughly 77 percent of the plant additions should be considered excess capacity and be recorded as plant held for future use ("PHFFU") and receive no rate base treatment at this time.

Q. If the Company had maintained its 2005 to 2006 growth rate, would GWC have reached build by the end of 2010?

A. If GWC had maintained its 2005 to 2006 growth rate of approximately 20 percent annually through year 2010, the Company would be serving over

1,000 customers today, which would make the additional new plant additions as more reasonable, but that did not happen.

Q. Was RUCO able to determine the total capacity of GWC's water system or in other words, how many customers the Company is capable of serving today?

A. Yes.

Q. How did RUCO determine the Company's current total capacity?

A. RUCO took into consideration a Staff engineering compliance memorandum (Attached as RUCO Exhibit 2) dated approximately six-months ago on September 2, 2010. According to Staff's engineering compliance report quoted below, the Company's water infrastructure currently has the capacity to serve 1,800 customers.

Staff's Review

According to the Company's Annual Report, the Company's water system consists of two wells (totaling 1,240 GPM), two storage tanks (totaling 930,000 gallons) and a distribution system serving 597 customers as of December 2007. Based on these plant capacities, **this system can currently serve approximately 1,800 customers.** In its filing, the Company proposed capital expenditure [sic] totaling $940,000 for a new Well #3 and related equipment, including engineering and contingency. Through data requests to the Company, Staff discovered that the capital plant and expenditure was not for a new Well #3, but actually for a Water Plant No. 3 site consisting of a 340,000 gallon storage tank and a booster system that will serve only a portion of the water system. Based on this finding, Staff has determined that the

> proposed Water Plant No. 3 would not meet the HUF tariff requirements because this water plant site would not benefit the entire water system. As a result, Staff concludes that this Company is not a good candidate for a HUF Tariff.

Q. Is RUCO relying on the Staff memo to make its excess capacity adjustment?

A. No. But RUCO considers it an important consideration and further support that a significant portion of GWC's plant is not used and useful.

Q. What source(s) is RUCO using in determining its excess capacity factor?

A. RUCO is primarily using the Company's compliance filing, dated July 31, 2007,[3] and attached as RUCO Exhibit 3. As a sanity check, RUCO utilizes the Company's response to an "Intervenor's" data request number 3 labeled as Appendix "A" and is attached as RUCO Exhibit 4.

Q. What figure does RUCO use to determine GWC has excess capacity?

A. RUCO contends GWC's system can serve a total of 1,288 customers.

The Company's compliance item Docket No. W-0200A-06-0281, dated July 31, 2007 referenced above, states that the Company anticipates 724 new customer connections over a time period of 2008 through 2001 on page 1, line 21. On July 31, 2007, the same day that the Company's compliance filing was docketed, the Company served only 564 customers

[3] Commission Docket No. W-02500A-06-0281

per the Company's 2007 Annual Report filed with the Commission. The two customer count numbers cited above result in 1,288 customers (564 customers served on July 2007 + 724 anticipated new customer connections = 1,288 customers) to be served by the Company. This 1,288 projected customer count was used as the denominator in my excess capacity factor calculation.

Q. Describe how you calculate the percentage of excess capacity since GWC's system was built to serve 1,288 customers but actually served approximately 620 customers in the Test Year?

A. RUCO contends that 43.12 percent of GWC's total plant is not used and useful.

The complete equation is shown below and an explanation follows:

$$(666 \times 1.10) / 1{,}288 = \mathbf{.5688}$$

The 666 in the above equation represents the highest number of customers that were connected to the system in year 2010, which is one year after the Test Year. I then multiplied the 666 customers by 1.10 to provide a margin of reserve for some future growth. The additional 10 percent in the margin of reserve exceeds RUCO's analysis that the Company grew by only 7 percent from the end of the Test Year to the end

of 2010 as shown in RUCO Exhibit 5, page 3. As explained earlier, the 1,288 figure represents the projected number of customers. The above calculation results in a factor of .5688, or 56.88 percent, which represents the percentage of used and useful plant. The remaining .4312, or 43.12 percent, is amount of excess capacity (1 - .5688 = .4312).

Q. What is a "margin of reserve" and why did RUCO use it?

A. It is a measure of available capacity over and above the actual number of customers being served at a given point in time. Reserve margin and reserve capacity are synonymous. For a producer of energy, it refers to the capacity of a producer to generate more energy than the system normally requires. For a transmission company, it refers to the capacity of the transmission infrastructure to handle additional energy transport if demand levels rise beyond expected peak levels.

Regulatory bodies usually require water and sewer companies and producers and transmission facilities to maintain a constant reserve margin of 10-20% of normal capacity as insurance against breakdowns in part of the system or sudden increases in demand.

Even though GWC's annual growth has slowed from past growth rates, it has not entirely ceased (i.e. approximately 40 additional customers in 2010). RUCO realizes the Company will continue some level of short-

term growth and accounts for it with its ten percent margin of reserve allowance.

Q. Why does RUCO believe a reserve margin is critical in examining the issue of excess capacity?

A. First, RUCO realizes that a water system cannot be designed to serve the exact same number of current customers in an economically feasible manner. Over the short-run or a period of one-year or less, there may be some excess capacity in a water system that is inevitable if we seek economies of scale. But, there should not be excess capacity over the long-run, particularly with water systems. In essence, excess capacity results in higher rates to the current ratepayers and is inherently unfair.

Q. Why didn't RUCO use the 1,800 customer figure in Staff's memo to determine its excess capacity factor?

A. RUCO did not use the 1,800 customer figure cited in Staff's report because of fire code compliance issues. The code relied on by the Golder Ranch Fire District ("GRFD"), which serves the ECR development, requires that a water system must have two hours of constant flow at 2,000 gallons per minute.

...

Q. What is the second reason why RUCO believes excess capacity exists in GWC's system?

A. RUCO believes that a prior GWC shareholder, D. R. Horton[4] who was also the developer of ECR, made a costly decision to add additional fire flow capacity as opposed to retrofitting, or installing during the construction phase, a small number of homes (approximately five at that time) with fire sprinklers. The additional, unnecessary fire flow capacity was far more expensive than providing sprinkler systems for five homes at the time. This decision came at the expense of approximately 80 to 85 percent of all GWC's ratepayers.

Q. What evidence does RUCO have to support its claim that the decision made by former shareholder D. R. Horton was financially harmful to the large majority of ratepayers residing in ECR?

A. Exhibit 1 to my direct testimony supports RUCO's position regarding this matter. Exhibit 1 is a letter, dated September 2003, from GRFD to Mr. Jim Morrison, Vice President of Construction for D.R. Horton Homes. Paragraph H on page 2 of the letter expresses D.R. Horton Home's desire to not have to install automatic sprinkler systems in homes exceeding 3,600 square feet in fire area in order to meet a GRFD requirement.[5] As an alternative, D. R. Horton Homes proposed to increase the available fire

[4] Per Company response to RUCO data request 1.12, D. R. Horton was a shareholder in Goodman Water Company from June 26, 2003 thru March 20, 2007.
[5] Section I, subsection A of the September 2003 GRFD letter.

flow capacity in the GWC system from 1,000 gallons per minute ("gpm") to 1,500 gpm, or a 50 percent increase in the rate of fire flow capacity.

Q. Did GWC build the fire flow upgrade stated in the letter?

A. Yes.

Q. Why does RUCO believe that 80 to 85 percent of GWC's ratepayers were financially harmed as a result of the decision to upgrade GWC's fire flow capacity instead of installing in-home fire sprinklers?

A. Because approximately 80 to 85 percent of the homes in the ECR development were not affected by GRFD's 3,600 square foot fire area requirement. Therefore, D. R. Horton's decision to upgrade for those five homes was imprudent. It is this fire flow requirement involving dwelling unit square footage that validates RUCO's position on this issue. Every ratepayer that has ever owned a dwelling in the ECR development and that has less than 3,600 square feet of fire area has always had sufficient minimum fire flow at 1,000 gpm. The September 2003 GRFD letter clearly points that very fact out in paragraph one on page two which states:

> **Water Development Plans** – The approved Water Development Plans were approved for 1,000 gpm fire flow and have notation that dwelling units exceeding 3,600 square feet in fire area shall have an automatic fire sprinkler system installed.

Because D. R. Horton Homes, the developer and former GWC shareholder made a business decision not to install automatic fire sprinkler systems in the small number of dwellings that had a fire area in excess of 3,600 square feet, GWC has been recovering in rates the costs associated with the fire flow upgrades just described. A situation which could have been avoided had D.R. Horton Homes simply retrofitted the small number of homes that were not in compliance with GRFD's requirements in 2003 or installed fire sprinklers in any additional homes that fell within the 3,600 square foot fire area threshold.

Q. Will GWC's ratepayers continue to pay higher rates as a result of the Company's business decision to upgrade its fire flow capacity?

A. Yes, if the Commission approves the unnecessary extra 500 gpm fire flow capacity built into the plant.

Q. Why does RUCO believe it is unfair that ratepayers should pay for GWC's decision to increase the minimum fire flow from 1,000 to 1,500 gpm?

A. RUCO does not believe ratepayers should pay the additional cost. Simply stated, the additional capacity was not needed or even necessary for the provision of water service. Quite frankly, it appears to RUCO that the additional capacity was not necessary to meet the fire flow compliance requirements for dwellings less than 3,600 square feet in fire area.

D. R. Horton shifted the cost of the fire flow compliance for a select few homes from D. R. Horton Homes' ledgers to those of the utility to be recovered from captive ratepayers.

Q. What adjustment did RUCO make to the Company's plant and accumulated depreciation to account for the excess capacity issue?

A. RUCO's adjustment to plant and accumulated depreciation for the excess capacity issue reduces plant by $2,358,931 and decreases accumulated depreciation by $316,267 as shown on Schedule TJC-3 with the detail on Schedule TJC-5.

Q. Would a hook-up fee mitigate the fire flow situation and overall increase in rates being proposed by the Company in this proceeding?

A. A hook-up fee instituted after the Company's prior rate case could have mitigated the rate increase being sought by GWC in this proceeding. In fact Decision No. 69404 ordered the following:

> IT IS FURTHER ORDERED that Goodman Water Company shall file a hook-up fee tariff with Docket Control, as a compliance item in this Docket, for Staffs review by July 31, 2007.

Q. Was the hook-up fee tariff ordered in Decision No. 69404 ever filed by the Company?

A. Yes. The Company filed the required hook-up fee tariff on July 31, 2007. Unfortunately, the tariff was filed under an incorrect docket number and was never addressed by Staff until September 2, 2010. After reviewing

the Company's hook-up fee tariff, Staff concluded that a hook-up fee at this time, would not benefit the entire water system. RUCO believes that Staff may not have come to the same conclusion had the hook-up fee tariff been addressed when the Company was in the process of building the additional infrastructure that is not serving existing customers. Hook-up fees collected during that period would have been treated as contributions-in-aid-of-construction and would have shielded customers from the costs of non-used and useful plant that GWC is attempting to recover in new rates.

Q. Please summarize why the Commission should adopt RUCO's recommended adjustment related to the excess capacity and fire flow issues in this case.

A. Quite simply GWC's current ratepayers should not have to pay higher rates for plant that is intended for future customers. While GWC may have constructed plant to serve anticipated growth, that growth never materialized. GWC's customers should not bare the entire burden of growth. In addition, GWC's ratepayers should not have to pay for fire flow upgrades that could have been avoided had a prior shareholder made a business decision to retrofit or include sprinkler systems in a small number of homes that fell within the requirements of the GRFD fire code.

The Commission, as it did in the recent Gold Canyon case, Decision No. 70662, should balance the interests of ratepayers and shareholders and spread the risk. RUCO has spread the risk by its proposal to use a ten percent margin of reserve. Moreover, RUCO's proposal will incent utilities to build capacity to meet its customers' needs.

For these reasons, RUCO believes the Commission should reject GWC's request for a 50.89 percent revenue increase over Test Year adjusted revenues and adopt RUCO's recommendation not to increase or decrease the current rates.

Q. Does a letter sent to GWC's customers on or around February 10, 2011 diminish in anyway RUCO's excess capacity adjustment?

A. No. The letter describes the Company's efforts to maintain water service during the recent cold snap experienced in Southern Arizona. In its letter attached as RUCO Exhibit 6, GWC states that it would not have been able to provide water without the 530,000 gallon reservoir located in the northeast corner of ECR.

Q. What is RUCO's opinion on this letter?

A. RUCO believes that it is commendable that GWC was able to maintain water service to its customers during the recent period of record cold weather. However, the point is that while the reservoir in question may

have played a role in keeping water flowing, it is not the only source of water storage in the Company's system that is subject to RUCO's excess capacity adjustment. The Company presently has 930,000 gallons of storage capacity, 400,000 of which is being provided by a reservoir that was afforded rate base treatment in the Company's prior rate case proceeding. RUCO's excess capacity adjustment does not identify any specific plant asset. Rather, the adjustment reflects excess plant capacity in terms of a percentage of total plant.

Rate Base Adjustment #3 – Advances in Aid of Construction ("AIAC")

Q. Please explain RUCO's rate base adjustment #3 to AIAC?

A. RUCO's rate base adjustment #3 to AIAC is a companion adjustment that corresponds to RUCO's rate base adjustment #2 – excess capacity. It was necessary to reduce the level of the AIAC balance using the same factor, .5688 or 56.88 percent that was used in making RUCO's excess capacity adjustment.

Q. What adjustment did RUCO make to the Company's AIAC balance to account for the excess capacity issue?

A. RUCO's adjustment to the Company's AIAC balance to account for the excess capacity issue reduces AIAC by $906,365 from the Company's adjusted Test Year balance of $2,101,905 to RUCO's recommended level

of $1,195,540 as shown on Schedule TJC-3 at line 5, column (D), with the detail on Schedule TJC-6.

Rate Base Adjustment #4 – Accumulated Deferred Income Taxes ("ADIT")

Q. Please explain RUCO's rate base adjustment #4 to ADIT?

A. RUCO's rate base adjustment #4 to ADIT is also a companion adjustment that corresponds to RUCO's rate base adjustment #2 – excess capacity. It was necessary to recalculate the level of ADIT using RUCO's recommended ratemaking/book balances of plant items after RUCO's excess capacity adjustments.

Q. What adjustment did RUCO make to the Company's ADIT balance to account for the excess capacity issue?

A. RUCO's adjustment to the Company's ADIT balance to account for RUCO's excess capacity adjustments reverses the Company's ADIT liability balance, which is a reduction to rate base, and creates an ADIT asset balance, which increases rate base accordingly. RUCO reduced the Company's adjusted Test Year ADIT liability balance of $135,342, which is a reduction to rate base, by $460,294 and creates an ADIT asset balance of $324,952, which is an addition to rate base and obviously does not benefit ratepayers. RUCO's adjustment is shown on Schedule TJC-3 at line 11, column (E), with the detail on Schedule TJC-7, page 1 and 2.

OPERATING EXPENSE ADJUSTMENTS

Operating Adjustment #1 – Depreciation Expense

Q. Please explain RUCO's adjustment to the depreciation expense.

A. RUCO's adjustment to depreciation expense reflects the Commission's approved depreciation rates applied to RUCO's recommended plant balances due to RUCO's Original Cost Rate Base ("OCRB") adjustment for excess capacity as shown on Schedule TJC-3 on line 1, column (C). RUCO's depreciation expense adjustment is shown on Schedule TJC-9 on line 19, column (B). The depreciation expense adjustment's detail is shown on Schedule TJC-10.

Q. What adjustment did RUCO make to the Company's adjusted Test Year depreciation expense?

A. RUCO's adjustment reduces the Company's adjusted test year depreciation expense by $98,254. The adjustment was driven by RUCO's rate base adjustment for excess capacity.

Operating Adjustment #2 – Property Tax Expense

Q. Has RUCO made an adjustment to the Company-proposed level of property tax expense?

A. Yes.

Q. Has RUCO calculated property tax expense using a methodology that has been adopted by the ACC in prior rate cases?

A. Yes. RUCO has used a modified version of the ADOR formula that has been adopted by the Commission in a number of prior rate cases. RUCO's calculation of property tax expense uses two years of adjusted gross operating revenues and one year of RUCO's proposed level of gross operating revenue to arrive at a three-year average of revenue that is subject to property tax. The calculation of property tax expense is shown on Schedule TJC -11.

Q. Are there any differences between RUCO's calculation of property tax expense and the Company's calculation?

A. Yes. There are three differences. All three differences are in the two adjusted Test Year revenues and the one-year of proposed level of revenue. Other than those differences, there is no difference between RUCO and the Company's property tax calculation methodology.

Q. What adjustment did RUCO make to the Company's adjusted Test Year property tax expense?

A. RUCO's adjustment reduces the Company's adjusted test year property tax expense by $3,036. The adjustment was driven by RUCO's rate base adjustment for excess capacity. RUCO's property tax expense adjustment

is shown on Schedule TJC-9 on line 31, column (C). The detail of the adjustment is shown on Schedule TJC-11 as referenced earlier.

Operating Adjustment #3 – Revenue Annualization

Q. Please explain the reasoning for RUCO's adjustment to the Company's adjusted Test Year revenues.

A. The Company made an adjustment to its "Test Year Book Results" to annualize GWC's revenues to the Test Year end number of customers. The Company's proposed adjustment is negative, which reduces the revenues for the Test Year book results by $7,359.

Q. Does RUCO agree with the Company's negative revenue annualization adjustment?

A. No. GWC's adjustment presumes that Company will experience an erosion of revenue on a going forward basis. That assumption is far from the truth. As a matter of fact, RUCO believes the complete opposite is true.

Q. Why does RUCO believe the complete opposite is true and the Company will not experience an erosion of revenue on a going forward basis?

A. A review of the Company's Annual Reports filed with the Commission should lead one to the exact opposite conclusion.

Q. Did RUCO perform such an analysis?

A. Yes. RUCO performed a couple of analyses, including the review of GWC's Annual Reports filed with the Commission.

Q. Please discuss and provide RUCO's results of its analyses.

A. GWC's Annual Reports filed with the Commission annually showed the data regarding annual revenues from year to year since its inception:

Year	Revenue	% Change
2002	$ 63,349	N/A
2003	98,159	55%
2004	162,451	66%
2005	228,015	40%
2006	294,130	29%
2007	484,158	65%
2008	548,016	13%
2009	566,372	3%

Clearly, the data shows that the Company has never experienced any erosion of revenues and has steadily increased its revenues over the years. It is counter-intuitive, absent an explanation to presume lower revenues for GWC on a going forward basis.

...

Q. Please describe RUCO's second analysis regarding the Company's negative revenue annualization adjustment?

A. Schedules TJC-12 on pages 1 thru 7 shows RUCO's revenue annualization calculation. RUCO uses average year customer counts rather than the Company's Test Year end customer count to annualize revenues. The revenue annualization result using RUCO's average year customer counts was a negative $49. RUCO deemed the negative $49 as *de minimis* and provides Schedules TJC-12 in its direct filing for display purposes only.

Q. What adjustment did RUCO make to the Company's adjusted Test Year revenues?

A. RUCO's adjustment reverses the Company's adjustment and increases GWC's adjusted Test Year revenues by $7,359. RUCO's revenue annualization adjustment is shown on Schedule TJC-9 on line 1, column (D). This places the level of revenues back to the amount that was booked in the Test Year.

<u>Operating Adjustment #4 – Salaries and Wages</u>

Q. Did RUCO make an adjustment to the Company's adjusted Test Year wage and salary expense?

A. Yes.

Q. Please explain RUCO's adjustment to the salary and wage expense account?

A. The Company made an adjustment that increased the President's/ Manager's salary by 25 percent over the Test Year booked amount. This employee is also the largest shareholder in GWC and received his proportionate share of a $90,000 dividend paid in the Test Year. The 25 percent Company increase raised his salary $8,000 from $32,000 to $40,000. Considering the current economic conditions, RUCO believes the Company's adjustment is an excessive percentage increase when many people in today's market are taking cuts in salaries and/or losing jobs all together. RUCO calculated the inflation factor over the period of time since GWC's last rate case, which utilized a September 30, 2005 Test Year end, thru June 2010. The inflation factor was 9.42 percent over that time frame. RUCO multiplied the 9.42 percent inflation factor by the Test Year book result of $32,000 to obtain a more reasonable wage increase in today's economic environment, which equals $3,014 (9.42% x $32,000 = $3,014). This downward adjustment is more palpable for the ratepayers and also fair to the President/Manager because it sustains the same buying power as he had before.

...

Q. What adjustment did RUCO make to the Company's adjusted Test Year wage and salary expense?

A. RUCO's adjustment decreases the Company's $40,000 adjusted Test Year salary and wage expense by $4,986. I will note that RUCO went out six-months beyond the Test Year when calculating the inflation factor to be applied to the Test Year book result of $32,000. There were payroll taxes that were also affected. RUCO reduced the associated payroll taxes by the same inflation factor used above. The adjustment for payroll taxes was $372 less too. These adjustments can be seen on Schedule TJC-9 on lines 5 and 20 in column (E). The detail of RUCO's wage and salary expense adjustment is shown on Schedule TJC-13.

Operating Adjustment #5 – Contractual Services

Q. Did RUCO make an adjustment to the Company's adjusted Test Year contractual services expense?

A. Yes.

Q. Please explain RUCO's adjustment to the contractual services expense account?

A. This adjustment is similar in respect to RUCO's previous operating income adjustment to salaries and wages expense. The Company made an adjustment to its Test Year book results to increase contractual services

expense by 25 percent from $16,000 to $20,000. Again, considering the current economic conditions, RUCO believes the Company's adjustment is an excessive percentage increase in today's economic environment. RUCO calculated the inflation factor over the same period of time - October 1, 2005 thru June 30, 2010 – which resulted in 9.42 percent. RUCO multiplied the 9.42 percent inflation factor by $16,000 to obtain a more reasonable increase in today's economic environment, which equals $1,507 (9.42% x $16,000 = $1,507). This downward adjustment is also more palpable for the ratepayers and also fair to the contractual service provider because it sustains the same buying power as before. This person is also a shareholder of GWC and received a proportionate share of the $90,000 dividend paid in the Test Year.

Q. What adjustment did RUCO make to the Company's adjusted Test Year contractual services expense?

A. RUCO's adjustment decreases the Company's $4,000 adjustment by $2,493. There were payroll taxes associated with this expense since it is for outside contractual services. The adjustment is shown on Schedule TJC-9 on line 11 in column (F). The detail of RUCO's contractual services adjustment is shown on Schedule TJC-14.

Operating Adjustment #6 – Outside Services/Meal Expense

Q. Please explain RUCO's adjustment to outside services expense?

A. This adjustment removes meal expenses apparently charged to the outside services account. The meal expenses were identified in the Company's response to Staff data request GTM 4.11.

Q. What is RUCO's rationale for disallowing the meal expenses and not allowed to be recovered through ratepayers' rates?

A. RUCO readily admits that the amount is small in light of other recommended adjustments in this case. RUCO's rationale is based on what the Internal Revenue Service ("IRS") allows as expense deductions when determining income tax payable, which the IRS allows only a 50 percent deduction of meals. In light of that, RUCO does not believe any amount of meal expense should be includable in determining water rates.

Q. What adjustment did RUCO make to remove the meals from the outside services account?

A. RUCO's adjustment decreases the Company's outside services account by $148. The adjustment is shown on Schedule TJC-9 on line 11 in column (G). The detail of RUCO's outside services adjustment is shown on Schedule TJC-15.

Operating Adjustment #7 – Income Tax Expense

Q. Have you calculated income tax expense based on RUCO's recommended adjusted operating income?

A. Yes. This adjustment is shown on Schedule TJC-17 for GWC. The primary difference between RUCO and the Company for this adjustment is the recommended amount of depreciation expense.

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.

RATE DESIGN

Q. Is RUCO recommending a rate design that reflects the $36,000 total revenue decrease, which is shown in RUCO's revenue requirement Schedule TJC-1 on line 8 in column (B) for GWC?

A. No, not at this time.

...

Q. What level of revenue does RUCO's rate design produce?

A. RUCO's rate design generates $567,889, which approximates GWC's present rates' revenues. RUCO does not recommend either a rate increase or a rate decrease in its direct testimony.

Q. What amount of revenues does the Company's present rates generate compared to RUCO's recommended rates?

A. GWC's present rates generate the following revenues for its different customer classifications as shown below:

Meter Sizes	Classification	Company Present Revenues	RUCO Recommended Revenues
5/8 x ¾"	Residential	$ 438,217	$ 438,964
¾"	Residential	88,623	88,001
1"	Residential	6,812	6,700
1"	Commercial	13,599	14,882
1 ½"	Commercial	458	427
2"	Commercial	14,440	14,977
5/8 x ¾"	Construction	3,456	3,938
Total Revenues		$565,505	$567,889

These amounts are shown in RUCO's rate design model schedules and on the Company's Schedule H-1 in the "Total Revenues at Present Rates" column.

...

Q. Is RUCO recommending the same rates that the Company presently has?

A. No. RUCO recommends altering the ratio of the monthly minimum (fixed) and commodity (variable) charges and shifting more revenues into the commodity charge and less revenue in fixed monthly charge. However, the total gross revenues will remain approximately the same as the Company's present rates produce, as was shown in the earlier table. This will be accomplished while respecting the principle of gradualism.

Q. Why does RUCO's rate design shift more of the revenues into the commodity or variable charge and less revenue in the monthly minimum or fixed charge?

A. Over the past decade or longer, the Commission, RUCO, and water companies have been encouraging and promoting rate designs that raise the awareness and importance of water conservation in Arizona's desert country. Inverted multi-tiered commodity rate structures have been instituted by all to help foster the goal toward water conservation. RUCO strives for a ratio between the monthly minimum fixed charge and variable commodity charge to be approximately 40:60 percent respectively.

Having a 40:60 ratio between the monthly minimum and commodity charges encourage the water users, customers, to conserve and possibly lower their consumption, which could impact their water bills positively. When the 40:60 ratio is reversed, the price signal sent to the consumer is

much weaker than having more of the revenues built into the commodity charges. The consumer has no control whatsoever over the monthly minimum charge and any change in the customers' behavior to conserve will not impact the monthly minimum charge. On the other hand when more revenue is built into the commodity charge, consumers can actively participate more towards the goal of water conservation and have a direct impact on both their water consumption and the amount of commodity charges billed each month.

Q. What is GWC's current ratio of monthly minimum to commodity charges in its present rate structure?

A. The three meter sizes (5/8 x ¾", ¾ " and 1") in the residential classification have 62 percent in the monthly minimum and 38 percent in the commodity charges, which is the opposite of what it should be to send the proper price signal to encourage conservation.

Q. What ratio did RUCO use between the monthly minimum to commodity charges in its recommended rate design for GWC?

A. RUCO's rate design has a ratio of 55.2 percent in the monthly minimum and 44.8 percent in commodity charges for the total amount of revenues for of all customer classifications, which includes residential, commercial, and construction/standpipe.

Q. Did the Company propose moving more revenue to the commodity charges and less revenue in the monthly minimum charges in its proposed rates?

A. Yes. The Company's proposed rate design structure is quite similar to RUCO's. The Company also proposed an approximate 55:45 ratio between the monthly minimum and commodity charges respectively.

Q. Isn't a 55:45 ratio between the monthly minimum and commodity charges still short of RUCO's 40:60 ratio goal?

A. Yes. In designing rates, we do not want to drastically and suddenly change the structure of the rate design in one swoop. It is better to gradually move the Company and customers toward the ratio of 40:60. This is referred to as the principle of gradualism. When the Company files its next Application, RUCO will recommend a further advancement towards the 40:60 goal.

Q. What is the impact of RUCO's recommended rates on an average bill for a 5/8 x ¾ inch and ¾ inch metered residential customer?

A. I will provide the impact of RUCO's recommended rates on an average bill for a 5/8 x ¾ inch and a ¾ inch metered residential customer. The 5/8 x ¾ inch metered customer represents 85.7 percent of the Company's total customers. The present monthly bill for a 5/8 x ¾ inch residential customer using an average of 5,477 gallons is $66.73. RUCO's

recommended monthly bill for a 5/8 x ¾ inch residential customer using an average of 5,477 gallons is $66.57, a decrease of $0.16 or two-tenths of one percent less than the present rates.

The present monthly bill for a ¾ inch residential customer using an average 6,449 gallons is $93.57. RUCO's recommended monthly bill for a ¾ inch residential customer using an average of 6449 gallons is $92.43, a decrease of $1.14 or 1.2 percent less than the present rates.

The customer classifications' average and median rates are shown on respective Schedules TJC RD-5 for the residential and commercial classifications. The same information is provided for the construction/standpipe customer classification on Schedule TJC RD-3.

Q. I thought RUCO testified that it recommended neither a rate increase nor a rate decrease for GWC. Why are some customers receiving rate decreases as shown above?

A. The reason why some residential customers are receiving small rate decreases is due to RUCO's rate design structure that moves more revenues into the commodity charges and less in the monthly minimum charge. However, as soon as a customer exceeds the average gallon consumption point, the customer will see an increase in their bill under RUCO's recommended rate design over the Company's present rate

design because RUCO's commodity rates are higher than the Company's present commodity rates. Thus, a customer is awarded in lower monthly bills if he/she practices conservation whenever more revenues are moved to the commodity charges versus the monthly minimum charge. But again, once the customer exceeds the average consumption point, the reverse is true.

Q. Does RUCO's silence on any issue grant its acceptance?

A. No.

Q. Does this conclude your testimony on AWC?

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

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

GOLDER RANCH FIRE DISTRICT

Community Risk Prevention Division

Helping to make our community a better, safer place to live!

September 2003

Jim Morrison, Vice President Construction
D.R. Horton Homes
5255 E. Williams Circle
Suite 1030
Tucson, Arizona 85711

RE: Fire Code Review of Eagle Crest Ranch Development

Dear Mr. Morrison,

There have been recent discussions regarding some Fire Code deficiencies within the Eagle Crest Ranch Development. It is my intention to strive for fire code compliance and continue the good relations between Golder Ranch Fire District and D.R. Horton Homes. The two main issues at hand are as follows; fire flow requirements in relation to dwelling unit square footage, insufficient emergency secondary access. On the final plat for phase 2, I have also identified a concern regarding access for two separate cul-de-sacs with over 25 dwelling units each.

I. **Fire Flow**

A. **UFC Appendix III-A / IFC Appendix B – Section 5.1 One- and Two-Family Dwellings** - The minimum fire flow and flow duration requirements for one- and two-family dwellings having a fire area which does not exceed 3,600 square feet shall be 1,000 gallons per minute. Fire flow and flow duration for dwellings having a fire area in excess of 3,600 square feet shall not be less than that specified in UFC Table A-III-A-1. **Exception** – A reduction of 50 percent, as approved, is allowed when the building is provided with an approved automatic sprinkler system.

B. **UFC Appendix III-A – Section 4 Fire Area** - Defined as the total floor area of all floor levels within the exterior walls, and under horizontal projections of a roof of a building except as modified in Section 4. **Area Separation** – Portions of a building which are separated by one or more four-hour area separation walls constructed in accordance with the Building Code, without openings and provided with a 30-inch parapet, are allowed to be considered as separate fire areas.

C. **Horizontal Projections of a Roof** – GRFD interpretation and clarification with the latest editions of the fire code - Covered patios and porches that are not open on two or more sides are also considered as Fire Area for defining fire flow requirements.

D. **Garages** – Garages are included as Fire Area for defining fire flow requirements.

E. **Fire Area Exceeding 3,600 Square Feet** – The next step in Table A-III-A-1 is 1,750 gallons per minute for buildings not exceeding 4,800 square feet.

F. **Water Development Plans** – The approved Water Development Plans were approved for 1,000 gpm fire flow and have notation that dwelling units exceeding 3,600 square feet in fire area shall have an automatic fire sprinkler system installed.

G. **Situation** – The "*Kopopelli*" model consists of 3,682 square feet plus a 652 square foot garage and covered porches/patios open on two or more sides for a total of 4,334 square feet fire area. The "*Windsong*" model consists of 2,998 square feet plus a 676 square foot garage and covered porches/patios open on two or more sides for a total of 3,674 square feet fire area. Both of these models exceed 3,600 square feet and are required to have an automatic sprinkler system installed. D.R. Horton Homes has constructed and completed five (5) dwelling units that exceed 3,600 square feet in fire area, lots 147, 157, 162, 166, and 191. An automatic fire sprinkler system has not been installed in these dwelling units. A sixth dwelling unit exceeding 3,600 square feet is currently under construction, lot 193. An approved automatic sprinkler system has been installed for lot 193. Future lots might be sold and built upon with dwelling units exceeding 3,600 square feet.

H. **Proposed Solution** – Jim Morrison, D.R. Horton Homes, has expressed the desire of D.R. Horton Homes to not have to install automatic sprinkler systems in the homes exceeding 3,600 square feet and has proposed to increase the available fire flow to 1,500 gallons per minute. Westland Resources has modeled the existing water system and submitted documentation that the system could handle an increase of 500 gpm.

I. Dwelling units exceeding 3,600 square feet but not exceeding 4,800 square feet would require 1,750 gpm by Table A-III-A-1. Chief Fink and Fire Marshal Schoon have reviewed the situation, and due to an overall 500 gpm improvement for the entire development, agreed to allow the dwelling units to be constructed up to 4,800 in fire area, if 1,500 gpm is available.

II. Secondary Access

A. **UFC 1998 Supplement / IFC Appendix D**– Planned Area Developments where the number of dwelling units exceeds 25 shall be provided with separate and approved fire apparatus access roads. Exception – Where all dwelling units are protected by approved automatic sprinkler systems, access from two directions shall not be required. **Section 503.1.2 Additional access.** The code official is authorized to require more than one fire apparatus access road based on the potential for impairment of a single road by vehicle congestion, condition of terrain, climatic conditions, or other factors that could limit access.

B. **Situation** - The Development Plan was shown with two main access points; these being from Oracle Road onto Eagle Crest Boulevard, and from SaddleBrooke Boulevard onto Eagle Crest Boulevard. The SaddleBrooke Boulevard access point would not be installed until such time that the commercial properties on the Northwest corner of the development were started. The development has more than 500 dwelling units planned. The majority of dwelling units were further identified to be accessible from a single main roadway, Eagle Heights Drive. The developer agreed to install a secondary access point adjacent to lot 148 that leads to Edwin Road and it would be gated to allow for emergency use only. Any locking mechanism shall be approved by GRFD and adhere to the standard for approved key boxes of locking mechanisms. The required unobstructed width of fire apparatus access roads is 20 feet. The standard for emergency fire apparatus roads is 14 feet.

C. **Problem** – The secondary access has been completed. The gate is currently not locked. The gate is obstructed by a three foot high dirt and rock barrier placed between Edwin Road and the gate. The gate width is 14 feet; however, the access consistently narrows down to 9 feet wide as it meets with the development roadway adjacent to lot 148. This secondary access is unusable and does not meet the standard.

D. **Solution** – Correct the width deficiency, remove the dirt and rock barrier, and install a Knox Lock. A Knox Lock Form will be provided.

III. Long, Dead-End Roads with Single Point of Access

A. **UFC 1998 Supplement / IFC Appendix D** – Developments of one- or two family dwellings where the number of dwelling units exceeds 30 shall be provided with a minimum of two separate and approved fire apparatus access roads. **Exception:** Where all dwelling units are protected by approved residential sprinkler systems, access from two directions may not be required. **Section 503.1.2 Additional Access.** The code official is authorized to require more than one fire apparatus access road based on the potential for impairment of a single road by vehicle congestion, condition of terrain, climatic conditions, or other factors that could limit access.

B. **Situation** – The latest Final Plat GRFD has reviewed shows two long dead-end cul-de-sacs with a single point of access for each one. One of these roadways, Diamond Bay Drive, serves 104 lots and the other, Mountain Shadow Drive, serves 45 lots.

C. **Solution** - A second means of access shall be provided for each area or all dwelling units on these two points of access shall be constructed with an approved automatic sprinkler system.

RUCO EXHIBIT 2

ORIGINAL

MEMORANDUM

RECEIVED

2010 SEP -2 P 2: 22

AZ CORP COMMISSION
DOCKET CONTROL

Arizona Corporation Commission
DOCKETED
SEP 2 2010

DOCKETED BY	

TO: Docket Control Center

FROM: Steven M. Olea
Director
Utilities Division

DATE: September 2, 2010

RE: COMPLIANCE ITEM FOR DECISION NO. 69404 - IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY FOR A RATE INCREASE (DOCKET NO. W-02500A-06-0281)

Introduction

On April 16, 2007, the Commission granted Goodman Water Company ("Company") a rate increase per Decision No. 69404. The Decision ordered:

> *"...Goodman Water Company shall file a hook-up fee tariff with Docket Control, as a compliance item in this Docket, for Staff's review by July 31, 2007."*

Decision No. 69404, Findings of Fact No. 68, stated that in the rate proceeding no party recommended the hook-up fee matter and that the concept of the hook-up fee should be explored and the Company be directed to file a proposed hook-up fee tariff for Staff review.

Company's Filing

On July 31, 2007, the Company filed a hook-up fee ("HUF") tariff under a new docket number, W-02500A-07-0452. This new docket number was issued in error and was administratively closed and the HUF tariff filing was placed in W-02500A-06-0281 as a compliance matter.

In its filing, the Company proposed capital expenditure totaling $940,000 for a new Well #3 and related equipment, including engineering and contingency. The Company further proposed that the proportion of construction costs to be funded by the HUF tariff is 40 percent. As a result, the Company proposed a HUF starting at $500 for a 5/8 x 3/4-inch meter and graduated for larger meter sizes.

Staff's Review

According to the Company's Annual Report, the Company's water system consists of two wells (totaling 1,240 GPM), two storage tanks (totaling 930,000 gallons) and a distribution

system serving 597 customers as of December 2007. Based on these plant capacities, this system can currently serve approximately 1,800 customers.

In its filing, the Company proposed capital expenditure totaling $940,000 for a new Well #3 and related equipment, including engineering and contingency. Through data requests to the Company, Staff discovered that the capital plant and expenditure was not for a new Well #3, but actually for a Water Plant No. 3 site consisting of a 340,000 gallon storage tank and a booster system that will serve only a portion of the water system. Based on this finding, Staff has determined that the proposed Water Plant No. 3 would not meet the HUF tariff requirements because this water plant site would not benefit the entire water system. As a result, Staff concludes that this Company is not a good candidate for a HUF Tariff.

Staff's Recommendation

Staff recommends that the Commission not authorize a HUF tariff for this Company because the proposed water facilities related to the requested HUF Tariff will not benefit the entire water system. In addition, Staff concludes that the water system has sufficient capacity to meet the customer growth through 2019.

SMO:MSJ:lhm

Originator: Marlin Scott, Jr.

Service List for: Goodman Water Company
Docket No. W-02500A-06-0281

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RUCO EXHIBIT 3

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman

WILLIAM A. MUNDELL
Commissioner

JEFF HATCH-MILLER
Commissioner

KRISTIN K. MAYES
Commissioner

GARY PIERCE
Commissioner

Arizona Corporation Commission
DOCKETED
JUL 31 2007
DOCKETED BY

RECEIVED
2007 JUL 31 P 3: 47
AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY FOR REVIEW AND APPROVAL OF PROPOSED HOOK-UP FEE TARIFF

DOCKET NO.W-02500A-07-0281

APPLICATION

In compliance with Decision No. 69404, dated April 16, 2007, Goodman Water Company ("Goodman") submits for Staff's review this proposed Hook-Up Fee Tariff. The proposed Hook-Up Fee Tariff and related hook-up fees would be applicable to new customer connections to Goodman's system. The capital expenditures related to the proposed hook-up fees pertain to Goodman's construction requirements for the 2008-2011 time period. The anticipated new customer growth during this period is 724 new customer connections. The off-site facilities in question include a well #3 and related equipment and engineering. The proportion of anticipated construction costs proposed to be funded by the proposed hook-up fees is 40%.

Attached to this Application as Exhibit "A" is a schedule setting forth the assumptions and estimated future capital expenditures upon which the proposed hook-up fees are based. Exhibit

"A" also sets forth by meter size the amount of proposed hook-up fee applicable to each meter size, as well as the or percentage of anticipated new growth each meter size represents. Attached to this Application as Exhibit "B" is a copy of a proposed Hook-Up Fee Tariff.

