ORIGINAL

0000022531

RECEIVED

2005 AUG -1 P 4:43

AZ CORP COMMISSION
DOCUMENT CONTROL

ARIZONA WATER COMPANY
Robert W. Geake (No. 009695)
Vice President and General Counsel
3805 Black Canyon Highway
Phoenix, Arizona 85015-5351
Telephone: (602) 240-6860

FENNEMORE CRAIG, P.C.
A Professional Corporation
Norman D. James (No. 006901)
Jay L. Shapiro (No. 014650)
3003 North Central Avenue
Suite 2600
Phoenix, Arizona 85012-2913
Telephone: (602) 916-5000

Attorneys for Arizona Water Company

BEFORE THE ARIZONA CORPORATION COMMISSION

IN THE MATTER OF THE APPLICATION OF ARIZONA WATER COMPANY, AN ARIZONA CORPORATION, FOR ADJUSTMENTS TO ITS RATES AND CHARGES FOR UTILITY SERVICE FURNISHED BY ITS WESTERN GROUP AND FOR CERTAIN RELATED APPROVALS.	Docket No. W-01445A-04-0650

ARIZONA WATER COMPANY'S

CLOSING BRIEF

TABLE OF CONTENTS

TABLE OF CONTENTS
(continued)

ARIZONA WATER COMPANY
PRE-FILED TESTIMONY

Pre-Filed Testimony	Hearing Exhibit	Abbreviation
Direct Testimony of William M. Garfield	A-1	Garfield Dt.
Rebuttal Testimony of William M. Garfield	A-2	Garfield Rb.
Rejoinder Testimony of William M. Garfield	A-3	Garfield Rj.
Direct Testimony of Rick Henderson	A-4	Henderson Dt.
Direct Testimony of Michael J. Whitehead	A-5	Whitehead Dt.
Rebuttal Testimony of Michael J. Whitehead	A-6	Whitehead Rb.
Direct Testimony of Ralph J. Kennedy	A-7	Kennedy Dt.
Rebuttal Testimony of Ralph J. Kennedy	A-8	Kennedy Rb.
Rejoinder Testimony of Ralph J. Kennedy	A-9	Kennedy Rj.
Direct Testimony of Sheryl L. Hubbard	A-10	Hubbard Dt.
Rebuttal Testimony of Sheryl L. Hubbard	A-11	Hubbard Rb.
Rejoinder Testimony of Sheryl L. Hubbard	A-12	Hubbard Rj.

Direct Testimony of Thomas M. Zepp (Corrected version)	A-13	Zepp Dt.
Rebuttal Testimony of Thomas M. Zepp	A-14	Zepp Rb.
Rejoinder Testimony of Thomas M. Zepp	A-15	Zepp Rj.

STAFF PRE-FILED TESTIMONY

Pre-Filed Testimony	Hearing Exhibit	Abbreviation
Direct Testimony of Alejandro Ramirez	S-6	Ramirez Dt.
Surrebuttal Testimony of Alejandro Ramirez	S-7	Ramirez Sb.
Direct Testimony of Ronald E. Ludders	S-10	Ludders Dt.
Direct Testimony of Lyndon R. Hammon	S-29	Hammon Dt.
Supplemental Testimony of Steven M. Olea	S-30	Olea Supp.
Surrebuttal Testimony of Ronald E. Ludders	S-32	Ludders Sb.

RUCO PRE-FILED TESTIMONY

Pre-Filed Testimony	Hearing Exhibit	Abbreviation
Direct Testimony of William Rigsby	R-4	Rigsby Dt.
Surrebuttal Testimony of William Rigsby	R-5	Rigsby Sb.

Direct Testimony of Timothy J. Coley	R-28	Coley Dt.
Surrebuttal Testimony of Timothy J. Coley	R-29	Coley Sb.
Direct Testimony of William Rigsby	R-30	Rigsby Dt.
Notice of Errata (to Surrebuttal Testimony of William Rigsby)	R-32	Rigsby Err.

CITY OF CASA GRANDE PRE-FILED TESTIMONY

Pre-Filed Testimony	**Hearing Exhibit**	**Abbreviation**
Surrebuttal Testimony of Edward F. Harvey	CCG-2	Harvey Sb.
Direct Testimony of Edward F. Harvey	CCG-3	Harvey Dt.

I. INTRODUCTION.

A. Overview of Arizona Water and Its Western Group Systems.

Arizona Water Company ("Arizona Water" or "the Company") is a public service corporation that owns and operates 18 Commission regulated water utility systems throughout Arizona. Tr. at 252.[1] These systems are organized into three groups, the Northern Group, the Eastern Group and the Western Group. The Company recently received rate increases for its Eastern and Northern Groups. *See* Decision No. 66849 (March 19, 2004) (Eastern Group systems) and Decision No. 64282 (Dec. 28, 2001) (Northern Group systems). The Company's present rates and charges for utility service in the Western Group became effective over 12 years ago on January 1, 1993, and are based on operating results and investment in plant for test year 1990. Decision No. 58120 (Dec. 23, 1992) (all systems).

The Western Group consists of five water systems that as of the end of the test year, December 31, 2003, served 20,266 customers, as follows:

System	Customers	Percent of Total Western Group
Casa Grande	14,981	73.9%
Stanfield	218	1.1%
White Tank	1,337	6.6%
Ajo Heights	681	3.4%
Coolidge	3,049	15.0%
TOTAL	20,266	100.0%

[1] Citations to the record are made as follows: Citations to a witness' pre-filed testimony are abbreviated using the format on pages ii and iii, above, following the Table of Contents, which also lists the hearing exhibit number. Other hearing exhibits are cited by the hearing exhibit number and, where applicable, by page number, e.g., A-15 at 2. The hearing transcript is cited by page number, e.g., Tr. at 1.

Since 1990, the Company's Western Group gross plant has increased by more than $35 million. Garfield Dt. at 3. Arizona Water's net investment in plant in the Western Group has increased 67% since 1990, from $14.5 million to $24.2 million. Kennedy Dt. at 8. These plant additions consist of wells, reservoirs, transmission mains, treatment facilities and other construction projects that improve service to existing customers. Whitehead Dt. at 7. The following table summarizes the costs of Company-funded plant additions since the last test year for each system within the Western Group:

ARIZONA WATER COMPANY
WESTERN GROUP
COMPANY-FUNDED PLANT ADDITIONS 1990-2003

	Casa Grande	**Stanfield**	**White Tank**	**Ajo**	**Coolidge**
1990	1,076,315	152,242	67,062	18,882	76,293
1991	875,433	7,277	75,885	26,367	76,063
1992	496,763	8,528	96,611	35,185	44,706
1993	689,932	3,291	58,851	12,501	132,658
1994	1,079,792	1,533	148,418	76,564	178,752
1995	1,669,922	10,865	16,984	91,850	187,850
1996	1,109,962	38,117	72,262	51,681	323,752
1997	1,672,181	2,662	49,783	60,179	176,822
1998	784,321	831	86,584	29,946	89,793
1999	1,785,516	4,455	123,783	82,319	197,078
2000	1,702,976	36,726	125,421	119,106	300,157
2001	1,895,342	1,692	91,698	106,869	145,846
2002	1,953,859	78,551	1,070,347	62,773	229,842
Test Year 2003	2,259,687	941	62,261	11,567	225,290

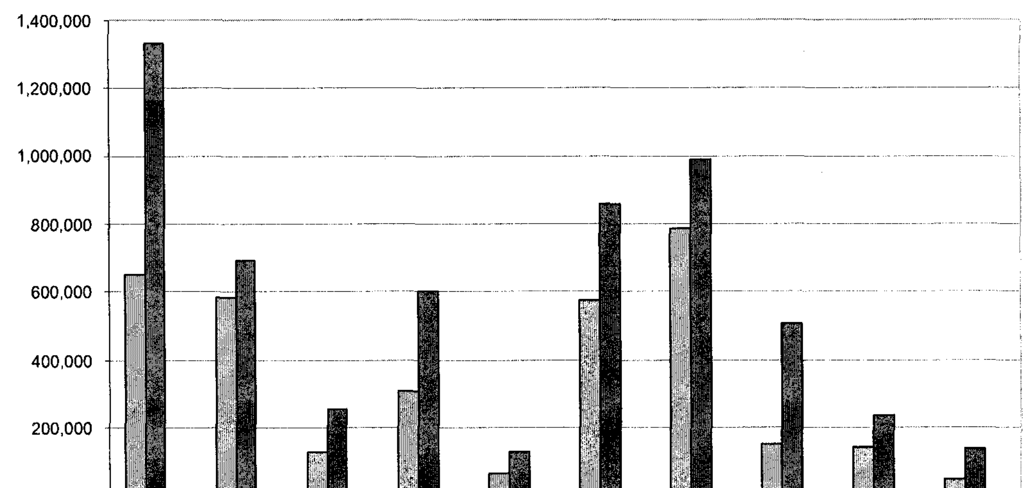
Id. at 5.

The Company also holds subcontracts for Central Arizona Project ("CAP") water with the Central Arizona Water Conservation District ("CAWCD") for the Company's White Tank, Coolidge and Casa Grande water systems. Garfield Dt. at 4. Pursuant to their subcontracts, those Western Group systems have been required to pay annual capital charges, which increased dramatically after the CAP delivery system became operational in 1993. Hubbard Dt. at 10. The Company has been deferring these charges in its accounting records since that time and, as of the end of the test year, the CAP M&I deferral balance was $3,525,803 for Casa Grande, $506,268 for White Tank and $1,046,011 for Coolidge. *Id.* at 12.

B. <u>Summary of the Company's Requested Relief.</u>

As stated, the present rates charged in the Western Group are based on 1990 operating expenses and utility plant. The economy has changed substantially since 1990, and so have the Company's operations. Kennedy Dt. at 4. From 1990 through mid-2004, inflation increased by more than 38%. *Id.* By now the increase is likely over 40%. As a result, the general costs of doing business have increased as reflected in the graph below. *Id.* at 5, 7. Regulatory changes, including the amendments to the Safe

Increase In Specific Western Group Expenses 1990 - 2003



	Depreciation	Property Taxes	City sales taxes	State Sales Taxes	Other Taxes	Income Taxes	Purchased Power	Purchased Water	Water Treatment	Blue Stake
1990	653,000	583,000	128,000	308,000	68,000	573,000	785,000	150,000	143,000	46,000
2003	1,333,000	690,000	255,000	602,000	128,000	860,000	991,000	506,000	237,000	139,000
% Increase	104.13%	18.35%	99.22%	95.45%	88.24%	50.09%	26.24%	237.33%	65.73%	202.17%

Drinking Water Act, have also increased the costs of testing, treatment and reporting. *Id.*

Due to the substantial plant additions and increasing costs since the last rate case for the Western Group systems, revenues are currently inadequate to cover the current cost of service and provide a reasonable rate of return on the Company's investment in water system facilities. Accordingly, test year data shows that the current adjusted rate of return on each of the five Western Group systems' adjusted rate base is below the current 10.5% weighted cost of capital:

Casa Grande	7.16 %
Stanfield	8.24 %
White Tank	7.28 %
Ajo	4.10 %
Coolidge	5.09 %

Hubbard Rj., Rejoinder Schedule SLH-RJ4 at 1-6.

In the instant application, Arizona Water is seeking rate increases for each of its Western Systems. This increase is based on the Company's financial data for calendar year 2003, the test year in this case, with appropriate adjustments to actual test year results and balances to obtain a normal or more realistic relationship between revenues, expenses and rate base during the period in which new rates will be in effect. *See* A.A.C. R14-2-103(A)(3) (definitions of "test year" and "pro forma adjustments"). The Company's proposed increase results in a total revenue requirement for the five Western Group systems of $1,464,966,[2] which results in operating income of $2,569,698[3] to

[2] The Company's rejoinder revenue requirement for the Western Group of $1,462,840 should be adjusted to remove from rate base charges of $8,113 posted to the account in error (Casa Grande) (Tr. at 572), the reduction in property taxes of $19,263 (Exhibit A-27) and the increase in purchased power expense of $22,779 (Hubbard Rj. at 9) and all applicable federal and state income tax effects.

produce a 10.50% rate of return on the Company's fair value rate base. Hubbard Rj., Rejoinder Schedule SLH-RJ4 at 1. By system, the percentage increases being requested are as follows:

System	Requested Increase by %
Casa Grande	13.1%
Stanfield	8.9%
White Tank	13.6%
Ajo	21.4%
Coolidge	17.2%

Tr. at 16. By comparison, the recommendations of Staff and RUCO result in substantially lower rate increases per system on a percentage basis:

System	Staff	RUCO
Casa Grande	0.05%	0.21%
Stanfield	4.35%	0.46%
White Tank	-0.47%	-1.13%
Ajo	15.05%	12.94%
Coolidge	0.42%	3.72%

E.g., Ludders Sb., REL-1 (Casa Grande) REL-1 (Stanfield) REL-1 (White Tank), REL-1 (Ajo), REL-1 (Coolidge) and Rigsby Dt., WAR-1 (Casa Grande), WAR-1 (Stanfield), Coley Dt., TJC-1 (White Tank), TJC-1 (Ajo), TJC-1 (Coolidge). Given the substantial passage of time between rate cases for these systems, the disparity between the Company and the other parties concerning the level of the necessary revenue increase is

[3] The Company's rejoinder required operating income of $2,570,550 should be decreased by $852 to reflect the effect of removal of $8,113 charges included in plant in error (Casa Grande) ($8,113 x .1050 = $852) (Tr. at 572).

surprising.

Arizona Water is also requesting authority to continue utilizing the purchased water and purchased power adjustment mechanisms ("PWAM" and "PPAM") approved by this Commission. *E.g.*, Kennedy Dt. at 19-21. Under the PWAM and PPAM, the amounts of those expenses that are included in operating expenses in this case would serve as the base amounts and be used to calculate the amounts to be recovered or refunded when increases or decreases in rates occur in future years.

Finally, Arizona Water is also requesting approval of an Arsenic Cost Recovery Mechanism ("ACRM") that would permit recovery of capital costs and certain specified recoverable O&M expenses directly related to the construction and operation of facilities to comply with the new maximum contaminant level for arsenic. The ACRM is the same mechanism already approved for the Company's Northern and Eastern Group systems. Decision No. 66400 (Northern Group); Decision No. 66849 (Eastern Group).

II. RECOVERY OF CENTRAL ARIZONA PROJECT COSTS.

A. Background on the Central Arizona Project and the Company's Request for Recovery of Deferred CAP M&I Capital Charges.

An extremely important issue in this proceeding is whether Arizona Water will be allowed to begin recovering the amounts it has paid to date to retain its CAP M&I allocations pursuant to the CAP subcontracts, which allow the Company to utilize renewable Colorado River water as a source of supply to provide utility service in its Casa Grande, Coolidge and White Tank systems. The annual CAP allocations for Casa Grande, Coolidge and White Tank are 8,884 acre-feet, 2,000 acre-feet and 968 acre-feet, respectively. *E.g.*, Garfield Rb. at 6; Tr. at 255-57. Current annual water demand in Casa Grande and Coolidge exceeds 13,000 acre-feet per year, and both systems are projected to grow rapidly. Garfield Rb. at 11. The White Tank system is growing at a rate of 150 customers per year, adding approximately 100 acre-feet of demand annually. *Id.* at 11-12. Consequently, there is no legitimate dispute that CAP water is needed as a long-term water supply and to reduce groundwater use.

Under the CAP subcontracts, Arizona Water is required to make two different payments. First, the Company must pay an annual CAP M&I capital charge, which is based on the acre-feet of water each system has been allocated multiplied by an annual charge per acre-foot established by the CAWCD. Garfield Rb. at 6. Notably, CAP M&I capital charges must be paid regardless of whether water is actually delivered. Garfield Rb. at 7; Tr. at 265-66 and 1095-97. The second type of subcontract payment is based on annual CAP power and operating expenses. Garfield Rb. at 6-7. The monthly payment is 1/12th of the actual annual water orders by the subcontractor and must be paid two months before deliveries actually occur. There is a year-end adjustment based on the difference between water ordered and delivered. That payment is based on actual water deliveries to the subcontractor, and therefore does not have to be paid until water deliveries actually occur. *Id.* at 7; Tr. at 1096.