Goodman Water Company requests that the Commission review the proposed Hook-Up Fee Tariff and hook-up fees which are the subject of this Application and issue an order approving the tariff and related hook-up fees.

RESPECTFULLY SUBMITTED this 31st day of July, 2007.

By: _____

Michael McNulty
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Lewis and Roca LLP
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Phone: (520) 629-4453
Fax: (520) 879-4732

Attorneys for Goodman Water Company

ORIGINAL and thirteen (13) copies of the foregoing filed this 31st day of July, 2007, with:

Arizona Corporation Commission
Docket Control – Utilities Division
1200 W. Washington Street
Phoenix, Arizona 85007

COPY of the foregoing hand-delivered
this 31st day of July, 2007, to:

Jane L. Rodda, Administrative Law Judge
Hearing Division
Arizona Corporation Commission
1200 W. Washington Street
Phoenix, Arizona 85007

Christopher C. Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 W. Washington Street
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Ernest G. Johnson, Director
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1200 W. Washington Street
Phoenix, Arizona 85007

Jayne Williams

EXHIBIT A

Goodman Water Company
Computation of Off-Site Facilities Hook-up Fee (HUF)

Exhibit A

Line No.							
1							
2	Off-Site Capital Expenditure Requirements 2008-2011						
3	Well # 3 and related equipment including engineering and contingency					$	940,000
4							
5							
6							
7	Total [1]					$	940,000
8							
9	Anticipated Customer Growth[1]	724					
10							
11	Computation of Equivalent 5/8 Inch Meters						
12							
13		Portion of	Projected	Meter Flow	Equivalent		
14	Meter Size	Anticipated Growth	Growth	Factor	5/8 Inch Meters		
15	5/8 Inch	98.90%	716	1.0	716		
16	3/4 Inch	0.00%		1.5	-		
17	1 Inch	0.55%	4	2.5	10		
18	1 1/2 Inch	0.00%		5.0	-		
19	2 Inch	0.55%	4	8.0	32		
20	3 inch	0.00%		16.0	-		
21	4 Inch	0.00%		25.0	-		
22	6 Inch	0.00%		30.0	-		
23		100.00%	724		758		
24	Total Equivalent 5/8 Inch Meters [2]						758
25							
26	Construction Costs Expected to be Funded by HUF (Percent times [1] equals [3])				40%	$	376,000
27							
28	HUF for Equivalent 5/8 Inch Metered Customer (rounded down) ([3] divided by [2] equals [4])					$	500
29							
30	Proposed Off-site Facilities Hook-up Fees by Meter Size						
31							
32	Meter Size						
33	5/8 Inch	$	500	[4]			
34	3/4 Inch	$	750	Scaled on 5/8 meter flow			
35	1 Inch	$	1,250	Scaled on 5/8 meter flow			
36	1 1/2 Inch	$	2,500	Scaled on 5/8 meter flow			
37	2 Inch	$	4,000	Scaled on 5/8 meter flow			
38	3 inch	$	8,000	Scaled on 5/8 meter flow			
39	4 Inch	$	12,500	Scaled on 5/8 meter flow			
40	6 Inch	$	15,000	Scaled on 5/8 meter flow			
41							
42	[1] Buildout of current certificated area is 958 customers. There are currently 500 customers. Expected addtions for 70 acres of commericial property						
43	within the existing CC&N is 258 - 5/8 inch metered customers, 4 - 1 inch metered customers, and 4 - 2 inch metered customers.						

EXHIBIT B

TARIFF SCHEDULE

Utility: Goodman Water Company
Docket No.: W-02500A-07
Phone No.: _____

Tariff Sheet No.: Page 1 of 3
Decision No.: _____
Effective: _____

OFF-SITE WATER FACILITIES HOOK-UP FEE

I. Purpose and Applicability

The purpose of the Off-Site Hook-Up Fees payable to Goodman Water Company ("Company") pursuant to this tariff is to equitably apportion the costs of constructing additional facilities to provide water production, storage and appropriate pressure among all new Service Connections.

These fees are applicable to all new Service Connections established after the effective date of this tariff. The fees are one-time charges and are payable as a condition to the Company's establishment of service, as more particularly provided below.

II. Definitions

Unless the context otherwise requires, the definitions set forth in R14-2-401 of the Arizona Corporation Commission's ("Commission") rules and regulations governing water utilities shall apply in interpreting this tariff schedule.

"Applicant" means any party entering into an agreement with Company for the installation of water facilities to serve new service connections.

"Company" means Goodman Water Company.

"Main Extension Agreement" means any agreement in which an Applicant agrees to advance the costs of the installation of water facilities to the Company to serve new service connections, or install water facilities to serve new service connections and transfer ownership of such water facilities to the Company, which agreement shall require the approval of the Commission (same as line extension agreement).

"Off-Site Facilities" means wells, storage tanks and related appurtenances necessary for proper water system operation, including engineering and design costs. Off-Site Facilities may also include booster pumps, pressure tanks, transmission mains and related appurtenances necessary for proper water system operation, if these facilities are not for the exclusive use of an Applicant and these facilities will benefit the entire water system.

"Service Connection" means and includes all service connections for single-family residential, commercial, industrial, or other uses, regardless of meter size.

TARIFF SCHEDULE

Utility: Goodman Water Company
Docket No.: W-02500A-07
Phone No.: _____

Tariff Sheet No.: Page 2 of 3
Decision No.: _____
Effective: _____

III. Off-Site Hook-Up Charges

Each new Service Connection shall pay the total off-site facilities hookup fee, derived from the following table:

OFF-SITE FACILITIES HOOKUP FEE TABLE	
Meter Size	**Total Fee**
5/8"	$500
¾"	$750
1"	$1250
1½"	$2500
2"	$4000
3"	$8000
4"	$12,500
6" or larger	$15,000

IV. Terms and Conditions

(A) Assessment of One Time Hook-Up Charge: The hook-up fee may be assessed only once per Service Connection, or lot within a platted subdivision (similar to meter and service line installation charges). However, this provision does not exempt from the hook-up fee, any newly created parcel(s) which are the result of further subdivision of a lot or land parcel and which do not have a Service Connection.

(B) Use of Off-Site Hook-Up Fee: Hook-Up Fees may only be used to pay for the capital items of Off-Site Facilities or for repayment of loans obtained for installation of Off-Site Facilities. Off-Site Hook-Up Fees shall not be used for repairs, maintenance, plant replacements, or operational purposes.

(C) Time of Payment:

(1) In the event that an Applicant is required to enter into a Main Extension Agreement, whereby the Applicant agrees to advance the costs of installing mains, valves, fittings, hydrants and other on-site improvements in order to extend service in accordance with R-14-2-406(B), payment of the fee(s) required hereunder shall be made by the Applicant within 15 calendar days after receipt of notification from the Company that the Utilities Division of the Commission has approved the Main Extension Agreement in accordance with R14-2-406(M).

(2) In the event that an Applicant is not required to enter into a Main Extension Agreement, the fee(s) hereunder shall be due and payable at the time the meter and service line installation fee is due and payable.

(D) Failure to Pay Charges; Delinquent Payments: Under no circumstances will the Company set a meter or otherwise allow service to be established if the Applicant has not paid in full all charges as provided by this Off-Site Hook-Up Fee Tariff.

(E) Off-Site Hook-Up Fee Non-refundable: The amounts collected by the Company pursuant to the Off-Site Hook-Up Fee Tariff shall be non-refundable contributions in aid of construction.

(F) Use of Charges Received: All funds collected by the Company as off-site hook-up fees, shall be deposited into a separate interest bearing trust account and used solely for the purposes of paying for the costs of Off-Site Facilities, including repayment of loans obtained for the installation of Off-Site Facilities that will benefit the entire water system.

(G) Off-Site Hook-Up Fees In Addition to Other Charges: The Off-Site Hook-Up Fees shall be in addition to any costs associated with a Main Extension Agreement for on-site facilities, and are in addition to the amounts to be advanced pursuant to charges authorized under other sections of this tariff.

(H) Disposition of Excess Funds: After all necessary and desirable Off-Site Facilities are constructed utilizing funds collected pursuant to the Off-Site Hook-Up Fee Tariff or the Off-Site Hook-Up Fee Tariff has been terminated by order of the Commission, any funds remaining in the trust shall be refunded. The manner of the refund shall be determined by the Commission at the time a refund becomes necessary.

(I) Fire Flow Requirements: In the event an Applicant for service has fire flow requirements that require the construction or installation of additional facilities whose costs are beyond the scope of those facilities costs provided for in the Company's current fees and charges, the Company may require the Applicant to install (as a non-refundable contribution) such additional facilities as are required to meet those fire flow requirements, in addition to the Off-Site Hook-Up Fee.

RUCO EXHIBIT 4

Appendix "A"

Planning Demand Criteria

Platted EDU's = 959

Residential person per housing unit (pphu) = 2.8

Demand per person = 125 gallons per capita per day (gpcd)

Planned Commercial = 83 Acres

Demand per Acre = 1,400 gallons per acre per day (gpad)

Commercial EDU's = 83 Acres x 1,400 gpad = 116,200 gallons / 125 gpcd / 2.8 pphu = 332 EDU's

Total EDU's at Buildout = 959 + 332 = 1,291

Storage Capacity Criteria (from master plan), ADD + fire flow plus 15%

Fire Flow = 2,000 gpm for 2 hours = 240,000 gallons

Well Capacity Criteria PDD

Booster Capacity = PDD + FF

Water Plant No. 1

Total Storage = 400,000 gallons

Fire Flow = 1,000 gpm for 2 hours (residential only) = 120,000 gallons

Available Storage = 280,000 gallons, 800 edus

Well No. 1 = 500 gpm, 1029 edu's

J- Zone Booster Station = 2,000 gpm

Well No. 2

800 gpm, 1646 edu's

Water Plant No. 3

Total Storage = 530,000 gallons

Storage Over size for future development = 190,000 gallons

Fire flow = 1,000 gpm for 2 hours = 120,000 gallons

Available Capacity = 220,000 gallons, 629 edu's

K- Zone Booster Capacity = 1,200 gpm

Water Plant No. 4

K-Zone Booster Station = 1,100 gpm

RUCO EXHIBIT 5

Goodman Water Company
Utility Plant Per Customer

Line No.	Acct. No.	Description	2002 Original Cost	2002 Per Customer Cost Per Average Year Customer Count	2002 Per Customer Cost Per Year End Customer Count	2003 Original Cost	2003 Per Customer Cost Per Average Year Customer Count	2003 Per Customer Cost Per Year End Customer Count	2004 Original Cost	2004 Per Customer Cost Per Average Year Customer Count	2004 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
2	302	Franchises	-	-	-	-	-	-	-	-	
3	303	Land & Land Rights	-	-	-	-	-	-	-	-	
4	304	Structures and Improvements	-	-	-	-	-	-	1,343	5	4
5	307	Wells and Springs	-	-	-	233,767	1,527	1,157	233,767	786	632
6	311	Pumping Equipment	-	-	-	542,915	3,547	2,688	582,420	1,959	1,574
7	320	Water Treatment Equipment	-	-	-	-	-	-	2,161	7	6
8	330	Distribution Reservoirs & Standpipes	-	-	-	251,477	1,643	1,245	251,476	846	680
9	331	Transmission and Distribution Mains	-	-	-	402,268	2,628	1,991	675,939	2,274	1,827
10	333	Services	94,596	4,487	1,332	160,177	1,046	793	212,697	716	575
11	334	Meter and Meter Installations	7,757	368	109	23,735	155	118	40,660	137	110
12	335	Hydrants	-	-	-	24,975	163	124	43,565	147	118
13	336	Backflow Prevention Devices	-	-	-	-	-	-	-	-	
14	339	Other Plant and Misc. Equipment	-	-	-	-	-	-	-	-	
15	340	Office Furniture and Equipment	-	-	-	-	-	-	-	-	
16	341	Transportation Equipment	-	-	-	-	-	-	-	-	
17	343	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	
18	344	Laboratory Equipment	-	-	-	-	-	-	-	-	
19	345	Power Operated Equipment	-	-	-	-	-	-	-	-	
20	346	Communication Equipment	-	-	-	-	-	-	-	-	
21	347	Miscellaneous Equipment	-	-	-	-	-	-	-	-	
22	348	Other Tangible Plant	-	-	-	-	-	-	-	-	
23		**Totals**	$ 102,353	$ 4,855	$ 1,442	$ 1,639,314	$ 10,709	$ 8,115	$ 2,044,028	$ 6,876	$ 5,524
24		Average and Year End Number of Customers		21	71		153	202		297	370
25		$ Increase for Average and Year End Number of Customers from Previous Yr.					5,854	6,674		(3,832)	(2,591)
26		% Increase for Average and Year End Number of Customers from Previous Yr.					121%	463%		-36%	-32%
27		Increase in Number of Test Year End Customers thru 2010									

Goodman Water Company
Utility Plant Per Customer

Line No.	Acct. No.	Description	2005 Original Cost	2005 Per Customer Cost Per Average Year Customer Count	2005 Per Customer Cost Per Year End Customer Count	2006 Original Cost	2006 Per Customer Cost Per Average Year Customer Count	2006 Per Customer Cost Per Year End Customer Count	2007 Original Cost	2007 Per Customer Cost Per Average Year Customer Count	2007 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchises	106,028	236	221	110,947	230	229	117,487	214	203
3	303	Land & Land Rights	-	-	-	-	-	-	-	-	-
4	304	Structures and Improvements	11,064	25	23	11,064	23	23	11,064	20	19
5	307	Wells and Springs	386,591	862	807	386,591	802	799	386,591	704	668
6	311	Pumping Equipment	686,993	1,532	1,434	686,993	1,426	1,419	689,956	1,256	1,192
7	320	Water Treatment Equipment	11,053	25	23	11,319	23	23	15,947	29	28
8	330	Distribution Reservoirs & Standpipes	294,459	657	615	294,459	611	608	365,809	668	634
9	331	Transmission and Distribution Mains	734,126	1,637	1,533	734,145	1,524	1,517	1,419,239	2,584	2,451
10	333	Services	146,541	327	306	146,543	304	303	289,895	528	501
11	334	Meter and Meter Installations	57,012	127	119	57,282	119	118	75,641	138	131
12	335	Hydrants	83,174	186	174	83,180	173	172	126,384	230	218
13	336	Backflow Prevention Devices	-	-	-	-	-	-	-	-	-
14	339	Other Plant and Misc. Equipment	152,473	340	318	165,718	344	342	166,477	303	288
15	340	Office Furniture and Equipment	-	-		-	-		-	-	
16	341	Transportation Equipment	-	-		-	-		-	-	
17	343	Tools, Shop and Garage Equipment	-	-		-	-		-	-	
18	344	Laboratory Equipment	-	-		-	-		-	-	
19	345	Power Operated Equipment	-	-		-	-		-	-	
20	346	Communication Equipment	-	-		-	-		-	-	
21	347	Miscellaneous Equipment	-	-		-	-		-	-	
22	348	Other Tangible Plant	-	-		-	-		-	-	
23		**Totals**	$ 2,669,514	$ 5,954	$ 5,573	$ 2,688,241	$ 5,579	$ 5,554	$ 3,665,490	$ 6,674	$ 6,331
24		Average and Year End Number of Customers		448	479		482	484		549	579
25		$ Increase for Average and Year End Number of Customers from Previous Yr.		(922)	49		(375)	(19)		1,094	777
26		% Increase for Average and Year End Number of Customers from Previous Yr.		-13%	1%		-6%	0%		20%	14%
27		Increase in Number of Test Year End Customers thru 2010									

Goodman Water Company
Utility Plant Per Customer

Line No.	Acct. No.	Description	2008 Original Cost	2008 Per Customer Cost Per Average Year Customer Count	2008 Per Customer Cost Per Year End Customer Count	2009 Original Cost	2009 Per Customer Cost Per Average Year Customer Count	2009 Per Customer Cost Per Year End Customer Count	2009 Original Cost	2010 Per Customer Cost Per Average Year Customer Count	2010 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$	$ -	$ -	$	$ -	$ -	$ -
2	302	Franchises	127,103	210	208	127,103	204	204	127,103	204	204
3	303	Land & Land Rights	494,159	817	807	494,159	791	793	494,159	791	793
4	304	Structures and Improvements	182,570	302	298	182,570	292	293	182,570	292	293
5	307	Wells and Springs	386,591	639	632	386,591	619	621	386,591	619	621
6	311	Pumping Equipment	965,499	1,595	1,578	968,654	1,551	1,555	968,654	1,551	1,555
7	320	Water Treatment Equipment	15,947	26	26	15,947	26	26	15,947	26	26
8	330	Distribution Reservoirs & Standpipes	836,894	1,383	1,367	836,891	1,340	1,343	836,891	1,340	1,343
9	331	Transmission and Distribution Mains	1,593,998	2,634	2,605	1,593,998	2,552	2,559	1,593,998	2,552	2,559
10	333	Services	386,946	639	632	386,946	620	621	386,946	620	621
11	334	Meter and Meter Installations	84,939	140	139	90,087	144	145	90,087	144	145
12	335	Hydrants	161,737	267	264	161,737	259	260	161,737	259	260
13	336	Backflow Prevention Devices	-	-		-	-		-	-	
14	339	Other Plant and Misc. Equipment	166,477	275	272	187,582	300	301	187,582	300	301
15	340	Office Furniture and Equipment	-	-		-	-		-	-	
16	341	Transportation Equipment	-	-		-	-		-	-	
17	343	Tools, Shop and Garage Equipment	-	-		-	-		-	-	
18	344	Laboratory Equipment	-	-		-	-		-	-	
19	345	Power Operated Equipment	-	-		-	-		-	-	
20	346	Communication Equipment	-	-		-	-		-	-	
21	347	Miscellaneous Equipment	-	-		-	-		-	-	
22	348	Other Tangible Plant	-	-		-	-		-	-	
23		Totals	$ 5,402,860	$ 8,928	$ 8,828	$ 5,432,265	$ 8,697	$ 8,720	$ 5,432,265	$ 8,697	$ 8,720
24		Average and Year End Number of Customers		605	612		625	623		649	666
25		$ Increase for Average and Year End Number of Customers from Previous Yr.		2,254	2,497		(230)	(109)		-	-
26		% Increase for Average and Year End Number of Customers from Previous Yr.		34%	39%		-3%	-1%		0%	0%
27		Increase in Number of Test Year End Customers thru 2010									6.90%

RUCO EXHIBIT 6

THE FREEZE & WATER DELIVERY TO THE CUSTOMERS OF GOODMAN WATER COMPANY

If you have been in town, it will come as no surprise we at Eagle Crest Ranch have experienced record or near record low temperatures over several nights. The "hard" freezes with lows in the mid and upper teens and high winds have caused significant damage to two of four Company's water plants.

In spite of the extensive damage, Goodman Water continued to deliver water to our customers without interruption. It was only because of the storage capacity provided by our recently completed reservoir in the northeast corner of Eagle Crest that Goodman Water experienced no system-wide interruption in water delivery. This situation is one example of why the regulatory agencies and sound engineering in system design required that reservoir.

A second key factor in allowing Goodman Water to continue in operation was the prompt response by Smyth Management Services. When our electronic monitoring system first detected signs of trouble, Smyth immediately dispatched repair crews to Eagle Crest. These people worked through the night in the bitter cold to repair or work around damaged components and to manually operate valves normally electronically controlled.

With the sound design of our water system and prompt response of our operator, to the best of our knowledge, no customer went without water. We sincerely hope that the worst of the winter weather is over, but should it happen again we are ready to respond in the same responsible fashion.

Goodman Water Company
Docket No. W-02500A-10-0382
Test Year Ended December 31, 2009

Direct Schedules

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SCH. NO.	PAGE NO.	TITLE
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TJC-4	1 - 5	RATE BASE ADJUSTMENT NO. 1 - TEST YEAR END PLANT AND ACCUMULATED DEPRECIATION
TJC-5	1	RATE BASE ADJUSTMENT NO. 2 - EXCESS CAPACITY
TJC-6	1	RATE BASE ADJUSTMENT NO. 3 - ADVANCES IN AID OF CONSTRUCTION ("AIAC")
TJC-7	1 & 2	RATE BASE ADJUSTMENT NO. 4 - ACCUMULATED DEFERRED INCOME TAXES
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TJC-15	1	OPERATING INCOME ADJUSTMENT NO. 6 - CONTRACTUAL SERVICES / MEALS
TJC-16	1	OPERATING INCOME ADJUSTMENT NO. 7 - INCOME TAX EXPENSE
TJC-17	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 2,402,221	$ 1,729,190
2	Adjusted Operating Income (Loss)	73,883	160,650
3	Current Rate Of Return (L2 / L1)	3.08%	9.29%
4	Required Operating Income (L5 X L1)	$ 253,194	$ 135,754
5	Required Rate Of Return On Fair Value Rate Base	10.54%	7.85%
6	Operating Income Deficiency (L4 - L2)	$ 179,311	$ (24,896)
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6254	1.4460
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 291,454	$ (36,000)
9	Adjusted Test Year Revenue	572,751	580,110
10	Proposed Annual Revenue (L8 + L9)	864,205	544,110
11	Required Percentage Increase In Revenue (L8 / L9)	50.89%	-6.21%
12	Rate Of Return On Common Equity	11.00%	9.00%

References:
Column (A): Company Schedules A-1, B-1, and C-1
Column (B): RUCO Schedule TJC-1, page 2, TJC-2, TJC-8, and TJC-19

REVENUE REQUIREMENT - CONT'D
GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Combined Federal And State Tax Rate (L10)	0.3085			
3	Subtotal (L1 + L2)	0.6915			
4	**Revenue Conversion Factor** (L1 / L3)	**1.4460**			
	CALCULATION OF EFFECTIVE TAX RATE:				
5	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
6	Arizona State Income Tax Rate	6.9680%			
7	Federal Taxable Income (L5 - L6)	93.0320%			
8	Applicable Federal Income Tax Rate (Col. (D), L34)	25.6658%			
9	Effective Federal Income Tax Rate (L7 X L8)	23.8774%			
10	Combined Federal And State Income Tax Rate (L6 + L9)	30.8454%			
11	RUCO Required Operating Income (Sch. TJC-1, Col. (B), L4)	$ 135,754			
12	RUCO Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Col. (B), L2)	160,650			
13	Required Increase In Operating Income (L11 - L12)		$ (24,896)		
14	Income Taxes On Recommended Revenue (Col. (D), L31)	$ 41,649			
15	Income Taxes On Test Year Revenue (Col. (D), L32)	52,753			
16	Required Increase In Revenue To Provide For Income Taxes (L14 - L15)		(11,104)		
17	Total Required Increase In Revenue (L13 + L16)		$ (36,000)		
	RUCO's CALCULATION OF INCOME TAX			RUCO Recommended	
18	RUCO Proposed Revenue (Sch. TJC-1, Col. (B), L10)			$ 544,110	
	Less:				
19	Operating Expense Excluding Income Tax (TJC-8, Col. (E), L37 + L35)			366,707	
20	Synchronized Interest (Col. (C), L37)			42,378	
21	Arizona Taxable Income (L18 - L19 - L20)			$ 135,025	
22	Arizona State Income Tax Rate			6.9680%	
23	Arizona Income Tax (L21 X L22)				$ 9,409
24	Fed. Taxable Income (L21 - L23)			$ 125,617	
25	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
26	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			6,250	
27	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			8,500	
28	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%			9,991	
29	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%			-	
30	Total Federal Income Tax (L25 + L26 + L27 + L28 + L29)				$ 32,241
31	Combined Federal And State Income Tax (L23 + L30)				$ 41,649
32	RUCO Adj'd Test Year Combined Federal and State Income Tax (TJC-8, Col. (C), L22)				$ 52,753
33	RUCO Proposed Income Tax Adjustment (L31 - L32) (See TJC-8, Col. (D), L22)				$ (11,104)
34	Applicable Federal Income Tax Rate (Col. (D), L30 / Col. (C), L24)				25.67%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
35	Rate Base (Sch. TJC-1, Col. (B), L1)			$ 1,729,190	
36	Weighted Avg. Cost Of Debt (Sch. TJC-19, Col. (C), L1)			2.45%	
37	Synchronized Interest (L35 X L36)			$ 42,378	

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 5,453,761	$ (2,351,723)	$ 3,102,039
2	Accumulated Depreciation	(731,205)	312,033	(419,172)
3	Rounding	(1)	-	(1)
4	Net Utility Plant In Service (L1 + L2 + L3)	$ 4,722,556	$ (2,039,690)	$ 2,682,866
	Less:			
5	Advances In Aid Of Const.	$ (2,101,905)	$ 906,365	$ (1,195,540)
6	Contribution In Aid Of Const.	$ -	$ -	$ -
7	Accumulated Amortization Of CIAC	-	-	-
8	NET CIAC (L6 + L7)	$ -	$ -	$ -
9	Customer Meter Deposits	$ (83,087)	$ -	$ (83,087)
10	Customer Hydrant Meter Deposits	$ -	$ -	$ -
11	Accumulated Deferred Income Taxes	$ (135,342)	$ 460,294	$ 324,952
12	Unamortized Finance Charges	$ -	$ -	$ -
13	Deferred Regulatory Assets	$ -	$ -	$ -
14	Allowance For Working Capital	$ -	$ -	$ -
15	TOTAL RATE BASE (Sum L's 4, 5, 8, 9 Thru 14)	$ 2,402,221	$ (673,031)	$ 1,729,190

References:
Column (A): Company Schedule B-1, Page 1 And Workpapers Schedule E-1
Column (B): TJC-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

Goodman Water Company
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ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 TEST YR PLT & ACC DEP	(C) ADJ # 2 EXCESS CAPACITY	(D) ADJ # 3 AIAC	(E) ADJ # 4 DEFERRED INCOME TAX	(F) INTENT'NLY LEFT BLANK	(G) INTENT'NLY LEFT BLANK	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 5,453,761	$ -	$ (2,351,723)	$ -	$ -	$ -	$ -	$ 3,102,039
2	Accumulated Depreciation	(731,205)	(3,268)	315,301	-	-	-	-	(419,172)
3	Rounding	(1)							(1)
4	Net Utility Plant In Service (L1 + L2 + L3)	$ 4,722,556	$ (3,268)	$ (2,036,422)	$ -	$ -	$ -	$ -	$ 2,682,866
	Less:								
5	Advances In Aid Of Const.	$ (2,101,905)	$ -	$ -	$ 906,365	$ -	$ -	$ -	$ (1,195,540)
6	Contribution In Aid Of Const.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Accumulated Amortization Of CIAC	-	-	-	-	-	-	-	-
8	NET CIAC (L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Customer Meter Deposits	$ (83,087)	$ -	$ -	$ -	$ -	$ -	$ -	$ (83,087)
10	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Accumulated Deferred Income Taxes	$ (135,342)	$ -	$ -	$ -	$ 460,294	$ -	$ -	$ 324,952
12	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TOTAL RATE BASE (Sum L's 4, 5, 8, 9 Thru 14)	$ 2,402,221	$ (3,268)	$ (2,036,422)	$ 906,365	$ 460,294	$ -	$ -	$ 1,729,190

References:
- Column (A): Company Schedule B-1, Page 1 And Workpapers Schedule E-1
- Column (B): Adjustment No. 1 - RUCO Adjustment To Test-Year GPIS And Acc. Dep. (See Testimony and Schedule TJC-4(2009))
- Column (C): Adjustment No. 2 - RUCO Adjustment for Excess Capacity (See Testimony)
- Column (D): Adjustment No. 3 - RUCO Adjustment to AIAC for Excess Capacity (See Testimony)
- Column (E): Adjustment No. 4 - RUCO Adjustment To Deferred Income Taxes for Excess Capacity (See Testimony and Schedule TJC-7)
- Column (F): Intentionally Left Blank
- Column (G): Intentionally Left Blank
- Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F), & (G)

Goodman Water Company
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Test Year Ended December 31, 2009

TEST YEAR PLANT SCHEDULES
PRIOR TEST YEAR ENDED SEPTEMBER 30, 2005

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) PER PRIOR DECISION NO. 69404 GROSS PLANT	(D) PER PRIOR DECISION NO. 69404 ACCUMULATED DEPRECIATION	(E) OCT - DEC 2005 PLANT ADDITIONS	(F) OCT - DEC 2005 PLANT ADJUSTMENTS	(G) OCT - DEC 2005 PLANT RETIREMENTS	(H) 2005 GROSS PLANT	(I) OCT - DEC 2005 DEPRE. EXPENSE	(J) DECEMBER 31 2005 ACCUMULATED DEPRECIATION BALANCE	(K) DECEMBER 31 2005 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 104,528	$ -	$ 1,500	$ -	$ -	$ 106,028	$ -	$ -	$ 106,028
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-	-	
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-	-	-	
4	304	Structures and Improvements	2.50%	3.33%	9,788	(306)	1,276	-	-	11,064	65	(372)	10,692
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-	-	
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-	-	
7	307	Wells & Springs	2.50%	3.33%	386,591	(17,925)	-	-	-	386,591	2,416	(20,342)	366,249
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-	-	
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-	-	
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-	-	
11	311	Electric Pumping Equipmemt	2.50%	12.50%	686,993	(35,041)	-	-	-	686,993	4,294	(39,335)	647,657
12	320	Water Treatment Equipment	2.50%	3.33%	11,054	(345)	-	-	-	11,054	69	(415)	10,639
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-	-	
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-	-	
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	294,460	(15,489)	-	-	-	294,460	1,840	(17,329)	277,131
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-	-	
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-	-	
18	331	Trans. and Dist. Mains	2.50%	2.00%	628,673	(29,324)	122,779	-	-	751,452	4,313	(33,637)	717,815
19	333	Services	2.50%	3.33%	129,274	(5,679)	17,266	-	-	146,540	862	(6,541)	139,999
20	334	Meters	2.50%	8.33%	67,497	(2,310)	270	-	-	67,767	423	(2,733)	65,034
21	335	Hydrants	2.50%	2.00%	46,955	(2,090)	36,220	-	-	83,175	407	(2,497)	80,678
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-	-	
23	339	Othere Plant and Misc. Equip.	2.50%	6.67%	-	-	152,473	-	-	152,473	476	(476)	151,997
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-	-	
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-	-	
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-	-	
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-	-	
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-	-	
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-	-	
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-	-	
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-	-	
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-	-	
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-	-	
34		Rounding			-	-	-	-	-	-	-	-	
35		**RUCO TOTAL WATER PLANT**			$ 2,365,811	$ (108,511)	$ 331,783	$ -	$ -	$ 2,697,594	$ 15,165	$ (123,676)	$ 2,573,918
37		Per Company Work Papers			$ 2,365,813	$ (108,509)	$ 331,783	$ -	$ -	$ 2,697,594	$ 15,165	$ (123,674)	$ 2,573,920
38		RUCO Increase/Decrease to GUPIS & Accum. Depre.			$ (2)	$ (2)	$ -	$ -	$ -	$ -	$ 0	$ (2)	$ (2)

References:
- Columns (A), (B), (C), & (D): Per Decision No. 69404
- Columns (E), (F), & (G): Company B-2 Schedules and Plant Additions' Workpapers
- Column (H): Column (C) + Column (E), (F), & (G)
- Column (I): RUCO's Depreciation Expense Formula
- Column (J): Column (D) + Column (I)
- Column (K): Column (H) + Column (J)

Goodman Water Company
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TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2006

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2006 PLANT ADDITIONS	(D) 2006 PLANT ADJUSTMENTS	(E) 2006 PLANT RETIREMENTS	(F) 2006 GROSS PLANT	(G) 2006 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2006 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2006 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 4,920	$ -	$ -	$ 110,948	$ -	$ -	$ 110,948
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-	-
4	304	Structures and Improvements	2.50%	3.33%	-	-	-	11,064	277	(648)	10,415
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	9,665	(30,006)	356,584
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	-	-	-	686,993	17,175	(56,510)	630,482
12	320	Water Treatment Equipment	2.50%	3.33%	266	-	-	11,320	280	(694)	10,626
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	-	-	-	294,460	7,362	(24,691)	269,769
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	-	-	-	751,452	18,786	(52,423)	699,028
19	333	Services	2.50%	3.33%	3	-	-	146,543	3,664	(10,204)	136,338
20	334	Meters	2.50%	8.33%	270	-	-	68,037	1,698	(4,430)	63,607
21	335	Hydrants	2.50%	2.00%	5	-	-	83,180	2,079	(4,576)	78,604
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Othere Plant and Misc. Equip.	2.50%	6.67%	13,245	-	-	165,718	3,977	(4,454)	161,264
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	-	-	-	-	-	-
0					$ 18,709	$ -	$ -	$ 2,716,303	$ 64,962	$ (188,638)	$ 2,527,665
35	**RUCO TOTAL WATER PLANT**										
37	Per Company Work Papers				$ 18,709	$ -	$ -	$ 2,716,303	$ 64,962	$ (188,636)	$ 2,527,667
38	RUCO Increase/Decrease to GUPIS & Accum. Depre.				$ -	$ -	$ -	$ -	$ (0)	$ (2)	$ (2)

Goodman Water Company
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TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2007

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2007 PLANT ADDITIONS	(D) 2007 PLANT ADJUSTMENTS	(E) 2007 PLANT RETIREMENTS	(F) 2007 GROSS PLANT	(G) 2007 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2007 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2007 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 6,539	$ -	$ -	$ 117,487	$ -	$ -	$ 117,487
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-	-
4	304	Structures and Improvements	2.50%	3.33%	-	-	-	11,064	338	(986)	10,077
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	11,804	(41,810)	344,780
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	2,963	-	-	689,956	63,110	(119,620)	570,335
12	320	Water Treatment Equipment	2.50%	3.33%	4,628	-	-	15,948	416	(1,111)	14,837
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	72,350	-	-	366,810	7,649	(32,340)	334,470
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	685,094	-	-	1,436,546	23,703	(76,126)	1,360,419
19	333	Services	2.50%	3.33%	143,352	-	-	289,895	6,663	(16,867)	273,027
20	334	Meters	2.50%	8.33%	18,359	-	(6,580)	79,816	4,721	(2,572)	77,244
21	335	Hydrants	2.50%	2.00%	43,205	-	-	126,385	2,270	(6,846)	119,539
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Othere Plant and Misc. Equip.	2.50%	6.67%	759	-	-	166,477	8,770	(13,224)	153,253
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	-	-	-	-	-	-
0					$ 977,249	$ -	$ (6,580)	$ 3,686,972	$ 129,445	$ (311,502)	$ 3,375,470
35	**RUCO TOTAL WATER PLANT**				$ 977,249	$ -	$ (6,580)	$ 3,686,972	$ 126,179	$ (308,235)	$ 3,378,737
37	Per Company Work Papers				$ -	$ -	$ -	$ -	$ 3,266	$ (3,267)	$ (3,267)
38	RUCO Increase/Decrease to GUPIS & Accum. Depre.										