During the test year, Arizona Water used a total of 2,279 acre-feet, or 26%, of its CAP allocation in the Casa Grande system. Hubbard Rb. at 15. CAP water was provided for non-potable uses to a power plant originally constructed by Reliant Energy and now owned by the Salt River Project, and to two golf courses. Tr. at 258. No CAP water is currently being used in the Coolidge and White Tank systems. Hubbard Rb. at 15; Tr. at 255 and 258. However, Arizona Water has already begun to plan for the increased use of CAP water in all three systems with CAP allocations. *E.g.,* Whitehead Rb. at 3. With respect to the White Tank system, the Company is participating with Maricopa County Water District and Arizona-American Water Company in a regional water treatment plant to be constructed west of Phoenix. Garfield Rb. at 13-14; Tr. at 254-57. Treated CAP water should be available and used by 2008. *Id.* With respect to the Casa Grande and Coolidge systems, the Company is planning a regional water treatment plant near the CAP canal. The Company has recently purchased a site for the treatment plant, designed the CAP raw water turnout and pipeline, and applied for a pipeline right-of-way from the State Land Department. Whitehead Rb. at 4-6. Treated CAP water should be available by 2012. *Id.* at 9.

Arizona law and state water policy strongly encourage the substitution of CAP water (and other renewable water resources) for groundwater. *See, e.g.*, A.R.S. §§ 45-401 (declaration of policy issued in connection with adoption of the Groundwater Code) and 45-2401 (declaration of policy issued in connection with authorizing the Arizona Water Banking Authority); Garfield Rb. at 5 and 7. In this case, the parties, with the possible exception of the City of Casa Grande ("City"), are in agreement that Arizona Water should utilize its CAP allocations and reduce its reliance on groundwater. *E.g.*, Garfield Rb. at 5-6; Tr. at 1129-30 ("Staff's position is that if a company has a CAP allocation, they should put it to economical use as soon as possible to help promote the state's goal of getting off the pump."); Tr. at 1031 (RUCO can support Mr. Olea's recommendations). Unfortunately, utilization of CAP water has proven to be problematic in several respects.

While CAP water is the lowest-cost renewable source, it is nevertheless much more expensive than groundwater. Tr. at 552-53. After the CAP delivery system was completed, the CAP M&I capital charges, which are used to repay the United States for the cost of constructing the delivery system, increased substantially. Garfield Rb. at 6; Tr. at 264-66 and 1097-98. Moreover, CAP water consists of untreated surface water that is transported from the Colorado River. In order to use CAP water, the utility is required to construct a turnout from the CAP canal, construct a system to transport CAP water to its service territory, and for potable uses, construct and operate a water treatment plant. Tr. at 1098-00. As a result of these costs, and the Commission's refusal to allow recovery of deferred CAP M&I capital charges until CAP water is actually being used, some Arizona water utilities elected to continue to pump groundwater and surrendered their CAP subcontracts. Tr. at 264-67; Exhibit A-36 at 30-32. While groundwater use often results in lower utility rates, such practices conflict with state water policy and, in the long-run, continued reliance solely on groundwater may jeopardize the utility's ability to meet customers water needs in the future.

These circumstances led the Water Supply Subcommittee of the Commission's Water Task Force to focus on ways to encourage water utilities to retain their CAP allocations and use CAP water, and for the Commission to develop a policy under which water utilities may recover their CAP-related costs prior to actual use. Exhibit A-36 at 30; Garfield Rb. at 8-10. These circumstances also led to the Commission's issuance of Decision No. 62993, which contains specific findings regarding recovery of CAP-related costs, and ordered "Staff to develop, through meetings with members of the industry, RUCO, and other interested parties, a detailed statement on CAP cost recovery by June 30, 2001." Decision No. 62993 (Nov. 3, 2000) at 9-10. Such a policy was in fact developed following additional meetings (*see* Exhibit A-37), and that policy is posted on the Commission's official internet site. Garfield Rb. at 9 and Exhibit WMG-R2.

The parties can spend a great deal of time debating whether the CAP cost recovery policy found on the agency's internet site was actually "adopted" by the Commission, whether Decision No. 62993 was self-executing, as it appears on its face, or whether Staff should in either case follow the policy, given that Staff wrote it and, presumably, believes it is reasonable and appropriate. The bottom line is, as Mr. Garfield testified, Arizona Water was an active participant in the development of the cost recovery policy and was certainly led to believe that it would be allowed to recover the deferred balance of its CAP M&I payments if it satisfied the criteria set forth in the policy. Tr. at 267-68; Garfield Rb. at 9-11. Given the amount of time and effort devoted by numerous persons to its development, it seems foolish to simply discard the policy.

The balance of the deferred CAP M&I capital charges as of December 31, 2003, is $3,525,803 for Casa Grande, $1,046,011 for Coolidge and $506,268 for White Tank, for a combined balance of $5,078,082. Hubbard Dt. at 12. Obviously, these balances are substantial, and they will continue to grow unless and until cost recovery is authorized.[4] Generally, there is no dispute that Arizona Water has been paying CAP M&I capital charges each year and, indeed, is required to do so in order to retain each system's CAP allocations under the terms of its CAP subcontracts. *E.g.*, Tr. at 1095-04. Moreover, Staff recognizes that Arizona Water has acted prudently in paying those charges to retain its rights to CAP water. Tr. at 1327-29. Under the circumstances, it makes no sense to delay recovery of M&I capital costs.

B. <u>The Parties' CAP Cost Recovery Proposals</u>.

Arizona Water and Staff have both presented proposals that would allow the Company to begin recovering its deferred CAP-related costs. Staff's proposal is contained in the Supplemental Testimony presented by Mr. Olea. Exhibit S-30. The Company is in agreement with much of Staff's proposal. However, there are disagreements regarding (1) the inclusion of a portion of the Casa Grande system's CAP M&I capital charge deferred balance in rate base and (2) the appropriate amortization period. In addition, the Company has no objection to the hook-up fee tariffs proposed by Staff (Schedules SMO-1 through SMO-3), and has no objection to most of the conditions proposed by Staff in Schedule SMO-4. However, as discussed below,

---

[4] The Company has been required to continue to pay CAP M&I capital charges annually since the end of the test year. To date, payments have been made for 2004 and 2005, and the initial installment for 2006 will be due in November.

several of the conditions are unnecessary and unreasonable. These disagreements are discussed below.

1. The Method of Recovering CAP-Related Costs.

The Company's CAP cost recovery proposal is set forth in Exhibit A-28. The first page of that exhibit pertains to the Company's Casa Grande system, in which, as previously discussed, the Company has been delivering CAP water to customers. With respect to Casa Grande, $142,896 would be included in rate base. That amount represents the portion of the deferred balance attributable to test year CAP water deliveries to two golf courses, which totaled 279 acre-feet. *See* Exhibit A-28 (note A). Although the Company actually delivered a total of 2,279 acre-feet of CAP water to Casa Grande customers during the test year, Reliant Energy entered into a contract under which it reimbursed the Company for a portion of deferred CAP M&I capital charges in return for the Company's commitment to deliver up to 2,000 acre-feet of untreated CAP water annually to its power plant. Garfield Rj. at 9; Hubbard Rj. at 5. The golf courses did *not* enter into a similar contractual arrangement. *Id.* Consequently, while untreated CAP water is delivered to the golf courses under the Company's NP-260 tariff, the Company has *not* been reimbursed for the deferred M&I capital charges related to those customers' use, and the Company has no long-term commitment to deliver CAP water to those customers. *Id.*

Accordingly, the pro rata portion of the deferred CAP M&I capital charge balance related to deliveries to the golf courses ($142,896) should be included in Casa Grande's rate base, as shown on page 1 of Exhibit A-28. There is no dispute that the Company has paid CAP M&I capital charges to retain its CAP subcontract, and that a portion of the Casa Grande system's allocation – 279 acre-feet – was actually used, satisfying the "used and useful" standard. Conversely, the remainder of the deferred CAP M&I capital charge balance for Casa Grande would not be included in rate base, and none of the deferred CAP M&I capital charge balances for Coolidge and White Tank would be included in rate base because those systems are not currently using CAP water.

It is appropriate to recover some costs from current customers by including a portion of the annual expense in rates. Tr. at 260, 472 and 726-27. Existing customers have benefited from the Company's CAP subcontracts. Garfield Rb. at 15-17. Staff, in contrast, proposes that the entire amount be recovered from future customers through hook-up fees. Tr. at 1177-80, 1227 and 1325-27. To minimize disputes, the Company has agreed to Staff's approach. Tr. at 268-69.