Goodman Water Company
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Test Year Ended December 31, 2009

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2008

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2008 PLANT ADDITIONS	(D) 2008 PLANT ADJUSTMENTS	(E) 2008 PLANT RETIREMENTS	(F) 2008 GROSS PLANT	(G) 2008 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2008 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2008 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 9,616	$ -	$ -	$ 127,103	$ -	$ -	$ 127,103
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	494,159	-	-	494,159	-	-	494,159
4	304	Structures and Improvements	2.50%	3.33%	171,506	-	-	182,570	3,224	(4,210)	178,359
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	12,873	(54,684)	331,907
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	275,541	-	-	965,497	103,466	(223,086)	742,411
12	320	Water Treatment Equipment	2.50%	3.33%	-	-	-	15,948	531	(1,642)	14,306
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	470,081	-	-	836,891	13,361	(45,701)	791,190
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	174,757	-	-	1,611,303	30,478	(106,605)	1,504,698
19	333	Services	2.50%	3.33%	97,051	-	-	386,946	11,269	(28,137)	358,809
20	334	Meters	2.50%	8.33%	9,299	-	-	89,115	7,036	(9,608)	79,507
21	335	Hydrants	2.50%	2.00%	35,352	-	-	161,737	2,881	(9,728)	152,009
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Othere Plant and Misc. Equip.	2.50%	6.67%	-	-	-	166,477	11,104	(24,328)	142,149
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	-	-	-	-	-	-
0											
35	**RUCO TOTAL WATER PLANT**				$ 1,737,362	$ -	$ -	$5,424,334	$ 196,224	$ (507,727)	$ 4,916,607
37	Per Company Work Papers				$ 1,737,362	$ -	$ -	$5,424,334	$ 196,224	$ (504,459)	$ 4,919,875
38	RUCO Increase/Decrease to GUPIS & Accum. Depre.				$ -	$ -	$ -	$ -	$ 0	$ (3,268)	$ (3,268)

Goodman Water Company
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TEST YEAR PLANT SCHEDULES - CONT'D
TEST YEAR ENDED DECEMBER 31, 2009

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2009 PLANT ADDITIONS	(D) 2009 PLANT ADJUSTMENTS	(E) 2009 PLANT RETIREMENTS	(F) 2009 GROSS PLANT	(G) 2009 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2009 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2009 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ -	$ -	$ -	$ 127,103	$ -	$ -	$ 127,103
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	494,159	-	-	494,159
4	304	Structures and Improvements	2.50%	3.33%	-	-	-	182,570	6,080	(10,290)	172,280
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	12,873	(67,557)	319,033
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	3,155	-	-	968,652	120,884	(343,970)	624,681
12	320	Water Treatment Equipment	2.50%	3.33%	-	-	-	15,948	531	(2,173)	13,775
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	-	-	-	836,891	18,579	(64,280)	772,611
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	18	-	-	1,611,321	32,226	(138,831)	1,472,489
19	333	Services	2.50%	3.33%	-	-	-	386,946	12,885	(41,022)	345,923
20	334	Meters	2.50%	8.33%	5,148	-	-	94,263	7,638	(17,245)	77,018
21	335	Hydrants	2.50%	2.00%	-	-	-	161,737	3,235	(12,962)	148,775
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Othere Plant and Misc. Equip.	2.50%	6.67%	21,105	-	-	187,582	11,808	(36,136)	151,446
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	1	-	1	-	-	-
0											
35		**RUCO TOTAL WATER PLANT**			$ 29,426	$ 1	$ -	$ 5,453,761	$ 226,739	$ (734,466)	$ 4,719,294
37		Per Company Work Papers			$ 29,426	$ -	$ -	$ 5,453,761	$ 226,739	$ (731,198)	$ 4,722,563
38		RUCO Increase/Decrease to GUPIS & Accum. Depre.			$ -	$ 1	$ -	$ -	$ 0	$ (3,268)	$ (3,269)

References:
- Columns (A) & (B): Per Decision No. 69404
- Columns (C), (D), & (E): Company B-2 Schedules and Plant Additions' Workpapers
- Column (F): Schedule TJC-4(2008), Column (F) + Column (C), (D), & (E)
- Column (G): RUCO's Depreciation Expense Formula
- Column (H): Schedule TJC-4(2008), Column (H) + Column (G)
- Column (I): Column (F) + Column (H)

Goodman Water Company
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RUCO's RATE BASE ADJUSTMENT NO. 2
WATER PLANT EXCESS CAPACITY ADJUSTMENT

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) COMPANY TOTAL PLANT BALANCE	(B) COMPANY ACCUM. DEPRE. BALANCE	(C) RUCO EXCESS CAPACITY FACTOR	(D) TOTAL WATER PLANT PER RUCO	(E) TOTAL ACCUM. DEPRE. PER RUCO
1	301	Organization Cost	$ 127,103	$ -	56.88%	$ 72,295	$ -
2	302	Franchise Cost	-	-	56.88%	-	-
3	303	Land and Land Rights	494,159	-	56.88%	281,072	-
4	304	Structures and Improvements	182,570	(10,285)	56.88%	103,844	(5,850)
5	305	Collecting and Impounding Res.	-	-	56.88%	-	-
6	306	Lakes, Rivers, and Other Intakes	-	-	56.88%	-	-
7	307	Wells & Springs	386,591	(67,423)	56.88%	219,889	(38,350)
8	308	Infiltration Galleries and Tunnels	-	-	56.88%	-	-
9	309	Supply Mains	-	-	56.88%	-	-
10	310	Power Generation Equipment	-	-	56.88%	-	-
11	311	Electric Pumping Equipmemt	968,652	(341,101)	56.88%	550,958	(194,014)
12	320	Water Treatment Equipment	15,947	(2,167)	56.88%	9,071	(1,233)
13	320.1	Water Treatment Plant	-	-	56.88%	-	-
14	320.2	Chemical Solution Feeders	-	-	56.88%	-	-
15	330	Dist. Reservoirs & Standpipe	836,890	(64,318)	56.88%	476,014	(36,583)
16	330.1	Storage Tanks	-	-	56.88%	-	-
17	330.2	Pressure Tanks	-	-	56.88%	-	-
18	331	Trans. and Dist. Mains	1,611,321	(139,059)	56.88%	916,501	(79,095)
19	333	Services	386,947	(40,947)	56.88%	220,091	(23,290)
20	334	Meters	94,263	(17,066)	56.88%	53,616	(9,707)
21	335	Hydrants	161,737	(12,984)	56.88%	91,994	(7,385)
22	336	Backflow Prevention Devices	-	-	56.88%	-	-
23	339	Othere Plant and Misc. Equip.	187,582	(35,847)	56.88%	106,695	(20,389)
24	340	Office Furniture and Fixtures	-	-	56.88%	-	-
25	340.1	Computers and Software	-	-	56.88%	-	-
26	341	Transportation Equipment	-	-	56.88%	-	-
27	342	Stores Equipment	-	-	56.88%	-	-
28	343	Tools and Work Equipment	-	-	56.88%	-	-
29	344	Laboratory Equipment	-	-	56.88%	-	-
30	345	Power Operated Equipment	-	-	56.88%	-	-
31	346	Communications Equipment	-	-	56.88%	-	-
32	347	Miscellaneous Equipment	-	-	56.88%	-	-
33	348	Other Tangible Plant	-	-	56.88%	-	-
34		Rounding	-			-	
35	**RUCO TOTAL WATER PLANT**		$ 5,453,761	$ (731,198)		$ 3,102,038	$ (415,897)

36	RUCO Excess Capacity Plant Adjustment	$ (2,351,723)
37	RUCO Excess Capacity Accumulated Depreciation Adjustment	$ 315,301

Note:

38	RUCO's Excess Capacity Factor	56.88%

References:
Column (A): Company B-2 Schedule and RUCO Schedule TJC-4(2009)
Column (B): Company B-2 Schedule
Column (C): RUCO's Excess Capacity Factor (L38) Above
Column(D): Column (A) x Column (N)
Column(E): Column (B) x Column (N)

RUCO's RATE BASE ADJUSTMENT NO. 3
EXCESS CAPACITY ADJUSTMENT TO ADVANCES IN AID OF CONSTRUCTION ("AIAC")

LINE NO.	DESCRIPTION	(A) AMOUNT
1	AIAC Balance Per Company	$ 2,101,905
	Less:	
2	RUCO's Excess Capacity Factor	56.88%
3	AIAC Balance Per RUCO	$ 1,195,540
4	RUCO's AIAC Adjustment	$ 906,365

RUCO's RATE BASE ADJUSTMENT NO. 4
ACCUMULATEDDEFERRED INCOME TAXES ("ADIT") FOR EXCESS CAPACITY

Line No.											
1	**Deferred Income Tax as of December 31, 2009**										
2				**Probability**	**Deductible TD**						
3				**of Realization**	**(Taxable TD)**						
4		**Adjusted**		**of Future**	**Expected to**	**Tax**	**Future Tax Asset**		**Future Tax Liability**	
5		**Book Value**	**Tax Value**	**Tax Benefit**	**be Realized**	**Rate[5]**	**Current**	**Non Current**	**Current**	**Non Current**
6	Plant-in-Service	$ 3,102,039 [1]								
7	Accum. Deprec.	(419,172) [1]								
8	CIAC	(836,878) [3]								
9	Fixed Assets	$ 1,845,989	$ 2,268,902 [2]	100.0%	$ 422,913	30.8%		130,449		-
10	AIAC		2,101,905 [4]	30.0%	$ 630,572 [4]	30.8%		$ 194,502		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	30.8%		$ -		
12							$ -	$ 324,952	$ -	$ -
13										
14					Net Asset (Liability)		$ 324,952			
15										
16	DIT Asset (Liability) per Books						$ -			
17										
18	Adjustment to DIT						$ (324,952)			
19										
20										
21										
22										
23										
24										
25	Footnotes - See page 2									
26										
27										
28										
29										
30										
31										
32										
33										
34										
35										
36										
37										
38										
39										

RUCO's RATE BASE ADJUSTMENT NO. 4 (CONT'D)
ACCUMULATEDDEFERRED INCOME TAXES ("ADIT") FOR EXCESS CAPACITY

Line No.				
1	**1 Adjusted per B-2, page 2**			
2	**2 Computation of Net Tax Value at December 31, 2009**			
3	Based on 2009 Tax Depreciation report (December 31, 2009)			
4	Unadjusted Cost per 2009 Tax Depr. Report	$ 4,938,108		
5	Reconciling Items not on tax report:			
6	Land costs not on tax, on books	494,159		
7	Net Unadjusted Cost tax Basis			$ 5,432,267
8				
9	Basis Reduction			
10	Basis Reduction 2009 and Prior Years (from 2009 Tax Depr. Report)	$ (14,706)		
11	Advanced or contributed plant with no depreciable basis listed on 2009 Tax Depr. Report	(2,707,816)		
12	Accumulated Depreciation 2008 and prior (2009 Tax Depr Report)	(339,352)		
13	2009 Current Year Tax Depreciation	(101,491)		-
14	Net Basis Reduction 2007 and Prior years			(3,163,365)
15	Net tax value of plant-in-service at December 31, 2008			$ 2,268,902
16				
17	**3 CIAC (including impact of change to probability of realization)**			
18				
19	Gross CIAC per B-2		$ -	
20	Less: Pre-1996 CIAC		-	
21	A.A per B-2	$ -		
22	A.A on Pre-1996 CIAC	-		
23	A.A. on Post 1996 CIAC		-	
24	Net CIAC before unrealized AIAC			$ -
25				
26	Unrealized AIAC Component			
27	Adjusted Net AIAC (see footnote 5 below)		$ (1,195,540)	
28	Unrealized AIAC Component % (1-Realized AIAC Component)		70.0%	
29				$ (836,878)
30	Total realizable CIAC			$ (836,878)
31				
32	**4 AIAC (including** impact of change in probability of realization)			
33	AIAC per B-2		$ (1,195,540)	
34	Less: Pre-1996 AIAC included for book and tax purposes		-	
35	Net AIAC before unrealized portion			$ (1,195,540)
36	Less: Unrealized AIAC (from Note 4, above)			$ 836,878
37	Net realizable AIAC			$ (358,662)
38				
39	**5 Effective tax rates Per C-3 schedule**			

OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Revenues:					
1	Metered Water Revenues	$ 559,013	$ 7,359	$ 566,372	$ (36,000)	$ 530,372
2	Unmetered Water Revenues	-	-	-	-	-
3	Other Water Revenues	13,738	-	13,738	-	13,738
4	TOTAL WATER REVENUES	$ 572,751	$ 7,359	$ 580,110	$ (36,000)	$ 544,110
	Operating Expenses:					
5	Salaries and Wages	$ 40,000	$ (4,986)	$ 35,014	$ -	$ 35,014
6	Purchased Water	-	-	-	-	-
7	Purchased Power	27,066	-	27,066	-	27,066
8	Chemicals	-	-	-	-	-
9	Repairs and Maintenance	7,746	-	7,746	-	7,746
10	Office Supplies and Expenses	14,855	-	14,855	-	14,855
11	Contractual Services	102,925	(2,641)	100,284	-	100,284
12	Water Testing	1,215	-	1,215	-	1,215
13	Rents	-	-	-	-	-
14	Transportation Expenses	-	-	-	-	-
15	Insurance - General Liability	9,669	-	9,669	-	9,669
16	Insurance - Health and Life	-	-	-	-	-
17	Reg. Comm. Exp. - Rate Case	20,000	-	20,000	-	20,000
18	Miscellaneous Expense	378	-	378	-	378
19	Depreciation Expense	227,855	(98,254)	129,601	-	129,601
20	Taxes Other Than Income	2,988	(372)	2,615	-	2,615
21	Property Taxes	21,299	(3,036)	18,263	-	18,263
22	Income Tax	22,873	29,880	52,753	(11,104)	41,649
23	TOTAL OPERATING EXPENSES	$ 498,868	$ (79,408)	$ 419,460	$ (11,104)	$ 408,356
24	**OPERATING INCOME (LOSS)**	$ 73,883		$ 160,650		$ 135,754

References:

Column (A): Company Schedule C-1
Column (B): TJC-9, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From TJC-1, Column (B), Line 8 And Income Tax From TJC-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

Goodman Water Company
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Test Year Ended December 31, 2009

SUMMARY OF OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 REV. & EXP. ANNUAL'N	(E) ADJ # 4 SALARIES & WAGES	(F) ADJ # 5 CONTRACTUAL SERVICES	(G) ADJ # 6 MEAL EXPENSE	(H) ADJ # 7 INCOME TAX	(I) RUCO AS ADJT'D
	Revenues:									
1	Metered Water Revenues	$ 559,013	$ -	$ -	$ 7,359	$ -	$ -	$ -	$ -	$ 566,372
2	Unmetered Water Revenues	-	-	-	-	-	-	-	-	-
3	Other Water Revenues	13,738	-	-	-	-	-	-	-	13,738
4	TOTAL WATER REVENUES	$ 572,751	$ -	$ -	$ 7,359	$ -	$ -	$ -	$ -	$ 580,110
	Operating Expenses:									
5	Salaries and Wages	$ 40,000	$ -	$ -	$ -	$ (4,986)	$ -	$ -	$ -	$ 35,014
6	Purchased Water	-	-	-	-	-	-	-	-	-
7	Purchased Power	27,066	-	-	-	-	-	-	-	27,066
8	Chemicals	-	-	-	-	-	-	-	-	-
9	Repairs and Maintenance	7,746	-	-	-	-	-	-	-	7,746
10	Office Supplies and Expenses	14,855	-	-	-	-	-	-	-	14,855
11	Contractual Services	102,925	-	-	-	-	(2,493)	(148)	-	100,284
12	Water Testing	1,215	-	-	-	-	-	-	-	1,215
13	Rents	-	-	-	-	-	-	-	-	-
14	Transportation Expenses	-	-	-	-	-	-	-	-	-
15	Insurance - General Liability	9,669	-	-	-	-	-	-	-	9,669
16	Insurance - Health and Life	-	-	-	-	-	-	-	-	-
17	Reg. Comm. Exp. - Rate Case	20,000	-	-	-	-	-	-	-	20,000
18	Miscellaneous Expense	378	-	-	-	-	-	-	-	378
19	Depreciation Expense	227,855	(98,254)	-	-	-	-	-	-	129,601
20	Taxes Other Than Income	2,988	-	-	-	(372)	-	-	-	2,615
21	Property Taxes	21,299	-	(3,036)	-	-	-	-	-	18,263
22	Income Tax	22,873	-	-	-	-	-	-	29,880	52,753
23	TOTAL OPERATING EXPENSES	$ 498,868	$ (98,254)	$ (3,036)	$ -	$ (5,358)	$ (2,493)	$ (148)	$ 29,880	$ 419,460
24	**OPERATING INCOME (LOSS)**	$ 73,883								$ 160,650

References:
Column (A): Company Schedule C-1
Column (B): TJC Testimony and Schedule TJC-10
Column (C): TJC Testimony and Schedule TJC-11
Column (D): TJC Testimony and Schedule TJC-12
Column (E): TJC Testimony and Schedule TJC-13
Column (F): TJC Testimony and Schedule TJC-14
Column (G): TJC Testimony and Schedule TJC-15
Column (H): TJC Testimony and Schedule TJC-16
Column (I): Sum Of Columns (A) Thru (H)

RUCO OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) RUCO TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE DECISION NO. 69404	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ 72,295	0.00%	$ -
2	302	Franchise Cost	-	0.00%	-
3	303	Land and Land Rights	281,072	0.00%	-
4	304	Structures and Improvements	103,844	3.33%	3,458
5	305	Collecting and Impounding Res.	-	2.50%	-
6	306	Lakes, Rivers, and Other Intakes	-	2.50%	-
7	307	Wells & Springs	219,889	3.33%	7,322
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	-	2.00%	-
10	310	Power Generation Equipment	-	5.00%	-
11	311	Electric Pumping Equipmemt	550,958	12.50%	68,870
12	320	Water Treatment Equipment	9,071	3.33%	302
13	320.1	Water Treatment Plant	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	476,014	2.22%	10,568
16	330.1	Storage Tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	916,501	2.00%	18,330
19	333	Services	220,091	3.33%	7,329
20	334	Meters	53,616	8.33%	4,466
21	335	Hydrants	91,994	2.00%	1,840
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Othere Plant and Misc. Equip.	106,695	6.67%	7,117
24	340	Office Furniture and Fixtures	-	6.67%	-
25	340.1	Computers and Software	-	20.00%	-
26	341	Transportation Equipment	-	20.00%	-
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	-	5.00%	-
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	-	5.00%	-
31	346	Communications Equipment	-	10.00%	-
32	347	Miscellaneous Equipment	-	10.00%	-
33	348	Other Tangible Plant	-	10.00%	-
34		Rounding	1		-
35	**RUCO TOTAL WATER PLANT**		$ 3,102,039		$ 129,601
	Less:				
36	Amortizations Of CIAC (TJC-2, Col. (C), Line 8)		$ -		-
37	TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)				$ 129,601
38	Test Year Depreciation Expense As Filed (Co. Sch. C-1)				227,855
39	Increase (Decrease) In Depreciation Expense (Line 37 - Line 37)				$ (98,254)
40	RUCO Adjustment (Line 39) (See TJC-9, Column (B), Line 19)				$ (98,254)

References: Column (A): TJC-5, Column (D)
Column (B): Per Decision No. 69404
Column (C): Column (A) X Column (B)

RUCO OPERATING INCOME ADJUSTMENT NO. 2
PROPERTY TAX COMPUTATION

LINE NO.	DESCRIPTION	REFERENCE	(A) AMOUNT	(B) TOTAL
	Calculation Of The Company's Full Cash Value:			
	Annual Operating Revenues:			
1	Adjusted Revenues In Year Ended December 2009	Sch. TJC-8, Col (C), Ln 4	$ 580,110	
2	Adjusted Revenues In Year Ended December 2009	Sch. TJC-8, Col (C), Ln 4	580,110	
3	Proposed Revenues	Sch. TJC-8, Col (E), Ln 4	544,110	
4	Total Three Year Operating Revenues	Sum Of Lines 1, 2 & 3	$ 1,704,329	
5	Average Annual Operating Revenues	Line 4 / 3	568,110	
6	Two Times Three Year Average Operating Revenues	Line 5 X 2		$ 1,136,220
	ADD:			
	10% Of Construction Work In Progress ("CWIP"):			
7	Test Year CWIP	Co. Sch. E-1	$ -	
8	10% Of CWIP	Line 7 X 10%		$ -
	SUBTRACT:			
	Transportation At Book Value:			
9	Original Cost Of Transportation Equipment	TJC-5, Col. (D), Ln 26	$ -	
10	Acc. Dep. Of Transportation Equipment	TJC-4, Col. (H), Ln 26	-	
11	Book Value Of Transportation Equipment	Line 9 + Line 10		$ -
12	Company's Full Cash Value ("FCV")	Sum Of Lines 6, 8 & 11		$ 1,136,220
	Calculation Of The Company's Tax Liability:			
	MULTIPLY:			
	FCV X Valuation Assessment Ratio X Property Tax Rates:			
13	Assessment Ratio	House Bill 2779	20.0%	
14	Assessed Value	Line 12 X Line 13	$ 227,244	
	Property Tax Rates:			
15	Primary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	7.4558%	
16	Secondary Tax Rate - 2009 Tax Notice	Co. Sch. C-2, Pg 3	0.0000%	
17	Estimated Tax Rate Liability	Line 15 + Line 16	7.4558%	
18	Company's Tax Liability - Based On Full Cash Value	Line 14 X Line 17		$ 16,943
19	Company's Tax on Parcels	Co. Sch. C-2, Pg 3		$ 1,320
20	Company's Total Tax Liability	Line 18 + Line 19		$ 18,263
21	Test Year Adjusted Property Tax Expense As Filed	Co. Sch. C-1, Line 25		21,299
22	Increase In Property Tax Expense	Line 20 - Line 21		$ (3,036)
23	RUCO Adjustment (See TJC-9, Column (C), Line 21)	Line 22		$ (3,036)

RUCO OPERATING INCOME ADJUSTMENT NO. 3
REVENUE ANNUALIZATION

LINE NO.	DESCRIPTION	(A) AMOUNT
1	Company Revenue Annualization Adjustment	$ (7,359)
2	RUCO's Recommended Revenue Annualization Amount (See TJC-7, Column (D))	-
3	RUCO Revenue Annualization Adjustment	$ 7,359

NOTE:
RUCO's Average Test Year Customer Count Revenue Annualization Amount (49)

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Residential 5/8 x 3/4" Meter

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL YEAR	AVERAGE CUSTOMERS
1	2009 AVERAGE TEST YEAR CUSTOMERS	532	532	532	532	532	532	532	532	532	532	532	532	6,379	
2	2009 ACTUAL CUSTOMERS BY MONTH	534	534	537	534	538	535	528	527	522	521	540	529	6,379	531.58
3	AVERAGE INCREASE IN CUSTOMERS	(2)	(2)	(5)	(2)	(6)	(3)	4	5	10	11	(8)	3		
4	AVERAGE REVENUE / PRESENT RATES	$ 61.08	$ 60.83	$ 63.19	$ 65.85	$ 70.41	$ 70.77	$ 70.88	$ 70.99	$ 66.19	$ 74.25	$ 69.47	$ 57.31		
5	REVENUE ANNUALIZATION / PRESENT RATES	$ (147.61)	$ (146.99)	$(342.29)	$ (159.14)	$(451.77)	$ (241.79)	$ 253.97	$ 325.39	$ 634.31	$ 785.84	$ (584.73)	$ 148.05	$ 73.25	
7	TOTAL INCREASE IN REVENUE PER RUCO	73													
8	INCREASE (DECREASE) IN REVENUE PER COMPANY	(1,997)													
9	RUCO REVENUE ADJUSTMENT	2,070													
10	GALLONS SOLD PER AVERAGE CUSTOMER	4,521	4,478	4,879	5,328	6,099	6,160	6,179	6,199	5,386	6,750	5,941	3,826		
11	INCREASE IN CUSTOMERS	(2)	(2)	(5)	(2)	(6)	(3)	4	5	10	11	(8)	3		
12	RUCO INCREASE IN GALLONS	(10,926)	(10,822)	(26,425)	(12,877)	(39,135)	(21,048)	22,140	28,411	51,612	71,438	(50,005)	9,883	12,245	
13	COMPANY INCREASE IN GALLONS													(1,997)	
14	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	14,241												14,241	

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LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL YEAR	AVERAGE CUSTOMERS
1	2009 AVERAGE TEST YEAR CUSTOMERS	76	76	76	76	76	76	76	76	76	76	76	76	914	
2	2009 ACTUAL CUSTOMERS BY MONTH	67	71	73	74	73	72	71	77	79	82	89	86	914	76.17
3	AVERAGE INCREASE IN CUSTOMERS	9	5	3	2	3	4	5	(1)	(3)	(6)	(13)	(10)		
4	AVERAGE REVENUE / PRESENT RATES	$ 84.79	$ 86.89	$ 90.56	$ 92.28	$ 100.19	$ 97.49	$ 102.53	$ 96.56	$ 94.70	$ 100.72	$ 94.14	$ 82.20		
5	REVENUE ANNUALIZATION / PRESENT RATES	$ 777.26	$ 448.91	$ 286.77	$ 199.94	$ 317.28	$ 406.21	$ 529.76	$ (80.47)	$ (268.32)	$ (587.56)	$ (1,208.18)	$ (808.25)	$ 13.35	
7	TOTAL INCREASE IN REVENUE PER RUCO	13													
8	INCREASE (DECREASE) IN REVENUE PER COMPANY	11,057													
9	RUCO REVENUE ADJUSTMENT	(11,043)													
10	GALLONS SOLD PER AVERAGE CUSTOMER	4,963	5,317	5,939	6,230	7,569	7,112	7,965	6,955	6,640	7,659	6,545	4,524		
11	INCREASE IN CUSTOMERS	9	5	3	2	3	4	5	(1)	(3)	(6)	(13)	(10)		
12	RUCO INCREASE IN GALLONS	45,496	27,473	18,806	13,499	23,968	29,632	41,154	(5,796)	(18,813)	(44,678)	(84,000)	(44,484)	2,259	
13	COMPANY INCREASE IN GALLONS													763,542	
14	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(761,283)												(761,283)	

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LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL YEAR	AVERAGE CUSTOMERS
1	2009 AVERAGE TEST YEAR CUSTOMERS	4	4	4	4	4	4	4	4	4	4	4	4	45	
2	2009 ACTUAL CUSTOMERS BY MONTH	4	4	4	6	4	4	4	3	3	3	3	3	45	3.75
3	AVERAGE INCREASE IN CUSTOMERS	(0)	(0)	(0)	(2)	(0)	(0)	(0)	1	1	1	1	1		
4	AVERAGE REVENUE / PRESENT RATES	$ 148.35	$ 149.83	$ 149.83	$ 160.66	$ 143.92	$ 129.14	$ 179.38	$ 141.95	$ 155.74	$ 159.68	$ 153.77	$ 134.07		
5	REVENUE ANNUALIZATION / PRESENT RATES	$ (37.09)	$ (37.46)	$ (37.46)	$ (361.49)	$ (35.98)	$ (32.29)	$ (44.84)	$ 106.46	$ 116.80	$ 119.76	$ 115.33	$ 100.55	$ (27.70)	
7	TOTAL INCREASE IN REVENUE PER RUCO	(28)													
8	INCREASE (DECREASE) IN REVENUE PER COMPANY	(1,382)													
9	RUCO REVENUE ADJUSTMENT	1,355													
10	GALLONS SOLD PER AVERAGE CUSTOMER	7,251	7,501	7,501	9,334	6,501	4,001	12,501	6,167	8,501	9,167	8,167	4,834		
11	INCREASE IN CUSTOMERS	(0)	(0)	(0)	(2)	(0)	(0)	(0)	1	1	1	1	1		
12	RUCO INCREASE IN GALLONS	(1,813)	(1,875)	(1,875)	(21,001)	(1,625)	(1,000)	(3,125)	4,625	6,375	6,875	6,125	3,625	(4,688)	
13	COMPANY INCREASE IN GALLONS													(22,282)	
14	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	17,594												17,594	

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Commercial 1" Meter

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL YEAR	AVERAGE CUSTOMERS
1	2009 AVERAGE TEST YEAR CUSTOMERS	2	2	2	2	2	2	2	2	2	2	2	2	26	
2	2009 ACTUAL CUSTOMERS BY MONTH	1	1	1	1	3	3	3	3	3	3	2	2	26	2.17
3	AVERAGE INCREASE IN CUSTOMERS	1	1	1	1	(1)	(1)	(1)	(1)	(1)	(1)	0	0		
4	AVERAGE REVENUE / PRESENT RATES	$ 700.63	$ 529.99	$ 785.95	$ 785.95	$ 546.58	$ 479.03	$ 533.54	$ 564.35	$ 438.74	$ 500.36	$ 394.90	$ 348.68		
5	REVENUE ANNUALIZATION / PRESENT RATES	$ 817.40	$ 618.32	$ 916.94	$ 916.94	$(455.48)	$ (399.19)	$(444.62)	$(470.29)	$ (365.62)	$ (416.97)	$ 65.82	$ 58.11	$ 841.35	
7	TOTAL INCREASE IN REVENUE PER RUCO	841													
8	INCREASE (DECREASE) IN REVENUE PER COMPANY	(260)													
9	RUCO REVENUE ADJUSTMENT	1,101													
10	GALLONS SOLD PER AVERAGE CUSTOMER	87,501	63,501	99,501	99,501	65,834	56,334	64,000	68,334	50,667	59,334	44,501	38,001		
11	INCREASE IN CUSTOMERS	1	1	1	1	(1)	(1)	(1)	(1)	(1)	(1)	0	0		
12	RUCO INCREASE IN GALLONS	102,084	74,084	116,084	116,084	(54,862)	(46,945)	(53,334)	(56,945)	(42,223)	(49,445)	7,417	6,333	118,334	
13	COMPANY INCREASE IN GALLONS													(14,500)	
14	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	132,834												132,834	

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Commercial 1.5" Meter

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL YEAR	AVERAGE CUSTOMERS
1	2009 AVERAGE TEST YEAR CUSTOMERS	0	0	0	0	0	0	0	0	0	0	0	0	2	
2	2009 ACTUAL CUSTOMERS BY MONTH	-	-	-	1	1	-	-	-	-	-	-	-	2	0.17
3	AVERAGE INCREASE IN CUSTOMERS	0	0	0	(1)	(1)	0	0	0	0	0	0	0		
4	AVERAGE REVENUE / PRESENT RATES	$ 211.50	$ 211.50	$ 211.50	$ 232.19	$ 226.28	$ 211.50	$ 211.50	$ 211.50	$ 211.50	$ 211.50	$ 211.50	$ 211.50		
5	REVENUE ANNUALIZATION / PRESENT RATES	$ 35.25	$ 35.25	$ 35.25	$ (193.49)	$(188.56)	$ 35.25	$ 35.25	$ 35.25	$ 35.25	$ 35.25	$ 35.25	$ 35.25	$ (29.55)	
7	TOTAL INCREASE IN REVENUE PER RUCO	(30)													
8	INCREASE (DECREASE) IN REVENUE PER COMPANY	(458)													
9	RUCO REVENUE ADJUSTMENT	429													
10	GALLONS SOLD PER AVERAGE CUSTOMER	-	-	-	3,501	2,501	-	-	-	-	-	-	-		
11	INCREASE IN CUSTOMERS	0	0	0	(1)	(1)	0	0	0	0	0	0	0	(5,001)	
12	RUCO INCREASE IN GALLONS	-	-	-	(2,917)	(2,084)	-	-	-	-	-	-	-	(458)	
13	COMPANY INCREASE IN GALLONS													(4,542)	
14	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	(4,542)													

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Commercial 2" Meter

LINE NO.	DESCRIPTION	JANUARY	FEBRUARY	MARCH	APRIL	MAY	JUNE	JULY	AUGUST	SEPTEMBER	OCTOBER	NOVEMBER	DECEMBER	TOTAL YEAR	AVERAGE CUSTOMERS
1	2009 AVERAGE TEST YEAR CUSTOMERS	2	2	2	2	2	2	2	2	2	2	2	2	19	
2	2009 ACTUAL CUSTOMERS BY MONTH	3	2	3	2	2	2	2	1	1	-	1	-	19	1.58
3	AVERAGE INCREASE IN CUSTOMERS	(1)	(0)	(1)	(0)	(0)	(0)	(0)	1	1	2	1	2		
4	AVERAGE REVENUE / PRESENT RATES	$ 744.28	$ 680.29	$ 830.78	$ 690.95	$ 733.61	$ 599.72	$ 680.29	$1,046.45	$ 772.72	$ 339.68	$ 1,003.79	$ 339.68		
5	REVENUE ANNUALIZATION / PRESENT RATES	$ (1,054.39)	$ (283.45)	$(1,176.94)	$ (287.90)	$(305.67)	$ (249.88)	$(283.45)	$ 610.43	$ 450.75	$ 537.83	$ 585.54	$ 537.83	$ (919.32)	
7	TOTAL INCREASE IN REVENUE PER RUCO	(919)													
8	INCREASE (DECREASE) IN REVENUE PER COMPANY	(14,318)													
9	RUCO REVENUE ADJUSTMENT	13,399													
10	GALLONS SOLD PER AVERAGE CUSTOMER	64,501	55,501	76,667	57,001	63,001	44,001	55,501	107,000	68,501	-	101,000	-		
11	INCREASE IN CUSTOMERS	(1)	(0)	(1)	(0)	(0)	(0)	(0)	1	1	2	1	2		
12	RUCO INCREASE IN GALLONS	(91,376)	(23,125)	(108,612)	(23,750)	(26,250)	(18,334)	(23,125)	62,417	39,959	-	58,917	-	(153,280)	
13	COMPANY INCREASE IN GALLONS													(1,250,008)	
14	RUCO DIFFERENCE IN GALLONS TO BE PRODUCED	1,096,728												1,096,728	

RUCO OPERATING INCOME ADJUSTMENT NO. 4
SALARIES & WAGES

Line No.			Amount
1	RUCO Adjustment to Salaries and Wages		
2			
3			
4	Company Request for Annual Salary of President/Manager		$ 40,000
5	Amount Recorded in Test Year		32,000
6	Increase (decrease) in Salaries and Wages		8,000
7			
8			
9	Company Adjustment to Test Year Book Amount		$ 8,000
10			
11	Inflation Factor Oct. 2005 thru June 2010 per InflationData.com		**9.42%**
12			
13	RUCO Adjustment to Test Year Book Amount		$ 3,014
14			
15	RUCO Adjustment to Salaries & Wages		$ (4,986)
16			
17			
18	Adjust Payroll Taxes to refelect RUCO Salaries and Wages		
19			
20	FICA per Company	6.02%	$ 2,408
21	FICA per RUCO	6.02%	2,108
22			
23	Medicare per Company	1.45%	580
24	Medicare per RUCO	1.45%	508
25			
26	FUTA per Company	0.80% (first $7,000 of wages)	56
27	FUTA per RUCO	0.80% (first $7,000 of wages)	56
28			
29	SUTA per Company	2.70% (first $7,000 of wages)	189
30	SUTA per RUCO	2.70% (first $7,000 of wages)	189
31			
32			
33	Total Payroll Taxes per Company		$ 3,233
34	Total Payroll Taxes per RUCO		2,861
35			
36	Payroll Taxes Recorded in Test Year		2,693
37			
38	Company Increase (decrease) in Payroll Taxes		$ 540
39	RUCO Increase (decrease) in Payroll Taxes		168
40			
41	RUCO Adjustment to Payroll Taxes		$ (372)

RUCO OPERATING INCOME ADJUSTMENT NO. 5
CONTRACTUAL SERVICES

Line No.		
1	Contractual Services - Jim Shiner	
2		
3	Company Request for Contractual Services 2010	$ 20,000
4	Contractual Services recorded during test year	16,000
5		
6	Company Increase (decrease) in Contractual Services	$ 4,000
7		
8		
9	Inflation Factor Oct. 2005 thru June 2010 per InflationData.com	**9.42%**
10		
11		
12	RUCO Adjustment to Test Year Book Amount	$ 1,507
13		
14	RUCO Recommended Contractual Services for J. Shiner	17,507
15		
16		
17	RUCO Adjustment to Contractual Services	$ (2,493)
18		
19		
20		

RUCO OPERATING INCOME ADJUSTMENT NO. 6
OUTSIDE SERVICES - MEALS

Line No.	Invoice No.	Date	Vendor	AMOUNT
1				
2	No Invoice No.	3/17/2009	CWH2 Services, LLC - Firebirds	$ 34.63
3				
4	30605	6/11/2009	CWH2 Services, LLC	27.01
5				
6	No Invoice No.	5/9/2009	CWH2 Services, LLC	57.82
7				
8	30609	10/20/2009	CWH2 Services, LLC - Firebirds	28.77
9				
10	Total Meals			148.23
11				
12				
13	RUCO Adjustment			(148)
14				
15				
16				
17				
18	**NOTE:**			
19	The Meals were identified in the Company's response to Staff Data Request GTM 4.11			
20				

RUCO OPERATING INCOME ADJUSTMENT NO. 7
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. TJC-9, Column (H), L24 + L22	$ 213,403
	LESS:		
2	Arizona State Tax	Line 11	(11,917)
3	Interest Expense	Note (A) Line 20	(42,378)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 159,108
5	Federal Tax Rate	Sch. TJC-1, Pg 2, Col. (D), L34	25.67%
6	Federal Income Tax Expense	Line 4 X line 5	$ 40,836
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 213,403
	LESS:		
8	Interest Expense	Note (A) Line 20	(42,378)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 171,025
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 11,917
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 40,836
13	State Income Tax Expense	Line 11	11,917
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 52,753
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		22,873
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 29,880
17	RUCO Adjustment (See Sch. TJC-9, Column (H), L22)	Line16	$ 29,880

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. RLM-2, Col. (E), L15)	$	1,729,190
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)		2.45%
20	Interest Expense (L17 X L18)	$	42,378

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST RATE
1	*Long-Term Debt*	40.00%	6.13%	2.45%
2	Common Equity	60.00%	9.00%	5.40%
3	Total Capitalization	100.00%		
4	*COST OF CAPITAL*			7.85%

References:
Columns (A) Thru (F): See Testimony Of RUCO Witness William Rigsby

RATE DESIGN
SCHEDULES

RESIDENTIAL RATE DESIGN

GOODMAN WATER COMPANY - RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
SUMMARY OF PRESENT, COMPANY PROPOSED & RUCO RECOMMENDED RATES

RATE SUMMARY

Present Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	6,379	384,291,369	0	$42.20	$269,197	21,179,764	$83,660	10,369,830	$61,286	3,385,985	$24,074	$438,217
3/4 - INCH	914	64,836,365	0	63.30	57,857	2,855,540	11,279	1,765,550	10,434	1,273,125	9,052	88,623
1 - INCH	45	3,822,500	0	105.50	4,748	338,500	2,001	9,000	64	0	0	6,812
1 1/2 - INCH	0	0	0	211.50	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	339.68	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	675.20	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,055.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,110.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	7,338	452,950,234			$331,801	24,373,804	$96,940	12,144,380	$71,784	4,659,110	$33,126	$533,651

Company Proposed Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	6,379	384,291,369	0	$56.97	$363,415	21,179,764	$143,931	10,369,830	$113,195	3,385,985	$44,466	$665,007
3/4 - INCH	914	64,836,365	0	85.46	78,107	2,855,540	19,405	1,765,550	19,272	1,273,125	16,719	133,504
1 - INCH	45	3,822,500	0	142.43	6,409	338,500	3,695	9,000	118	0	0	10,223
1 1/2 - INCH	0	0	0	284.85	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	455.76	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	911.52	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,424.25	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,848.50	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	7,338	452,950,234			$447,931	24,373,804	$167,031	12,144,380	$132,585	4,659,110	$61,185	$808,733

RUCO Recommended Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	6,379	384,291,369	0	$38.60	$246,232	21,179,764	$95,309	10,369,830	$69,996	3,385,985	$27,426	$438,964
3/4 - INCH	914	64,836,365	0	57.90	52,921	2,855,540	12,850	1,765,550	11,917	1,273,125	10,312	88,001
1 - INCH	45	3,822,500	0	96.50	4,343	338,500	2,285	9,000	73	0	0	6,700
1 1/2 - INCH	0	0	0	193.00	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	308.80	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	579.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	965.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	1,930.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	3,860.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	7,720.00	0	0	0	0	0	0	0	0
	7,338	452,950,234			$303,496	24,373,804	$110,444	12,144,380	$81,987	4,659,110	$37,739	$533,665

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-2

GOODMAN WATER COMPANY - RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
REVENUE COMPARISON

LINE NO.	METER SIZE	PERESENT RATES MONTHLY MINIMUM	PERESENT RATES COMMODITY CHARGE	PERESENT RATES TOTAL REVENUE	COMPANY PROPOSED RATES MONTHLY MINIMUM	COMPANY PROPOSED RATES COMMODITY CHARGE	COMPANY PROPOSED RATES TOTAL REVENUE	RUCO RECOMMENDED RATES MONTHLY MINIMUM	RUCO RECOMMENDED RATES COMMODITY CHARGE	RUCO RECOMMENDED RATES TOTAL REVENUE
1	5/8 - INCH	$ 269,197	$ 169,020	$ 438,217	$ 363,415	$ 301,592	$ 665,007	$ 246,232	$ 192,732	$ 438,964
2	3/4 - INCH	57,857	30,766	88,623	78,107	55,397	133,504	52,921	35,080	88,001
3	1 - INCH	4,748	2,065	6,812	6,409	3,813	10,223	4,343	2,358	6,700
4	1 1/2 - INCH	-	-	-	-	-	-	-	-	-
5	2 - INCH	-	-	-	-	-	-	-	-	-
6	3 - INCH	-	-	-	-	-	-	-	-	-
7	4 - INCH	-	-	-	-	-	-	-	-	-
8	6 - INCH	-	-	-	-	-	-	-	-	-
9	8 - INCH	-	-	-	-	-	-	-	-	-
10	10 - INCH	-	-	-	-	-	-	-	-	-
11	TOTALS	$ 331,801	$ 201,850	$ 533,651	$ 447,931	$ 360,802	$ 808,733	$ 303,496	$ 230,169	$ 533,665
12	PERCENTAGE	62.18%	37.82%	100.00%	55.39%	44.61%	100.00%	56.87%	43.13%	100.00%

GOODMAN WATER COMPANY - RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-3

LINE NO.	DESCRIPTION					PRESENT RATES	COMPANY PROPOSED	RUCO PROPOSED
1	**RECOMMENDED MONTHLY MINIMUM USAGE CHARGE:**							
2								
3	(RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS)							
4	5/8 - INCH					$42.20	$56.97	$38.60
5	3/4 - INCH					63.30	85.46	57.90
6	1 - INCH					105.50	142.43	96.50
7	1 1/2 - INCH					211.50	284.85	193.00
8	2 - INCH					339.68	455.76	308.80
9	3 - INCH					675.20	911.52	579.00
10	4 - INCH					1,055.00	1,424.25	965.00
11	6 - INCH					2,110.00	2,848.50	1,930.00
12	8 - INCH					0.00	0.00	3,860.00
13	10 - INCH					0.00	0.00	7,720.00
14								
15	**GALLONS INCLUDED IN MONTHLY MINIMUM USAGE CHARGE:**							
16								
17	RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS					0	0	0
18								
19	**RECOMMENDED COMMODITY RATES BY METER SIZE**							
20								
21	5/8 - INCH							
22	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	4,000	GALLONS:	$ 3.95	$ 6.80	$ 4.50
23	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	4,001	TO	9,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
24	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
25								
26	3/4 - INCH							
27	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	4,000	GALLONS:	$ 3.95	$ 6.80	$ 4.50
28	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
29	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
30								
31	1 - INCH							
32	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	22,500	GALLONS:	$ 5.91	$ 10.92	$ 6.75
33	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
34	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ 13.13	$ -
35								
36	1 1/2 - INCH							
37	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	34,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
38	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
39	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
40								
41	2 - INCH							
42	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	45,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
43	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	45,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
44	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
45								
46	3 - INCH							
47	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	68,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
48	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	68,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
49	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
50								
51	4 - INCH							
52	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	90,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
53	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	90,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
54	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
55								
56	6 - INCH							
57	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	135,000	GALLONS:	$ 5.91	$ 10.92	$ 6.75
58	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	135,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
59	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
60								
61	8 - INCH							
62	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:	$ 5.91	$ 10.92	$ 6.75
63	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
64	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
65								
66	10 - INCH							
67	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:	$ 5.91	$ 10.92	$ 6.75
68	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.13	$ 8.10
69	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -

GOODMAN WATER COMPANY - RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
MONTHLY MINIMUM CHARGES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-4

LINE NO.	METER SIZE	(A) COMPANY PRESENT RATES	(B) COMPANY PROPOSED RATES	(C) COMPANY DOLLAR INCREASE	(D) COMPANY PERCENT. INCREASE	(E) RUCO RECOMMENDED RATES	(F) RUCO DOLLAR INCREASE	(G) RUCO PERCENT. INCREASE
1	5/8 - INCH	$ 42.20	$ 56.97	$ 14.77	35.00%	$ 38.60	$ (3.60)	-8.53%
2	3/4 - INCH	63.30	85.46	22.16	35.00%	57.90	(5.40)	-8.53%
3	1 - INCH	105.50	142.43	36.93	35.00%	96.50	(9.00)	-8.53%
4	1 1/2 - INCH	211.50	284.85	73.35	34.68%	193.00	(18.50)	-8.75%
5	2 - INCH	339.68	455.76	116.08	34.17%	308.80	(30.88)	-9.09%
6	3 - INCH	675.20	911.52	236.32	35.00%	579.00	(96.20)	-14.25%
7	4 - INCH	1,055.00	1,424.25	369.25	35.00%	965.00	(90.00)	-8.53%
8	6 - INCH	2,110.00	2,848.50	738.50	35.00%	1,930.00	(180.00)	-8.53%
9	GALLONS INCLUDED IN MONHTLY MINIMUM CHARGE	0	0			0		

REFERENCES
COLUMN (A) THRU COLUMN (D): COMPANY SCHEDULE H-3, PAGE 1 OF 3
COLUMN (E): TESTIMONY TJC
COLUMN (F): COLUMN (E) - COLUMN (A)
COLUMN (G): COLUMN (F) ÷ COLUMN (A)

GOODMAN WATER COMPANY - RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-5

RUCO RECOMMENDED RATES

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	$38.60	$57.90	$96.50	$193.00	$308.80	$579.00	$965.00	$1,930.00	$3,860.00	$7,720.00
2	1,000	43.10	62.40	103.25	199.75	315.55	585.75	971.75	1,936.75	3,868.10	7,728.10
3	2,000	47.60	66.90	110.00	206.50	322.30	592.50	978.50	1,943.50	3,876.20	7,736.20
4	3,000	52.10	71.40	116.75	213.25	329.05	599.25	985.25	1,950.25	3,884.30	7,744.30
5	4,000	56.60	75.90	123.50	220.00	335.80	606.00	992.00	1,957.00	3,892.40	7,752.40
6	5,000	63.35	82.65	130.25	226.75	342.55	612.75	998.75	1,963.75	3,900.50	7,760.50
7	6,000	70.10	89.40	137.00	233.50	349.30	619.50	1,005.50	1,970.50	3,908.60	7,768.60
8	7,000	76.85	96.15	143.75	240.25	356.05	626.25	1,012.25	1,977.25	3,916.70	7,776.70
9	8,000	83.60	102.90	150.50	247.00	362.80	633.00	1,019.00	1,984.00	3,924.80	7,784.80
10	9,000	90.35	109.65	157.25	253.75	369.55	639.75	1,025.75	1,990.75	3,932.90	7,792.90
11	10,000	98.45	117.75	164.00	260.50	376.30	646.50	1,032.50	1,997.50	3,941.00	7,801.00
12	15,000	138.95	158.25	197.75	294.25	410.05	680.25	1,066.25	2,031.25	3,981.50	7,841.50
13	20,000	179.45	198.75	231.50	328.00	443.80	714.00	1,100.00	2,065.00	4,022.00	7,882.00
14	25,000	219.95	239.25	268.63	361.75	477.55	747.75	1,133.75	2,098.75	4,062.50	7,922.50
15	50,000	422.45	441.75	471.13	552.10	653.05	916.50	1,302.50	2,267.50	4,265.00	8,125.00
16	75,000	624.95	644.25	673.63	754.60	855.55	1,094.70	1,471.25	2,436.25	4,467.50	8,327.50
17	100,000	827.45	846.75	876.13	957.10	1,058.05	1,297.20	1,653.50	2,605.00	4,670.00	8,530.00
18	125,000	1,029.95	1,049.25	1,078.63	1,159.60	1,260.55	1,499.70	1,856.00	2,773.75	4,872.50	8,732.50
19	150,000	1,232.45	1,251.75	1,281.13	1,362.10	1,463.05	1,702.20	2,058.50	2,962.75	5,075.00	8,935.00
20	175,000	1,434.95	1,454.25	1,483.63	1,564.60	1,665.55	1,904.70	2,261.00	3,165.25	5,277.50	9,137.50
21	200,000	1,637.45	1,656.75	1,686.13	1,767.10	1,868.05	2,107.20	2,463.50	3,367.75	5,480.00	9,340.00
22	250,000	2,042.45	2,061.75	2,091.13	2,172.10	2,273.05	2,512.20	2,868.50	3,772.75	5,885.00	9,745.00
23	500,000	4,067.45	4,086.75	4,116.13	4,197.10	4,298.05	4,537.20	4,893.50	5,797.75	7,910.00	11,770.00
24	1,000,000	8,117.45	8,136.75	8,166.13	8,247.10	8,348.05	8,587.20	8,943.50	9,847.75	11,960.00	15,820.00
25	2,000,000	16,217.45	16,236.75	16,266.13	16,347.10	16,448.05	16,687.20	17,043.50	17,947.75	20,060.00	23,920.00
26	3,000,000	24,317.45	24,336.75	24,366.13	24,447.10	24,548.05	24,787.20	25,143.50	26,047.75	28,160.00	32,020.00
27	4,000,000	32,417.45	32,436.75	32,466.13	32,547.10	32,648.05	32,887.20	33,243.50	34,147.75	36,260.00	40,120.00
28	5,000,000	40,517.45	40,536.75	40,566.13	40,647.10	40,748.05	40,987.20	41,343.50	42,247.75	44,360.00	48,220.00
29											
30											
31	AVG. NO. OF CUST:	532	76	4	0	0	0	0	0	0	0
32											
33	AVG. USE (GAL.):	5,477	6,449	7,722	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
34	MONTHLY BILL:	$66.57	$92.43	$148.63	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35											
36	MEDIAN USE (GAL.) :	4,718	4,920	7,071	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	MONTHLY BILL:	$61.45	$82.11	$144.23	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

GOODMAN WATER COMPANY - RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-6

RUCO RECOMMENDED CHANGES EXPRESSED IN DOLLARS

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	($3.60)	($5.40)	($9.00)	($18.50)	($30.88)	($96.20)	($90.00)	($180.00)	$3,860.00	$7,720.00
2	1,000	(3.05)	(4.85)	(8.16)	(17.66)	(30.04)	(95.36)	(89.16)	(179.16)	3,860.99	7,720.99
3	2,000	(2.50)	(4.30)	(7.32)	(16.82)	(29.20)	(94.52)	(88.32)	(178.32)	3,861.98	7,721.98
4	3,000	(1.95)	(3.75)	(6.48)	(15.98)	(28.36)	(93.68)	(87.48)	(177.48)	3,862.97	7,722.97
5	4,000	(1.40)	(3.20)	(5.64)	(15.14)	(27.52)	(92.84)	(86.64)	(176.64)	3,863.96	7,723.96
6	5,000	(0.56)	(2.36)	(4.80)	(14.30)	(26.68)	(92.00)	(85.80)	(175.80)	3,864.95	7,724.95
7	6,000	0.28	(1.52)	(3.96)	(13.46)	(25.84)	(91.16)	(84.96)	(174.96)	3,865.94	7,725.94
8	7,000	1.12	(0.68)	(3.12)	(12.62)	(25.00)	(90.32)	(84.12)	(174.12)	3,866.93	7,726.93
9	8,000	1.96	0.16	(2.28)	(11.78)	(24.16)	(89.48)	(83.28)	(173.28)	3,867.92	7,727.92
10	9,000	2.80	1.00	(1.44)	(10.94)	(23.32)	(88.64)	(82.44)	(172.44)	3,868.91	7,728.91
11	10,000	3.79	1.99	(0.60)	(10.10)	(22.48)	(87.80)	(81.60)	(171.60)	3,869.90	7,729.90
12	15,000	8.74	6.94	3.60	(5.90)	(18.28)	(83.60)	(77.40)	(167.40)	3,874.85	7,734.85
13	20,000	13.69	11.89	7.80	(1.70)	(14.08)	(79.40)	(73.20)	(163.20)	3,879.80	7,739.80
14	25,000	18.64	16.84	12.38	2.50	(9.88)	(75.20)	(69.00)	(159.00)	3,884.75	7,744.75
15	50,000	43.39	41.59	37.13	25.90	11.87	(54.20)	(48.00)	(138.00)	3,909.50	7,769.50
16	75,000	68.14	66.34	61.88	50.65	36.62	(32.15)	(27.00)	(117.00)	3,934.25	7,794.25
17	100,000	92.89	91.09	86.63	75.40	61.37	(7.40)	(4.50)	(96.00)	3,959.00	7,819.00
18	125,000	117.64	115.84	111.38	100.15	86.12	17.35	20.25	(75.00)	3,983.75	7,843.75
19	150,000	142.39	140.59	136.13	124.90	110.87	42.10	45.00	(51.75)	4,008.50	7,868.50
20	175,000	167.14	165.34	160.88	149.65	135.62	66.85	69.75	(27.00)	4,033.25	7,893.25
21	200,000	191.89	190.09	185.63	174.40	160.37	91.60	94.50	(2.25)	4,058.00	7,918.00
22	250,000	241.39	239.59	235.13	223.90	209.87	141.10	144.00	47.25	4,107.50	7,967.50
23	500,000	488.89	487.09	482.63	471.40	457.37	388.60	391.50	294.75	4,355.00	8,215.00
24	1,000,000	983.89	982.09	977.63	966.40	952.37	883.60	886.50	789.75	4,850.00	8,710.00
25	2,000,000	1,973.89	1,972.09	1,967.63	1,956.40	1,942.37	1,873.60	1,876.50	1,779.75	5,840.00	9,700.00
26	3,000,000	2,963.89	2,962.09	2,957.63	2,946.40	2,932.37	2,863.60	2,866.50	2,769.75	6,830.00	10,690.00
27	4,000,000	3,953.89	3,952.09	3,947.63	3,936.40	3,922.37	3,853.60	3,856.50	3,759.75	7,820.00	11,680.00
28	5,000,000	4,943.89	4,942.09	4,937.63	4,926.40	4,912.37	4,843.60	4,846.50	4,749.75	8,810.00	12,670.00
29											
30											
31	AVG. NO. OF CUST:	532	76	4	0	0	0	0	0	0	0
32											
33	AVG. USE (GAL.):	5,477	6,449	7,722	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
34	MONTHLY BILL:	($0.16)	($1.14)	($2.51)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35											
36	MEDIAN USE (GAL.) :	4,718	4,920	7,071	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	MONTHLY BILL:	($0.79)	($2.42)	($3.06)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

COMMERCIAL RATE DESIGN

GOODMAN WATER COMPANY - COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
SUMMARY OF PRESENT, COMPANY PROPOSED & RUCO RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-1

RATE SUMMARY

Present Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	0	0	0	$42.20	$0	0	$0	0	$0	0	$0	$0
3/4 - INCH	0	0	0	63.30	0	0	0	0	0	0	0	0
1 - INCH	26	17,675,900	0	105.50	2,756	484,900	2,866	1,122,000	7,977	0	0	13,599
1 1/2 - INCH	2	66,000	0	211.50	423	6,000	35	0	0	0	0	458
2 - INCH	19	13,745,661	0	339.68	6,458	751,995	4,444	497,611	3,538	0	0	14,440
3 - INCH	0	0	0	675.20	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,055.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,110.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	47	31,487,561	0		$9,636	1,242,895	$7,346	1,619,611	$11,515	0	$0	$28,497

Company Proposed Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	0	0	0	$56.97	$0	0	$0	0	$0	0	$0	$0
3/4 - INCH	0	0	0	85.46	0	0	0	0	0	0	0	0
1 - INCH	26	17,675,900	0	142.43	3,720	484,900	5,297	1,122,000	14,736	0	0	23,754
1 1/2 - INCH	2	66,000	0	284.85	570	6,000	66	0	0	0	0	635
2 - INCH	19	13,745,661	0	455.76	8,664	751,995	8,212	497,611	6,533	0	0	23,409
3 - INCH	0	0	0	911.52	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,424.25	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,848.50	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	47	31,487,561	0		$12,955	1,242,895	$13,575	1,619,611	$21,269	0	$0	$47,799

RUCO Recommended Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	0	0	0	$38.60	$0	0	$0	0	$0	0	$0	$0
3/4 - INCH	0	0	0	57.90	0	0	0	0	0	0	0	0
1 - INCH	26	17,675,900	0	96.50	2,521	484,900	3,273	1,122,000	9,088	0	0	14,882
1 1/2 - INCH	2	66,000	0	193.00	386	6,000	41	0	0	0	0	427
2 - INCH	19	13,745,661	0	308.80	5,871	751,995	5,076	751,995	4,031	0	0	14,977
3 - INCH	0	0	0	579.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	965.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	1,930.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	3,860.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	7,720.00	0	0	0	0	0	0	0	0
	47	31,487,561	0		$8,777	1,242,895	$8,390	1,873,995	$13,119	0	$0	$30,286

GOODMAN WATER COMPANY - COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
REVENUE COMPARISON

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-2

LINE NO.	METER SIZE	PERESENT RATES MONTHLY MINIMUM	PERESENT RATES COMMODITY CHARGE	PERESENT RATES TOTAL REVENUE	COMPANY PROPOSED RATES MONTHLY MINIMUM	COMPANY PROPOSED RATES COMMODITY CHARGE	COMPANY PROPOSED RATES TOTAL REVENUE	RUCO RECOMMENDED RATES MONTHLY MINIMUM	RUCO RECOMMENDED RATES COMMODITY CHARGE	RUCO RECOMMENDED RATES TOTAL REVENUE
1	5/8 - INCH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	3/4 - INCH	-	-	-	-	-	-	-	-	-
3	1 - INCH	2,756	10,843	13,599	3,720	20,034	23,754	2,521	12,361	14,882
4	1 1/2 - INCH	423	35	458	570	66	635	386	41	427
5	2 - INCH	6,458	7,982	14,440	8,664	14,745	23,409	5,871	9,107	14,977
6	3 - INCH	-	-	-	-	-	-	-	-	-
7	4 - INCH	-	-	-	-	-	-	-	-	-
8	6 - INCH	-	-	-	-	-	-	-	-	-
9	8 - INCH	-	-	-	-	-	-	-	-	-
10	10 - INCH	-	-	-	-	-	-	-	-	-
11	TOTALS	$ 9,636	$ 18,861	$ 28,497	$ 12,955	$ 34,844	$ 47,799	$ 8,777	$ 21,508	$ 30,286
12	PERCENTAGE	33.81%	66.19%	100.00%	27.10%	72.90%	100.00%	28.98%	71.02%	100.00%

GOODMAN WATER COMPANY - COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-3

LINE NO.	DESCRIPTION	PRESENT RATES	COMPANY PROPOSED	RUCO PROPOSED
1	**RECOMMENDED MONTHLY MINIMUM USAGE CHARGE:**			
2				
3	(RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS)			
4	5/8 - INCH	$42.20	$56.97	$38.60
5	3/4 - INCH	63.30	85.46	57.90
6	1 - INCH	105.50	142.43	96.50
7	1 1/2 - INCH	211.50	284.85	193.00
8	2 - INCH	339.68	455.76	308.80
9	3 - INCH	675.20	911.52	579.00
10	4 - INCH	1,055.00	1,424.25	965.00
11	6 - INCH	2,110.00	2,848.50	1,930.00
12	8 - INCH	0.00	0.00	3,860.00
13	10 - INCH	0.00	0.00	7,720.00
14				
15	**GALLONS INCLUDED IN MONTHLY MINIMUM USAGE CHARGE:**			
16				
17	RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS	0	0	0
18				
19	**RECOMMENDED COMMODITY RATES BY METER SIZE**			
20				
21	5/8 - INCH			
22	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 4,000 GALLONS:	$ 3.95	$ 6.80	$ 4.50
23	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - 4,001 TO 9,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
24	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER 9,000 GALLONS:	$ 7.11	$ 13.13	$ 8.10
25				
26	3/4 - INCH			
27	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 4,000 GALLONS:	$ 3.95	$ 6.80	$ 4.50
28	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER 9,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
29	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER 9,000 GALLONS:	$ 7.11	$ 13.13	$ 8.10
30				
31	1 - INCH			
32	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 22,500 GALLONS:	$ 5.91	$ 10.92	$ 6.75
33	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
34	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ 13.13	$ -
35				
36	1 1/2 - INCH			
37	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 34,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
38	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
39	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -
40				
41	2 - INCH			
42	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 45,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
43	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - 45,001 TO ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
44	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -
45				
46	3 - INCH			
47	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 68,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
48	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - 68,001 TO ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
49	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -
50				
51	4 - INCH			
52	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 90,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
53	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - 90,001 TO ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
54	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -
55				
56	6 - INCH			
57	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 135,000 GALLONS:	$ 5.91	$ 10.92	$ 6.75
58	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - 135,001 TO ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
59	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -
60				
61	8 - INCH			
62	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 0 GALLONS:	$ 5.91	$ 10.92	$ 6.75
63	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
64	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -
65				
66	10 - INCH			
67	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - ZERO TO 0 GALLONS:	$ 5.91	$ 10.92	$ 6.75
68	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ 7.11	$ 13.13	$ 8.10
69	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) - OVER ######### GALLONS:	$ -	$ -	$ -

GOODMAN WATER COMPANY - COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
MONTHLY MINIMUM CHARGES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-4

LINE NO.	METER SIZE	(A) COMPANY PRESENT RATES	(B) COMPANY PROPOSED RATES	(C) COMPANY DOLLAR INCREASE	(D) COMPANY PERCENT. INCREASE	(E) RUCO RECOMMENDED RATES	(F) RUCO DOLLAR INCREASE	(G) RUCO PERCENT. INCREASE
1	5/8 - INCH	$ 42.20	$ 56.97	$ 14.77	35.00%	$ 38.60	$ (3.60)	-8.53%
2	3/4 - INCH	63.30	85.46	22.16	35.01%	57.90	(5.40)	-8.53%
3	1 - INCH	105.50	142.43	36.93	35.01%	96.50	(9.00)	-8.53%
4	1 1/2 - INCH	211.50	284.85	73.35	34.68%	193.00	(18.50)	-8.75%
5	2 - INCH	339.68	455.76	116.08	34.17%	308.80	(30.88)	-9.09%
6	3 - INCH	675.20	911.52	236.32	35.00%	579.00	(96.20)	-14.25%
7	4 - INCH	1,055.00	1,424.25	369.25	35.00%	965.00	(90.00)	-8.53%
8	6 - INCH	2,110.00	2,848.50	738.50	35.00%	1,930.00	(180.00)	-8.53%
9	8 - INCH	0.00	0.00	0.00	#DIV/0!	3,860.00	3,860.00	#DIV/0!
10	10 - INCH	0.00	0.00	0.00	#DIV/0!	7,720.00	7,720.00	#DIV/0!
11	GALLONS INCLUDED IN MONHTLY MINIMUM CHARGE	0	0			0		

REFERENCES
COLUMN (A) THRU COLUMN (D): COMPANY SCHEDULE H-3, PAGE 1 OF 3
COLUMN (E): TESTIMONY XXX
COLUMN (F): COLUMN (E) - COLUMN (A)
COLUMN (G): COLUMN (F) ÷ COLUMN (A)

GOODMAN WATER COMPANY - COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-5

RUCO RECOMMENDED RATES

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	$38.60	$57.90	$96.50	$193.00	$308.80	$579.00	$965.00	$1,930.00	$3,860.00	$7,720.00
2	1,000	43.10	62.40	103.25	199.75	315.55	585.75	971.75	1,936.75	3,868.10	7,728.10
3	2,000	47.60	66.90	110.00	206.50	322.30	592.50	978.50	1,943.50	3,876.20	7,736.20
4	3,000	52.10	71.40	116.75	213.25	329.05	599.25	985.25	1,950.25	3,884.30	7,744.30
5	4,000	56.60	75.90	123.50	220.00	335.80	606.00	992.00	1,957.00	3,892.40	7,752.40
6	5,000	63.35	82.65	130.25	226.75	342.55	612.75	998.75	1,963.75	3,900.50	7,760.50
7	6,000	70.10	89.40	137.00	233.50	349.30	619.50	1,005.50	1,970.50	3,908.60	7,768.60
8	7,000	76.85	96.15	143.75	240.25	356.05	626.25	1,012.25	1,977.25	3,916.70	7,776.70
9	8,000	83.60	102.90	150.50	247.00	362.80	633.00	1,019.00	1,984.00	3,924.80	7,784.80
10	9,000	90.35	109.65	157.25	253.75	369.55	639.75	1,025.75	1,990.75	3,932.90	7,792.90
11	10,000	98.45	117.75	164.00	260.50	376.30	646.50	1,032.50	1,997.50	3,941.00	7,801.00
12	15,000	138.95	158.25	197.75	294.25	410.05	680.25	1,066.25	2,031.25	3,981.50	7,841.50
13	20,000	179.45	198.75	231.50	328.00	443.80	714.00	1,100.00	2,065.00	4,022.00	7,882.00
14	25,000	219.95	239.25	268.63	361.75	477.55	747.75	1,133.75	2,098.75	4,062.50	7,922.50
15	50,000	422.45	441.75	471.13	552.10	653.05	916.50	1,302.50	2,267.50	4,265.00	8,125.00
16	75,000	624.95	644.25	673.63	754.60	855.55	1,094.70	1,471.25	2,436.25	4,467.50	8,327.50
17	100,000	827.45	846.75	876.13	957.10	1,058.05	1,297.20	1,653.50	2,605.00	4,670.00	8,530.00
18	125,000	1,029.95	1,049.25	1,078.63	1,159.60	1,260.55	1,499.70	1,856.00	2,773.75	4,872.50	8,732.50
19	150,000	1,232.45	1,251.75	1,281.13	1,362.10	1,463.05	1,702.20	2,058.50	2,962.75	5,075.00	8,935.00
20	175,000	1,434.95	1,454.25	1,483.63	1,564.60	1,665.55	1,904.70	2,261.00	3,165.25	5,277.50	9,137.50
21	200,000	1,637.45	1,656.75	1,686.13	1,767.10	1,868.05	2,107.20	2,463.50	3,367.75	5,480.00	9,340.00
22	250,000	2,042.45	2,061.75	2,091.13	2,172.10	2,273.05	2,512.20	2,868.50	3,772.75	5,885.00	9,745.00
23	500,000	4,067.45	4,086.75	4,116.13	4,197.10	4,298.05	4,537.20	4,893.50	5,797.75	7,910.00	11,770.00
24	1,000,000	8,117.45	8,136.75	8,166.13	8,247.10	8,348.05	8,587.20	8,943.50	9,847.75	11,960.00	15,820.00
25	2,000,000	16,217.45	16,236.75	16,266.13	16,347.10	16,448.05	16,687.20	17,043.50	17,947.75	20,060.00	23,920.00
26	3,000,000	24,317.45	24,336.75	24,366.13	24,447.10	24,548.05	24,787.20	25,143.50	26,047.75	28,160.00	32,020.00
27	4,000,000	32,417.45	32,436.75	32,466.13	32,547.10	32,648.05	32,887.20	33,243.50	34,147.75	36,260.00	40,120.00
28	5,000,000	40,517.45	40,536.75	40,566.13	40,647.10	40,748.05	40,987.20	41,343.50	42,247.75	44,360.00	48,220.00
29											
30											
31	AVG. NO. OF CUST:	0	0	2	0	2	0	0	0	0	0
32											
33	AVG. USE (GAL.):	#DIV/0!	#DIV/0!	61,520	3,000	65,731	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
34	MONTHLY BILL:	#DIV/0!	#DIV/0!	$564.44	$213.25	$780.47	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35											
36	MEDIAN USE (GAL.) :	#DIV/0!	#DIV/0!	100,392	3,000	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	MONTHLY BILL:	#DIV/0!	#DIV/0!	$879.30	$213.25	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

GOODMAN WATER COMPANY - COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-6

RUCO RECOMMENDED CHANGES EXPRESSED IN DOLLARS

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	($3.60)	($5.40)	($9.00)	($18.50)	($30.88)	($96.20)	($90.00)	($180.00)	$3,860.00	$7,720.00
2	1,000	(3.05)	(4.85)	(8.16)	(17.66)	(30.04)	(95.36)	(89.16)	(179.16)	3,860.99	7,720.99
3	2,000	(2.50)	(4.30)	(7.32)	(16.82)	(29.20)	(94.52)	(88.32)	(178.32)	3,861.98	7,721.98
4	3,000	(1.95)	(3.75)	(6.48)	(15.98)	(28.36)	(93.68)	(87.48)	(177.48)	3,862.97	7,722.97
5	4,000	(1.40)	(3.20)	(5.64)	(15.14)	(27.52)	(92.84)	(86.64)	(176.64)	3,863.96	7,723.96
6	5,000	(0.56)	(2.36)	(4.80)	(14.30)	(26.68)	(92.00)	(85.80)	(175.80)	3,864.95	7,724.95
7	6,000	0.28	(1.52)	(3.96)	(13.46)	(25.84)	(91.16)	(84.96)	(174.96)	3,865.94	7,725.94
8	7,000	1.12	(0.68)	(3.12)	(12.62)	(25.00)	(90.32)	(84.12)	(174.12)	3,866.93	7,726.93
9	8,000	1.96	0.16	(2.28)	(11.78)	(24.16)	(89.48)	(83.28)	(173.28)	3,867.92	7,727.92
10	9,000	2.80	1.00	(1.44)	(10.94)	(23.32)	(88.64)	(82.44)	(172.44)	3,868.91	7,728.91
11	10,000	3.79	1.99	(0.60)	(10.10)	(22.48)	(87.80)	(81.60)	(171.60)	3,869.90	7,729.90
12	15,000	8.74	6.94	3.60	(5.90)	(18.28)	(83.60)	(77.40)	(167.40)	3,874.85	7,734.85
13	20,000	13.69	11.89	7.80	(1.70)	(14.08)	(79.40)	(73.20)	(163.20)	3,879.80	7,739.80
14	25,000	18.64	16.84	12.38	2.50	(9.88)	(75.20)	(69.00)	(159.00)	3,884.75	7,744.75
15	50,000	43.39	41.59	37.13	25.90	11.87	(54.20)	(48.00)	(138.00)	3,909.50	7,769.50
16	75,000	68.14	66.34	61.88	50.65	36.62	(32.15)	(27.00)	(117.00)	3,934.25	7,794.25
17	100,000	92.89	91.09	86.63	75.40	61.37	(7.40)	(4.50)	(96.00)	3,959.00	7,819.00
18	125,000	117.64	115.84	111.38	100.15	86.12	17.35	20.25	(75.00)	3,983.75	7,843.75
19	150,000	142.39	140.59	136.13	124.90	110.87	42.10	45.00	(51.75)	4,008.50	7,868.50
20	175,000	167.14	165.34	160.88	149.65	135.62	66.85	69.75	(27.00)	4,033.25	7,893.25
21	200,000	191.89	190.09	185.63	174.40	160.37	91.60	94.50	(2.25)	4,058.00	7,918.00
22	250,000	241.39	239.59	235.13	223.90	209.87	141.10	144.00	47.25	4,107.50	7,967.50
23	500,000	488.89	487.09	482.63	471.40	457.37	388.60	391.50	294.75	4,355.00	8,215.00
24	1,000,000	983.89	982.09	977.63	966.40	952.37	883.60	886.50	789.75	4,850.00	8,710.00
25	2,000,000	1,973.89	1,972.09	1,967.63	1,956.40	1,942.37	1,873.60	1,876.50	1,779.75	5,840.00	9,700.00
26	3,000,000	2,963.89	2,962.09	2,957.63	2,946.40	2,932.37	2,863.60	2,866.50	2,769.75	6,830.00	10,690.00
27	4,000,000	3,953.89	3,952.09	3,947.63	3,936.40	3,922.37	3,853.60	3,856.50	3,759.75	7,820.00	11,680.00
28	5,000,000	4,943.89	4,942.09	4,937.63	4,926.40	4,912.37	4,843.60	4,846.50	4,749.75	8,810.00	12,670.00
29											
30											
31	AVG. NO. OF CUST:	0	0	2	0	2	0	0	0	0	0
32											
33	AVG. USE (GAL.):	#DIV/0!	#DIV/0!	61,520	3,000	65,731	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
34	MONTHLY BILL:	#DIV/0!	#DIV/0!	$48.53	($15.98)	$27.45	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35											
36	MEDIAN USE (GAL.) :	#DIV/0!	#DIV/0!	100,392	3,000	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	MONTHLY BILL:	#DIV/0!	#DIV/0!	$87.02	($15.98)	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

STANDPIPE RATE DESIGN

GOODMAN WATER COMPANY - CONSTRUCTION / STANDPIPE RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
SUMMARY OF PRESENT, COMPANY PROPOSED & RUCO RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-1

RATE SUMMARY

Present Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8- INCH	12	5,347,337	0	$0.00	$0	486,122	$3,456	0	$0	0	$0	$3,456
3/4 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
1 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
1 1/2 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	12	5,347,337	0		$0	486,122	$3,456	0	$0	0	$0	$3,456

Company Proposed Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8- INCH	12	5,347,337	0	$0.00	$0	486,122	$6,382	0	$0	0	$0	$6,382
3/4 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
1 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
1 1/2 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	12	5,347,337	0		$0	486,122	$6,382	0	$0	0	$0	$6,382

RUCO Recommended Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8- INCH	12	5,347,337	0	$0.00	$0	486,122	$3,938	0	$0	0	$0	$3,938
3/4 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
1 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
1 1/2 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	12	5,347,337	0		$0	486,122	$3,938	0	$0	0	$0	$3,938

GOODMAN WATER COMPANY - CONSTRUCTION / STANDPIPE RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-1

LINE NO.	DESCRIPTION						PRESENT RATES	COMPANY PROPOSED	RUCO PROPOSED
1	**RECOMMENDED MONTHLY MINIMUM USAGE CHARGE:**								
2									
3	(RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS)								
4	5/8- INCH						$0.00	$0.00	$0.00
5	3/4 - INCH						0.00	0.00	0.00
6	1 - INCH						0.00	0.00	0.00
7	1 1/2 - INCH						0.00	0.00	0.00
8	2 - INCH						0.00	0.00	0.00
9	3 - INCH						0.00	0.00	0.00
10	4 - INCH						0.00	0.00	0.00
11	6 - INCH						0.00	0.00	0.00
12	8 - INCH						0.00	0.00	0.00
13	10 - INCH						0.00	0.00	0.00
14									
15	**GALLONS INCLUDED IN MONTHLY MINIMUM USAGE CHARGE:**								
16									
17	RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS						0	0	0
18									
19	**RECOMMENDED COMMODITY RATES BY METER SIZE**								
20									
21	5/8- INCH								
22	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.13	$ 8.10
23	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	999,999,999,999,999,000	TO	0	GALLONS:		$ -	$ -	$ -
24	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
25									
26	3/4 - INCH								
27	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
28	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
29	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
30									
31	1 - INCH								
32	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
33	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
34	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
35									
36	1 1/2 - INCH								
37	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
38	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
39	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
40									
41	2 - INCH								
42	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
43	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	1	TO	0	GALLONS:		$ -	$ -	$ -
44	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
45									
46	3 - INCH								
47	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
48	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	1	TO	0	GALLONS:		$ -	$ -	$ -
49	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
50									
51	4 - INCH								
52	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
53	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	1	TO	0	GALLONS:		$ -	$ -	$ -
54	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
55									
56	6 - INCH								
57	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
58	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	1	TO	0	GALLONS:		$ -	$ -	$ -
59	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
60									
61	8 - INCH								
62	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
63	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
64	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
65									
66	10 - INCH								
67	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ -	$ -	$ 8.10
68	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -
69	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		0	GALLONS:		$ -	$ -	$ -

GOODMAN WATER COMPANY - CONSTRUCTION / STANDPIPE RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-3

RUCO RECOMMENDED RATES

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
2	1,000	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10	8.10
3	2,000	16.20	16.20	16.20	16.20	16.20	16.20	16.20	16.20	16.20	16.20
4	3,000	24.30	24.30	24.30	24.30	24.30	24.30	24.30	24.30	24.30	24.30
5	4,000	32.40	32.40	32.40	32.40	32.40	32.40	32.40	32.40	32.40	32.40
6	5,000	40.50	40.50	40.50	40.50	40.50	40.50	40.50	40.50	40.50	40.50
7	6,000	48.60	48.60	48.60	48.60	48.60	48.60	48.60	48.60	48.60	48.60
8	7,000	56.70	56.70	56.70	56.70	56.70	56.70	56.70	56.70	56.70	56.70
9	8,000	64.80	64.80	64.80	64.80	64.80	64.80	64.80	64.80	64.80	64.80
10	9,000	72.90	72.90	72.90	72.90	72.90	72.90	72.90	72.90	72.90	72.90
11	10,000	81.00	81.00	81.00	81.00	81.00	81.00	81.00	81.00	81.00	81.00
12	15,000	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50	121.50
13	20,000	162.00	162.00	162.00	162.00	162.00	162.00	162.00	162.00	162.00	162.00
14	25,000	202.50	202.50	202.50	202.50	202.50	202.50	202.50	202.50	202.50	202.50
15	50,000	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00	405.00
16	75,000	607.50	607.50	607.50	607.50	607.50	607.50	607.50	607.50	607.50	607.50
17	100,000	810.00	810.00	810.00	810.00	810.00	810.00	810.00	810.00	810.00	810.00
18	125,000	1,012.50	1,012.50	1,012.50	1,012.50	1,012.50	1,012.50	1,012.50	1,012.50	1,012.50	1,012.50
19	150,000	1,215.00	1,215.00	1,215.00	1,215.00	1,215.00	1,215.00	1,215.00	1,215.00	1,215.00	1,215.00
20	175,000	1,417.50	1,417.50	1,417.50	1,417.50	1,417.50	1,417.50	1,417.50	1,417.50	1,417.50	1,417.50
21	200,000	1,620.00	1,620.00	1,620.00	1,620.00	1,620.00	1,620.00	1,620.00	1,620.00	1,620.00	1,620.00
22	250,000	2,025.00	2,025.00	2,025.00	2,025.00	2,025.00	2,025.00	2,025.00	2,025.00	2,025.00	2,025.00
23	500,000	4,050.00	4,050.00	4,050.00	4,050.00	4,050.00	4,050.00	4,050.00	4,050.00	4,050.00	4,050.00
24	1,000,000	8,100.00	8,100.00	8,100.00	8,100.00	8,100.00	8,100.00	8,100.00	8,100.00	8,100.00	8,100.00
25	2,000,000	16,200.00	16,200.00	16,200.00	16,200.00	16,200.00	16,200.00	16,200.00	16,200.00	16,200.00	16,200.00
26	3,000,000	24,300.00	24,300.00	24,300.00	24,300.00	24,300.00	24,300.00	24,300.00	24,300.00	24,300.00	24,300.00
27	4,000,000	32,400.00	32,400.00	32,400.00	32,400.00	32,400.00	32,400.00	32,400.00	32,400.00	32,400.00	32,400.00
28	5,000,000	40,500.00	40,500.00	40,500.00	40,500.00	40,500.00	40,500.00	40,500.00	40,500.00	40,500.00	40,500.00
29											
30											
31	AVG. NO. OF CUST:	1	0	0	0	0	0	0	0	0	0
32											
33	AVG. USE (GAL.):	40,500	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
34	MONTHLY BILL:	$328.05	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
35											
36	MEDIAN USE (GAL.) :	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!
37	MONTHLY BILL:	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!	#DIV/0!

EXHIBIT
RUCO
ADMITTED

GOODMAN WATER COMPANY

DOCKET NO. W-02500A-10-0382

SURREBUTTAL TESTIMONY

OF

TIMOTHY J. COLEY

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

JUNE 13, 2011

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INTRODUCTION

Q. Please state your name for the record.

A. My name is Timothy J. Coley.

Q. Have you previously filed testimony regarding this docket?

A. Yes, I have. I filed direct testimony in this docket on March 21, 2011.

Q. What is the purpose of your surrebuttal testimony?

A. My surrebuttal testimony will address Goodman Water Company's ("GWC" or "Company") rebuttal comments pertaining to the adjustments I recommended in my direct testimony. This testimony will address RUCO's recommended revenue requirements, rate base, operating revenue and expense adjustments along with rate design. As a final issue, I will propose a hookup fee ("HUF") that the Commission may consider.

The Director of RUCO, Ms. Jodi Jerich, will sponsor separate testimony on RUCO's policy issues pertaining to GWC's excess capacity. Ms. Jerich will also sponsor RUCO's position regarding the Company's additional rebuttal rate case expense request.

Mr. William Rigsby will sponsor RUCO's recommended cost of capital for the Company.

SUMMARY OF RECOMMENDATIONS

Required Revenue

Q. What are RUCO's recommended surrebuttal revenue requirements for GWC?

A. RUCO's recommended Original Cost and Fair Value Rate Base ("OCRB" and "FVRB") is $1,755,118. The total increase in gross revenue is $8,715.

Rate Base Adjustments

Adjustment No. 1 - Accumulated Depreciation – This is the same adjustment that RUCO made in its direct testimony and was fully explained there. The adjustment corrected a Company depreciation expense formula and increased accumulated depreciation by $3,268 accordingly.

Adjustment No. 2 – Excess Capacity – RUCO's surrebuttal excess capacity methodology differs from the methodology RUCO used in its direct testimony. However, I did mention this alternative methodology in my direct testimony on pages 15 and 16. The adjustment reduces plant in service by $1,360,580 and accumulated depreciation by $269,307, which RUCO deems as excess capacity. This will be discussed in great detail later.

Adjustment No. 3 – Advances in Aid of Construction ("AIAC") – This is a corresponding adjustment to RUCO's rate base adjustment #2 above for AIAC. The adjustment reduces the AIAC balance by $497,983 thereby increasing rate base accordingly. This too will be discussed in greater detail later.

Adjustment No. 4 – Accumulated Deferred Income Taxes ("ADIT") – This adjustment is a result of RUCO's three previous rate base adjustments to plant, accumulated depreciation, and AIAC. The adjustment increases the ADIT liability balance by $50,545 thereby decreasing rate base correspondingly.

Operating Income Adjustments

Adjustment No. 1 – Depreciation Expense – This adjustment is the result of RUCO's recommended plant balances that RUCO deems as used and useful. The adjustment reduces the Company's depreciation expense by $44,136.

Adjustment No. 2 – Property Tax – This adjustment is the result of RUCO's recommended levels of gross revenues. The adjustment reduces the Company's property tax expense by $3,570.

Adjustment No. 3 – Revenue and Expense Annualization – RUCO accepts the Company's revised rebuttal revenue and expense annualization calculation. The adjustment increases revenue by $21,708 and purchased power by $577 on a going forward basis.

Adjustment No. 4 – Salaries & Wages – This adjustment was explained in my direct testimony. It reduces salary and wage expense by $4,986 based on the Consumer Price Index ("CPI"). An additional complementary adjustment to taxes other than income tax expense associated with these salaries and wages was made that reduced those taxes by $372.

Adjustment No. 5 – Contractual Services – This adjustment was explained in my direct testimony also. It reduces contractual services expense by $2,493 based on the CPI too. No additional complementary adjustment to taxes other than income tax expense is necessary for this adjustment.

Adjustment No. 6 – Water Testing – The Commission Engineering Staff recommended this adjustment in its direct testimony to increase water testing expense by $1,568. RUCO hereby adopts Staff's proposed adjustment here in its surrebuttal testimony.

Adjustment No. 7 – Income Tax – This adjustment is a direct result of RUCO's level of operating income less income taxes that is taxed by the

federal and state governments. The adjustment increases income tax expense by $17,162.

Rate Design

Q. What type of rate design is RUCO recommending?

A. RUCO is recommending a rate design that is quite similar to what the Company proposes but of course using RUCO's recommended increase in gross revenue. The rate design consists of three-inverted blocks of rates for the 5/8 x 3/4 inch and ¾ inch meters for all classes of customers. The remaining meter sizes consist of two-inverted blocks of rates. RUCO utilizes the same break-over points of usage that the Company proposes. Both RUCO and the Company propose shifting more revenue to the commodity charge rather than the monthly minimum as the present rates currently do. The rates are shown on RUCO's Rate Design Schedules TJC RD-1 thru TJC RD-7.