The Company also proposes a 10-year amortization period for the deferred CAP M&I capital charges because the charges have been accumulated over a period of approximately 10 years. Tr. at 727. Staff, in contrast, proposes a longer, 20-year amortization period. Mr. Olea explained, however, that the amortization period would be subject to modification in future rate cases. Tr. at 1182-83. As Mr. Carlson explained, the total revenues collected by the Company will depend on the number of new customers added each year. At this time, then, a 10-year amortization period is appropriate.

2. Staff's Conditions and the CAP Water Use Plan ("CAPWUP")

The conditions set forth in Schedule SMO-4, as clarified by Mr. Olea during cross-examination by the Company's counsel (Tr. at 1184-01), are generally acceptable to the Company. Initially, the Company had concerns regarding Condition 2, which states that the Company "must make best faith efforts to include the cities of Casa Grande and Coolidge in the development of the CAPWUP." As Mr. Garfield testified, the Company has no objection to obtaining input from the cities and discussing its plans to utilize CAP water. Mr. Garfield also emphasized, however, that the Company must be solely responsible for key decisions regarding CAP treatment and use. Tr. at 272-73.

See also Southern Pacific Co. v. Ariz. Corp. Comm'n, 98 Ariz. 339, 343, 404 P.2d 692, 694-95 (1965) ("it cannot be doubted but that a public utility may, *in the first instance*, in the exercise of its managerial functions, determine the type and extent of service to the public within the limits of adequacy and reasonableness") (emphasis in original).

Mr. Olea clarified that the purpose of Condition 2 is to ensure that the cities receive sufficient information for their own planning purposes and have a reasonable opportunity to provide input to the Company, but added that the "final decision on how the company does anything is the company's." Tr. at 1191-93. He also explained that Condition 2 "is not supposed to give the cities more rights than they already legally have." Tr. at 1193.

Two of the conditions proposed by Staff do present difficulties, however. Although the Company has no objection to preparing and submitting the CAPWUP to Staff, under Condition 4, the CAPWUP must be approved by Staff before the Company files its next general rate case. Moreover, Staff's approval would be deemed a sufficiency requirement under A.A.C. R14-2-103. The Commission has already ordered the Company to file general rate applications for its Northern Group and Eastern Group systems by no later than September 30, 2007. Decision No. 66849 (Eastern Group) at 31 and 41; Decision No. 66400 (Northern Group) at 9-10 and 23. Those general rate applications must be based on a 2006 test year in order to reflect the Company's investment in arsenic treatment facilities and the expenses associated with operating them. *Id.* In this case, the Company has again requested approval to implement the same ACRM, and anticipates filing a rate application for all three groups in 2007.

Consequently, Condition 4 may thwart the Commission's Order. If Staff fails to approve the Company's CAPWUP by the time that general rate application is to be filed, the rate application will not be considered sufficient and the case cannot proceed. This problem is compounded by the fact that although the Company would be required under Condition 1 to submit a CAPWUP by December 31, 2006, or six months prior to the submission of its next general rate application, whichever occurs first, there is no similar deadline imposed on Staff to act upon it or approve it. If Staff fails to act promptly, the Company may be precluded from doing what the Commission has previously ordered.

In addition to creating a conflict with those prior Commission orders, delaying rate relief because of lack of approval of the CAPWUP may affect the Company's financial viability. The magnitude of costs associated with arsenic treatment is not disputed. With the exception of Pivotal Group, all of the parties to this case participated in the second phase of the Northern Group rate case, which resulted in approval of the first ACRM in Decision No. 66400, and in the Eastern Group rate case, in which the same ACRM was authorized for those water systems in Decision No. 66849. Given the magnitude of the costs associated with arsenic treatment, Arizona Water will almost certainly require revenue increases in order to recover those costs of service and to earn a just and reasonable return on its investment in utility plant. *See, e.g.,* Decision No. 66400 at 3-4; Garfield Dt. at 6-9; Kennedy Dt. at 10-16.

Condition 5 is also problematic. That condition provides that if the Commission disapproves the CAPWUP, the hook-up fee "shall be terminated" and the Company "shall refund" all amounts collected to that point together with interest at the rate of 6%. This condition is unnecessary and, frankly, punitive in nature.

Mr. Olea testified that the "whole basis" for Staff's recommendations concerning CAP is "for the company to start recovering its costs now, based on the fact that costs are increasing and the amount . . . of the deferral is building up." Tr. at 1203. Mr. Olea continued:

> If we are already to the point where we know that the CAP [water] is needed and they are going to eventually use it, let's start recovering some of it now. . . . And if the

> company doesn't meet certain milestones, then not only will the cost recovery stop, but they will have to actually refund it.

Tr. at 1203-04.

However, when Mr. Olea was asked whether the Company would be allowed to recover the amount that was refunded at a later date, he was unable to explain what would actually occur:

> Actually, I mean if the refund actually had to take place, I don't know what Staff would recommend as far as when the company came back. And I definitely don't know what the Commission would approve.

Tr. at 1204. Mr. Olea suggested that the Company may be allowed to collect the funds again or, alternatively, that the amounts refunded would be "just lost to the company" and would come "out of the stockholders' pockets." *Id.*

Under the circumstances, there is no reason to impose a refund requirement. The possibility that cost recovery would be discontinued provides a very strong incentive for the Company to prepare a CAPWUP that is acceptable to Staff and, ultimately, to the Commission. Tr. at 277-8. Requiring the Company to not only cease collection of hook-up fees, but to also refund the amounts collected would create additional risk to the Company. *Id.* In short, the Company believes Condition 5 should be modified to simply provide that the CAP hook-up fee must be immediately discontinued if the CAPWUP is not approved, which will provide ample incentive for the Company to complete a reasonable CAPWUP.

C. <u>The City's Recommendations Are Unreasonable, Unnecessary and Should Be Rejected</u>.

The City opposes recovery of any CAP M&I capital charges until Arizona Water prepares a water resource master plan containing the various information set forth in Exhibit CCG-7 and demonstrates why the use of CAP water "is the best long-term strategy for ratepayers." Tr. at 33 and 892. Moreover, the City does not simply want this master plan prepared, but also wants what its counsel euphemistically refers to as "real-time" input into the master plan, i.e., the right to participate in Arizona Water's business decisions.

Boiled down to its essence, the City's demands in this case can be traced back to its failed attempt to condemn and take over a substantial portion of Arizona Water's Casa Grande system. *See City of Casa Grande v. Arizona Water Co.,* 199 Ariz. 547, 20 P.2d 590 (App. 2001); Exhibit R-6 (Superior Court Order dismissing condemnation action). In short, both the Arizona Court of Appeals and Superior Court ruled that the City failed to comply with A.R.S. § 9-514, which requires a municipal corporation to obtain voter approval prior to acquiring a public utility. *Id.*

Mr. Olea testified that the City's proposed master plan content includes far more detail than Staff needs to verify that Arizona Water has a reasonable plan to use its CAP allocations. Tr. at 1201-02. He also testified that substantial portions of the City's master plan content are vague and uncertain. Tr. at 1208-12. In addition, he recognized that the master plan envisioned by the City would likely be more costly than Staff's CAPWUP (which, in Mr. Olea's view, could be prepared in-house (Tr. at 1200)), and may result in additional costs being passed on to Casa Grande ratepayers in the form of higher rates. Tr. at 1212. Finally, Mr. Olea disagreed with the City's view that cost recovery should be withheld to "leverage compliance" with the Commission's "directive" (Harvey Sb. at 3), i.e., produce a master plan acceptable to the City. Tr. at 1202-03. There is simply no legitimate basis for the City's recommendation.