Other Issues

Hookup Fee ("HUF") Tariff

Q. Is RUCO proposing a HUF in the instant case for GWC?

A. Yes.

Q. Please describe the HUF that RUCO proposes?

A. RUCO proposes the following HUF:

RUCO's Proposed Off-site Facilities Hook-up Fees bv Meter Size

Meter Size	Amount	
5/8 Inch	$ 150	
3/4 Inch	225	Scaled on 5/8 meter flow
1 Inch	375	Scaled on 5/8 meter flow
1 1/2 Inch	750	Scaled on 5/8 meter flow
2 Inch	1,200	Scaled on 5/8 meter flow
3 inch	2,400	Scaled on 518 meter flow
4 Inch	3,750	Scaled on 5/8 meter flow
6 Inch	4,500	Scaled on 5/8 meter flow

Q. How did RUCO determine its proposed HUF tariff?

A. In the Company's response to RUCO data request 4.08, GWC stated, "The Company's construction expenditures in 2010 were approximately $5,500. These expenditures related to meter and meter installations, and were recorded accordingly." The Company's 2010 Annual Report indicates that GWC added 40 new customers since Mr. Bourassa's revised rebuttal Schedule H filing. That results in approximately $150 of capital expenditures per new connection as shown above for the 5/8 inch meter. The remaining meters are scaled on the 5/8 meter using the NARUC meter multiplier.

Since the Company has plant in place to serve up to 1,800 customers[1], the HUF fee needs only to cover the costs of the meters and their installation. Any amount higher than this would provide the utility excess cash beyond the true costs of the hook-up.

Q. How does RUCO propose the Company record the HUF?

A. RUCO proposes that the Company should record the HUF as contributions in aid of construction.

Deferred Depreciation Expense Accounting Order

Q. Is RUCO proposing the Commission adopt an accounting order that would allow the Company to recover the depreciation expense forgone from RUCO excluding the plant from rate base in its excess capacity adjustment?

A. Yes. Exclusion of the excess capacity in current rates merely changes from whom the costs are recovered and when. When growth actually occurs, the full amount of the investment found at that time to be prudent would receive rate base treatment and rate recovery. RUCO also recommends that any excess capacity disallowance in this case carry with it an accounting order that would allow the Company to eventually recover any depreciation expense that accrued on the excess capacity prior to the time it was placed in rate base. This would be accomplished through a

[1] Staff Report, September 2, 2010, p. 2.

deferral accounting order and eventual amortization when the capacity becomes used and useful. Thus, once new customers materialize and the excess portions of the plant are placed in rate base, the Company would be made whole.

ORIGINAL COST RATE BASE ("OCRB") ADJUSTMENTS

Adjustment No. 1 – Accumulated Depreciation

Q. Please explain RUCO's adjustment that increased the Company's accumulated depreciation balance by $3,268?

A. This adjustment was explained in detail in my direct testimony. In short, the adjustment corrected the Company's depreciation expense formulae in year 2007 when two different depreciation rates were utilized.

Q. Did the Company accept RUCO's correction to the depreciation expense calculation for year 2007?

A. Yes. The Company made rebuttal adjustment #2 labeled (C) that corrected the depreciation expense calculation for year 2007.

Adjustment No. 2 – Excess Capacity

Q. Did the Company accept RUCO's excess capacity adjustment?

A. No. However, the Company did make two adjustments that reduced plant in service by $107,350, which could be viewed as excess capacity adjustments.

Q. How did the Company respond to RUCO's excess capacity adjustment?

A. The Company said it "strongly disagrees with RUCO's arithmetic approach and resulting conclusion." In essence, the Company claims I am unqualified to make an excess capacity adjustment since I am not a licensed professional engineer. GWC also stated that, "Under RUCO's approach, RUCO eliminates 43% of the cost of the 400,000 gallon storage tank at Water Plant No. 1."

The Company is critical of RUCO's excess capacity adjustment on several other points. First the Company stated, "RUCO also eliminates 43% of the meter costs even though there are only 649 meters installed at the end of the test year and the fact that there were over 620 active customers at the end of the test year. In other words, RUCO's recommendation only recognizes the cost of about 370 meters (649 X 57%)." Second, the Company stated "that RUCO eliminates 43% of the cost of the Company's two (2) wells. Whereas, Mr. Scott and Mr. Taylor find that both wells are necessary and used and useful."

Finally, the Company concludes that the basis for RUCO's excess capacity adjustment was flawed because "RUCO believes the Company over-anticipated GWC's build-out date and constructed plant to serve the projected build out. However, Mr. Coley's analysis is an after-the-fact analysis. As previously indicated, the Company acted prudently in

building plant based upon what was known at the time the plant design and construction decisions were made."

Q. How do you respond to the Company's assertions regarding RUCO's excess capacity adjustment?

A. First, I agree with the Company that I am not a licensed professional engineer. But as this Commission has made clear before, one does not have to be an engineer to determine what plant is used and useful. In Decision No. 58743, in the matter of the Application of Pima Utility, this Commission said:

> Although there was evidence that a small percentage of this additional plant may be considered used and useful from an engineering perspective, as of the date of this hearing, for ratemaking purposes this additional plant is not used and useful under the circumstances."

I am also not an attorney, but I am a rate analyst, and the Commission has made it clear in numerous cases, including Pima Utility and the recent Gold Canyon case, Decision No. 70624, that excess capacity is not reserved only for the opinion of an engineer. The Company's one-dimensional view of this issue flies in the face of what this Commission has decided on this issue historically.

All intervening parties in this case made an excess capacity adjustment to some varying degree in direct testimonies except for the Company until its rebuttal testimony. It is obvious to most of us that some level of excess

capacity exists either through an engineering analysis or an accounting analysis.

Even Staff's engineer has concluded that there is excess capacity. Staff and the Company cannot even agree on what an appropriate "engineering analysis" should be. They both have a different "planning horizon".

RUCO's analysis included recognition of the Company's engineering design and Staff's engineering reports over several years. In fact in RUCO's direct testimony schedules, RUCO's denominator in its excess capacity factor came straight from Westland Resources, Inc., which outlines the "Planning and Design Criteria EDU's" that was used to design GWC's water system. I would contend that RUCO's methodology to make its excess capacity adjustment is more than a mere "arithmetic approach." The calculation is 50 percent of actual customer growth (accounting in nature) and 50 percent from an engineering firm's design report that designed GWC's water system.

Q. Mr. Coley, from the 500 foot level, why does RUCO believe its excess capacity methodology is preferable to the Company and Staff's?

A. The Company and Staff have performed an "engineering analysis" to determine excess capacity. The "engineering analysis" looks at a "planning horizon" which includes estimates of customer growth over a

five year period. Under the engineering approach, as long as the estimates were reasonable at they time they were made, the plant that was built to serve the growth is recoverable.

From RUCO's perspective, the problem with the "engineering analysis" is that the risk that the customer growth will not occur is all placed on the current ratepayers. In cases like the present case where the growth estimates were grossly overstated, the current ratepayers are being asked to shoulder a very heavy burden. Only in a regulatory environment can such a lopsided analysis ever be considered. This is further supported and discussed in Ms. Jerich's testimony.

As Ms. Jerich's testimony will explain, RUCO does not buy into the "engineering analysis". Rather, RUCO's position is that the current customers should only have to pay for the plant designed for them that is currently and actually being used. This is a standard and well known ratemaking principle and should not be abandoned here.

The utility's claim that RUCO's position is a disincentive for the utility to build new plant because the utility will not recover its costs if their growth projections are wrong. RUCO recognizes this concern and agrees that it is a valid concern. In response, RUCO proposes a "reserve margin" which is an amount of excess capacity, not the full amount, consistent with the facts and circumstances of any given case that will allow the utility's

recovery of a portion of the excess capacity for the purpose of providing an incentive to build.

RUCO's position, conceptually, is a mitigating position designed to balance the risk between shareholders and ratepayers of un-obtained growth. Without that balance, the Company has no incentive to check its growth projections. Furthermore, RUCO has never proposed that the Company not recover that portion of the excess capacity that is denied. RUCO agrees that the Company should recover the excess capacity when it becomes used and useful.

Q. Please address the Company's assertion that RUCO's excess capacity adjustment eliminates 43 percent of a 400,000 gallon storage tank at Water Plant No. 1.

A. I agree with the Company that RUCO's direct testimony excess capacity adjustment did indeed remove approximately 43 percent of the 400,000 gallon storage tank at Water Plant No. 1. The adjustment has been modified and updated in RUCO's surrebuttal excess capacity adjustment, which now allows recovery of 100 percent of that water storage tank. This is reflected in RUCO's Surrebuttal Schedule TJC-5. RUCO's surrebuttal adjustment for excess capacity will be discussed in great detail later in this testimony.

Q. Please respond to the Company's claim that RUCO's direct testimony adjustment for excess capacity eliminates 43% of the meter costs.

A. RUCO again agrees with the Company's claim that RUCO's excess capacity methodology that was utilized in its direct testimony did in fact remove approximately 43 percent of the meter costs. This too has been modified and updated in surrebuttal testimony. Now, 100 percent of the meters are considered to be used and useful. This is also reflected in RUCO's Surrebuttal Schedule TJC-5.

In addition to the meter costs, RUCO also modified and updated its direct testimony excess capacity adjustment here in the surrebuttal phase to account for the services and hydrants accounts as 100 percent used and useful as shown on RUCO Schedule TJC-5 too.

Q. Please respond to the Company's assertion that RUCO eliminated 43 percent of the cost of the Company's two wells in its direct testimony excess capacity adjustment.

A. RUCO agrees with the Company that the direct testimony adjustment for excess capacity did eliminate approximately 43 percent of the two wells. Again, this adjustment has been modified and updated in RUCO's surrebuttal testimony. RUCO now recognizes the two wells as being 100 percent used and useful. This is shown on RUCO Surrebuttal Schedule TJC-5 also.

Q. Earlier you mentioned the Company made two rebuttal adjustments that reduced plant in service by $107,350, what two adjustments did GWC make in its rebuttal filing that reduced plant in service by the $107,350?

A. The Company claimed to remove the "cost" of over sizing the 530,000 gallon water storage tank plant addition at Water Plant No. 3, which the Company claimed the cost was $72,350. In addition, GWC reduced the cost of an inter-Company land acquisition by $35,000 for a total Company rebuttal adjustment of $107,350.

Q. Does RUCO agree with the Company's rebuttal adjustments to plant in service that reduces rate base by $107,350?

A. RUCO agrees that an adjustment is necessary to reduce plant in service for both of the accounts referenced above. However, RUCO does not believe the Company's adjustments go far enough. The Company appears to have made a small acknowledgement of excess capacity, but the evidence demands a much larger adjustment.

Q. What adjustments does RUCO recommend for the land and storage tanks accounts in its surrebuttal testimony?

A. Both RUCO and the Commission Staff recommend the Commission adopt much larger adjustments for both of the accounts. RUCO recommends reducing the land account by $225,673 while Staff recommended a direct testimony adjustment that decreases the cost basis of the Company's

2008 land purchase by $369,500 because it was a non-arm's-length transaction.

As for the storage tank over sizing adjustment, RUCO recommends an adjustment to reduce the account balance by $194,456. Staff recommended decreasing the storage tank account by $185,049 in its direct testimony. I might add that the Eagle Crest Ranch Subdivision Homeowners ("ECR") also recommended reducing both of the accounts.

Q. What amounts did ECR recommend to decrease the land and storage tank accounts by?

A. From reviewing their testimony, it is difficult to determine the exact amounts that ECR is recommending, but its overall excess capacity adjustment recommendation is in the ballpark of both RUCO and Staff's recommendations regarding those two accounts.

Q. Specifically, does RUCO agree with the Company's adjustment to reduce the cost for "over sizing" the storage tank account by $72,350?

A. No.

Q. Please explain RUCO's reason for disagreeing with the Company's $72,350 reduction for "over sizing" the storage tank account for Water Plant No. 3.

A. The "over sizing" was a direct result of the Company's intention to serve an additional or extension of GWC's current Certificate of Convenience & Necessity ("CC&N") located west of Oracle Road. Since the Company "over sized" the tank by 190,000 gallons, RUCO's rationale was that the Company "over sized" the tank by 35.85 percent (190,000 gallons / 530,000 gallons = 35.85 percent). RUCO's excess capacity factor of 35.85 was multiplied by the $542,431 of the total storage tank plant additions in 2007 and 2008 for Water Plant No. 3. All costs associated with Water Plant No. 3 should be subject to the excess capacity adjustment and not just the additional metal that it took to "over size" the tank vessel itself.

Q. Does RUCO have any other concerns regarding the "over sizing" of Water Plant No. 3 storage tank?

A. Yes. The Company booked $72,350 in 2007 of what it describes as the cost for the storage tank's "over sizing" while the remaining $470,081 to complete the tank's construction was not booked until one-year later in 2008. This appears to be a classic case of putting the buggy in front of the horse to RUCO. At the time of this writing, RUCO has issued a data request seeking more information about this bizarre booking of costs. The

question is how one knows its precise costs before something is completely built and all invoices have been issued and received.

RUCO's excess capacity storage tank adjustment of $194,456 is reflected in surrebuttal Schedule TJC-5.

Q. In your surrebuttal summary of rate base adjustments section, you mentioned that RUCO's methodology in calculating its excess capacity differed in direct testimony than what RUCO proposes here in surrebuttal testimony. What is the primary difference in RUCO's methodology regarding its surrebuttal excess capacity adjustment?

A. The primary difference is RUCO's surrebuttal methodology focuses solely on GWC's plant additions since its last rate case and takes dead aim at those plant items. I will fully discuss this methodology in more detail next.

Q. Why did RUCO modify its methodology in surrebuttal?

A. The Company's rate analyst, Thomas Bourassa, stated, among other things that "RUCO uses the shotgun approach and reduces the cost of all plant without consideration as to whether plant is actually necessary and used and useful." RUCO does not necessarily agree with Mr. Bourassa on this issue as is discussed further in Ms. Jerich's testimony. However, the Company has raised some valid points and rather than parse arguments, RUCO has reconsidered its methodology for calculating its

excess capacity adjustment. RUCO's surrebuttal methodology is more adapted to the facts and circumstances of this case. RUCO's surrebuttal methodology is more of a rifle than shotgun shot approach aimed directly at the Company's plant additions since GWC's last rate case. Specifically, it is the Company's following eight plant accounts that RUCO deems as having excess capacity:

1. Organization
2. Land
3. Structures & Improvements
4. Electric Pumping Equipment
5. Water Treatment Equipment
6. Reservoirs & Standpipe
7. Transmission & Distribution Mains
8. Other Plant & Misc. Equip.

Q. Please explain the difference in RUCO's direct and surrebuttal methodologies for determining its excess capacity calculation in more detail.

A. RUCO's excess capacity methodology differs from its direct testimony in essentially two aspects. For comparative purposes, I will briefly summarize RUCO's direct excess capacity methodology. RUCO simply utilized the number of customer counts at the end of year 2010 - one-year post test year end – and added a ten percent reserve margin[2] (666 x 1.10 = 733). The number of customers at the end of year 2010 including the 10 percent reserve margin (733) was then divided by 1,288[3] equivalent

[2] Ms. Jerich discusses RUCO's ten percent reserve margin for this case in detail in her testimony.
[3] The 1,288 EDU's was reported by the Company in a compliance filing to the Commission, dated July 31, 2007 and was attached as an exhibit in RUCO's direct testimony as RUCO Exhibit 3. As

dwelling units ("EDU's") that the system was engineered and designed to serve (733 / 1,288 = 56.88%) to obtain the used and useful factor of 56.88 percent. The 56.88 percent used and useful factor was then multiplied by all total plant account balances, which resulted in RUCO's used and useful plant in service recommendation of $3,102,039 and was shown on RUCO's Direct Schedules TJC-5, TJC-3, and TJC-2.

Q. Please explain RUCO's surrebuttal methodology in determining its used and useful factor to account for GWC's excess capacity?

A. RUCO's surrebuttal excess capacity methodology measures the customer and plant growth on a percentage basis since the Company's last rate case, which utilized a test year end of September 30, 2005. In other words, it does not include plant and customers from the last rate case and earlier. GWC had **459** customers at the end of that test year. As in RUCO's direct testimony, RUCO simply utilized the number of customer counts at the end of year 2010 - one-year post test year end – and added a reserve margin of ten percent (666 customers x 1.10 reserve margin = **733**[4] customers) to obtain RUCO's first number in its customer growth calculation since GWC's last rate case.

a sanity check, RUCO utilized the Company's response to an "Intervenor's" data request number 3 labeled as Appendix "A" and was attached as RUCO Exhibit 4 in the same testimony.

[4] This number is rounded for presentation purposes. The actual number is 732.6.

Next, I subtract the **459** customers that GWC served in its last rate case at test year end September 30, 2005 from the **733** customers, as calculated above, which results in a customer growth number of **274** customers (733 – 459 = **274** additional customers) since GWC's last rate case. The **274** additional customers since the last rate case is then divided by the **459** customers GWC served at test year end September 30, 2005 (274 / 459 = **59.61%** customer growth rate since GWC's last rate case) that results in the **59.61** percent of customer growth since the Company's last rate case.

The final number of RUCO's surrebuttal excess capacity methodology measures GWC's plant growth in dollars since the Company's last rate case also. Commission Decision No. 69404, dated April 16, 2007, authorized $2,365,813 of gross plant in service. The Company has added $3,087,948 of plant additions since that previous rate case. That results in a **130.52** percent increase ($3,087,948 plant additions / $2,365,813 plant authorized in last rate case = **130.52%** increase in plant) in plant additions since September 30, 2005.

RUCO derives its surrebuttal used and useful factor of **45.67** percent, shown on Surrebuttal Schedule TJC-5, by dividing the customer growth rate of **59.61** percent, including the reserve margin, by the additional plant growth of **130.52** percent (59.61% customer growth / 130.52% plant growth = **45.67%**) since the Company's last rate case. Unlike RUCO's

direct testimony excess capacity methodology, RUCO's surrebuttal used and useful factor of **45.67** percent is multiplied by only the corresponding plant additions since GWC's last rate case.

Q. Did RUCO provide any direct testimony regarding its current surrebuttal excess capacity methodology?

A. Yes. RUCO's direct testimony on pages 15 and 16 summarized the methodology that is used here in its surrebuttal testimony. In addition, RUCO filed direct errata testimony that further discussed the excess capacity methodology used in its surrebuttal testimony.

Q. When answering the following question, please refer to the scenario in the table below:

Year	Number of Customers	Percentage of Customer Growth
2006	484[5]	
2007	579[6]	20%
2008	695[7]	20%
2009	834[8]	20%
2010	1,001[9]	20%

[5] GWC's actual year end customer counts in the Company's Annual Report filed with the ACC.
[6] Id.
[7] The projected 20% customer growth rate from the previous year.
[8] Id.
[9] Id.

Would RUCO be recommending an excess capacity adjustment in this case if the Company had actually experienced an annual growth rate of 20 percent through 2010?

A. No.

Q. Why not?

A. To plug those numbers, as shown in that table into RUCO's surrebuttal excess capacity calculation, as explained earlier, it would produce the following result:

(1,001 customers x 1.10 reserve margin) = **1,101**

$$\frac{1{,}101 - 459^{10}}{459} = \frac{642}{459} = 140\% \text{ customer growth}$$

As one can see, the 140 percent of customer growth since the Company's last rate case would exceed the 130.52 percent plant growth measured in dollars over the same time period as shown on the previous page. There would be no excess capacity in this scenario because customer growth did not lag behind the plant growth. However, this scenario did not play out. Thus, excess capacity exists that was built to serve future growth that does not exist today. The current ratepayers of GWC should not be held

[10] GWC's actual test year end September 30, 2005 customer count.

completely responsible for the Company's errant growth projections, which are shown and evidenced in RUCO's Exhibit 1.

Q. Did RUCO make any unique excess capacity adjustments for any of GWC's rate base items that did not utilize RUCO's 45.67 percent used and useful factor explained on the previous pages?

A. Yes. RUCO made two unique used and useful adjustments when accounting for its excess capacity adjustment(s).

Q. Please explain RUCO's excess capacity adjustments to the two rate base items that did not utilize the 45.67 percent used and useful factor that RUCO calculated and explained earlier?

A. The first rate base item concerns the plant account of Distribution Reservoirs & Standpipe. This was briefly discussed earlier. In determining the excess capacity factor for that account, RUCO simply divided the "over sized" 190,000 gallons, which the Company admitted to in its rebuttal testimony, by the 530,000 gallon total capacity of the storage tank (190,000 / 530,000 = 35.85%) to obtain the 35.85 percent excess capacity factor. The used and useful factor is the reciprocal of the excess capacity factor, which is 64.15 percent. The 64.15 percent was multiplied by the 2007 and 2008 Distribution Reservoirs & Standpipe plant additions totaling $542,431 since GWC's last rate case that resulted in $347,975

(64.15% x $542,431 = $347,975[11]) as being used and useful and the remaining $194,456 deemed as excess capacity, as previously noted on page 13. Please refer to that page for a further discussion regarding this storage tank adjustment.

Q. What is the second rate base item that RUCO utilized a different and unique used and useful factor when making its excess capacity adjustments?

A. The second rate base item that had a different and unique used and useful factor, other than the 45.67 percent referenced earlier, for the calculation of the excess capacity adjustment was AIAC. This will be discussed and explained more fully later in the surrebuttal adjustment section for AIAC.

Q. Is RUCO still asserting that the fire flow upgrades are a primary driver in its excess capacity adjustment?

A. No. In response to RUCO data request 4.05, the Company stated GWC "did not pay for or otherwise record any costs for upgrading the fire flow capacity for Water Plant #4." Although when first asked by the "Interveners" in data request 3.04, GWC requested more time to look into the fire flow upgrade costs and would provide a supplemental response later. RUCO never saw the Company's supplemental response to the

[11] Due to rounding the percentage in the calculation.

"Interveners" for this issue. The Company apparently did not know what it had paid for and what D. R. Horton Homes had paid for. That was somewhat confounding to RUCO.

Q. Is RUCO recommending the same excess capacity methodology as it did in the Gold Canyon case?

A. No. Gold Canyon involved a completely different set of facts and circumstances. RUCO's argument on excess capacity is the same, but the calculation used to arrive at its adjustment is different.

In Gold Canyon, RUCO calculated a reserve margin. The reserve margin was calculated as follows:

> As shown on Schedule RLM-4 under the heading "NOTE", the Company's data indicates at the end of 2005 the influent flow rate at the Gold Canyon Water Reclamation Facility was 0.708 mgd out of a maximum capacity of 1.9 mgd. This indicates that 62.74 percent of the total capacity in the new treatment plant is in excess of the test-year ratepayers needs. However, to incorporate an "excess reserve" component I selected the projected flow rate at the end of 2008 of 1.367 mgd (equating to an excess capacity of 28.05 percent) as a reasonable determinant to calculate the percentage of excess capacity at this wastewater treatment plant.

In the instant case, RUCO determined a 10 percent reserve margin is more appropriate. First, RUCO realizes that a water system cannot be designed to serve the exact same number of current customers in an economically feasible manner. Over the short-run or a period of one-year or less, there may be some excess capacity in a water system that is inevitable if we seek economies of scale. But, there should not be excess capacity over the long-run, particularly with water systems. In essence, excess capacity results in higher rates to the current ratepayers and is inherently unfair.

The Company's growth projection miscalculations should not be the entire burden of the current ratepayers. This is more fully addressed in Ms. Jerich's testimony too.

Second, RUCO's 10 percent reserve margin exceeds the Company's 6 percent customer growth rate from year 2009 to 2010. The reserve margin of 10 percent allows ample time for the Company to make any necessary service line connections and meter installations.

Finally, RUCO has balanced the risks between the current ratepayers and the shareholders by its proposal to use a 10 percent margin of reserve. Moreover, RUCO's proposal will incent utilities to build capacity as needed to meet its customers' new service connections.

In both cases, the reserve margin benefits the utility. It also shifts some of the risk that growth will not occur from the ratepayer to the shareholder. At the same time, it provides the Company incentive to build the plant necessary to meet its customers' needs.

Q. Are there any other issues pertaining to the Company's rebuttal comments regarding RUCO's excess capacity adjustment and/or points of clarification that RUCO wishes to address?

A. Yes.

Q. Please continue.

A. RUCO will present another way to analyze the impact of the additional $3.1 million in plant additions on a per customer basis, which produces much the same results as what RUCO recommends in its surrebuttal schedules for GWC's revenue requirement. The analysis will look at what the year end plant values and per year end customer counts were over a period of years of 2003 thru 2012[12]. The analysis divides the total year end plant values by the year end customer counts (i.e. for test year end 2009 the calculation would be $5,453,761 / 626 = $8,712), which results in a plant value per customer using the following data point table (See RUCO Exhibit 2 – Pages 1 thru 4):

[12] Years 2011 and 2012 were projected at the 2009 to 2010 customer and plant growth rates of 40 and $5,500 respectively.

Year	Year End Plant Value	Year End Customers	Plant Per Customer
2003	$ 1,639,314	202	$ 8,115
2004	2,044,028	370	5,524
2005	2,697,594	479	5,632
2006	2,716,303	484	5,612
2007	3,686,972	579	6,368
2008	5,424,334	612	8,863
2009	5,453,761	626	8,712
2010	5,459,261	666	8,197
2011	5,464,761	706	7,741 *
2012	5,470,261	746	7,334 *

- Projected at 2010 customer and plant growth levels of 40 additional customers and $5,500 of additional capital expenditures for meter and service installations.

That data shows that the plant value per customer is higher in years 2008 and 2009 than any other years since the conception of GWC.

Q. That is true Mr. Coley, but isn't the plant value per customer in 2003 also high?

A. Yes, but the Company was experiencing significant growth at that time. The following year in 2004 there was a significant drop in the plant value per customer from $8,115 in year 2003 to $5,524 in year 2004 because of the 83 percent customer growth rate during those years.

To expand on the analysis using the same data point table above, one could also calculate the average and median plant values per customer over the seven-year period of 2003 thru test year end 2009. The average plant value per customer over the seven-year period is $6,975 while the median is $6,368 of plant value per customer over the same time period.

Referring back to the data point table for test year end 2009, the 2009 plant value per customer, shown in the last column to the right, shows that GWC's ratepayers are saddled with $8,712[13] of plant per customer. This is graphically shown in RUCO's Exhibits 3 and 4. Whereas, the average and median plant value per customer over the seven-year period was $6,975 and $6,368.

From that data, one can multiply the number of customers at test year end of 626[14] by the difference between the $8,712 of plant per customer in the test year end, as shown in the data point table for 2009, less the average and/or median plant value per customer over the seven-year time period, which results in an excess capacity calculation as shown on the following page:

[13] The $8,712 is only superseded by one-year in the data point table, which was the previous year 2008 in which the plant value per customer was $8,863.
[14] As updated in the Company's rebuttal filing.

	Average Plant Per Customer	Median Plant Per Customer
Plant Value per Customer in 2009[15]	$ 8,712	$ 8,712
Average and Median Plant Value[16]	**6,975**	**6,368**
Difference	$ 1,737	$ 2,344
x Number of Customers in 2009	626	626
Excess Capacity per Customer	$ 1,087,362	$ 1,467,344

Q. Well Mr. Coley, that method of determining excess capacity also yields similar results to RUCO's surrebuttal adjustment of $1,360,580 for excess capacity doesn't it?

A. Yes, it does. Any way one rolls, slices, or dices it, it comes up as excess capacity.

Q. Briefly comment on Mr. Bourassa's inference that when the Company made the decision to construct all of the $3.1 million in plant additions the decision makers were not privy to the upcoming economic and real estate collapse, and therefore, the decision was prudent to construct the plant, which in essence has the capacity to serve all customers at build-out.

A. The issue here is not prudency. The issue is what plant is used and useful at the time of the Commission's review as supported in Ms. Jerich's testimony. The Arizona Corporation Commission ("ACC") ruled in Decision No. 64282, dated December 28, 2001, the following:

[15] As shown in RUCO's data point table.
[16] The average and median plant are based on the seven-year period of 2003 thru 2009.

> **E. Plant Held For Future Use**
>
> In order to take advantage of an Arizona Department of Transportation ("ADOT") highway improvement project, Arizona Water installed 80 feet of 12-inch steel casing across State Highway 260 in Lakeside by means of an open trench. The Company plans to utilize the new steel casing to replace an existing water line in 2003 to serve a subdivision. Arizona Water claims that the $17,912 cost of the project, compared to the approximately $40,000 cost if the open trench had not been used, reflects a prudent decision by the Company that will result in savings to customers.
>
> We agree that the Company's decision to take advantage of the ADOT project was prudent. However, we disagree that the Company is entitled to recover the cost of placing the steel casing in this proceeding since the plant is not used and useful at this time. After the project to the subdivision is completed, the Company may seek inclusion in rate base. Until the plant is being used for provision of utility service the costs are not includable in the Company's rate base.

RUCO's excess capacity argument simply reiterates that Decision's ruling that the Commission should not allow the Company to include the plant additions in rate base that was designed to serve the number of build-out customers even if the decision makers' original decision may have been prudent. Again, this is not a prudency issue. It is a used and useful issue.

In fact, the Commission' Engineering Staff has stated in numerous reports to the ACC that on November 24, 2006, "The Company's current well source and storage capacity," which was 400,000 gallons or 530,000 less

than today's storage capacity, "are adequate to serve the present customer base and reasonable growth[17]."

On September 2, 2010, Staff Engineering compliance report for Decision No. 69404 stated the following:

> According to the Company's Annual Report, the Company's water system consists of two wells (totaling 1,240 GPM), two storage tanks (totaling 930,000 gallons) and a distribution system serving 597 customers as of December 2007. Based on these plant capacities, this system can currently serve approximately 1,800 customers.
>
> Staff concludes that the water system has sufficient capacity to meet the customer growth through 2019.

For all of these reasons stated in this testimony, $1.36 million of the $3.1 million of the plant additions is <u>not</u> used and useful and is excess capacity. These plant additions should be recorded as plant held for future use and <u>not</u> be afforded rate base treatment at this time. After the Company approaches build-out capacity, the Company may seek inclusion in rate base at that time.

Q. Can you cite a real world example of why this distinction between prudency and the used and useful principle is so critical in regulation?

A. Yes. Suppose I performed an analysis in mid 2007 that supported my decision to build a local six-bay auto mechanic shop. I acted in good faith

[17] Direct Testimony of Staff's Engineer in GWC's last rate case in Docket No. W-02500A-06-0281.

on the results from my analysis. My decision was made prudently to construct the six-bay shop based upon what was known at the time of the shop design. The economy began to collapse as the shop was being completed. As it turned out, my customer base would only support three of my six-bays, but I had invested an amount that required enough customers to support the six-bay investment. Could I simply charge my customer base more to make up the deficiency between the six versus three-bay shop? The answer is obviously no. If I did so in a competitive environment, my customer base would go down the road to another auto mechanic shop for service. GWC's ratepayers do not have that alternative because the Company is the sole provider of water service in the area. Yet, the Company wants to pass all the costs along to the roughly 650 current ratepayers for a plant designed to serve approximately 1,000 customers. That is simply wrong.

Q. In RUCO's opinion, did the Company act prudently?

A. RUCO questions whether the Company acted prudently when it built the plant.

There were some indicators already present that GWC should have considered when constructing plant for build-out capacity. For instance, the following year end customer growth table should have provided some level of caution in proceeding as shown on the next page:

Year	Number of Customers	Number of Customer Growth	Percentage of Customer Growth
2002	71	71	100%
2003	202	131	185%
2004	370	168	83%
2005	479	109	29%
2006	484	5	1%
2007	579	95	20%
2008	612	33	6%
2009	626	14	2%
2010	666	40	6%

As can be seen in the customer growth table above, there was certainly a pattern of slowing growth in both the number and percentage of customers from 2004 thru 2006, as well as in 2008.

Q. Please sum up RUCO's testimony regarding GWC's glaring excess capacity issue.

A. RUCO's surrebuttal position is overall the same as its direct testimony position with the exception of the method used in calculating GWC's excess capacity adjustment. I will reiterate my overall direct testimony and surrebuttal position that, quite frankly, "GWC's current ratepayers should not have to pay higher rates for plant that is intended for future" customer growth. While GWC may have constructed plant to serve

anticipated growth (See RUCO Exhibit 1 on lines 20 and 21), that growth never materialized. GWC's customers should not bare the entire burden of the Company's growth miscalculations. The Company is already afforded a monopoly status and protected from any and all outside competitive forces. To further insulate the Company from risk at the total expense of its ratepayers is unfair and inappropriate. I also agree with Eagle Crest's Interveners' position that it would be an inter-generational inequity to do so.

RUCO also would strongly support the Eagle Crest's Interveners' position that the land acquisition from an affiliate should be booked on GWC's books at the lower of cost or market value as prescribed by the NARUC Guidelines of cost allocations.

RUCO believes that the Company at all times was keenly aware that it over-anticipated GWC's build-out date as shown in RUCO Exhibit 1 and wrongly constructed the plant that would be necessary to serve the projected number of customers at an erroneous projected build-out date.

The situation is both very similar and exactly opposite of the key line in the movie Field of Dreams, which was "If you build it, they[sic] will come." GWC built it, but they are not coming. At GWC's public comment meeting in Saddlebrook, Arizona on May 18, 2011, a realtor in the area provided

public comment that potential homebuyers are avoiding buying in Eagle Crest Ranch ("ECR") Subdivision simply because of the current high water rates. Another substantial rate increase will undoubtedly continue to hinder growth in ECR and keep rates high on the existing ratepayers.

RUCO is not recommending that the Company should never be afforded and receive rate base treatment of the excess capacity. As the excess capacity becomes used and useful and the Commission approves rate base treatment of the plant, the Company can earn a return on it at that point. If the Commission allows the Company to rate base this excess capacity now and earn a return on it, potential buyers in ECR will have to factor in their decisions to pay water bills that are approximately 50 percent higher than they are today. These buyers will be attracted to homes down the road where water rates are lower and reasonable. This is likely to stunt growth. The current ECR homeowners will be strapped with higher rates and a water system that was intended to serve some additional 50 percent of customers who may never come.

RUCO's excess capacity adjustment may be the key to hold rates in check and may encourage future homebuyers to purchase in ECR. Build-out would allow approximately 1,000 ratepayers to pay for a system that it is built for today and not the 650 ratepayers that exist now. Another 50

percent increase in rates now could very well destabilize an already shaky real estate market and drive people away from buying in ECR.

Q. What adjustment(s) does RUCO make to GWC's plant in service to account for the Company's excess capacity?

A. RUCO's excess capacity adjustment reduces plant in service by $1,360,580 and decreases the corresponding accumulated depreciation balance by $269,307 using the same criteria. The adjustment is shown on RUCO Surrebuttal Schedules TJC- 5, TJC-3, and TJC-2.

Adjustment No. 3 – Advances in Aid of Construction ("AIAC")

Q. Did the Company address RUCO's AIAC adjustment in its rebuttal testimony?

A. No, not directly. RUCO believes the Company carte blanche addressed RUCO's AIAC adjustment through its comments regarding the excess capacity adjustment, which was addressed in great detail on the previous pages here.

Q. Please explain RUCO's surrebuttal adjustment to the Company's AIAC balance because you mentioned earlier that it was unique as compared to RUCO's overall excess capacity adjustment for plant in service.

A. RUCO's AIAC adjustment allowed 100 percent of the AIAC balance authorized in Commission Decision No. 69404, which was $971,695. The

AIAC added since that Decision was $1,130,210. RUCO allowed 55.94 percent of the additional AIAC ($971,695 + ($1,130,210 x 55.94%) = $1,603,922) since the last rate case referenced above.

Q. How did RUCO determine that 55.94 percent of the newly added AIAC since the Company's last rate case should be allowed?

A. RUCO's AIAC calculation of the 55.94 percent is shown on RUCO's Surrebuttal Schedule TJC-6, page 2 of 2. The calculation resembles a weighted cost of capital calculation. The calculation determines each plant account additions since GWC's last rate case and divides the amount of each plant account additions to the total plant additions of $3,087,948, which results in a percentage for each plant account in the third column labeled "Percentage to Total." That percentage is then multiplied by the percentage of each plant account that RUCO deems as the used and useful factor for that particular account, which results in a weighted average for each account. The last column on Schedule TJC-6, page 2 of 2 is then summed up to obtain the 55.94 percent AIAC used and useful factor.

Q. What adjustment does RUCO make to the Company's adjusted test year AIAC balance to account for the Company's excess capacity?

A. RUCO decreases GWC's AIAC balance by $497,983, which results in an increase to the Company's rate base accordingly.

Adjustment No. 4 – Accumulated Deferred Income Taxes ("ADIT")

Q. Did the Company address RUCO's ADIT adjustment in rebuttal testimony?

A. The Company briefly addressed RUCO's ADIT adjustment and made some minor calculation corrections for calculating the tax basis of the fixed assets on a separate schedule.

Q. Does RUCO accept the Company's corrections to the tax basis of the fixed assets?

A. Yes.

Q. What adjustment does RUCO make to the Company's adjusted test year ADIT balance in surrebuttal?

A. RUCO's adjustment increases the ADIT liability balance by $50,545, which decreases rate base accordingly to account for RUCO's excess capacity adjustments and fixed asset balances.

OPERATING INCOME ADJUSTMENTS

Q. Please explain RUCO's overall surrebuttal operating income adjustments.

A. Overall, RUCO's surrebuttal operating income adjustments are quite similar to its direct testimony operating income adjustments, which were all explained there, with two exceptions.

Q. Please explain RUCO's two surrebuttal operating income adjustment exceptions that are different than in RUCO's direct testimony.

A. The two exceptions are RUCO's surrebuttal operating income adjustment #6. In direct testimony, that adjustment was to remove meals charged to contractual services. Here in surrebuttal the meal expenses adjustment was eliminated as being *de minimis*. In surrebuttal, a water testing expense adjustment replaced it.

Each of RUCO's operating income adjustments will be briefly explained here. A more thorough explanation for each adjustment is contained in RUCO's direct testimony. The adjustments are as follows:

<u>Adjustment No. 1 – Depreciation Expense</u>

Q. Please explain RUCO's adjustment to the Company's adjusted test year depreciation expense.

A. RUCO's adjustment to depreciation expense reflects the Commission's approved depreciation rates applied to RUCO's recommended plant balances due to RUCO's Original Cost Rate Base ("OCRB") adjustment #2 for excess capacity as shown on Schedule TJC-3 on line 1, column (C). RUCO's depreciation expense adjustment is shown on Schedule TJC-9 on line 19, column (B). The depreciation expense adjustment's detail is shown on Schedule TJC-10.

Q. What adjustment did RUCO make to the Company's adjusted Test Year depreciation expense?

A. RUCO's adjustment reduces the Company's adjusted test year depreciation expense by $44,136. The adjustment was driven by RUCO's rate base adjustment #2 for excess capacity and is shown on Schedule TJC-10

Adjustment No. 2 – Property Tax Expense

Q. What adjustment was necessary to the Company's adjusted test year property tax expense in RUCO's surrebuttal testimony?

A. RUCO decreased the Company's adjusted test year property tax expense by $3,570. The adjustment is due solely to the differences between the Company and RUCO's recommended level of proposed revenue. The adjustment is shown on Schedule TJC-11.

RUCO also adopted Staff's method of including the effective property tax rate into the gross revenue conversion factor ("GRCF") for consistency sake. The Company also adopted the same method in its rebuttal testimony for the same reason.

Adjustment No. 3 – Revenue and Expense Annualization

Q. What adjustment was necessary to account for the Company's updated rebuttal adjusted test year metered water revenue and purchased power expense in RUCO's surrebuttal testimony?

A. RUCO accepted the Company's newly revised rebuttal revenue and expense annualization adjustment that corrected several billing determinants. GWC thoroughly explains the problem(s) that were found in its direct Application H Schedules and corrected them in rebuttal. RUCO increased metered water revenue by $21,708 and increased purchased power expense by $577 accordingly as shown on Schedule TJC-9, Column (D). RUCO and the Company should be in agreement on this adjustment.

Adjustment No. 4 – Salaries and Wages

Q. Did the Company accept RUCO's direct adjustment to salaries and wage expense?

A. No.

Q. Does RUCO recommend the same adjustment to salaries and wage expense that it did in direct testimony?

A. Yes.

Q. How did the Company respond in rebuttal to RUCO's adjustment to salaries and wage expense?

A. The Company basically responds that "the Company's proposed $40,000 annual salary is very reasonable. If GWC were to hire someone other than Mr. Sears to perform the same duties as Mr. Sears, the annual compensation required would be much higher." In the Company's last rate case, the Commission approved Mr. Sears' annual salary of $32,000 in Decision No. 69404 at 10. RUCO continues to oppose the Company's proposed $8,000 or 25 percent increase.

Q. How does RUCO respond in its surrebuttal testimony to the Company's rebuttal comments concerning Mr. Sear's salary and wage expense?

A. All of the Company's comments regarding RUCO's adjustment to Mr. Sear's salary and wage expense does not alleviate the fact that a 25 percent wage increase in today's current economic market and downturn is simply excessive. RUCO maintains its direct testimony reasoning here in surrebuttal testimony.

Q. Please briefly explain what adjustment to salary and wage expense that RUCO also recommends in its surrebuttal testimony.

A. RUCO's adjustment decreases the Company's $40,000 adjusted Test Year salary and wage expense by $4,986. I will note that RUCO went out six-months beyond the Test Year when calculating the inflation factor to

be applied to the Test Year book result of $32,000. There were payroll taxes that were also affected. RUCO reduced the associated payroll taxes by the same inflation factor. The adjustment for payroll taxes was reduced by $372. These adjustments can be seen on Schedule TJC-9 on lines 5 and 20 in column (E). The detail of RUCO's wage and salary expense adjustment is shown on Schedule TJC-12.

Adjustment No. 5 – Contractual Services

Q. Did the Company accept RUCO's direct adjustment to contractual services expense?

A. No.

Q. Does RUCO recommend the same adjustment to contractual services expense that it did in direct testimony?

A. Yes.

Q. How did the Company respond in rebuttal to RUCO's adjustment to contractual services expense?

A. The Company basically responds in a manner that is quite similar in nature to RUCO's previous adjustment for salary and wage expense. The Company stated that "Mr. Shiner's responsibilities and time devoted to the Company increased between 2005 and 2009." RUCO's adjustment recognizes that fact and allows 38 percent of the Company's adjustment.

Q. How does RUCO respond in its surrebuttal testimony to the Company's rebuttal comments concerning Mr. Shiner's increase in contractual services expense?

A. Again, all of the Company's comments regarding RUCO's adjustment to Mr. Shiner's increase in contractual services expense does not alleviate the fact that a 25 percent wage increase in today's current economic market and downturn is simply excessive. RUCO maintains its direct testimony reasoning here in surrebuttal testimony.

Q. Please briefly explain what adjustment to contractual services expense that RUCO also recommends in its surrebuttal testimony.

A. RUCO's adjustment decreases the Company's $4,000 adjustment by $2,493. There were no payroll taxes associated with this expense since it is for outside contractual services. The adjustment is shown on Schedule TJC-9 on line 11 in column (F). The detail of RUCO's contractual services adjustment is shown on Schedule TJC-13.

Adjustment No. 6 – Water Testing Expense

Q. Please explain RUCO's adjustment that increases the Company's water testing expense by $1,568.

A. RUCO's adjustment adopts Staff's Engineering recommendation that increased GWC's adjusted Test Year water testing expense by $1,568.

The Company accepted Staff's adjustment in rebuttal as RUCO does here in surrebuttal.

Adjustment No. 6 – Income Tax Expense

Q. Have you calculated income tax expense based on RUCO's surrebuttal recommended adjusted operating income?

A. Yes. This adjustment is shown on Schedule TJC-15 for GWC.

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.

RATE DESIGN

Q. Is RUCO recommending a rate design that reflects its $8,715 revenue increase, which is shown on RUCO's revenue requirement Schedule TJC-1 on line 8 in column (B) for GWC?

A. Yes.

Q. Please describe RUCO's rate design?

A. It essentially mirrors the Company's overall structure for designing rates. Both the Company and RUCO recommend shifting more of the revenue to be derived through the commodity rate(s) rather than the monthly fixed charge.

The rate design consists of three-inverted blocks of rates for the 5/8 x 3/4 inch and ¾ inch meters for all classes of customers. The remaining meter sizes consist of two-inverted blocks of rates. RUCO utilizes the same break-over points of usage that the Company proposes.

Q. What level of revenue does RUCO's surrebuttal rate design produce?

A. RUCO's rate design generates $589,439 in metered water revenues. With the Company's miscellaneous revenues of $13,738, RUCO's rate design plus the miscellaneous revenues produce RUCO's proposed annual revenue of $603,177. That is three-dollars more than reflected in Schedule TJC-1 on line 10.

Q. What amount of revenues does the Company's present rates and rebuttal proposed rates generate compared to RUCO's surrebuttal recommended rates?

A. GWC's present rates generate the following revenues for its different customer classifications as shown on the next page:

Meter Sizes	Classification	Company Present Revenues	Company Proposed Revenues	RUCO Recommended Revenues
5/8 x ¾"	Residential	$ 438,217	$ 625,588	$ 442,579
¾"	Residential	88,623	119,680	95,833
1"	Residential	6,812	10,803	6,008
1"	Commercial	13,599	31,159	24,591
1 ½"	Commercial	458	3,200	2,322
2"	Commercial	14,440	26,887	18,107
5/8 x ¾"	Construction	3,456	0	0
Total Revenues		$ 565,605	$ 817,317 *	$ 589,440 *

* With Revenue Annualization

These amounts are shown in RUCO's Rate Design Schedules TJC RD-1 thru TJC RD-7 and on the Company's Schedule H-1 in the "Total Revenues at Present Rates" column.

Q. What is the impact of RUCO's recommended rates on an average bill for a 5/8 x ¾ inch and ¾ inch metered residential customer?

A. The 5/8 x ¾ inch metered customer represents 85.7 percent of the Company's total customers. The present monthly bill for a 5/8 x ¾ inch residential customer using an average of 5,520 gallons is $66.98. RUCO's recommended monthly bill for a 5/8 x ¾ inch residential customer using an average of 5,520 gallons is $66.84, a decrease of $0.14 or two-tenths of one percent less than the present rates.

The present monthly bill for a ¾ inch residential customer using an average 6,028 gallons is $91.08. RUCO's recommended monthly bill for a ¾ inch residential customer using an average of 6,028 gallons is $89.39, a decrease of $1.69 or 1.9 percent less than the present rates.

The customer classifications' average and median rates are shown on the respective Schedules TJC RD-5 for the residential and commercial classifications. The same information is provided for the construction/standpipe customer classification on Schedule TJC RD-1.

Q. Why are some customers receiving rate decreases as noted above because RUCO is recommending a rate increase of $8,715?

A. The reason why some residential customers are receiving small rate decreases is due to RUCO's rate design structure that moves more revenues into the commodity charges and less in the monthly minimum charge. However, as soon as a customer exceeds the average gallon consumption point, the customer will see an increase in their bill under RUCO's recommended rate design over the Company's present rate design because RUCO's commodity rates are higher than the Company's present commodity rates. Thus, a customer is awarded in lower monthly bills if he/she practices conservation whenever more revenues are moved to the commodity charges versus the monthly minimum charge. But

again, once the customer exceeds the average consumption point, the reverse is true.

OTHER ISSUES

Q. What other issue(s) would RUCO want to address?

A. One of the two other issues is RUCO's proposed HUF, which was fully discussed on pages 6 thru 8.

The second issue was RUCO's proposal for the Commission to grant GWC a deferred accounting order that would allow the Company to recover any foregone depreciation expense from RUCO's excess capacity adjustment in a future rate case. This was more fully discussed earlier on page 8.

Q. Does your silence on any issue constitute RUCO's acceptance.

A. No.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

RUCO EXHIBIT 1

ORIGINAL

BEFORE THE ARIZONA CORPORATION COMMISSION

MIKE GLEASON
Chairman

WILLIAM A. MUNDELL
Commissioner

JEFF HATCH-MILLER
Commissioner

KRISTIN K. MAYES
Commissioner

GARY PIERCE
Commissioner

Arizona Corporation Commission
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AZ CORP COMMISSION
DOCKET CONTROL

IN THE MATTER OF THE APPLICATION OF GOODMAN WATER COMPANY FOR REVIEW AND APPROVAL OF PROPOSED HOOK-UP FEE TARIFF	DOCKET NO. W-02500A-07-0281 APPLICATION

In compliance with Decision No. 69404, dated April 16, 2007, Goodman Water Company ("Goodman") submits for Staff's review this proposed Hook-Up Fee Tariff. The proposed Hook-Up Fee Tariff and related hook-up fees would be applicable to new customer connections to Goodman's system. The capital expenditures related to the proposed hook-up fees pertain to Goodman's construction requirements for the 2008-2011 time period. The anticipated new customer growth during this period is 724 new customer connections. The off-site facilities in question include a well #3 and related equipment and engineering. The proportion of anticipated construction costs proposed to be funded by the proposed hook-up fees is 40%.

Attached to this Application as Exhibit "A" is a schedule setting forth the assumptions and estimated future capital expenditures upon which the proposed hook-up fees are based. Exhibit

RUCO EXHIBIT 2

Goodman Water Company
Utility Plant Per Customer

Line No.	Acct. No.	Description	2002 Original Cost	2002 Per Customer Cost Per Average Year Customer Count	2002 Per Customer Cost Per Year End Customer Count	2003 Original Cost	2003 Per Customer Cost Per Average Year Customer Count	2003 Per Customer Cost Per Year End Customer Count	2004 Original Cost	2004 Per Customer Cost Per Average Year Customer Count	2004 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
2	302	Franchises	-	-	-	-	-	-	-	-	
3	303	Land & Land Rights	-	-	-	-	-	-	-	-	
4	304	Structures and Improvements	-	-	-	-	-	-	1,343	5	4
5	307	Wells and Springs	-	-	-	233,767	1,527	1,157	233,767	786	632
6	311	Pumping Equipment	-	-	-	542,915	3,547	2,688	582,420	1,959	1,574
7	320	Water Treatment Equipment	-	-	-	-	-	-	2,161	7	6
8	330	Distribution Reservoirs & Standpipes	-	-	-	251,477	1,643	1,245	251,476	846	680
9	331	Transmission and Distribution Mains	-	-	-	402,268	2,628	1,991	675,939	2,274	1,827
10	333	Services	94,596	4,487	1,332	160,177	1,046	793	212,697	716	575
11	334	Meter and Meter Installations	7,757	368	109	23,735	155	118	40,660	137	110
12	335	Hydrants	-	-	-	24,975	163	124	43,565	147	118
13	336	Backflow Prevention Devices	-	-	-	-	-	-	-	-	
14	339	Other Plant and Misc. Equipment	-	-	-	-	-	-	-	-	
15	340	Office Furniture and Equipment	-	-	-	-	-	-	-	-	
16	341	Transportation Equipment	-	-	-	-	-	-	-	-	
17	343	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	
18	344	Laboratory Equipment	-	-	-	-	-	-	-	-	
19	345	Power Operated Equipment	-	-	-	-	-	-	-	-	
20	346	Communication Equipment	-	-	-	-	-	-	-	-	
21	347	Miscellaneous Equipment	-	-	-	-	-	-	-	-	
22	348	Other Tangible Plant	-	-	-	-	-	-	-	-	
23		**Totals**	$ 102,353	$ 4,855	$ 1,442	$ 1,639,314	$ 10,709	$ 8,115	$ 2,044,028	$ 6,876	$ 5,524
24		Average and Year End Number of Customers		21	71		153	202		297	370
25		$ Increase for Average and Year End Number of Customers from Previous Yr.					5,854	6,674		(3,832)	(2,591)
26		% Increase for Average and Year End Number of Customers from Previous Yr.					626%	185%		94%	83%
27		Increase in Number of Year End Customers thru 2012			71			131			168

Goodman Water Company
Utility Plant Per Customer

Line No.	Acct. No.	Description	2005 Original Cost	2005 Per Customer Cost Per Average Year Customer Count	2005 Per Customer Cost Per Year End Customer Count	2006 Original Cost	2006 Per Customer Cost Per Average Year Customer Count	2006 Per Customer Cost Per Year End Customer Count	2007 Original Cost	2007 Per Customer Cost Per Average Year Customer Count	2007 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchises	106,028	236	221	110,948	230	229	117,487	214	203
3	303	Land & Land Rights	-	-	-	-	-	-	-	-	-
4	304	Structures and Improvements	11,064	25	23	11,064	23	23	11,064	20	19
5	307	Wells and Springs	386,591	862	807	386,591	802	799	386,591	704	668
6	311	Pumping Equipment	686,993	1,532	1,434	686,993	1,426	1,419	689,955	1,256	1,192
7	320	Water Treatment Equipment	11,054	25	23	11,319	23	23	15,947	29	28
8	330	Distribution Reservoirs & Standpipes	294,460	657	615	294,460	611	608	366,810	668	634
9	331	Transmission and Distribution Mains	751,451	1,676	1,569	751,451	1,560	1,553	1,436,546	2,615	2,481
10	333	Services	146,540	327	306	146,543	304	303	289,895	528	501
11	334	Meter and Meter Installations	67,767	151	141	68,037	141	141	79,816	145	138
12	335	Hydrants	83,174	186	174	83,180	173	172	126,384	230	218
13	336	Backflow Prevention Devices	-	-	-	-	-	-	-	-	-
14	339	Other Plant and Misc. Equipment	152,473	340	318	165,718	344	342	166,477	303	288
15	340	Office Furniture and Equipment	-	-	-	-	-	-	-	-	-
16	341	Transportation Equipment	-	-	-	-	-	-	-	-	-
17	343	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-
18	344	Laboratory Equipment	-	-	-	-	-	-	-	-	-
19	345	Power Operated Equipment	-	-	-	-	-	-	-	-	-
20	346	Communication Equipment	-	-	-	-	-	-	-	-	-
21	347	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-
22	348	Other Tangible Plant	-	-	-	-	-	-	-	-	-
23		**Totals**	$ 2,697,594	$ 6,017	$ 5,632	$ 2,716,303	$ 5,637	$ 5,612	$ 3,686,972	$ 6,713	$ 6,368
24		Average and Year End Number of Customers		448	479		482	484		549	579
25		$ Increase for Average and Year End Number of Customers from Previous Yr.		(860)	107		(380)	(20)		1,075	756
26		% Increase for Average and Year End Number of Customers from Previous Yr.		51%	29%		7%	1%		14%	20%
27		Increase in Number of Year End Customers thru 2012			109			5			95

Goodman Water Company
Utility Plant Per Customer

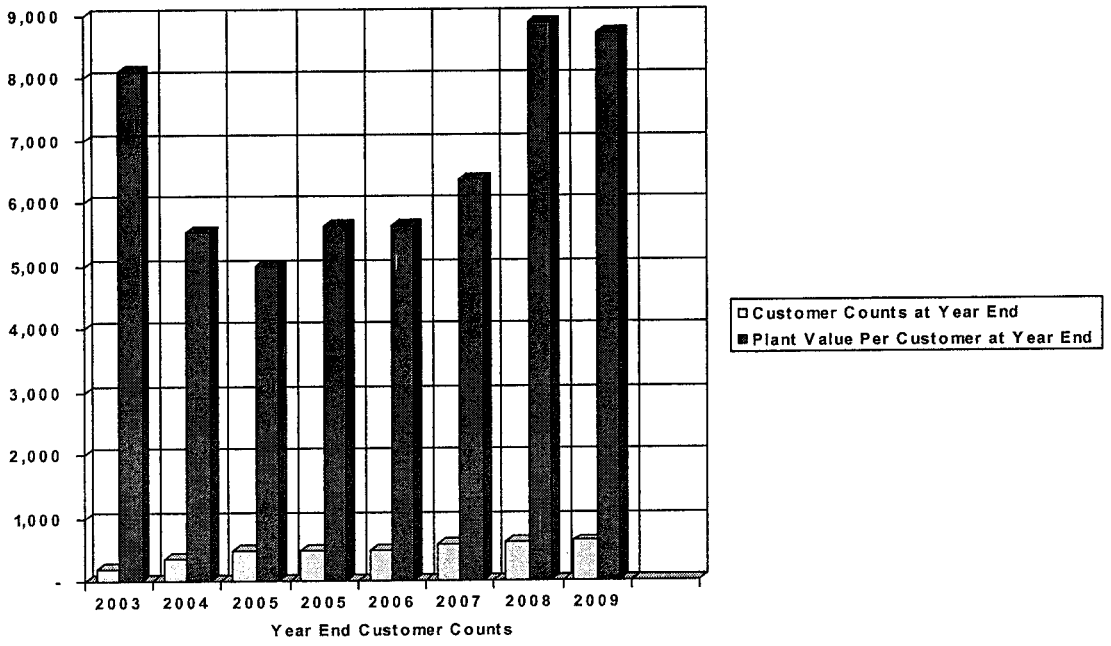
Line No.	Acct. No.	Description	2008 Original Cost	2008 Per Customer Cost Per Average Year Customer Count	2008 Per Customer Cost Per Year End Customer Count	2009 Original Cost	2009 Per Customer Cost Per Average Year Customer Count	2009 Per Customer Cost Per Year End Customer Count	2010 Original Cost	2010 Per Customer Cost Per Average Year Customer Count	2010 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchises	127,103	210	208	127,103	203	203	127,103	196	191
3	303	Land & Land Rights	494,159	817	807	494,159	791	789	494,159	762	742
4	304	Structures and Improvements	182,570	302	298	182,570	292	292	182,570	281	274
5	307	Wells and Springs	386,591	639	632	386,591	619	618	386,591	596	580
6	311	Pumping Equipment	965,496	1,595	1,578	968,652	1,550	1,547	968,652	1,493	1,454
7	320	Water Treatment Equipment	15,947	26	26	15,947	26	25	15,947	25	24
8	330	Distribution Reservoirs & Standpipes	836,890	1,383	1,367	836,890	1,339	1,337	836,890	1,290	1,257
9	331	Transmission and Distribution Mains	1,611,302	2,663	2,633	1,611,321	2,579	2,574	1,611,321	2,484	2,419
10	333	Services	386,947	639	632	386,947	619	618	386,947	596	581
11	334	Meter and Meter Installations	89,115	147	146	94,263	151	151	99,763	154	150
12	335	Hydrants	161,737	267	264	161,737	259	258	161,737	249	243
13	336	Backflow Prevention Devices	-	-	-	-	-	-	-	-	-
14	339	Other Plant and Misc. Equipment	166,477	275	272	187,582	300	300	187,582	289	282
15	340	Office Furniture and Equipment	-	-	-	-	-	-	-	-	-
16	341	Transportation Equipment	-	-	-	-	-	-	-	-	-
17	343	Tools, Shop and Garage Equipment	-	-	-	-	-	-	-	-	-
18	344	Laboratory Equipment	-	-	-	-	-	-	-	-	-
19	345	Power Operated Equipment	-	-	-	-	-	-	-	-	-
20	346	Communication Equipment	-	-	-	-	-	-	-	-	-
21	347	Miscellaneous Equipment	-	-	-	-	-	-	-	-	-
22	348	Other Tangible Plant	-	-	-	-	-	-	-	-	-
23		**Totals**	$ 5,424,334	$ 8,963	$ 8,863	$ 5,453,761	$ 8,728	$ 8,712	$ 5,459,261	$ 8,415	$ 8,197
24		Average and Year End Number of Customers		605	612		625	626		649	666
25		$ Increase for Average and Year End Number of Customers from Previous Yr.		2,251	2,495		(235)	(151)		(313)	(515)
26		% Increase for Average and Year End Number of Customers from Previous Yr.		10%	6%		3%	2%		4%	6%
27		Increase in Number of Year End Customers thru 2012			33			14			40

Goodman Water Company
Utility Plant Per Customer

Line No.	Acct. No.	Description	Projected 2011 Original Cost	Projected 2011 Per Customer Cost Per Average Year Customer Count	Projected 2011 Per Customer Cost Per Year End Customer Count	Projected 2011 Original Cost	Projected 2012 Per Customer Cost Per Average Year Customer Count	Projected 2012 Per Customer Cost Per Year End Customer Count
1	301	Organization	$ -	$ -	$ -	$ -	$ -	$ -
2	302	Franchises	127,103	185	180	127,103	175	170
3	303	Land & Land Rights	494,159	719	700	494,159	679	662
4	304	Structures and Improvements	182,570	266	259	182,570	251	245
5	307	Wells and Springs	386,591	562	548	386,591	531	518
6	311	Pumping Equipment	968,652	1,409	1,372	968,652	1,331	1,299
7	320	Water Treatment Equipment	15,947	23	23	15,947	22	21
8	330	Distribution Reservoirs & Standpipes	836,890	1,217	1,185	836,890	1,150	1,122
9	331	Transmission and Distribution Mains	1,611,321	2,343	2,282	1,611,321	2,215	2,160
10	333	Services	386,947	563	548	386,947	532	519
11	334	Meter and Meter Installations	105,263	153	149	110,763	152	148
12	335	Hydrants	161,737	235	229	161,737	222	217
13	336	Backflow Prevention Devices	-	-	-	-	-	-
14	339	Other Plant and Misc. Equipment	187,582	273	266	187,582	258	251
15	340	Office Furniture and Equipment	-	-	-	-	-	-
16	341	Transportation Equipment	-	-	-	-	-	-
17	343	Tools, Shop and Garage Equipment	-	-	-	-	-	-
18	344	Laboratory Equipment	-	-	-	-	-	-
19	345	Power Operated Equipment	-	-	-	-	-	-
20	346	Communication Equipment	-	-	-	-	-	-
21	347	Miscellaneous Equipment	-	-	-	-	-	-
22	348	Other Tangible Plant	-	-	-	-	-	-
23		**Totals**	$5,464,761	$ 7,947	$ 7,741	$5,470,261	$ 7,518	$ 7,334
24		Average and Year End Number of Customers		688	706		728	746
25		$ Increase for Average and Year End Number of Customers from Previous Yr.		(468)	(456)		(429)	(407)
26		% Increase for Average and Year End Number of Customers from Previous Yr.		6%	6%		6%	6%
27		Increase in Number of Year End Customers thru 2012			40			40

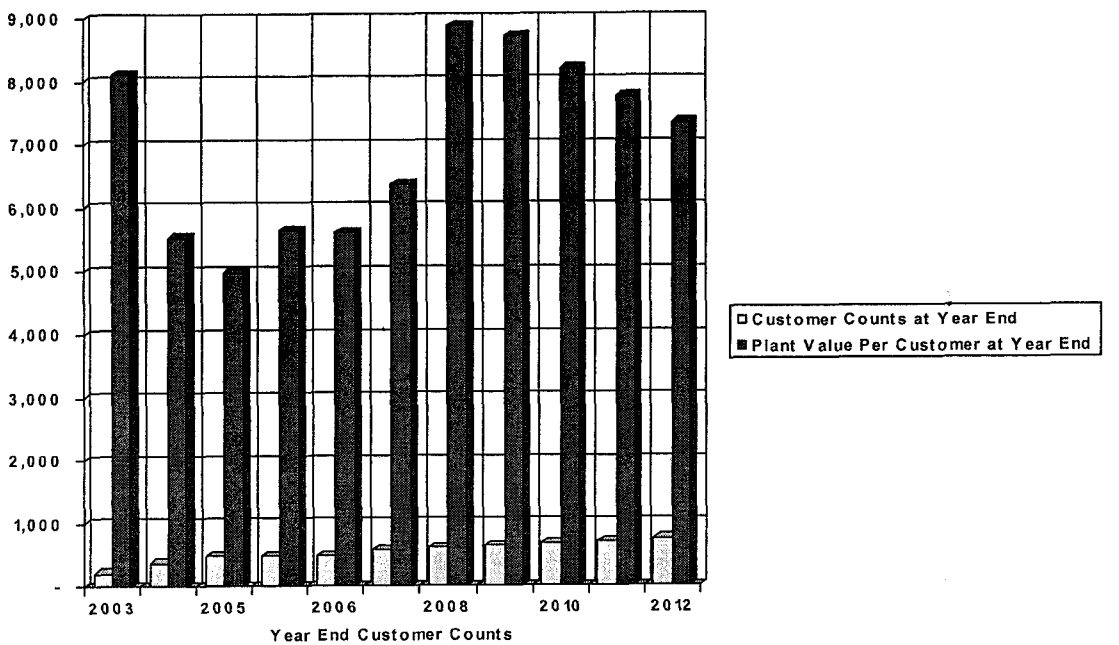
RUCO EXHIBIT 3

YEAR END PLANT VALUE PER CUSTOMER



RUCO EXHIBIT 4

YEAR END PLANT VALUE PER CUSTOMER



GOODMAN WATER COMPANY –
TJC SURREBUTTAL RESIDENTIAL RATE DESIGN SCHEDULES

DOCKET NO. W-02500A-10-0382

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
SUMMARY OF PRESENT, COMPANY PROPOSED & RUCO RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-1

RATE SUMMARY

Present Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	6,373	386,941,940	0	$42.20	$268,941	21,253,000	$83,949	10,466,540	$61,857	3,457,000	$24,579	$439,326
3/4 - INCH	1,032	68,421,848	0	63.30	65,326	3,330,500	13,155	1,988,168	11,750	901,500	6,410	96,641
1 - INCH	30	3,630,000	0	105.50	3,165	314,000	1,856	109,000	775	0	0	5,796
1 1/2 - INCH	0	0	0	211.50	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	339.68	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	675.20	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,055.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,110.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	7,435	458,993,788	0		$337,431	24,897,500	$98,961	12,563,708	$74,382	4,358,500	$30,989	$541,763

Company Proposed Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	6,373	386,941,940	0	$52.20	$332,680	21,253,000	$133,490	10,466,540	$117,956	3,457,000	$46,344	$630,469
3/4 - INCH	1,032	68,421,848	0	78.30	80,808	3,330,500	20,919	1,988,168	22,406	901,500	12,085	136,218
1 - INCH	30	3,630,000	0	130.50	3,915	314,000	3,539	109,000	1,461	0	0	8,915
1 1/2 - INCH	0	0	0	261.01	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	417.61	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	835.22	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,305.04	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,610.07	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	7,435	458,993,788	0		$417,402	24,897,500	$157,948	12,563,708	$141,823	4,358,500	$58,429	$775,603

RUCO Recommended Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	6,373	386,941,940	0	$38.00	$242,174	21,253,000	$96,701	10,466,540	$73,266	3,457,000	$30,439	$442,579
3/4 - INCH	1,032	68,421,848	0	57.00	58,824	3,330,500	15,154	1,988,168	13,917	901,500	7,938	95,833
1 - INCH	30	3,630,000	0	95.00	2,850	314,000	2,198	109,000	960	0	0	6,008
1 1/2 - INCH	0	0	0	190.00	0	0	0	0	0	0	0	0
2 - INCH	0	0	0	304.00	0	0	0	0	0	0	0	0
3 - INCH	0	0	0	570.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	950.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	1,900.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	3,800.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	7,600.00	0	0	0	0	0	0	0	0
	7,435	458,993,788	0		$303,848	24,897,500	$114,053	12,563,708	$88,143	4,358,500	$38,376	$544,420

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
REVENUE COMPARISON

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-2

LINE NO.	METER SIZE	PERESENT RATES MONTHLY MINIMUM	PERESENT RATES COMMODITY CHARGE	PERESENT RATES TOTAL REVENUE	COMPANY PROPOSED RATES MONTHLY MINIMUM	COMPANY PROPOSED RATES COMMODITY CHARGE	COMPANY PROPOSED RATES TOTAL REVENUE	RUCO RECOMMENDED RATES MONTHLY MINIMUM	RUCO RECOMMENDED RATES COMMODITY CHARGE	RUCO RECOMMENDED RATES TOTAL REVENUE
1	5/8 - INCH	$ 268,941	$ 170,386	$ 439,326	$ 332,680	$ 297,790	$ 630,469	$ 242,174	$ 200,405	$ 442,579
2	3/4 - INCH	65,326	31,315	96,641	80,808	55,410	136,218	58,824	37,009	95,833
3	1 - INCH	3,165	2,631	5,796	3,915	5,000	8,915	2,850	3,158	6,008
4	1 1/2 - INCH	-	-	-	-	-	-	-	-	-
5	2 - INCH	-	-	-	-	-	-	-	-	-
6	3 - INCH	-	-	-	-	-	-	-	-	-
7	4 - INCH	-	-	-	-	-	-	-	-	-
8	6 - INCH	-	-	-	-	-	-	-	-	-
9	8 - INCH	-	-	-	-	-	-	-	-	-
10	10 - INCH	-	-	-	-	-	-	-	-	-
11	TOTALS	$ 337,431	$ 204,332	$ 541,763	$ 417,402	$ 358,200	$ 775,603	$ 303,848	$ 240,572	$ 544,420
12	PERCENTAGE	62.28%	37.72%	100.00%	53.82%	46.18%	100.00%	55.81%	44.19%	100.00%

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-3

LINE NO.	DESCRIPTION						PRESENT RATES	COMPANY PROPOSED	RUCO PROPOSED
1	**RECOMMENDED MONTHLY MINIMUM USAGE CHARGE:**								
2									
3	(RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS)								
4	5/8 - INCH						$42.20	$52.20	$38.00
5	3/4 - INCH						63.30	78.30	57.00
6	1 - INCH						105.50	130.50	95.00
7	1 1/2 - INCH						211.50	261.01	190.00
8	2 - INCH						339.68	417.61	304.00
9	3 - INCH						675.20	835.22	570.00
10	4 - INCH						1,055.00	1,305.04	950.00
11	6 - INCH						2,110.00	2,610.07	1,900.00
12	8 - INCH						0.00	0.00	3,800.00
13	10 - INCH						0.00	0.00	7,600.00
14									
15	**GALLONS INCLUDED IN MONTHLY MINIMUM USAGE CHARGE:**								
16									
17	RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS						0	0	0
18									
19	**RECOMMENDED COMMODITY RATES BY METER SIZE**								
20									
21	5/8 - INCH								
22	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	4,000	GALLONS:		$ 3.95	$ 6.28	$ 4.55
23	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	4,001	TO	9,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
24	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
25									
26	3/4 - INCH								
27	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	4,000	GALLONS:		$ 3.95	$ 6.28	$ 4.55
28	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
29	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
30									
31	1 - INCH								
32	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	22,500	GALLONS:		$ 5.91	$ 11.27	$ 7.00
33	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
34	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ 13.41	$ -
35									
36	1 1/2 - INCH								
37	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	34,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
38	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
39	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -
40									
41	2 - INCH								
42	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	45,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
43	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	45,001	TO	999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
44	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -
45									
46	3 - INCH								
47	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	68,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
48	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	68,001	TO	999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
49	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -
50									
51	4 - INCH								
52	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	90,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
53	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	90,001	TO	999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
54	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -
55									
56	6 - INCH								
57	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	135,000	GALLONS:		$ 5.91	$ 11.27	$ 7.00
58	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	135,001	TO	999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.41	$ 8.80
59	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -
60									
61	8 - INCH								
62	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ 5.91	$ 10.92	$ 7.00
63	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.13	$ 8.80
64	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -
65									
66	10 - INCH								
67	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:		$ 5.91	$ 10.92	$ 7.00
68	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ 7.11	$ 13.13	$ 8.80
69	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:		$ -	$ -	$ -

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
MONTHLY MINIMUM CHARGES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-4

LINE NO.	METER SIZE	(A) COMPANY PRESENT RATES	(B) COMPANY PROPOSED RATES	(C) COMPANY DOLLAR INCREASE	(D) COMPANY PERCENT. INCREASE	(E) RUCO RECOMMENDED RATES	(F) RUCO DOLLAR INCREASE	(G) RUCO PERCENT. INCREASE
1	5/8 - INCH	$ 42.20	$ 52.20	$ 10.00	23.70%	$ 38.00	$ (4.20)	-9.95%
2	3/4 - INCH	63.30	78.30	15.00	23.70%	57.00	(6.30)	-9.95%
3	1 - INCH	105.50	130.50	25.00	23.70%	95.00	(10.50)	-9.95%
4	1 1/2 - INCH	211.50	261.01	49.51	23.41%	190.00	(21.50)	-10.17%
5	2 - INCH	339.68	417.61	77.93	22.94%	304.00	(35.68)	-10.50%
6	3 - INCH	675.20	835.22	160.02	23.70%	570.00	(105.20)	-15.58%
7	4 - INCH	1,055.00	1,305.04	250.04	23.70%	950.00	(105.00)	-9.95%
8	6 - INCH	2,110.00	2,610.07	500.07	23.70%	1,900.00	(210.00)	-9.95%
9	GALLONS INCLUDED IN MONHTLY MINIMUM CHARGE	0	0			0		

REFERENCES
COLUMN (A) THRU COLUMN (D): COMPANY SCHEDULE H-3, PAGE 1 OF 3
COLUMN (E): TESTIMONY TJC
COLUMN (F): COLUMN (E) - COLUMN (A)
COLUMN (G): COLUMN (F) ÷ COLUMN (A)

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-5

RUCO RECOMMENDED RATES

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	$38.00	$57.00	$95.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	1,000	42.55	61.55	102.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	2,000	47.10	66.10	109.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	3,000	51.65	70.65	116.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5	4,000	56.20	75.20	123.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	5,000	63.20	82.20	130.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	6,000	70.20	89.20	137.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	7,000	77.20	96.20	144.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9	8,000	84.20	103.20	151.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	9,000	91.20	110.20	158.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	10,000	100.00	119.00	165.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	15,000	144.03	163.03	200.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	20,000	188.05	207.05	235.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	25,000	232.08	251.08	274.51	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	50,000	452.20	471.20	494.63	N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	75,000	672.32	691.32	714.76	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	100,000	892.45	911.45	934.88	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	125,000	1,112.57	1,131.57	1,155.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	150,000	1,332.69	1,351.69	1,375.12	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	175,000	1,552.81	1,571.81	1,595.25	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	200,000	1,772.94	1,791.94	1,815.37	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	250,000	2,213.18	2,232.18	2,255.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	500,000	4,414.41	4,433.41	4,456.84	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	1,000,000	8,816.86	8,835.86	8,859.29	N/A	N/A	N/A	N/A	N/A	N/A	N/A
25	2,000,000	17,621.76	17,640.76	17,664.19	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	3,000,000	26,426.66	26,445.66	26,469.09	N/A	N/A	N/A	N/A	N/A	N/A	N/A
27	4,000,000	35,231.56	35,250.56	35,273.99	N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	5,000,000	44,036.46	44,055.46	44,078.89	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29											
30											
31	AVG. NO. OF CUST:	531	86	3	0	0	0	0	0	0	0
32											
33	AVG. USE (GAL.):	5,520	6,027	11,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	MONTHLY BILL:	$66.84	$89.39	$172.00	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35											
36	MEDIAN USE (GAL.) :	4,787	5,767	5,800	N/A	N/A	N/A	N/A	N/A	N/A	N/A
37	MONTHLY BILL:	$61.71	$87.57	$135.60	N/A	N/A	N/A	N/A	N/A	N/A	N/A

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-6

RUCO RECOMMENDED CHANGES EXPRESSED IN DOLLARS

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	($4.20)	($6.30)	($10.50)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	1,000	(3.60)	(5.70)	(9.41)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	2,000	(3.00)	(5.10)	(8.32)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	3,000	(2.40)	(4.50)	(7.23)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5	4,000	(1.80)	(3.90)	(6.14)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	5,000	(0.71)	(2.81)	(5.05)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	6,000	0.38	(1.72)	(3.96)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	7,000	1.47	(0.63)	(2.87)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9	8,000	2.56	0.46	(1.78)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	9,000	3.65	1.55	(0.69)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	10,000	5.34	3.24	0.40	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	15,000	13.82	11.72	5.85	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	20,000	22.29	20.19	11.30	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	25,000	30.77	28.67	18.26	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	50,000	73.14	71.04	60.63	N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	75,000	115.51	113.41	103.01	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	100,000	157.89	155.79	145.38	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	125,000	200.26	198.16	187.75	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	150,000	242.63	240.53	230.12	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	175,000	285.00	282.90	272.50	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	200,000	327.38	325.28	314.87	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	250,000	412.12	410.02	399.61	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	500,000	835.85	833.75	823.34	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	1,000,000	1,683.30	1,681.20	1,670.79	N/A	N/A	N/A	N/A	N/A	N/A	N/A
25	2,000,000	3,378.20	3,376.10	3,365.69	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	3,000,000	5,073.10	5,071.00	5,060.59	N/A	N/A	N/A	N/A	N/A	N/A	N/A
27	4,000,000	6,768.00	6,765.90	6,755.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	5,000,000	8,462.90	8,460.80	8,450.39	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29											
30											
31	AVG. NO. OF CUST:	531	86	3	0	0	0	0	0	0	0
32											
33	AVG. USE (GAL.):	5,520	6,027	11,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	MONTHLY BILL:	($0.14)	($1.69)	$1.49	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35											
36	MEDIAN USE (GAL.) :	4,787	5,767	5,800	N/A	N/A	N/A	N/A	N/A	N/A	N/A
37	MONTHLY BILL:	($0.94)	($1.97)	($4.18)	N/A	N/A	N/A	N/A	N/A	N/A	N/A

GOODMAN WATER COMPANY - SURREBUTTAL RESIDENTIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-7

RUCO RECOMMENDED CHANGES EXPRESSED AS A PERCENTAGE

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	-10.0%	-10.0%	-10.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
2	1,000	-7.8%	-8.5%	-8.4%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
3	2,000	-6.0%	-7.2%	-7.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
4	3,000	-4.4%	-6.0%	-5.9%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
5	4,000	-3.1%	-4.9%	-4.8%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
6	5,000	-1.1%	-3.3%	-3.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
7	6,000	0.5%	-1.9%	-2.8%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
8	7,000	1.9%	-0.7%	-2.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
9	8,000	3.1%	0.4%	-1.2%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
10	9,000	4.2%	1.4%	-0.4%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
11	10,000	5.6%	2.8%	0.2%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
12	15,000	10.6%	7.7%	3.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
13	20,000	13.4%	10.8%	5.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
14	25,000	15.3%	12.9%	7.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
15	50,000	19.3%	17.8%	14.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
16	75,000	20.7%	19.6%	16.8%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
17	100,000	21.5%	20.6%	18.4%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
18	125,000	22.0%	21.2%	19.4%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
19	150,000	22.3%	21.6%	20.1%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
20	175,000	22.5%	21.9%	20.6%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
21	200,000	22.6%	22.2%	21.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
22	250,000	22.9%	22.5%	21.5%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
23	500,000	23.4%	23.2%	22.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
24	1,000,000	23.6%	23.5%	23.2%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
25	2,000,000	23.7%	23.7%	23.5%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
26	3,000,000	23.8%	23.7%	23.6%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
27	4,000,000	23.8%	23.8%	23.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
28	5,000,000	23.8%	23.8%	23.7%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
29											
30											
31	AVG. NO. OF CUST:	531	86	3	0	0	0	0	0	0	0
32											
33	AVG. USE (GAL.):	5,520	6,027	11,000	N/A	N/A	N/A	N/A	N/A	N/A	N/A
34	MONTHLY BILL:	-0.2%	-1.9%	0.9%	N/A	N/A	N/A	N/A	N/A	N/A	N/A
35											
36	MEDIAN USE (GAL.) :	4,787	5,767	5,800	N/A	N/A	N/A	N/A	N/A	N/A	N/A
37	MONTHLY BILL:	-1.5%	-2.2%	-3.0%	N/A	N/A	N/A	N/A	N/A	N/A	N/A

GOODMAN WATER COMPANY –
TJC SURREBUTTAL COMMERCIAL RATE DESIGN SCHEDULES

DOCKET NO. W-02500A-10-0382

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
SUMMARY OF PRESENT, COMPANY PROPOSED & RUCO RECOMMENDED RATES

RATE SUMMARY

Present Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	0	0	0	$42.20	$0	0	$0	0	$0	0	$0	$0
3/4 - INCH	0	0	0	63.30	0	0	0	0	0	0	0	0
1 - INCH	36	27,835,236	0	105.50	3,798	615,000	3,635	1,915,476	13,619	0	0	21,052
1 1/2 - INCH	12	66,000	0	211.50	2,538	6,000	35	0	0	0	0	2,573
2 - INCH	24	14,997,400	0	339.68	8,152	661,500	3,909	701,900	4,991	0	0	17,052
3 - INCH	0	0	0	675.20	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,055.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,110.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	72	42,898,636	0		$14,488	1,282,500	$7,580	2,617,376	$18,610	0	$0	$40,677