III. RATE BASE.

A. Legal Expenses Relating to Casa Grande's Condemnation and Other Litigation.

The Company seeks Commission approval to include several items in its Plant Account No. 303 in the rate base for the Casa Grande system. *See* Exhibit A-21. Plant account No. 303 concerns the "cost of land and land rights and includes such items as leasing or acquiring property, obtaining water rights or grants and the costs of condemnation proceedings." Exhibit S-37. The items in plant account 303 are broken down as follows:

Description	**Account 303 Costs**
Condemnation Legal Fees	$314,353
Effluent Legal fees	453,101[5]
Franchise	12,749
Hydrology Studies	34,770
Other	1,288
Total	$816,261

Exhibit A-21.[6]

The legal fees were incurred by Arizona Water between 1999 and 2003 in four separate lawsuits involving the City and the Company. The condemnation action was initiated by the City in an effort to condemn a portion of the Company's CC&N, plant, customers and all of its CAP allocation. Garfield Rb. at 22-23; Garfield Rj. at 3-4. The effluent legal fees were incurred in a dispute between the City and Arizona Water over the Company's contract with an electric generating plant and the City's efforts to sell

[5] The "effluent" legal fees involved three actions. The Company incurred $34,301 defending a complaint brought to the Commission by the City. Exhibit A-21. The Company also initiated suit against the City over the effluent matter, first in federal court, and then after that action was dismissed in state court. The Company incurred $418,800 in that litigation. *Id.*

[6] As stated above, the Company has removed $8113 initially recorded in Plant Account 303 for "Fennemore Craig" as those amounts involved a prior rate case and were inadvertently recorded in account 303. Tr. at 572.

effluent to that plant. Garfield Rb. at 23-24; Garfield Rj. at 6.

While no other party appears to object to including the franchise, hydrology and "Other" costs in rate base (a total of $48,807), Staff, RUCO and the City object to including either the legal fees associated with the City's attempt to condemn Arizona Water's Casa Grande system or the legal fees incurred by Arizona Water in connection with the effluent dispute. Opposition to including the legal fees in rate base is grounded primarily on whether the expenses incurred by Arizona Water provided a benefit to ratepayers. Ludders Dt. at 16; Rigsby Dt. at 25; Harvey Sb. at 8. The Company submits ratepayers did and still are benefiting from the Company's decision to incur these costs.

In 1990, the City sought voter approval to acquire a portion of Arizona Water's Casa Grande water system. Exhibit A-33. The City electorate voted against that acquisition. *Id.* The citizens of Casa Grande also voted against the City getting into the water utility business. *Id.* Several years later, the City ignored the electorate and filed a condemnation action to again attempt to take over a large portion of the Casa Grande system. Garfield Rb. at 21; Exhibit A-21. *See also City of Casa Grande v. Arizona Water Company*, 199 Ariz. 547, 549, 20 P. 3d 590, 592 (App. 2001). Arizona Water filed an action against the City which resulted in the trial court ruling that the attempted takeover was unlawful because the City first needed the approval of its voters to condemn any portion of Arizona Water's system. Exhibit R-6 at 3. Surely the Company's customers benefited from the Company's defense against the City's unlawful exercise of government power against Arizona Water and its customers that would have disrupted the operations and increased the costs of providing water service to customers in this area. In fact, had the City followed the will of its citizens, Arizona Water would not have had to incur over $300,000 defending against the City's illegal attempt to take over a large portion of the Company's Casa Grande system.

Ratepayers also benefited from the defense against the City's unlawful condemnation attempt because the City planned to cherry-pick portions of the Company's water system. Garfield Rb. at 22; Garfield Rj. at 3-4. In addition to attempting to take over the entire Casa Grande CAP water right, the City sought to take nearly all of the key infrastructure. However, the City did not intend to take all of the Company's CC&N or all of its customers. *Id.* The City's ill-advised take over plan would have left a significant number of customers at grave risk. Had the City been allowed to go forward, the City would have taken necessary infrastructure and left some customers without reliable water utility service and still others without water resources altogether. *Id.* Without question, the Company's remaining customers would have been saddled with higher costs of service as a result of the City's imprudent (and unlawful) takeover attempt. Certainly ratepayers benefited when Arizona Water acted to protect customers' ability to obtain reliable water utility service at reasonable rates.[7]

The Company's customers also stood to benefit from the Company's actions in the effluent matter. The City initiated a competing water service within the Company's CC&N by selling effluent to one of the Company's customers. Garfield Rb. at 23. At the time, the Company was working with the customer to provide non-potable CAP water to the customer's facility. The City's service deprived all of the Company's customers of the benefits of the Company increasing its use of CAP water. The Company also sought to protect the benefit to its customers to be realized if the Company were able to allocate a greater portion of its operating expenses to a larger customer base through rates. In fact, as a result of the City's competing sales, the Company's customers will likely face the impact of paying higher deferred CAP M&I

[7] Notably, the appellate court found it significant that Arizona Water's customers benefited from the continued regulation of rates and services by the Commission. *City of Casa Grande*, 199 Ariz. at 551, 20 P. 3d at 594.

capital charges in the future. Garfield Rb. at 23. That the court ultimately allowed the City to sell effluent to Arizona Water's customer does not change the fact that the Company sought to protect and benefit its customers.

Finally, the Commission should reject suggestions that recovery be disallowed because costs booked under Plant Account 303 will be in rate base in "perpetuity." *E.g.*, Rigsby Sb. at 16. For one thing, it is wrong to penalize the Company for following the applicable accounting guidelines. No other party suggested an alternative means of booking these legitimate, necessary expenses, they just arbitrarily eliminated them from consideration. For ratemaking purposes, the disputed costs could be amortized and accordingly would not remain in rate base forever. Tr. at 574, 587.

B. <u>Cash Working Capital Allowance</u>.

The Company's recommended working capital allowance was determined using lead/lag factors adopted by this Commission last year when the rates for the Eastern Group were established. Hubbard Rb. at 10-12, *citing* Decision No. 66849 at 9; Tr. at 993. In that decision, the Commission adopted lead/lag factors for federal income taxes equal to 2.52 days, and for state income taxes of 27.05 days. Nothing has changed since that decision was issued that would warrant ignoring this precedent. Hubbard Rb. at 11.

Nevertheless, Staff and RUCO recommend that working capital be determined in a manner that is inconsistent with this recent Commission decision for the Company. As a result, Staff has reduced the working capital allowance by nearly $80,000. Hubbard Rb. at 12. Yet Staff admits that nothing has changed in the law or the manner in which Arizona Water operates that would justify changing the lead/lag factors for income taxes in the determination of working capital. *Id.* at 1242-43. Thus, Staff has failed to meet its burden of proof on this issue.

RUCO recommends that working capital allowance be reduced by approximately $270,000. Coley Dt. at 11. RUCO uses the same lead/lag factors it offered in the

Northern and Eastern Group rate cases, which factors were rejected by the Commission. Hubbard Rb. at 12, *citing* Decision No. 66849 at 9 and Decision No. 64282 at 6. The only explanation offered by RUCO for recommending lead/lag factors twice rejected by the Commission for this Company appears to be that RUCO should have done a better job presenting its position in the prior cases. *See* Tr. at 992-93. This does not justify adoption of RUCO's position.

Likewise, RUCO's Exhibit R-24 does not salvage the unsupported testimony of RUCO witness Coley on the subject of the lead/lag factors for income taxes. Coley Sb. at 4. The simple fact remains; every entity has unique business characteristics and operating procedures that impact the determination of lead/lag factors. Tr. at 811. This is clearly shown by the factors for other utilities RUCO presented in its testimony. Coley Sb. at 4. Without knowing the specifics of each entity's unique characteristics and procedures, another utility's lead/lag factors cannot just be applied to Arizona Water. Tr. at 811. Therefore, the Company's recommended lead/lag factors for federal and state income taxes should be adopted.

C. Other Rate Base Issues.

Staff accepted the level of accumulated depreciation determined by the Company for each of the Western Group systems. Ludders Dt., Schedules REL-3. RUCO made a number of adjustments to accumulated depreciation in its pre-filed testimony and then, at the hearing, accepted the Company's adjustment for accumulated depreciation. Tr. at 1025-26.

As discussed above in the section on deferred CAP M&I charges, the Company continues to recommend that a small portion of those deferred M&I charges be included in the rate base for the Casa Grande system. Tr. at 724-25, 729; 781; Exhibit A-28. Including $142,000 of the more than $3.5 million total deferred balance in rate base is appropriate because it represents the portion of the CAP allocation for the Casa Grande system that is presently being used. *Id.* Although no other party disputes that Arizona Water used a portion of its CAP allocation during the test year, no other party supports including this small portion of the deferred CAP M&I charges balance in rate base. However, because that portion of the deferred CAP M&I charges balance represents used and useful property of the Company, rate base treatment is appropriate. Tr. at 804.

IV. <u>INCOME STATEMENT</u>.

A. <u>RUCO Revenue and Expense Annualization Adjustments</u>.

All parties made an adjustment to the test year to annualize revenues and expenses. Arizona Water annualized revenues and expenses to reflect the number of customers being served at the end-of the test year using only the 5/8-inch meter customers because 96% of customer growth occurred in this meter class. Hubbard Dt. at 25-26. This was consistent with the annualization of revenues and expenses approved by the Commission in the Company's recent rate case for its Eastern Group. Decision No. 66849 at 12. Staff accepted the Company's annualization adjustment. Tr. at 1238-39.

RUCO offers a different and flawed methodology for annualizing revenues and expenses. In fact, RUCO annualized revenues and expenses by using all customer classes, even though the Commission rejected this approach in the Eastern Group case because it overstates revenue. Tr. at 995-96, *citing* Decision No. 66840 at 12. *See also* Tr. at 998 (admitting that RUCO's annualization is contrary to Decision 66849). Nevertheless, RUCO attempts to justify its position on two grounds. First, RUCO argues that the Company improperly measures growth from the mid-point of the test year. However, it is acceptable for water utilities to use average customer growth in the annualization of revenue and expenses. Tr. at 1318-19.

Second, RUCO argues that its regression analysis supports its annualization of revenues and expenses. However, RUCO's regression analysis was based on outdated data that resulted in its initial flawed conclusion that transmission, distribution and source of supply costs do not increase with customer growth. Tr. at 996-98, 1000. Later, RUCO witness Coley updated his analysis and concluded that transmission and distribution expenses are impacted by customer growth. *Id.* Yet, RUCO did not provide the Company with any revised testimony or discovery responses, and offered no revision to its admittedly erroneous annualization of revenues and expenses. Clearly, RUCO's annualization adjustment should be rejected.

B. <u>Property Tax Expense</u>.

The Arizona Department of Revenue determines the value of utility property for tax purposes using a formula that is based on the utility's revenues. Tr. at. 1005. For this reason, the Commission has repeatedly utilized proposed revenue increases to determine an appropriate level of property tax expense to be recovered through rates. *E.g., Rio Rico Utilities*, Decision No. 67279 at 8 (use of only historic revenues understates the expense level); *Arizona Water Company*, Decision No. 64282 at 12-13 (Commission accepted Arizona Water Company's property tax calculation, which included proposed revenues); *Bella Vista Water Company*, Decision No. 65350 (Nov. 1, 2002) at 16 (Commission concluded that "the most logical approach is to use the two most recent historic years' revenues, and the projected revenues under the newly approved rates."). *See also Arizona-American Water Company*, Decision No. 67093 (June 30, 2004) at 9-10. Staff and the Company have utilized adjusted revenues in determining a recommended level of property tax expense. Exhibit A-27; Tr. at 1238. Staff and the Company have also recommended an adjustment to take into account the impacts of recently approved legislation that lowers the assessment ratio for utility property. *Id.*

For the eighth time in the last few years, RUCO argues for using only historical revenues to determine property tax expense. Exhibit A-31; Tr. at 1002-03. RUCO asserts that its methodology is superior because it has used historical revenues to come up with a level of property tax expense that is nearly equal to the Company's 2004 property tax bill. Tr. at 1004. All RUCO has done, however, is use the historic revenues to recalculate Arizona water's 2004 property taxes. That calculation fails to take into account any increased revenues resulting from this proceeding, which increases will impact the level of this expense. *Id.* As a result, RUCO's calculation significantly understates property tax expense and should again be rejected.

C. <u>Adjustment to Purchased Power Expense</u>.

The Company purchases power from Arizona Public Service Company ("APS"), which recently received increases in its rates and charges for electrical service. Hubbard Rj. at 8-9. Company witness Hubbard determined the increases in each of the two tariffs under which Arizona Water buys power from APS and made a pro forma adjustment to the test year purchased power expenses. *Id.* The adjustment uses test year demand and APS's current rates to reflect the recommended level of purchased power expense.

Staff accepts the Company's recommended adjustment and purchased power level expense. Tr. at 1238. RUCO also agrees with the methodology used by Ms. Hubbard to make an adjustment to the test year. *Id.* at 1033-36. However, RUCO recommends a level of purchased power expense that is a few thousand dollars lower than the level of this expense supported by the Company and Staff. *Id.* at 1041. The Company's calculations applied the revised rates for APS's E-32 and E-221 tariffs to the actual test year consumption subject to each specific tariff. Tr. at 765. RUCO was unable to explain the discrepancy; so the recommendation made by the Company and Staff should be adopted.

D. <u>Rate Case Expense</u>.

The Company initially included an adjustment for rate case expense equal to

$253,550, amortized over a three-year period. Hubbard Dt. at 31. This was an estimate of the actual amount of rate case expense, which obviously cannot be determined until the case concludes. The Company has proposed to update its request for recovery of rate case expense at the reply brief stage of the proceeding. Hubbard Rb. at 25. Through June 2005, before the transcripts were available and briefing underway, Arizona Water's actual rate case expense was $226,815. *See* Supplemental Response to RUCO Data Request 1.10(b), copy attached hereto as Brief Exhibit 1.

RUCO has not proposed an adjustment to rate case expense. Rigsby Dt. at 30. On the other hand, Staff proposes rate case expense of $225,000. Ludders Dt. at 11. Staff's initial witness Ron Ludders asserted that his recommended level of rate case expense is more consistent with precedent in other rate cases involving Arizona Water. However, no expense is more case-specific than rate case expense. Rate case expense does not arise from the test year but from the proceedings themselves and the unique circumstances presented. Mr. Ludders' testimony fails to consider the unique circumstances in this case. In fact, no evidence regarding the rate case expense being too high is present at all. Rather, Staff's recommendation is made without any regard for the complexity of this case, the number of parties or the issues in dispute. Accordingly, Staff's recommendation is arbitrary and unreasonable.

V. PURCHASED POWER AND WATER ADJUSTMENT MECHANISMS.

Arizona Water is requesting approval to continue utilizing the adjustment mechanisms approved by the Commission. Decision No. 64282;[8] Decision No. 58120 at 30; Decision No. 55069 (June 13, 1986) at 20-21. The PPAM and PWAM allow the Company to adjust its rates, through a surcharge mechanism, in response to changes in

[8] Continuation of the adjustment mechanisms was not a contested issue during the Northern Group proceedings.

the rates for purchased water and purchased power. Kennedy Dt. at 19-21. Purchased water and purchased power are two of Arizona Water's most significant operating expenses. The Company's purchased water expense was $753,510, as adjusted, during the test year. Hubbard Rj., Exhibit SLH-RJ4 at 1. The Company's test year purchased power expense, as adjusted, was $1,006,540. *Id.* Accordingly, relatively modest increases in the rates for power and water will have a significant impact on the ability of each Western Group system to earn its authorized rate of return, as shown in the following table.

TABLE 1

	Purchased Power as a Percentage Of			Purchased Power as a Percentage Of		
System	Operating Expenses	O&M Expenses	Operating Income	Operating Expenses	O&M Expenses	Operating Income
	Ludders Corrected					
Ajo	0.79%	1.01%	8.58%	54.86%	54.86%	467.24%
Casa Grande	12.02%	19.40%	68.66%	11.92%	11.92%	42.20%
Stanfield	16.56%	30.17%	67.27%	0.00%	0.00%	0.00%
White Tank	11.84%	20.79%	64.56%	9.91%	9.91%	30.78%
Coolidge	7.34%	11.64%	96.69%	6.69%	6.69%	55.59%

There is a significant likelihood that the Company's cost for power provided by APS will increase in the near future.[9] Arizona Water purchases power from APS, which is regulated by the Commission. Hubbard Rj. at 8-9. The Company's test year purchased power expense, as adjusted, was $1,006,540. Hubbard Rj., Exhibit SLH-RJ4 at 1. Rates and charges for electric utility service have been increasing. APS was granted rate increases by the Commission in April 2005. Decision No. 67744 (April 7, 2005). Notably, APS was granted authority to implement an adjustment mechanism (Power Supply Adjustor) to recover increases in fuel costs, allowing APS to pass those

[9] The Commission can also take administrative notice of APS's most recent rate application filed with the Commission on July 22, 2005. While no decision has been made, the fact of the filing further supports the Company's concerns over future increases in purchased power.

costs on to Arizona Water in the future. This means that the Company's costs for power are at least as volatile as APS's cost of producing that power. Tr. at 1047-48.