Company Proposed Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	0	0	0	$52.20	$0	0	$0	0	$0	0	$0	$0
3/4 - INCH	0	0	0	78.30	0	0	0	0	0	0	0	0
1 - INCH	36	27,835,236	0	130.50	4,698	615,000	6,931	1,915,476	25,678	0	0	37,308
1 1/2 - INCH	12	66,000	0	261.01	3,132	6,000	68	0	0	0	0	3,200
2 - INCH	24	14,997,400	0	417.61	10,023	661,500	7,455	701,900	9,410	0	0	26,887
3 - INCH	0	0	0	835.22	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	1,305.04	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	2,610.07	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	0.00	0	0	0	0	0	0	0	0
	72	42,898,636	0		$17,853	1,282,500	$14,454	2,617,376	$35,088	0	$0	$67,394

RUCO Recommended Rates

A Meter Size	B Number of Bills	C Total Gallons Consumed (Midrange)	D Minimum Gallons	E Monthly Minimum Charge	F Metered Minimum Revenue B X E	G Tier One Gallons Subject to Comodity Charge (Midrange)	H Tier One Commodity Revenue per 1,000 Gal.	I Tier Two Gallons Subject to Comodity Charge (Midrange)	J Tier Two Commodity Revenue per 1,000 Gal.	K Tier Three Gallons Subject to Comodity Charge (Midrange)	L Tier Three Commodity Revenue per 1,000 Gal.	M Total Metered Revenue F + H + J + L
5/8 - INCH	0	0	0	$38.00	$0	0	$0	0	$0	0	$0	$0
3/4 - INCH	0	0	0	57.00	0	0	0	0	0	0	0	0
1 - INCH	36	27,835,236	0	95.00	3,420	615,000	4,305	1,915,476	16,866	0	0	24,591
1 1/2 - INCH	12	66,000	0	190.00	2,280	6,000	42	0	0	0	0	2,322
2 - INCH	24	14,997,400	0	304.00	7,296	661,500	4,631	661,500	6,180	0	0	18,107
3 - INCH	0	0	0	570.00	0	0	0	0	0	0	0	0
4 - INCH	0	0	0	950.00	0	0	0	0	0	0	0	0
6 - INCH	0	0	0	1,900.00	0	0	0	0	0	0	0	0
8 - INCH	0	0	0	3,800.00	0	0	0	0	0	0	0	0
10 - INCH	0	0	0	7,600.00	0	0	0	0	0	0	0	0
	72	42,898,636	0		$12,996	1,282,500	$8,978	2,576,976	$23,046	0	$0	$45,019

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-2

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
REVENUE COMPARISON

LINE NO.	METER SIZE	PERESENT RATES MONTHLY MINIMUM	PERESENT RATES COMMODITY CHARGE	PERESENT RATES TOTAL REVENUE	COMPANY PROPOSED RATES MONTHLY MINIMUM	COMPANY PROPOSED RATES COMMODITY CHARGE	COMPANY PROPOSED RATES TOTAL REVENUE	RUCO RECOMMENDED RATES MONTHLY MINIMUM	RUCO RECOMMENDED RATES COMMODITY CHARGE	RUCO RECOMMENDED RATES TOTAL REVENUE
1	5/8 - INCH	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2	3/4 - INCH	-	-	-	-	-	-	-	-	-
3	1 - INCH	3,798	17,254	21,052	4,698	32,609	37,308	3,420	21,171	24,591
4	1 1/2 - INCH	2,538	35	2,573	3,132	68	3,200	2,280	42	2,322
5	2 - INCH	8,152	8,900	17,052	10,023	16,865	26,887	7,296	10,811	18,107
6	3 - INCH	-	-	-	-	-	-	-	-	-
7	4 - INCH	-	-	-	-	-	-	-	-	-
8	6 - INCH	-	-	-	-	-	-	-	-	-
9	8 - INCH	-	-	-	-	-	-	-	-	-
10	10 - INCH	-	-	-	-	-	-	-	-	-
11	TOTALS	$ 14,488	$ 26,189	$ 40,677	$ 17,853	$ 49,542	$ 67,394	$ 12,996	$ 32,023	$ 45,019
12	PERCENTAGE	35.62%	64.38%	100.00%	26.49%	73.51%	100.00%	28.87%	71.13%	100.00%

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
RECOMMENDED RATES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-3

LINE NO.	DESCRIPTION					PRESENT RATES	COMPANY PROPOSED	RUCO PROPOSED
1	**RECOMMENDED MONTHLY MINIMUM USAGE CHARGE:**							
2								
3	(RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS)							
4	5/8 - INCH					$42.20	$52.20	$38.00
5	3/4 - INCH					63.30	78.30	57.00
6	1 - INCH					105.50	130.50	95.00
7	1 1/2 - INCH					211.50	261.01	190.00
8	2 - INCH					339.68	417.61	304.00
9	3 - INCH					675.20	835.22	570.00
10	4 - INCH					1,055.00	1,305.04	950.00
11	6 - INCH					2,110.00	2,610.07	1,900.00
12	8 - INCH					0.00	0.00	3,800.00
13	10 - INCH					0.00	0.00	7,600.00
14								
15	**GALLONS INCLUDED IN MONTHLY MINIMUM USAGE CHARGE:**							
16								
17	RESIDENTIAL, COMMERCIAL AND MISC. CUSTOMERS					0	0	0
18								
19	**RECOMMENDED COMMODITY RATES BY METER SIZE**							
20								
21	5/8 - INCH							
22	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	4,000	GALLONS:	$ 3.95	$ 6.28	$ 4.55
23	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	4,001	TO	9,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
24	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
25								
26	3/4 - INCH							
27	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	4,000	GALLONS:	$ 3.95	$ 6.28	$ 4.55
28	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
29	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		9,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
30								
31	1 - INCH							
32	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	22,500	GALLONS:	$ 5.91	$ 11.27	$ 7.00
33	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
34	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ 13.41	$ -
35								
36	1 1/2 - INCH							
37	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	34,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
38	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
39	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
40								
41	2 - INCH							
42	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	45,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
43	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	45,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
44	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
45								
46	3 - INCH							
47	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	68,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
48	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	68,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
49	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
50								
51	4 - INCH							
52	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	90,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
53	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	90,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
54	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
55								
56	6 - INCH							
57	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	135,000	GALLONS:	$ 5.91	$ 11.27	$ 7.00
58	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	135,001	TO	999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
59	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
60								
61	8 - INCH							
62	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:	$ 5.91	$ 11.27	$ 7.00
63	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
64	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -
65								
66	10 - INCH							
67	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	ZERO	TO	0	GALLONS:	$ 5.91	$ 11.27	$ 7.00
68	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ 7.11	$ 13.41	$ 8.80
69	COMMODITY RATE (PER 1,000 GAL. OVER MINIMUM) -	OVER		999,999,999,999,999,000	GALLONS:	$ -	$ -	$ -

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
MONTHLY MINIMUM CHARGES

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-4

LINE NO.	METER SIZE	(A) COMPANY PRESENT RATES	(B) COMPANY PROPOSED RATES	(C) COMPANY DOLLAR INCREASE	(D) COMPANY PERCENT. INCREASE	(E) RUCO RECOMMENDED RATES	(F) RUCO DOLLAR INCREASE	(G) RUCO PERCENT. INCREASE
1	5/8 - INCH	$ 42.20	$ 52.20	$ 10.00	23.70%	$ 38.00	$ (4.20)	-9.95%
2	3/4 - INCH	63.30	78.30	15.00	23.70%	57.00	(6.30)	-9.95%
3	1 - INCH	105.50	130.50	25.00	23.70%	95.00	(10.50)	-9.95%
4	1 1/2 - INCH	211.50	261.01	49.51	23.41%	190.00	(21.50)	-10.17%
5	2 - INCH	339.68	417.61	77.93	22.94%	304.00	(35.68)	-10.50%
6	3 - INCH	675.20	835.22	160.02	23.70%	570.00	(105.20)	-15.58%
7	4 - INCH	1,055.00	1,305.04	250.04	23.70%	950.00	(105.00)	-9.95%
8	6 - INCH	2,110.00	2,610.07	500.07	23.70%	1,900.00	(210.00)	-9.95%
9	8 - INCH	0.00	0.00	0.00	#DIV/0!	3,800.00	3,800.00	#DIV/0!
10	10 - INCH	0.00	0.00	0.00	#DIV/0!	7,600.00	7,600.00	#DIV/0!
11	GALLONS INCLUDED IN MONHTLY MINIMUM CHARGE	0	0			0		

REFERENCES
COLUMN (A) THRU COLUMN (D): COMPANY SCHEDULE H-3, PAGE 1 OF 3
COLUMN (E): TESTIMONY XXX
COLUMN (F): COLUMN (E) - COLUMN (A)
COLUMN (G): COLUMN (F) ÷ COLUMN (A)

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

PRESENT RATES

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	$42.20	$63.30	$105.50	$211.50	$339.68	$675.20	$1,055.00	$2,110.00	$0.00	$0.00
2	1,000	46.15	67.25	111.41	217.41	345.59	681.11	1,060.91	2,115.91	7.11	7.11
3	2,000	50.10	71.20	117.32	223.32	351.50	687.02	1,066.82	2,121.82	14.22	14.22
4	3,000	54.05	75.15	123.23	229.23	357.41	692.93	1,072.73	2,127.73	21.33	21.33
5	4,000	58.00	79.10	129.14	235.14	363.32	698.84	1,078.64	2,133.64	28.44	28.44
6	5,000	63.91	85.01	135.05	241.05	369.23	704.75	1,084.55	2,139.55	35.55	35.55
7	6,000	69.82	90.92	140.96	246.96	375.14	710.66	1,090.46	2,145.46	42.66	42.66
8	7,000	75.73	96.83	146.87	252.87	381.05	716.57	1,096.37	2,151.37	49.77	49.77
9	8,000	81.64	102.74	152.78	258.78	386.96	722.48	1,102.28	2,157.28	56.88	56.88
10	9,000	87.55	108.65	158.69	264.69	392.87	728.39	1,108.19	2,163.19	63.99	63.99
11	10,000	94.66	115.76	164.60	270.60	398.78	734.30	1,114.10	2,169.10	71.10	71.10
12	15,000	130.21	151.31	194.15	300.15	428.33	763.85	1,143.65	2,198.65	106.65	106.65
13	20,000	165.76	186.86	223.70	329.70	457.88	793.40	1,173.20	2,228.20	142.20	142.20
14	25,000	201.31	222.41	256.25	359.25	487.43	822.95	1,202.75	2,257.75	177.75	177.75
15	50,000	379.06	400.16	434.00	526.20	641.18	970.70	1,350.50	2,405.50	355.50	355.50
16	75,000	556.81	577.91	611.75	703.95	818.93	1,126.85	1,498.25	2,553.25	533.25	533.25
17	100,000	734.56	755.66	789.50	881.70	996.68	1,304.60	1,658.00	2,701.00	711.00	711.00
18	125,000	912.31	933.41	967.25	1,059.45	1,174.43	1,482.35	1,835.75	2,848.75	888.75	888.75
19	150,000	1,090.06	1,111.16	1,145.00	1,237.20	1,352.18	1,660.10	2,013.50	3,014.50	1,066.50	1,066.50
20	175,000	1,267.81	1,288.91	1,322.75	1,414.95	1,529.93	1,837.85	2,191.25	3,192.25	1,244.25	1,244.25
21	200,000	1,445.56	1,466.66	1,500.50	1,592.70	1,707.68	2,015.60	2,369.00	3,370.00	1,422.00	1,422.00
22	250,000	1,801.06	1,822.16	1,856.00	1,948.20	2,063.18	2,371.10	2,724.50	3,725.50	1,777.50	1,777.50
23	500,000	3,578.56	3,599.66	3,633.50	3,725.70	3,840.68	4,148.60	4,502.00	5,503.00	3,555.00	3,555.00
24	1,000,000	7,133.56	7,154.66	7,188.50	7,280.70	7,395.68	7,703.60	8,057.00	9,058.00	7,110.00	7,110.00
25	2,000,000	14,243.56	14,264.66	14,298.50	14,390.70	14,505.68	14,813.60	15,167.00	16,168.00	14,220.00	14,220.00
26	3,000,000	21,353.56	21,374.66	21,408.50	21,500.70	21,615.68	21,923.60	22,277.00	23,278.00	21,330.00	21,330.00
27	4,000,000	28,463.56	28,484.66	28,518.50	28,610.70	28,725.68	29,033.60	29,387.00	30,388.00	28,440.00	28,440.00
28	5,000,000	35,573.56	35,594.66	35,628.50	35,720.70	35,835.68	36,143.60	36,497.00	37,498.00	35,550.00	35,550.00
29											
30											
31	AVG. NO. OF CUST:	0	0	3	1	2	0	0	0	0	0
32											
33	AVG. USE (GAL.):	N/A	N/A	70,291	500	56,808	N/A	N/A	N/A	N/A	N/A
34	MONTHLY BILL:	N/A	N/A	$578.27	$214.46	$689.59	N/A	N/A	N/A	N/A	N/A
35											
36	MEDIAN USE (GAL.) :	N/A	N/A	100,714	N/A	100,286	N/A	N/A	N/A	N/A	N/A
37	MONTHLY BILL:	N/A	N/A	$794.58	N/A	$998.71	N/A	N/A	N/A	N/A	N/A

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-6

RUCO RECOMMENDED CHANGES EXPRESSED IN DOLLARS

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	($4.20)	($6.30)	($10.50)	($21.50)	($35.68)	($105.20)	($105.00)	($210.00)	$3,800.00	$7,600.00
2	1,000	(3.60)	(5.70)	(9.41)	(20.41)	(34.59)	(104.11)	(103.91)	(208.91)	3,801.69	7,601.69
3	2,000	(3.00)	(5.10)	(8.32)	(19.32)	(33.50)	(103.02)	(102.82)	(207.82)	3,803.39	7,603.39
4	3,000	(2.40)	(4.50)	(7.23)	(18.23)	(32.41)	(101.93)	(101.73)	(206.73)	3,805.08	7,605.08
5	4,000	(1.80)	(3.90)	(6.14)	(17.14)	(31.32)	(100.84)	(100.64)	(205.64)	3,806.78	7,606.78
6	5,000	(0.71)	(2.81)	(5.05)	(16.05)	(30.23)	(99.75)	(99.55)	(204.55)	3,808.47	7,608.47
7	6,000	0.38	(1.72)	(3.96)	(14.96)	(29.14)	(98.66)	(98.46)	(203.46)	3,810.17	7,610.17
8	7,000	1.47	(0.63)	(2.87)	(13.87)	(28.05)	(97.57)	(97.37)	(202.37)	3,811.86	7,611.86
9	8,000	2.56	0.46	(1.78)	(12.78)	(26.96)	(96.48)	(96.28)	(201.28)	3,813.56	7,613.56
10	9,000	3.65	1.55	(0.69)	(11.69)	(25.87)	(95.39)	(95.19)	(200.19)	3,815.25	7,615.25
11	10,000	5.34	3.24	0.40	(10.60)	(24.78)	(94.30)	(94.10)	(199.10)	3,816.95	7,616.95
12	15,000	13.82	11.72	5.85	(5.15)	(19.33)	(88.85)	(88.65)	(193.65)	3,825.42	7,625.42
13	20,000	22.29	20.19	11.30	0.30	(13.88)	(83.40)	(83.20)	(188.20)	3,833.90	7,633.90
14	25,000	30.77	28.67	18.26	5.75	(8.43)	(77.95)	(77.75)	(182.75)	3,842.37	7,642.37
15	50,000	73.14	71.04	60.63	42.68	21.84	(50.70)	(50.50)	(155.50)	3,884.75	7,684.75
16	75,000	115.51	113.41	103.01	85.05	64.22	(19.22)	(23.25)	(128.25)	3,927.12	7,727.12
17	100,000	157.89	155.79	145.38	127.42	106.59	23.16	10.05	(101.00)	3,969.49	7,769.49
18	125,000	200.26	198.16	187.75	169.80	148.96	65.53	52.42	(73.75)	4,011.86	7,811.86
19	150,000	242.63	240.53	230.12	212.17	191.33	107.90	94.79	(37.43)	4,054.24	7,854.24
20	175,000	285.00	282.90	272.50	254.54	233.71	150.27	137.17	4.95	4,096.61	7,896.61
21	200,000	327.38	325.28	314.87	296.91	276.08	192.65	179.54	47.32	4,138.98	7,938.98
22	250,000	412.12	410.02	399.61	381.66	360.82	277.39	264.28	132.06	4,223.73	8,023.73
23	500,000	835.85	833.75	823.34	805.38	784.55	701.12	688.01	555.79	4,647.45	8,447.45
24	1,000,000	1,683.30	1,681.20	1,670.79	1,652.83	1,632.00	1,548.57	1,535.46	1,403.24	5,494.90	9,294.90
25	2,000,000	3,378.20	3,376.10	3,365.69	3,347.73	3,326.90	3,243.47	3,230.36	3,098.14	7,189.80	10,989.80
26	3,000,000	5,073.10	5,071.00	5,060.59	5,042.63	5,021.80	4,938.37	4,925.26	4,793.04	8,884.70	12,684.70
27	4,000,000	6,768.00	6,765.90	6,755.49	6,737.53	6,716.70	6,633.27	6,620.16	6,487.94	10,579.60	14,379.60
28	5,000,000	8,462.90	8,460.80	8,450.39	8,432.43	8,411.60	8,328.17	8,315.06	8,182.84	12,274.50	16,074.50
29											
30											
31	AVG. NO. OF CUST:	0	0	3	1	2	0	0	0	0	0
32											
33	AVG. USE (GAL.):	N/A	N/A	70,291	500	56,808	N/A	N/A	N/A	N/A	N/A
34	MONTHLY BILL:	N/A	N/A	$95.02	($20.96)	$33.38	N/A	N/A	N/A	N/A	N/A
35											
36	MEDIAN USE (GAL.) :	N/A	N/A	100,714	N/A	100,286	N/A	N/A	N/A	N/A	N/A
37	MONTHLY BILL:	N/A	N/A	$146.59	N/A	$107.08	N/A	N/A	N/A	N/A	N/A

GOODMAN WATER COMPANY - SURREBUTTAL COMMERCIAL RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
BILLING ANALYSIS

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-7

RUCO RECOMMENDED CHANGES EXPRESSED AS A PERCENTAGE

LINE NO.	CONSUMPTION IN GALLONS	(A) 5/8 - INCH	(B) 3/4 - INCH	(C) 1 - INCH	(D) 1.5 - INCH	(E) 2 - INCH	(F) 3 - INCH	(G) 4 - INCH	(H) 6 - INCH	(G) 8 - INCH	(H) 10 - INCH
1	0	-10.0%	-10.0%	-10.0%	-10.2%	-10.5%	-15.6%	-10.0%	-10.0%	#DIV/0!	#DIV/0!
2	1,000	-7.8%	-8.5%	-8.4%	-9.4%	-10.0%	-15.3%	-9.8%	-9.9%	53469.6%	106915.5%
3	2,000	-6.0%	-7.2%	-7.1%	-8.7%	-9.5%	-15.0%	-9.6%	-9.8%	26746.8%	53469.7%
4	3,000	-4.4%	-6.0%	-5.9%	-8.0%	-9.1%	-14.7%	-9.5%	-9.7%	17839.1%	35654.4%
5	4,000	-3.1%	-4.9%	-4.8%	-7.3%	-8.6%	-14.4%	-9.3%	-9.6%	13385.3%	26746.8%
6	5,000	-1.1%	-3.3%	-3.7%	-6.7%	-8.2%	-14.2%	-9.2%	-9.6%	10713.0%	21402.2%
7	6,000	0.5%	-1.9%	-2.8%	-6.1%	-7.8%	-13.9%	-9.0%	-9.5%	8931.5%	17839.1%
8	7,000	1.9%	-0.7%	-2.0%	-5.5%	-7.4%	-13.6%	-8.9%	-9.4%	7659.0%	15294.1%
9	8,000	3.1%	0.4%	-1.2%	-4.9%	-7.0%	-13.4%	-8.7%	-9.3%	6704.6%	13385.3%
10	9,000	4.2%	1.4%	-0.4%	-4.4%	-6.6%	-13.1%	-8.6%	-9.3%	5962.3%	11900.7%
11	10,000	5.6%	2.8%	0.2%	-3.9%	-6.2%	-12.8%	-8.4%	-9.2%	5368.4%	10713.0%
12	15,000	10.6%	7.7%	3.0%	-1.7%	-4.5%	-11.6%	-7.8%	-8.8%	3586.9%	7149.9%
13	20,000	13.4%	10.8%	5.1%	0.1%	-3.0%	-10.5%	-7.1%	-8.4%	2696.1%	5368.4%
14	25,000	15.3%	12.9%	7.1%	1.6%	-1.7%	-9.5%	-6.5%	-8.1%	2161.7%	4299.5%
15	50,000	19.3%	17.8%	14.0%	8.1%	3.4%	-5.2%	-3.7%	-6.5%	1092.8%	2161.7%
16	75,000	20.7%	19.6%	16.8%	12.1%	7.8%	-1.7%	-1.6%	-5.0%	736.5%	1449.1%
17	100,000	21.5%	20.6%	18.4%	14.5%	10.7%	1.8%	0.6%	-3.7%	558.3%	1092.8%
18	125,000	22.0%	21.2%	19.4%	16.0%	12.7%	4.4%	2.9%	-2.6%	451.4%	879.0%
19	150,000	22.3%	21.6%	20.1%	17.1%	14.1%	6.5%	4.7%	-1.2%	380.1%	736.5%
20	175,000	22.5%	21.9%	20.6%	18.0%	15.3%	8.2%	6.3%	0.2%	329.2%	634.6%
21	200,000	22.6%	22.2%	21.0%	18.6%	16.2%	9.6%	7.6%	1.4%	291.1%	558.3%
22	250,000	22.9%	22.5%	21.5%	19.6%	17.5%	11.7%	9.7%	3.5%	237.6%	451.4%
23	500,000	23.4%	23.2%	22.7%	21.6%	20.4%	16.9%	15.3%	10.1%	130.7%	237.6%
24	1,000,000	23.6%	23.5%	23.2%	22.7%	22.1%	20.1%	19.1%	15.5%	77.3%	130.7%
25	2,000,000	23.7%	23.7%	23.5%	23.3%	22.9%	21.9%	21.3%	19.2%	50.6%	77.3%
26	3,000,000	23.8%	23.7%	23.6%	23.5%	23.2%	22.5%	22.1%	20.6%	41.7%	59.5%
27	4,000,000	23.8%	23.8%	23.7%	23.5%	23.4%	22.8%	22.5%	21.4%	37.2%	50.6%
28	5,000,000	23.8%	23.8%	23.7%	23.6%	23.5%	23.0%	22.8%	21.8%	34.5%	45.2%
29											
30											
31	AVG. NO. OF CUST:	0	0	3	1	2	0	0	0	0	0
32											
33	AVG. USE (GAL.):	N/A	N/A	70,291	500	56,808	N/A	N/A	N/A	N/A	N/A
34	MONTHLY BILL:	N/A	N/A	16.4%	-9.8%	4.8%	N/A	N/A	N/A	N/A	N/A
35											
36	MEDIAN USE (GAL.) :	N/A	N/A	100,714	N/A	100,286	N/A	N/A	N/A	N/A	N/A
37	MONTHLY BILL:	N/A	N/A	18.4%	N/A	10.7%	N/A	N/A	N/A	N/A	N/A

GOODMAN WATER COMPANY –
TJC SURREBUTTAL CONSTRUCTION-STANDPIPE RATE DESIGN SCHEDULE

DOCKET NO. W-02500A-10-0382

GOODMAN WATER COMPANY - SURREBUTTAL CONSTRUCTION / STANDPIPE RATE DESIGN
TEST YEAR ENDED DECEMBER 31, 2009
RATE DATA INPUT

DOCKET NO. W-02500A-10-0382
SCHEDULE TJC RD-1

PRESENT RATES	[1] GENERAL SERVICE 5/8- INCH	[2] GENERAL SERVICE 3/4 - INCH	[3] GENERAL SERVICE 1 - INCH	[4] GENERAL SERVICE 1 1/2 - INCH	[5] GENERAL SERVICE 2 - INCH	[6] GENERAL SERVICE 3 - INCH	[7] GENERAL SERVICE 4 - INCH	[8] GENERAL SERVICE 6 - INCH	[9] GENERAL SERVICE 8 - INCH	[10] GENERAL SERVICE 10 - INCH
Basic Charge:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier One Rate:	7.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier Two Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier Three Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier Four Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier Five Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier Six Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gallons in Minimum:	0	0	0	0	0	0	0	0	0	0
Tier One Upper Limit:	999,999,999,999,999,000	0	0	0	0	0	0	0	0	0
Tier Two Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Three Upper Limit:	0	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000
Tier Four Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Five Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Six Upper Limit:	0	0	0	0	0	0	0	0	0	0
Number of Tiers:	1	1	1	1	1	1	1	1	1	1

COMPANY PROPOSED RATES	[1] GENERAL SERVICE 5/8- INCH	[2] GENERAL SERVICE 3/4 - INCH	[3] GENERAL SERVICE 1 - INCH	[4] GENERAL SERVICE 1 1/2 - INCH	[5] GENERAL SERVICE 2 - INCH	[6] GENERAL SERVICE 3 - INCH	[7] GENERAL SERVICE 4 - INCH	[8] GENERAL SERVICE 6 - INCH	[9] GENERAL SERVICE 8 - INCH	[10] GENERAL SERVICE 10 - INCH
Basic Charge:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier One Rate:	13.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Two Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Three Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Four Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Five Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Six Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gallons in Minimum:	0	0	0	0	0	0	0	0	0	0
Tier One Upper Limit:	999,999,999,999,999,000	0	0	0	0	0	0	0	0	0
Tier Two Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Three Upper Limit:	0	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000
Tier Four Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Five Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Six Upper Limit:	0	0	0	0	0	0	0	0	0	0
Number of Tiers:	1	1	1	1	1	1	1	1	1	1

RUCO RECOMMENDED RATES	[1] GENERAL SERVICE 5/8- INCH	[2] GENERAL SERVICE 3/4 - INCH	[3] GENERAL SERVICE 1 - INCH	[4] GENERAL SERVICE 1 1/2 - INCH	[5] GENERAL SERVICE 2 - INCH	[6] GENERAL SERVICE 3 - INCH	[7] GENERAL SERVICE 4 - INCH	[8] GENERAL SERVICE 6 - INCH	[9] GENERAL SERVICE 8 - INCH	[10] GENERAL SERVICE 10 - INCH
Basic Charge:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Tier One Rate:	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80	8.80
Incremental Tier Two Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Three Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Four Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Five Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Incremental Tier Six Rate:	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Gallons in Minimum:	0	0	0	0	0	0	0	0	0	0
Tier One Upper Limit:	999,999,999,999,999,000	0	0	0	0	0	0	0	0	0
Tier Two Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Three Upper Limit:	0	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000	999,999,999,999,999,000
Tier Four Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Five Upper Limit:	0	0	0	0	0	0	0	0	0	0
Tier Six Upper Limit:	0	0	0	0	0	0	0	0	0	0
Number of Tiers:	1	1	1	1	1	1	1	1	1	1

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TJC-3	1	ORIGINAL COST RATE BASE ADJUSTMENTS
TJC-4	1 - 5	RATE BASE ADJUSTMENT NO. 1 - TEST YEAR END PLANT AND ACCUMULATED DEPRECIATION
TJC-5	1	RATE BASE ADJUSTMENT NO. 2 - EXCESS CAPACITY
TJC-6	1 & 2	RATE BASE ADJUSTMENT NO. 3 - ADVANCES IN AID OF CONSTRUCTION ("AIAC")
TJC-7	1 & 2	RATE BASE ADJUSTMENT NO. 4 - ACCUMULATED DEFERRED INCOME TAXES
TJC-8	1	SUMMARY OF OPERATING INCOME
TJC-9	1	OPERATING INCOME ADJUSTMENTS
TJC-10	1	OPERATING INCOME ADJUSTMENT NO. 1 - TEST YEAR DEPRECIATION EXPENSE
TJC-11	1	OPERATING INCOME ADJUSTMENT NO. 2 - PROPERTY TAX EXPENSE
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TJC-12	1	OPERATING INCOME ADJUSTMENT NO. 4 - SALARIES & WAGE EXPENSE
TJC-13	1	OPERATING INCOME ADJUSTMENT NO. 5 - CONTRACTUAL SERVICES EXPENSE
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TJC-14	1	OPERATING INCOME ADJUSTMENT NO. 7 - INCOME TAX EXPENSE
TJC-15	1	COST OF CAPITAL

REVENUE REQUIREMENT

LINE NO.	DESCRIPTION	(A) COMPANY OCRB/FVRB COST	(B) RUCO OCRB/FVRB COST
1	Fair Value Rate Base	$ 2,402,221	$ 1,755,118
2	Adjusted Operating Income (Loss)	73,883	131,842
3	Current Rate Of Return (L2 / L1)	3.08%	7.51%
4	Required Operating Income (L5 X L1)	$ 253,194	$ 137,790
5	Required Rate Of Return On Fair Value Rate Base	10.54%	7.85%
6	Operating Income Deficiency (L4 - L2)	$ 179,311	$ 5,948
7	Gross Revenue Conversion Factor (RLM-1, Pg 2)	1.6254	1.4653
8	Increase In Gross Revenue Requirement (L7 X L6)	$ 291,454	$ 8,715
9	Adjusted Test Year Revenue	572,751	594,459
10	Proposed Annual Revenue (L8 + L9)	864,204	603,174
11	Required Percentage Increase In Revenue (L8 / L9)	50.89%	1.47%
12	Rate Of Return On Common Equity	11.00%	9.00%

References:
Column (A): Company Schedules A-1, B-1, and C-1
Column (B): RUCO Schedule TJC-1, page 2, TJC-2, TJC-8, and TJC-19

REVENUE REQUIREMENT - CONT'D
GROSS REVENUE CONVERSION FACTOR

LINE NO.	DESCRIPTION	(A)	(B)	(C)	(D)
	CALCULATION OF GROSS REVENUE CONVERSION FACTOR:				
1	Revenue	1.0000			
2	Proposed Bad Debt Expense (Per Co. Workpapers)	-			
4	Subtotal (L1 thru L2)	1.0000			
5	Combined Federal And State Tax Rate (L13)	0.3175			
6	Subtotal (L4 - L5)	0.6825			
7	**Revenue Conversion Factor** (L1 / L6)	**1.4653**			
	CALCULATION OF EFFECTIVE TAX RATE:				
8	Operating Income Before Taxes (Arizona Taxable Income)	100.0000%			
9	Arizona State Income Tax Rate	6.9680%			
10	Federal Taxable Income (Col. (D), L37)	93.0320%			
11	Applicable Federal Income Tax Rate (Col. (D), L34)	25.9051%			
12	Effective Federal Income Tax Rate (L10 X L11)	24.1000%			
13	Combined Federal And State Income Tax Rate (L9 + L12)	31.0680%			
	CALCULATION OF EFFECTIVE PRPERTY TAX FACTOR:				
	Unity	100.0000%			
	Combined Federal and State Tax Rate	31.0680%			
	1 Minus Combined Income Tax Rate	68.9320%			
	Property Tax Factor	0.009941067			
	Effective Property Tax Factor	0.006852576			
	Combined Federal, State and Property Tax RateTax Rate	31.7533%			
14	RUCO Required Operating Income (Sch. TJC-1, Col. (B), L4)	$ 137,790			
15	RUCO Adj'd T.Y. Oper'g Inc. (Loss) (Sch. TJC-1, Col. (B), L2)	131,842			
16	Required Increase In Operating Income (L14 - L15)		$ 5,948		
17	Income Taxes On Recommended Revenue (Col. (D), L34)	$ 42,716			
18	Income Taxes On Test Year Revenue (Col. (D), L35)	40,035			
19	Required Increase In Revenue To Provide For Income Taxes (L17 - L18)		2,681		
	Property Tax with Recommended Revenue	$ 17,815			
	Propertry Tax on TestYear Revenue	17,729			
	Increase in Property Tax Due to Increase in Revenue		$ 87		
20	Total Required Increase In Revenue (L16 + L19)		$ 8,715		
	RUCO's CALCULATION OF INCOME TAX			RUCO Recommended	
21	RUCO Proposed Revenue (Sch. TJC-1, Col. (B), L10)			$ 603,174	
	Less:				
22	Operating Expense Excluding Income Tax (TJC-8, Col. (E), L23 - L22)			422,668	
23	Synchronized Interest (Col. (C), L40)			43,013	
24	Arizona Taxable Income (L21 - L22 - L23)			$ 137,493	
25	Arizona State Income Tax Rate			6.9680%	
26	Arizona Income Tax (L24 X L25)				$ 9,580
27	Fed. Taxable Income (L24 - L26)			$ 127,912	
28	Fed. Tax On 1st Inc. Bracket ($1 - $50,000) @ 15%			$ 7,500	
29	Fed. Tax On 2nd Inc. Bracket ($50,001 - $75,000) @ 25%			6,250	
30	Fed. Tax On 3rd Inc. Bracket ($75,001 - $100,000) @ 34%			8,500	
31	Fed. Tax On 4th Inc. Bracket ($100,001 - $335,000) @ 39%			10,886	
32	Fed. Tax On 5th Inc. Bracket ($335,001 - $10M) @ 34%			-	
33	Total Federal Income Tax (L28 + L29 + L30 + L31 + L32)				$ 33,136
34	Combined Federal And State Income Tax (L26 + L33)				$ 42,716
35	RUCO Adj'd Test Year Combined Federal and State Income Tax (TJC-8, Col. (C), L22)				$ 40,035
36	RUCO Proposed Income Tax Adjustment (L34 - L35) (See TJC-8, Col. (D), L22)				$ 2,681
37	Applicable Federal Income Tax Rate (Col. (D), L33 / Col. (C), L27)				25.91%
	CALCULATION OF INTEREST SYNCHRONIZATION:				
38	Rate Base (Sch. TJC-1, Col. (B), L1)			$ 1,755,118	
39	Weighted Avg. Cost Of Debt (Sch. TJC-17, Col. (C), L1)			2.45%	
40	Synchronized Interest (L38 X L39)			$ 43,013	

SUMMARY OF ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) RUCO ADJUSTMENTS	(C) RUCO AS ADJUSTED OCRB/FVRB
1	Gross Utility Plant In Service	$ 5,453,761	$ (1,360,580)	$ 4,093,181
2	Accumulated Depreciation	(731,205)	266,039	(465,165)
3	Rounding	(1)	-	(1)
4	Net Utility Plant In Service (L1 + L2 + L3)	$ 4,722,556	$ (1,094,541)	$ 3,628,015
	Less:			
5	Advances In Aid Of Const.	$ (2,101,905)	$ 497,983	$ (1,603,922)
6	Contribution In Aid Of Const.	$ -	$ -	$ -
7	Accumulated Amortization Of CIAC	-	-	-
8	NET CIAC (L6 + L7)	$ -	$ -	$ -
9	Customer Meter Deposits	$ (83,087)	$ -	$ (83,087)
10	Customer Hydrant Meter Deposits	$ -	$ -	$ -
11	Accumulated Deferred Income Taxes	$ (135,342)	$ (50,545)	$ (185,888)
12	Unamortized Finance Charges	$ -	$ -	$ -
13	Deferred Regulatory Assets	$ -	$ -	$ -
14	Allowance For Working Capital	$ -	$ -	$ -
15	TOTAL RATE BASE (Sum L's 4, 5, 8, 9 Thru 14)	$ 2,402,221	$ (647,103)	$ 1,755,118

References:
Column (A): Company Schedule B-1, Page 1 And Workpapers Schedule E-1
Column (B): TJC-3, Columns (B) Thru (G)
Column (C): Column (A) + Column (B)

Goodman Water Company
Docket No. W-02500A-10-0382
Test Year Ended December 31, 2009

ORIGINAL COST RATE BASE ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED OCRB/FVRB	(B) ADJ # 1 TEST YR PLT & ACC DEP	(C) ADJ # 2 EXCESS CAPACITY	(D) ADJ # 3 AIAC	(E) ADJ # 4 DEFERRED INCOME TAX	(F) INTENT'NLY LEFT BLANK	(G) INTENT'NLY LEFT BLANK	(H) RUCO ADJ'TED OCRB/FVRB
1	Gross Utility Plant In Service	$ 5,453,761	$ -	$ (1,360,580)	$ -	$ -	$ -	$ -	$ 4,093,181
2	Accumulated Depreciation	(731,205)	(3,268)	269,307	-	-	-	-	(465,165)
3	Rounding	(1)							(1)
4	Net Utility Plant In Service (L1 + L2 + L3)	$ 4,722,556	$ (3,268)	$ (1,091,273)	$ -	$ -	$ -	$ -	$ 3,628,015
	Less:								
5	Advances In Aid Of Const.	$ (2,101,905)	$ -	$ -	$ 497,983	$ -	$ -	$ -	$ (1,603,922)
6	Contribution In Aid Of Const.	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
7	Accumulated Amortization Of CIAC	-	-	-	-	-	-	-	-
8	NET CIAC (L6 + L7)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
9	Customer Meter Deposits	$ (83,087)	$ -	$ -	$ -	$ -	$ -	$ -	$ (83,087)
10	Customer Hydrant Meter Deposits	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
11	Accumulated Deferred Income Taxes	$ (135,342)	$ -	$ -	$ -	$ (50,545)	$ -	$ -	$ (185,888)
12	Unamortized Finance Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	Deferred Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
14	Allowance For Working Capital	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
15	TOTAL RATE BASE (Sum L's 4, 5, 8, 9 Thru 14)	$ 2,402,221	$ (3,268)	$ (1,091,273)	$ 497,983	$ (50,545)	$ -	$ -	$ 1,755,118

References:

Column (A): Company Schedule B-1, Page 1 And Workpapers Schedule E-1
Column (B): Adjustment No. 1 - RUCO Adjustment To Test-Year GPIS And Acc. Dep. (See Testimony and Schedule TJC-4(2009))
Column (C): Adjustment No. 2 - RUCO Adjustment for Excess Capacity (See Testimony)
Column (D): Adjustment No. 3 - RUCO Adjustment to AIAC for Excess Capacity (See Testimony)
Column (E): Adjustment No. 4 - RUCO Adjustment To Deferred Income Taxes for Excess Capacity (See Testimony and Schedule TJC-7)
Column (F): Intentionally Left Blank
Column (G): Intentionally Left Blank
Column (H): Sum Of Columns (A), (B), (C), (D), (E), (F), & (G)

Goodman Water Company
Docket No. W-02500A-10-0382
Test Year Ended December 31, 2009