Under these circumstances, the use of adjustment mechanisms is appropriate to protect the financial integrity of each Western Group system, as recently occurred when the Commission approved a 24% rate increase for Ajo Improvement Company, the sole supplier of water for the Company's Ajo system. Kennedy Rj. at 3-4. Under the PWAM, Arizona Water was able to recover the roughly $35,000 increase in purchased water costs for that system. Without the PWAM, the Company would have had negative operating income requiring an emergency rate increase for its Ajo system. *Id.* This is exactly the type of situation Commission-approved adjuster mechanisms are designed to prevent. As explained by the Arizona Court of Appeals:

> [Automatic adjustment clauses] allow a utility to increase or decrease rates automatically "in relation to fluctuations in certain, narrowly defined operating expenses." . . . Automatic adjustment clauses are designed to ensure that utilities maintain a relatively constant profit despite an increase in a specific cost anticipated by the adjustment clause. An automatic increase allows a utility to recoup cost increases by passing the cost on to the customer, while at the same time maintaining the utility's net income. . . . The same is true in the converse situation, that of an automatic decrease. The decrease in cost is passed on to the customer without disturbing a utility's profit. In essence, an automatic adjustment clause is designed to offset cost increases or decreases, leaving the utility's ultimate net income unchanged.

Residential Utility Consumer Office v. Ariz. Corp. Comm'n, 199 Ariz. 588, 591-92, 20 P.3d 1169, 1172-73 (App. 2001) (citations omitted), *quoting Scates*, 118 Ariz. at 535, 578 P.2d at 616. *See also* Tr. at 1246 (adjusters "protect utility's opportunity to earn its authorized rate of return when rates go up").

The Commission recognized this when it last addressed the current PPAM and PWAM for the Western Group:

> If purchased power and/or water costs are trending upward,

> gradually recognizing those increasing costs through incremental rate adjustments sends a more appropriate price signal to users and receives greater customer acceptance than the less frequent, but far larger, rate increases contemplated in Staff's proposal.

Decision No. 58120 at 30.

More recently, in Decision No. 62993 (Nov. 3, 2000), the Commission specifically approved of the use of adjustment mechanisms, based on the discussion of the use of those mechanisms that took place in connection with the Commission's Water Task Force. Decision No. 62993 at 1 (Exhibit A-39). One of the issues addressed by the Commission was the agency's policy regarding A.R.S. § 40-370. That statute instructs the Commission to "authorize water utilities to recover increases in specific operating costs by means of a surcharge on water sales and to reduce rates when those specific operating costs decrease." A.R.S. § 40-370(A). The expenses that may be considered are limited to specific, readily identifiable costs that are subject to the control of another person, including the cost of purchasing water and power.

In discussing this statute, the Commission indicated that it had recently approved adjustment mechanisms for Arizona Water, allowing that utility to recover costs associated with the Monitoring Assistance Program administered by the Arizona Department of Environmental Quality, and for Rio Verde Utilities, allowing that utility to recover cost increases associated with the purchase of CAP water. Decision No. 62993 at 6. The Commission stated that these decisions "indicate that the Commission's policy on A.R.S. § 40-370 applications is to support appropriate pass-throughs, which should mitigate the industries [*sic*] concerns." *Id.* As discussed above, the Commission also approved an ACRM for the Company's Eastern and Northern Groups.

In summary, Arizona Water's PPAM and PWAM are "appropriate" adjusters.

Each addresses a specific operating expense. Both of these expenses are significant, beyond the utility's control, and likely to change on a regular basis. Moreover, the adjusters benefit ratepayers in two respects. First, the adjusters minimize the need for emergency or repeated rate cases when these significant expenses increase. *See* Kennedy Rj. at 3-4. Second, when the costs of water or power decrease, the rates to ratepayers are decreased to reflect the reduction in the Company's operating expenses. Tr. at 1246. Therefore, the PPAM and PWAM are equitable because they work to the benefit of both the Company and customers.

Staff, RUCO and the City oppose approval of the Company's request to continue utilizing the PPAM and PWAM. The City opposes these adjuster mechanisms because it alleges that the costs are not outside of Arizona Water's control. Harvey Sb. at 6. The City's witness is an applied economist from Colorado and he clearly lacks the requisite knowledge to testify on this issue. The Company has little to no control over who provides electric power and wholesale water in its respective service areas, or the rates that it pays. Kennedy Rj. at 4. *See also* Tr. at 1047-48; 1246.

Staff begins by miscalculating the relationship between these expenses and the Company's total operating expenses. *See* Kennedy Rb. at 4-5, *discussing* Ludders Dt. at 7-8. Beyond that, Staff never comes to terms with each system's assertion that the relevant measure is the impact of eliminating the adjusters on each system's opportunity to earn its authorized rate of return. Ludders Sb. at 6. Nor does Staff provide any other basis for eliminating the PPAM and PWAM. RUCO proposes to eliminate the PPAM and PWAM to be consistent with the Commission's decision in the Eastern Group case. Rigsby Dt. at 10; Rigsby Sb. at 21-22.

Neither party, however, provides a legitimate basis for its position. Again, the irony should not go unnoticed by the Commission. As discussed above, RUCO recommends a working capital allowance, an annualization of revenues and expenses and property tax expense that are contrary to the Eastern Group decision. In those instances, deviating from precedent benefits ratepayers at the expense of the Company. However, elimination of the adjusters consistent with the Eastern Group decision will likely prejudice Arizona Water. Moreover, RUCO clings to one prior Arizona Water decision and ignores three others. Decision No. 64282; Decision No. 58120 at 30; Decision No. 55069 (June 13, 1986) at 20-21. The Commission has previously approved the adjuster mechanisms for Arizona Water and should do so again.

VI. COST OF CAPITAL.

A. Overview.

Over the past 100 years, the United States Supreme Court, as well as various federal and state courts (including Arizona), have stated that a regulated utility is entitled to earn a return on equity that is sufficient to allow the utility to attract capital on reasonable terms, and is commensurate with returns on investments in other enterprises having corresponding risks. These decisions were summarized in a recent article as follows:

> The Supreme Court's *Bluefield Water Works* . . . and . . . *Hope Natural Gas* . . . decisions, as recently reinforced in its Duquesne Light . . . decision, set the standard for judging the lawfulness of equity returns authorized for utilities by ratemaking agencies. Under the *Bluefield-Hope* standard, the equity return must enable the utility to (1) attract additional capital on reasonable terms (the capital attraction standard); and (2) realize a return on equity commensurate with the returns earned by enterprises with comparable risks (the comparable earnings standard). In "reaffirming these teachings of Hope," the *Duquesne* Court noted that "[o]ne of the elements *always relevant* to setting the rate under Hope is the return investors expect given the risk of the enterprise."

W. Whittaker, "*The Discounted Cash Flow Methodology: Its Use In Estimating A Utility's Cost of Equity*," 12 Energy Law Journal (1991) at 265, *citing Bluefield Water Works & Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679, 692-93 (1923); *Fed. Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944); *Duquesne Light Co. v. Barasch*, 488 U.S. 299, 314-15 (1989).

Similarly, in summarizing the standard for determining the lawfulness of a utility's authorized rate of return, Dr. Phillips states in his treatise on public utility regulation:

> The relevant economic criteria enunciated by the [Supreme] Court are three: financial integrity, capital attraction and comparable earnings. Stated another way, the rate of return allowed a public utility should be high enough (1) to maintain the financial integrity of the enterprise, (2) to enable the utility to attract the new capital it needs to serve the public, and (3) to provide a return on common equity that is commensurate with returns on investments and enterprises of corresponding risk. These three economic criteria are interrelated and have been used widely for many years by regulatory commissions throughout the country in determining the rate of return allowed by public utilities.

Charles F. Phillips, Jr., *The Regulation of Public Utilities* 381-382 (1993). *See also Sun City Water Co. v. Arizona Corp. Comm'n*, 26 Ariz. App. 304, 309, 547 P.2d 1104, 1109 (1976) (quoting and following *Bluefield Water Works*); Zepp Dt. at 7-8 (discussing standard for a "fair rate of return"); Rigsby Dt. at 5-6 (acknowledging the *Bluefield* and *Hope* criteria). As explained below, the equity cost recommendations made by Staff and RUCO in this case violate these standards, i.e., they are not commensurate with returns earned by firms with corresponding risks and they will not allow Arizona Water to attract capital on reasonable terms.