TEST YEAR PLANT SCHEDULES
PRIOR TEST YEAR ENDED SEPTEMBER 30, 2005

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) PER PRIOR DECISION NO. 69404 GROSS PLANT	(D) PER PRIOR DECISION NO. 69404 ACCUMULATED DEPRECIATION	(E) OCT - DEC 2005 PLANT ADDITIONS	(F) OCT - DEC 2005 PLANT ADJUSTMENTS	(G) OCT - DEC 2005 PLANT RETIREMENTS	(H) 2005 GROSS PLANT	(I) OCT - DEC 2005 DEPRE. EXPENSE	(J) DECEMBER 31 2005 ACCUMULATED DEPRECIATION BALANCE	(K) DECEMBER 31 2005 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 104,528	$ -	$ 1,500	$ -	$ -	$ 106,028	$ -	$ -	$ 106,028
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-	-	
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-	-	-	
4	304	Structures and Improvements	2.50%	3.33%	9,788	(306)	1,276	-	-	11,064	65	(372)	10,692
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-	-	
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-	-	
7	307	Wells & Springs	2.50%	3.33%	386,591	(17,925)	-	-	-	386,591	2,416	(20,342)	366,249
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-	-	
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-	-	
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-	-	
11	311	Electric Pumping Equipmemt	2.50%	12.50%	686,993	(35,041)	-	-	-	686,993	4,294	(39,335)	647,657
12	320	Water Treatment Equipment	2.50%	3.33%	11,054	(345)	-	-	-	11,054	69	(415)	10,639
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-	-	
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-	-	
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	294,460	(15,489)	-	-	-	294,460	1,840	(17,329)	277,131
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-	-	
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-	-	
18	331	Trans. and Dist. Mains	2.50%	2.00%	628,673	(29,324)	122,779	-	-	751,452	4,313	(33,637)	717,815
19	333	Services	2.50%	3.33%	129,274	(5,679)	17,266	-	-	146,540	862	(6,541)	139,999
20	334	Meters	2.50%	6.33%	67,497	(2,310)	270	-	-	67,767	423	(2,733)	65,034
21	335	Hydrants	2.50%	2.00%	46,955	(2,090)	36,220	-	-	83,175	407	(2,497)	80,678
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-	-	
23	339	Other Plant and Misc. Equip.	2.50%	6.67%	-	-	152,473	-	-	152,473	476	(476)	151,997
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-	-	
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-	-	
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-	-	
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-	-	
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-	-	
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-	-	
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-	-	
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-	-	
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-	-	
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-	-	
34		Rounding			2	-	-	-	-	2	-	-	
35	**RUCO TOTAL WATER PLANT**				$ 2,365,813	$ (108,511)	$ 331,783	$ -	$ -	$ 2,697,596	$ 15,165	$ (123,676)	$ 2,573,918
37	Per Company Work Papers				$ 2,365,813	$ (108,509)	$ 331,783	$ -	$ -	$ 2,697,594	$ 15,165	$ (123,674)	$ 2,573,920
38	RUCO Increase/Decrease to GUPIS & Accum. Depre.				$ -	$ (2)	$ -	$ -	$ -	$ 2	$ 0	$ (2)	$ (2)

References:
Columns (A), (B), (C), & (D): Per Decision No. 69404
Columns (E), (F), & (G): Company B-2 Schedules and Plant Additions' Workpapers
Column (H): Column (C) + Column (E), (F), & (G)
Column (I): RUCO's Depreciation Expense Formula
Column (J): Column (D) + Column (I)
Column (K): Column (H) + Column (J)

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2006

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2006 PLANT ADDITIONS	(D) 2006 PLANT ADJUSTMENTS	(E) 2006 PLANT RETIREMENTS	(F) 2006 GROSS PLANT	(G) 2006 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2006 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2006 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 4,920	$ -	$ -	$ 110,948	$ -	$ -	$ 110,948
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-	-
4	304	Structures and Improvements	2.50%	3.33%	-	-	-	11,064	277	(648)	10,415
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	9,665	(30,006)	356,584
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	-	-	-	686,993	17,175	(56,510)	630,482
12	320	Water Treatment Equipment	2.50%	3.33%	266	-	-	11,320	280	(694)	10,626
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	-	-	-	294,460	7,362	(24,691)	269,769
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	-	-	-	751,452	18,786	(52,423)	699,028
19	333	Services	2.50%	3.33%	3	-	-	146,543	3,664	(10,204)	136,338
20	334	Meters	2.50%	8.33%	270	-	-	68,037	1,698	(4,430)	63,607
21	335	Hydrants	2.50%	2.00%	5	-	-	83,180	2,079	(4,576)	78,604
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	2.50%	6.67%	13,245	-	-	165,718	3,977	(4,454)	161,264
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	-	-	2	-	-	-
0											
35		**RUCO TOTAL WATER PLANT**			$ 18,709	$ -	$ -	$ 2,716,305	$ 64,962	$ (188,638)	$ 2,527,665
37		Per Company Work Papers			$ 18,709	$ -	$ -	$ 2,716,303	$ 64,962	$ (188,636)	$ 2,527,667
38		RUCO Increase/Decrease to GUPIS & Accum. Depre.			$ -	$ -	$ -	$ 2	$ (0)	$ (2)	$ (2)

Goodman Water Company
Docket No. W-02500A-10-0382
Test Year Ended December 31, 2009

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2007

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2007 PLANT ADDITIONS	(D) 2007 PLANT ADJUSTMENTS	(E) 2007 PLANT RETIREMENTS	(F) 2007 GROSS PLANT	(G) 2007 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2007 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2007 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 6,539	$ -	$ -	$ 117,487	$ -	$ -	$ 117,487
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	-	-	-	-
4	304	Structures and Improvements	2.50%	3.33%	-	-	-	11,064	338	(986)	10,077
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	11,804	(41,810)	344,780
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	2,963	-	-	689,956	63,110	(119,620)	570,335
12	320	Water Treatment Equipment	2.50%	3.33%	4,628	-	-	15,948	416	(1,111)	14,837
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	72,350	-	-	366,810	7,649	(32,340)	334,470
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	685,094	-	-	1,436,546	23,703	(76,126)	1,360,419
19	333	Services	2.50%	3.33%	143,352	-	-	289,895	6,663	(16,867)	273,027
20	334	Meters	2.50%	8.33%	18,359	-	(6,580)	79,816	4,721	(2,572)	77,244
21	335	Hydrants	2.50%	2.00%	43,205	-	-	126,385	2,270	(6,846)	119,539
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	2.50%	6.67%	759	-	-	166,477	8,770	(13,224)	153,253
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	-	-	2	-	-	2
0											
35		**RUCO TOTAL WATER PLANT**			$ 977,249	$ -	$ (6,580)	$ 3,686,974	$ 129,445	$ (311,502)	$ 3,375,472
37		Per Company Work Papers			$ 977,249	$ -	$ (6,580)	$ 3,686,972	$ 126,179	$ (308,235)	$ 3,378,737
38		RUCO Increase/Decrease to GUPIS & Accum. Depre.			$ -	$ -	$ -	$ 2	$ 3,266	$ (3,267)	$ (3,265)

Goodman Water Company
Docket No. W-02500A-10-0382
Test Year Ended December 31, 2009

TEST YEAR PLANT SCHEDULES - CONT'D
YEAR ENDED DECEMBER 31, 2008

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2008 PLANT ADDITIONS	(D) 2008 PLANT ADJUSTMENTS	(E) 2008 PLANT RETIREMENTS	(F) 2008 GROSS PLANT	(G) 2008 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2008 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2008 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ 9,616	$ -	$ -	$ 127,103	$ -	$ -	$ 127,103
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	494,159	-	-	494,159	-	-	494,159
4	304	Structures and Improvements	2.50%	3.33%	171,506	-	-	182,570	3,224	(4,210)	178,359
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	12,873	(54,684)	331,907
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	275,541	-	-	965,497	103,466	(223,086)	742,411
12	320	Water Treatment Equipment	2.50%	3.33%	-	-	-	15,948	531	(1,642)	14,306
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	470,081	-	-	836,891	13,361	(45,701)	791,190
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	174,757	-	-	1,611,303	30,478	(106,605)	1,504,698
19	333	Services	2.50%	3.33%	97,051	-	-	386,946	11,269	(28,137)	358,809
20	334	Meters	2.50%	8.33%	9,299	-	-	89,115	7,036	(9,608)	79,507
21	335	Hydrants	2.50%	2.00%	35,352	-	-	161,737	2,881	(9,728)	152,009
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	2.50%	6.67%	-	-	-	166,477	11,104	(24,328)	142,149
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	-	-	2	-	-	-
0											
35	**RUCO TOTAL WATER PLANT**				$ 1,737,362	$ -	$ -	$5,424,336	$ 196,224	$ (507,727)	$ 4,916,607
37	Per Company Work Papers				$ 1,737,362	$ -	$ -	$5,424,334	$ 196,224	$ (504,459)	$ 4,919,875
38	RUCO Increase/Decrease to GUPIS & Accum. Depre.				$ -	$ -	$ -	$ 2	$ 0	$ (3,268)	$ (3,268)

Goodman Water Company
Docket No. W-02500A-10-0382
Test Year Ended December 31, 2009

TEST YEAR PLANT SCHEDULES - CONT'D
TEST YEAR ENDED DECEMBER 31, 2009

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) Deprec. Rate 10/1/2005 Thru 4/30/2007	(B) Deprec. Rate After 4/30/2007	(C) 2009 PLANT ADDITIONS	(D) 2009 PLANT ADJUSTMENTS	(E) 2009 PLANT RETIREMENTS	(F) 2009 GROSS PLANT	(G) 2009 RUCO CALCULATED ANNUAL DEP.	(H) DECEMBER 31 2009 ACCUMULATED DEPRECIATION BALANCE	(I) DECEMBER 31 2009 NET PLANT VALUE
1	301	Organization Cost	0.00%	0.00%	$ -	$ -	$ -	$ 127,103	$ -	$ -	$ 127,103
2	302	Franchise Cost	0.00%	0.00%	-	-	-	-	-	-	-
3	303	Land and Land Rights	0.00%	0.00%	-	-	-	494,159	-	-	494,159
4	304	Structures and Improvements	2.50%	3.33%	-	-	-	182,570	6,080	(10,290)	172,280
5	305	Collecting and Impounding Res.	2.50%	2.50%	-	-	-	-	-	-	-
6	306	Lakes, Rivers, and Other Intakes	2.50%	2.50%	-	-	-	-	-	-	-
7	307	Wells & Springs	2.50%	3.33%	-	-	-	386,591	12,873	(67,557)	319,033
8	308	Infiltration Galleries and Tunnels	2.50%	6.67%	-	-	-	-	-	-	-
9	309	Supply Mains	2.50%	2.00%	-	-	-	-	-	-	-
10	310	Power Generation Equipment	2.50%	5.00%	-	-	-	-	-	-	-
11	311	Electric Pumping Equipmemt	2.50%	12.50%	3,155	-	-	968,652	120,884	(343,970)	624,681
12	320	Water Treatment Equipment	2.50%	3.33%	-	-	-	15,948	531	(2,173)	13,775
13	320.1	Water Treatment Plant	2.50%	3.33%	-	-	-	-	-	-	-
14	320.2	Chemical Solution Feeders	2.50%	20.00%	-	-	-	-	-	-	-
15	330	Dist. Reservoirs & Standpipe	2.50%	2.22%	-	-	-	836,891	18,579	(64,280)	772,611
16	330.1	Storage Tanks	2.50%	2.22%	-	-	-	-	-	-	-
17	330.2	Pressure Tanks	2.50%	5.00%	-	-	-	-	-	-	-
18	331	Trans. and Dist. Mains	2.50%	2.00%	18	-	-	1,611,321	32,226	(138,831)	1,472,489
19	333	Services	2.50%	3.33%	-	-	-	386,946	12,885	(41,022)	345,923
20	334	Meters	2.50%	8.33%	5,148	-	-	94,263	7,638	(17,245)	77,018
21	335	Hydrants	2.50%	2.00%	-	-	-	161,737	3,235	(12,962)	148,775
22	336	Backflow Prevention Devices	2.50%	6.67%	-	-	-	-	-	-	-
23	339	Other Plant and Misc. Equip.	2.50%	6.67%	21,105	-	-	187,582	11,808	(36,136)	151,446
24	340	Office Furniture and Fixtures	2.50%	6.67%	-	-	-	-	-	-	-
25	340.1	Computers and Software	2.50%	20.00%	-	-	-	-	-	-	-
26	341	Transportation Equipment	2.50%	20.00%	-	-	-	-	-	-	-
27	342	Stores Equipment	2.50%	4.00%	-	-	-	-	-	-	-
28	343	Tools and Work Equipment	2.50%	5.00%	-	-	-	-	-	-	-
29	344	Laboratory Equipment	2.50%	10.00%	-	-	-	-	-	-	-
30	345	Power Operated Equipment	2.50%	5.00%	-	-	-	-	-	-	-
31	346	Communications Equipment	2.50%	10.00%	-	-	-	-	-	-	-
32	347	Miscellaneous Equipment	2.50%	10.00%	-	-	-	-	-	-	-
33	348	Other Tangible Plant	2.50%	10.00%	-	-	-	-	-	-	-
34		Rounding			-	1	-	1	-	-	-
0											
35		**RUCO TOTAL WATER PLANT**			$ 29,426	$ 1	$ -	$ 5,453,761	$ 226,739	$ (734,466)	$ 4,719,294
37		Per Company Work Papers			$ 29,426	$ -	$ -	$ 5,453,761	$ 226,739	$ (731,198)	$ 4,722,563
38		RUCO Increase/Decrease to GUPIS & Accum. Depre.			$ -	$ 1	$ -	$ -	$ 0	$ (3,268)	$ (3,269)

References:
- Columns (A) & (B): Per Decision No. 69404
- Columns (C), (D), & (E): Company B-2 Schedules and Plant Additions' Workpapers
- Column (F): Schedule TJC-4(2008), Column (F) + Column (C), (D), & (E)
- Column (G): RUCO's Depreciation Expense Formula
- Column (H): Schedule TJC-4(2008), Column (H) + Column (G)
- Column (I): Column (F) + Column (H)

Goodman Water Company
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RUCO's RATE BASE ADJUSTMENT NO. 2
WATER PLANT EXCESS CAPACITY ADJUSTMENT

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) PER PRIOR DECISION NO. 69404 COMPANY TOTAL PLANT BALANCE	(B) PER PRIOR DECISION NO. 69404 COMPANY ACCUM. DEPRE. BALANCE	(C) SINCE DECISION NO. 69404 COMPANY PLANT ADDITIONS	(D) SINCE DECISION NO. 69404 ADDITIONAL ACCUMULATED DEPRECIATION	(E) RUCO PLANT ADDITIONS USED & USEFUL FACTOR	TOTAL WATER PLANT PER RUCO	TOTAL ACCUM. DEPRE. PER RUCO
1	301	Organization Cost	$ 104,528	$ -	$ 22,575	$ -	45.67%	$ 114,837	$ -
2	302	Franchise Cost	-	-	-	-	100.00%	-	-
3	303	Land and Land Rights	-	-	494,159	-	45.67%	225,673	-
4	304	Structures and Improvements	9,788	(306)	172,782	(9,979)	45.67%	88,694	(4,864)
5	305	Collecting and Impounding Res.	-	-	-	-	100.00%	-	-
6	306	Lakes, Rivers, and Other Intakes	-	-	-	-	100.00%	-	-
7	307	Wells & Springs	386,591	(17,925)	-	(49,498)	100.00%	386,591	(67,424)
8	308	Infiltration Galleries and Tunnels	-	-	-	-	100.00%	-	-
9	309	Supply Mains	-	-	-	-	100.00%	-	-
10	310	Power Generation Equipment	-	-	-	-	100.00%	-	-
11	311	Electric Pumping Equipmemt	686,993	(35,041)	281,659	(306,060)	45.67%	815,621	(174,814)
12	320	Water Treatment Equipment	11,054	(345)	4,894	(1,822)	45.67%	13,289	(1,178)
13	320.1	Water Treatment Plant	-	-	-	-	100.00%	-	-
14	320.2	Chemical Solution Feeders	-	-	-	-	100.00%	-	-
15	330	Dist. Reservoirs & Standpipe	294,460	(15,489)	542,431	(48,829)	64.15%	642,435	(46,813)
16	330.1	Storage Tanks	-	-	-	-	100.00%	-	-
17	330.2	Pressure Tanks	-	-	-	-	100.00%	-	-
18	331	Trans. and Dist. Mains	628,673	(29,324)	982,648	(109,735)	45.67%	1,077,430	(79,438)
19	333	Services	129,274	(5,679)	257,672	(35,268)	100.00%	386,946	(40,947)
20	334	Meters	67,497	(2,310)	26,766 *	(14,756)	100.00%	94,263	(17,066)
21	335	Hydrants	46,955	(2,090)	114,782	(10,894)	100.00%	161,737	(12,984)
22	336	Backflow Prevention Devices	-	-	-	-	100.00%	-	-
23	339	Other Plant and Misc. Equip.	-	-	187,582	(35,847)	45.67%	85,665	(16,371)
24	340	Office Furniture and Fixtures	-	-	-	-	100.00%	-	-
25	340.1	Computers and Software	-	-	-	-	100.00%	-	-
26	341	Transportation Equipment	-	-	-	-	100.00%	-	-
27	342	Stores Equipment	-	-	-	-	100.00%	-	-
28	343	Tools and Work Equipment	-	-	-	-	100.00%	-	-
29	344	Laboratory Equipment	-	-	-	-	100.00%	-	-
30	345	Power Operated Equipment	-	-	-	-	100.00%	-	-
31	346	Communications Equipment	-	-	-	-	100.00%	-	-
32	347	Miscellaneous Equipment	-	-	-	-	100.00%	-	-
33	348	Other Tangible Plant	-	-	-	-		-	-
34		Rounding	2	2	(1)	-		-	-
35		**COMPANY TOTAL PLANT & ACCUM. DEPRE.**	$ 2,365,813	$ (108,509)	$ 3,087,948	$ (622,689)		$ 4,093,181	$ (461,898)

36	RUCO Excess Capacity Plant Adjustment	$ (1,360,580)
37	RUCO Excess Capacity Accumulated Depreciation Adjustment	$ 269,307

Note:

38	RUCO's Used & Useful Factor (See RUCO Exhibit X)	45.67%
39	RUCO's Used & Useful Factor for Distribution Reservoirs	64.15%

References:
Column (A): Company B-2 Schedule and RUCO Schedule TJC-4(2009)
Column (B): Company B-2 Schedule
Column (C): Company B-2 Schedules- Plant Additions less Retirements
Column (D): Company B-2 Schedule - Accumulated Depreciation
Column (C): RUCO's Excess Capacity Factor (L38) Above
Column(D): Column (A) x Column (N)
Column(E): Column (B) x Column (N)

RUCO's RATE BASE ADJUSTMENT NO. 3
EXCESS CAPACITY ADJUSTMENT TO ADVANCES IN AID OF CONSTRUCTION ("AIAC")

LINE NO.	DESCRIPTION	(A) AMOUNT
1	AIAC Balance Per Prior Decision No. 69404	$ 971,695
2	AIAC Added Since Prior Decision No. 69404	1,130,210
3	RUCO's Used and Useful AIAC Factor (See Sch. TJC-6, page 2 of 2)	55.94%
4	AIAC Balance Per RUCO	$ 1,603,922
5	RUCO's AIAC Adjustment	$ 497,983

RUCO's RATE BASE ADJUSTMENT NO. 3
USED & USEFUL FACTOR FOR ADVANCES IN AID OF CONSTRUCTION ("AIAC")

Line No.	Plant Accounts	New Plant Additions	Percent to Total	RUCO Percentage Allowed	Weighted Average
	Organization Cost	$ 22,575	0.73%	45.67%	0.33%
	Franchise Cost	-	0.00%	45.67%	0.00%
	Land and Land Rights	494,159	16.00%	45.67%	7.31%
	Structures and Improvements	172,782	5.60%	45.67%	2.56%
	Collecting and Impounding Res.	-	0.00%	45.67%	0.00%
	Lakes, Rivers, and Other Intakes	-	0.00%	45.67%	0.00%
	Wells & Springs	-	0.00%	45.67%	0.00%
	Infiltration Galleries and Tunnels	-	0.00%	45.67%	0.00%
	Supply Mains	-	0.00%	45.67%	0.00%
	Power Generation Equipment	-	0.00%	45.67%	0.00%
	Electric Pumping Equipmemt	281,659	9.12%	45.67%	4.17%
	Water Treatment Equipment	4,894	0.16%	45.67%	0.07%
	Water Treatment Plant	-	0.00%	45.67%	0.00%
	Chemical Solution Feeders	-	0.00%	45.67%	0.00%
	Dist. Reservoirs & Standpipe	542,431	17.57%	64.15%	11.27%
	Storage Tanks	-	0.00%	45.67%	0.00%
	Pressure Tanks	-	0.00%	45.67%	0.00%
	Trans. and Dist. Mains	982,648	31.82%	45.67%	14.53%
	Services	257,672	8.34%	100.00%	8.34%
	Meters	26,766	0.87%	100.00%	0.87%
	Hydrants	114,782	3.72%	100.00%	3.72%
	Backflow Prevention Devices	-	0.00%	45.67%	0.00%
	Other Plant and Misc. Equip.	187,582	6.07%	45.67%	2.77%
	Office Furniture and Fixtures	-	0.00%	45.67%	0.00%
	Computers and Software	-	0.00%	45.67%	0.00%
	Transportation Equipment	-	0.00%	45.67%	0.00%
	Stores Equipment	-	0.00%	45.67%	0.00%
	Tools and Work Equipment	-	0.00%	45.67%	0.00%
	Laboratory Equipment	-	0.00%	45.67%	0.00%
	Power Operated Equipment	-	0.00%	45.67%	0.00%
	Communications Equipment	-	0.00%	45.67%	0.00%
	Miscellaneous Equipment	-	0.00%	45.67%	0.00%
	Other Tangible Plant	-	0.00%	45.67%	0.00%
	Total Plant Additions	$3,087,948	100.00%		
	RUCO Used and Useful AIAC Factor				**55.94%**

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Accumulated Deferred Income Tax as of December 31, 2009

Line No.		Adjusted Book Value	Tax Value	Probability of Realization of Future Tax Benefit	Deductible TD (Taxable TD) Expected to be Realized	Tax Rate[5]	Future Tax Asset Current	Future Tax Asset Non Current	Future Tax Liability Current	Future Tax Liability Non Current
6	Plant-in-Service	$ 4,093,181 [1]								
7	Accum. Deprec.	(465,165) [1]								
8	CIAC	(1,122,745) [3]								
9	Fixed Assets	$ 2,505,271	$ 1,438,680 [2]	100.0%	$ (1,066,590)	31.8%		-		(338,677)
10	AIAC		1,603,922 [4]	30.0%	$ 481,177 [4]	31.8%		$ 152,789		
11	Tax Benefits from O.L. Carry Forward.			100.0%	$ -	31.8%		$ -		
12							$ -	$ 152,789	$ -	$ (338,677)
13										
14	ADIT Net Asset (Liability) per Surrebuttal				Net Asset (Liability)		$ (185,888)			
15										
16	ADIT Asset (Liability) per Company						$ (135,342)			
17										
18	RUCO Adjustment to DIT						$ 50,545			

Footnotes - See page 2 of 2

Goodman Water Company
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Test Year Ended December 31, 2009

Line No.				
1	**1 Adjusted per B-2, page 2**			
2	**2 Computation of Net Tax Value at December 31, 2009**			
3	Based on 2009 Tax Depreciation report (December 31, 2009)			
4	Unadjusted Cost per 2009 Tax Depr. Report	$ 4,938,108		
5	Reconciling Items not on tax report:			
6	Land costs not on tax, on books (adjusted by RUCO 45.67% of $494,159)	225,673		
7	Net Unadjusted Cost tax Basis			$ 5,163,781
8				
9	Basis Reduction/Additions			
10	Basis Reduction 2009 and Prior Years (from 2009 Tax Depr. Report)	$ (14,706)		
11	Advanced or contributed plant with no depreciable basis listed on 2009 Tax Depr. Report (after RUCO AIAC adj)	(2,209,833)		
12	Accumulated Depreciation 2008 and prior (2009 Tax Depr Report)	(339,352)		
13	RUCO Adjustments to Plant-in-service (depreciatble only, net of RUCO land adjustment)	(1,261,570)		
14	Tax Depr related to RUCO adjustment	201,851		
15	2009 Current Year Tax Depreciation	(101,491)		-
16	Net Basis Reduction 2007 and Prior years			(3,725,101)
17	Net tax value of plant-in-service at December 31, 2008			$ 1,438,680
18				
19	**3 CIAC (including impact of change to probability of realization)**			
20				
21	Gross CIAC per B-2		$ -	
22	Less: Pre-1996 CIAC		-	
23	A.A per B-2	$ -		
24	A.A on Pre-1996 CIAC	-		
25	A.A. on Post 1996 CIAC		-	
26	Net CIAC before unrealized AIAC			$ -
27				
28	Unrealized AIAC Component			
29	Adjusted Net AIAC (see footnote 5 below)		$ 1,603,922	
30	Unrealized AIAC Component % (1-Realized AIAC Component)		70.0%	
31				$ 1,122,745
32	Total realizable CIAC			$ 1,122,745
33				
34	**4 AIAC (including impact of change in probability of realization)**			
35	AIAC per B-2		$ 1,603,922	
36	Less: Pre-1996 AIAC included for book and tax purposes		-	
37	Net AIAC before unrealized portion			$ 1,603,922
38	Less: Unrealized AIAC (from Note 4, above)			$(1,122,745)
39	Net realizable AIAC			$ 481,177
40				
41	**5 Effective tax rates Per Schedule TJC-1, page 2 of 2**			31.75%

SUMMARY OF OPERATING INCOME

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) RUCO TEST YEAR ADJM'TS	(C) RUCO TEST YEAR AS ADJ'TED	(D) RUCO PROP'D CHANGES	(E) RUCO AS RECOMM'D
	Revenues:					
1	Metered Water Revenues	$ 559,013	$ 21,708	$ 580,721	$ 8,715	$ 589,437
2	Unmetered Water Revenues	-	-	-	-	-
3	Other Water Revenues	13,738	-	13,738	-	13,738
4	TOTAL WATER REVENUES	$ 572,751	$ 21,708	$ 594,459	$ 8,715	$ 603,174
	Operating Expenses:					
5	Salaries and Wages	$ 40,000	$ (4,986)	$ 35,014	$ -	$ 35,014
6	Purchased Water	-	-	-	-	-
7	Purchased Power	27,066	577	27,642	-	27,642
8	Chemicals	-	-	-	-	-
9	Repairs and Maintenance	7,746	-	7,746	-	7,746
10	Office Supplies and Expenses	14,855	-	14,855	-	14,855
11	Contractual Services	102,925	(2,493)	100,432	-	100,432
12	Water Testing	1,215	1,568	2,783	-	2,783
13	Rents	-	-	-	-	-
14	Transportation Expenses	-	-	-	-	-
15	Insurance - General Liability	9,669	-	9,669	-	9,669
16	Insurance - Health and Life	-	-	-	-	-
17	Reg. Comm. Exp. - Rate Case	20,000	-	20,000	-	20,000
18	Miscellaneous Expense	378	-	378	-	378
19	Depreciation Expense	227,855	(44,136)	183,719	-	183,719
20	Taxes Other Than Income	2,988	(372)	2,615	-	2,615
21	Property Taxes	21,299	(3,570)	17,728	87	17,815
22	Income Tax	22,873	17,162	40,035	2,681	42,716
23	TOTAL OPERATING EXPENSES	$ 498,868	$ (36,250)	$ 462,617	$ 2,767	$ 465,384
24	**OPERATING INCOME (LOSS)**	$ 73,883		$ 131,842		$ 137,790

References:

Column (A): Company Schedule C-1
Column (B): TJC-9, Columns (B) Thru (H)
Column (C): Column (A) + Column (B)
Column (D): Revenue From TJC-1, Column (B), Line 8 And Income Tax From TJC-1, Column (B), Line 8 - Line 6
Column (E): Column (C) + Column (D)

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OPERATING INCOME ADJUSTMENTS
TEST YEAR AS FILED AND ADJUSTMENTS

LINE NO.	DESCRIPTION	(A) COMPANY AS FILED	(B) ADJ # 1 DEP. EXPENSE	(C) ADJ # 2 PROPERTY TAX	(D) ADJ # 3 REV. & EXP. ANNUAL'N	(E) ADJ # 4 SALARIES & WAGES	(F) ADJ # 5 CONTRACTUAL SERVICES	(G) ADJ # 6 WATER TESTING	(H) ADJ # 7 INCOME TAX	(I) RUCO AS ADJT'D
	Revenues:									
1	Metered Water Revenues	$ 559,013	$ -	$ -	$ 21,708	$ -	$ -	$ -	$ -	$ 580,721
2	Unmetered Water Revenues	-	-	-	-	-	-	-	-	-
3	Other Water Revenues	13,738	-	-	-	-	-	-	-	13,738
4	TOTAL WATER REVENUES	$ 572,751	$ -	$ -	$ 21,708	$ -	$ -	$ -	$ -	$ 594,459
	Operating Expenses:									
5	Salaries and Wages	$ 40,000	$ -	$ -	$ -	$ (4,986)	$ -	$ -	$ -	$ 35,014
6	Purchased Water	-	-	-	-	-	-	-	-	-
7	Purchased Power	27,066	-	-	577	-	-	-	-	27,642
8	Chemicals	-	-	-	-	-	-	-	-	-
9	Repairs and Maintenance	7,746	-	-	-	-	-	-	-	7,746
10	Office Supplies and Expenses	14,855	-	-	-	-	-	-	-	14,855
11	Contractual Services	102,925	-	-	-	-	(2,493)	-	-	100,432
12	Water Testing	1,215	-	-	-	-	-	1,568	-	2,783
13	Rents	-	-	-	-	-	-	-	-	-
14	Transportation Expenses	-	-	-	-	-	-	-	-	-
15	Insurance - General Liability	9,669	-	-	-	-	-	-	-	9,669
16	Insurance - Health and Life	-	-	-	-	-	-	-	-	-
17	Reg. Comm. Exp. - Rate Case	20,000	-	-	-	-	-	-	-	20,000
18	Miscellaneous Expense	378	-	-	-	-	-	-	-	378
19	Depreciation Expense	227,855	(44,136)	-	-	-	-	-	-	183,719
20	Taxes Other Than Income	2,988	-	-	-	(372)	-	-	-	2,615
21	Property Taxes	21,299	-	(3,570)	-	-	-	-	-	17,728
22	Income Tax	22,873	-	-	-	-	-	-	17,162	40,035
23	TOTAL OPERATING EXPENSES	$ 498,868	$ (44,136)	$ (3,570)	$ 577	$ (5,358)	$ (2,493)	$ 1,568	$ 17,162	$ 462,617
24	**OPERATING INCOME (LOSS)**	$ 73,883								$ 131,842

References:
Column (A): Company Schedule C-1
Column (B): TJC Testimony and Schedule TJC-10
Column (C): TJC Testimony and Schedule TJC-11
Column (D): TJC Testimony and Schedule TJC-12
Column (E): TJC Testimony and Schedule TJC-13
Column (F): TJC Testimony and Schedule TJC-14
Column (G): TJC Testimony and Schedule TJC-15
Column (H): TJC Testimony and Schedule TJC-16
Column (I): Sum Of Columns (A) Thru (H)

RUCO OPERATING INCOME ADJUSTMENT NO. 1
TEST YEAR DEPRECIATION EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT NAME	(A) RUCO TOTAL PLANT VALUE	(B) APPROVED DEPRECIATION RATE DECISION NO. 69404	(C) TEST YEAR DEPRECIATION EXPENSE
1	301	Organization Cost	$ 114,837	0.00%	$ -
2	302	Franchise Cost	-	0.00%	-
3	303	Land and Land Rights	225,673	0.00%	-
4	304	Structures and Improvements	88,694	3.33%	2,954
5	305	Collecting and Impounding Res.	-	2.50%	-
6	306	Lakes, Rivers, and Other Intakes	-	2.50%	-
7	307	Wells & Springs	386,591	3.33%	12,873
8	308	Infiltration Galleries and Tunnels	-	6.67%	-
9	309	Supply Mains	-	2.00%	-
10	310	Power Generation Equipment	-	5.00%	-
11	311	Electric Pumping Equipmemt	815,621	12.50%	101,953
12	320	Water Treatment Equipment	13,289	3.33%	443
13	320.1	Water Treatment Plant	-	3.33%	-
14	320.2	Chemical Solution Feeders	-	20.00%	-
15	330	Dist. Reservoirs & Standpipe	642,435	2.22%	14,262
16	330.1	Storage Tanks	-	2.22%	-
17	330.2	Pressure Tanks	-	5.00%	-
18	331	Trans. and Dist. Mains	1,077,430	2.00%	21,549
19	333	Services	386,946	3.33%	12,885
20	334	Meters	94,263	8.33%	7,852
21	335	Hydrants	161,737	2.00%	3,235
22	336	Backflow Prevention Devices	-	6.67%	-
23	339	Other Plant and Misc. Equip.	85,665	6.67%	5,714
24	340	Office Furniture and Fixtures	-	6.67%	-
25	340.1	Computers and Software	-	20.00%	-
26	341	Transportation Equipment	-	20.00%	-
27	342	Stores Equipment	-	4.00%	-
28	343	Tools and Work Equipment	-	5.00%	-
29	344	Laboratory Equipment	-	10.00%	-
30	345	Power Operated Equipment	-	5.00%	-
31	346	Communications Equipment	-	10.00%	-
32	347	Miscellaneous Equipment	-	10.00%	-
33	348	Other Tangible Plant	-	10.00%	-
34		Rounding	-		-
35		**COMPANY TOTAL PLANT & ACCUM. DEPRE.**	$ 4,093,181		$ 183,719
		Less:			
36		Amortizations Of CIAC (TJC-2, Col. (C), Line 8)	$ -		-
37		TOTAL DEPRECIATION EXPENSE (Line 35 + Line 36)			$ 183,719
38		Test Year Depreciation Expense As Filed (Co. Sch. C-1)			227,855
39		Increase (Decrease) In Depreciation Expense (Line 37 - Line 37)			$ (44,136)
40		RUCO Adjustment (Line 39) (See TJC-9, Column (B), Line 19)			$ (44,136)

References: Column (A): TJC-5, Column (D)
Column (B): Per Decision No. 69404
Column (C): Column (A) X Column (B)

RUCO 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 - 2009	$ 594,459	$ 594,459
2	Multiplied by 2	2	2
3	Subtotal (Line 1 • Line 2)	$ 1,188,918	$ 1,188,918
4a	RUCO Adjusted Test Year Revenues - 2009	594,459	
4b	RUCO Recommended Revenue, Per Schedule TJC-8		603,174
5	Subtotal (Line 4 + Line 5)	$ 1,783,376	$ 1,792,092
6	Number of Years	3	3
7	Three Year Average (Line 5 / Line 6)	$ 594,459	$ 597,364
8	Department of Revenue Mutilplier	2	2
9	Revenue Base Value (Line 7 * Line 8)	$ 1,188,918	$ 1,194,728
10	Plus: 10% of CWIP -	-	-
11	Less: Net Book Value of Licensed Vehicles	-	-
12	Full Cash Value (Line 9 + Line 10 - Line 11)	$ 1,188,918	$ 1,194,728
13	Assessment Ratio	20.0%	20.0%
14	Assessment Value (Line 12 * Line 13)	$ 237,784	$ 238,946
15	Composite Property Tax Rate (Per Company Schedule C-2, Page 3, Line 16)	7.4558%	7.4558%
16	RUCO Proposed Property Tax Expense (Line 14 * Line 15)	$ 17,729	
17	Company Proposed Property Tax	21,299	
18	RUCO Test Year Adjustment (Line 16-Line 17)	$ (3,570)	
19	Property Tax - RUCO Recommended Revenue (Line 14 * Line 15)		$ 17,815
20	RUCO Test Year Adjusted Property Tax Expense (Line 16)		17,729
21	Increase/(Decrease) to Property Tax Expense		$ 87
22	Increase/(Decrease) to Property Tax Expense		$ 87
23	Increase in Revenue Requirement		8,715
24	Decrease to Property Tax per Dollar Increase in Revenue (Line19/Line 20)		0.994107%

References:
Column (A): Company Schedule C-1 Page 3
Column (B): TJC Testimony

RUCO OPERATING INCOME ADJUSTMENT NO. 4
SALARIES & WAGES

Line No.			Amount
1	RUCO Adjustment to Salaries and Wages		
2			
3			
4	Company Request for Annual Salary of President/Manager		$ 40,000
5	Amount Recorded in Test Year		32,000
6	Increase (decrease) in Salaries and Wages		8,000
7			
8			
9	Company Adjustment to Test Year Book Amount		$ 8,000
10			
11	Inflation Factor Oct. 2005 thru June 2010 per InflationData.com		**9.42%**
12			
13	RUCO Adjustment to Test Year Book Amount		$ 3,014
14			
15	RUCO Adjustment to Salaries & Wages		$ (4,986)
16			
17			
18	Adjust Payroll Taxes to refelect RUCO Salaries and Wages		
19			
20	FICA per Company	6.02%	$ 2,408
21	FICA per RUCO	6.02%	2,108
22			
23	Medicare per Company	1.45%	580
24	Medicare per RUCO	1.45%	508
25			
26	FUTA per Company	0.80% (first $7,000 of wages)	56
27	FUTA per RUCO	0.80% (first $7,000 of wages)	56
28			
29	SUTA per Company	2.70% (first $7,000 of wages)	189
30	SUTA per RUCO	2.70% (first $7,000 of wages)	189
31			
32			
33	Total Payroll Taxes per Company		$ 3,233
34	Total Payroll Taxes per RUCO		2,861
35			
36	Payroll Taxes Recorded in Test Year		2,693
37			
38	Company Increase (decrease) in Payroll Taxes		$ 540
39	RUCO Increase (decrease) in Payroll Taxes		168
40			
41	RUCO Adjustment to Payroll Taxes		$ (372)

RUCO OPERATING INCOME ADJUSTMENT NO. 5
CONTRACTUAL SERVICES

Line No.		
1	Contractual Services - Jim Shiner	
2		
3	Company Request for Contractual Services 2010	$ 20,000
4	Contractual Services recorded during test year	16,000
5		
6	Company Increase (decrease) in Contractual Services	$ 4,000
7		
8		
9	Inflation Factor Oct. 2005 thru June 2010 per InflationData.com	**9.42%**
10		
11		
12	RUCO Adjustment to Test Year Book Amount	$ 1,507
13		
14	RUCO Recommended Contractual Services for J. Shiner	17,507
15		
16		
17	RUCO Adjustment to Contractual Services	$ (2,493)
18		
19		
20		

RUCO OPERATING INCOME ADJUSTMENT NO. 7
INCOME TAX EXPENSE

LINE NO.	DESCRIPTION	(A) REFERENCE	(B) AMOUNT
	FEDERAL INCOME TAXES:		
1	Operating Income Before Taxes	Sch. TJC-9, Column (H), L24 + L22	$ 171,877
	LESS:		
2	Arizona State Tax	Line 11	(8,979)
3	Interest Expense	Note (A) Line 20	(43,013)
4	Federal Taxable Income	Sum Of Lines 1 Thru 3	$ 119,885
5	Federal Tax Rate	Sch. TJC-1, Pg 2, Col. (D), L34	25.91%
6	Federal Income Tax Expense	Line 4 X line 5	$ 31,056
	STATE INCOME TAXES:		
7	Operating Income Before Taxes	Line 1	$ 171,877
	LESS:		
8	Interest Expense	Note (A) Line 20	(43,013)
9	State Taxable Income	Sum Of Lines 7 & 8	$ 128,864
10	State Tax Rate	Tax Rate	6.97%
11	State Income Tax Expense	Line 9 X Line 10	$ 8,979
	TOTAL INCOME TAX EXPENSE:		
12	Federal Income Tax Expense	Line 6	$ 31,056
13	State Income Tax Expense	Line 11	8,979
14	Total Income Tax Expense Per RUCO	Line12 + Line 13	$ 40,035
15	Total Income Tax Expense Per Company (Per Company Sch. C-1)		22,873
16	Total Income Tax Adjustment	Line 14 - Line 15	$ 17,162
17	RUCO Adjustment (See Sch. TJC-9, Column (H), L22)	Line16	$ 17,162

NOTE (A):
Interest Synchronization:

18	Adjusted Rate Base (Sch. RLM-2, Col. (E), L15)	$ 1,755,118
19	Weighted Cost Of Debt (Sch. RLM-14, Col. (F), L1)	2.45%
20	Interest Expense (L17 X L18)	$ 43,013

COST OF CAPITAL

LINE NO.	DESCRIPTION	(A) CAPITAL RATIO	(B) COST	(C) WEIGHTED COST RATE
1	Long-Term Debt	40.00%	6.13%	2.45%
2	Common Equity	60.00%	9.00%	5.40%
3	Total Capitalization	100.00%		
4	COST OF CAPITAL			7.85%

References:
Columns (A) Thru (F): See Testimony Of RUCO Witness William Rigsby