B. <u>Capital Structure and Cost of Debt.</u>

The parties are in agreement that Arizona Water's company-wide capital structure as of December 31, 2003, should be used to determine the weighted cost of capital and overall rate of return on rate base. That capital structure was as follows:

	Amount	Percentage of Total
Long Term Debt	$ 22,200,000	26.6%
Common Equity	61,116,374	73.4%
Total Capital	$ 83,316,374	100.00%

Exhibit A-17, Schedule D-1. *See also* Ramirez Dt. at 6; Rigsby Dt. at 41.

The parties also agree that Arizona Water's cost of long term debt is 8.43%, which results in a weighted cost of debt of 2.25%. *Id.* Again, there is no material difference on this issue between the parties. *See* Ramirez Sb., Schedule AXR-1 (capital structure and weighted cost of capital); Rigsby Dt., Schedule WAR-1 (same).

Consequently, the primary area of disagreement is the appropriate return on common equity. The Company proposes an equity return of 11.25%, which produces a weighted cost of capital of 10.5%. Exhibit A-17, Schedule D-1. Staff recommends an equity cost of 9.1%, resulting in a weighted cost of capital of 8.9%. Ramirez Sb. at 1; Schedule AXR-1. Finally, RUCO recommends an equity cost of 9.44%, resulting in a weighted cost of capital of 9.17%. Rigsby Dt. at 4; Schedule WAR-1. These differences are significant. Staff's recommendation reduces the required increase in revenues for the Western Group by $768,000, or about 30%. RUCO's recommendation reduces the required increase in revenues for the Western Group by $639,000, or nearly 25%. Kennedy Rb. at 7. If adopted, the Staff and RUCO recommendations would violate the comparable earnings and attraction of capital standards, adversely impacting the Company's ability to obtain financing for the construction of arsenic treatment facilities later this year, as well as increasing the cost of this new debt. *Id.*

C. **The Cost of Equity.**

1. **Summary of the Company's Cost of Equity Estimates.**

Arizona Water's cost of capital expert, Dr. Thomas Zepp, prepared estimates of the cost of equity based on the discounted cash flow ("DCF") models used by the

Federal Energy Regulatory Commission ("FERC") and Risk Premium method used by the Office of the Ratepayer Advocate of the California Public Utility Commission ("PUC"). Zepp Dt. at 29-38 (description of FERC DCF models)[10] and 38-45 (description of California PUC Risk Premium method). Dr. Zepp selected the models and inputs used by the FERC and the California PUC staff, rather than the methods he would personally prefer, to show that the methods and inputs used by Staff and RUCO are biased downward and produce equity cost estimates that are unreasonably low. Tr. at 50; Zepp Rj. at 5.

The updated equity cost estimates presented in Dr. Zepp's Rejoinder Testimony using the FERC 1-step (constant growth) and 2-step (multi-stage growth) DCF models and the California PUC Risk Premium approach range from 10.2% to 10.9% based on the six publicly-traded water utilities included in the sample group.[11] Zepp Rj., Rejoinder Tables 1 through 7 and Rejoinder Table 11 (summary of equity cost estimates). Arizona Water is riskier than the publicly traded water utilities in the same group, and therefore requires a higher return on equity than those utilities. *E.g.*, Zepp Dt. at 15-26; Kennedy Rb. at 10-11; Zepp Rb. at 26-29; Zepp Rj. at 25-27.

In addition, Dr. Zepp restated the equity cost estimates made by the Staff and RUCO witnesses using the information provided in their witnesses' schedules and work papers, but employing conceptually correct inputs. Using the FERC 1-step and 2-step

---

[10] Dr. Zepp attached a copy of a recent FERC decision, *Southern California Edison Company*, Opinion No. 445 (July 26, 2000), to his Direct Testimony, which illustrates the FERC DCF method.

[11] The Company and Staff used the same six publicly-traded water utilities, American States Water, Aqua America, California Water Service, Connecticut Water Services, Middlesex Water Company and SJW Corp. *E.g.*, Zepp Rj., Rejoinder Tables 1-4; Ramirez Sb., Schedules AXR-2 through AXR-7. RUCO, in contrast, used the three largest publicly-traded water utilities in this group, American States Water, Aqua America and California Water Service, because forward-looking financial data is available for those three utilities. Rigsby Dt. at 18; Tr. at 155-56.

DCF models with the data reported in Mr. Ramirez's Direct Testimony, Dr. Zepp found the indicated cost of equity is 11.2% to 11.5%. Zepp Rb., Rebuttal Tables 5 and 6. Dr. Zepp also restated Mr. Ramirez's constant growth and multi-stage DCF models in his Rebuttal Testimony, which resulted in an average equity cost estimate of 10.9%. *Id.* at Rebuttal Tables 7-10 and 12.

In his Rejoinder Testimony, Dr. Zepp restated Mr. Ramirez's constant growth DCF estimate using the projected growth rates reported in Mr. Ramirez's Surrebuttal Testimony, which produced an equity cost of 10.5%. Zepp Rj. at 12 and Rejoinder Table 11. Dr. Zepp similarly restated Mr. Ramirez's multi-stage DCF model estimate and his capital asset pricing model ("CAPM") estimate, using the information in Mr. Ramirez Surrebuttal Testimony and work papers, and found that the indicated equity cost is 9.9% and 10.1%, respectively. *Id.* at 16 and 18, and Rejoinder Table 11.

Dr. Zepp also restated the equity cost estimates made by RUCO's witness, Mr. Rigsby, using the information reported by Mr. Rigsby in his pre-filed testimony but with conceptually correct inputs. Again, the indicated equity costs produced by the models increased substantially, and range from 10.3% to 11.0%. Zepp Rj., Rejoinder Table 11. None of Dr. Zepp's restatements of the Staff and RUCO models include any adjustment for Arizona Water's additional risks.

2. Comparable Earnings Analysis.

In order to place the parties' equity cost estimates in perspective, it is necessary to also consider the actual, authorized and projected returns on equity for sample groups of publicly traded water utilities that are used by the parties. Indeed, as previously discussed, the comparable earnings standard established by the United States Supreme Court in decisions such as *Bluefield Water Works* and *Hope Natural Gas* require use of the returns earned by enterprises of comparable risk as a measure of the fair equity return for Arizona Water.

In his Rebuttal Testimony, Dr. Zepp considered the returns on equity that have been authorized for the water utilities in the sample group, which range from 9.7% to 12.7% and average 10.4%, as well as the average risk premium found in Commission decisions prior to 2001 (when Staff used different methods to estimate the cost of equity), which results in an equity cost of 10.7%. Zepp Rb. at 7-10 and Rebuttal Tables 1 and 2. Moreover, AUS Utility Reports and Value Line report the following current (i.e., actual) and projected returns on equity for the sample group:

Company	Current ROE	2006	2008-10
American States	9.1%	9.5%	12.0%
California Water	9.6%	10.5%	11.05%
Aqua America	11.7%	12.5%	13.0%
Connecticut Water	10.9%	-	-
Middlesex Water	9.8%	-	-
SJW Corp.	11.8%	-	-
Average	10.5%	10.8%	12.0%
Value Line Water Industry Composite	11.0%	11.5%	12.0%

See Exhibits A-19 and A-20. These actual and projected equity returns are consistent with the results obtained by Dr. Zepp using the FERC DCF models and the California PUC Risk Premium method. These equity returns are also substantially higher than the recommendations made by Staff and RUCO for Arizona Water.

Moreover, as Dr. Zepp explains, since Arizona Water's previous rate case for its Eastern Group, interest rates and the estimated betas of the water utility sample have increased, indicating the cost of equity has increased as well. Yet the benchmark equity return established by Staff in the Eastern Group case, based on the sample water utilities, was 9.2% - *higher than the equity cost estimate by Staff in this case.* Zepp Rb.

at 10-12. Obviously, something is wrong.

In short, the methods used by Staff and RUCO are flawed and depress the cost of equity. The remainder of this section will focus on those methods as compared to the methods used by the FERC and the California PUC staff, and show how the inputs chosen by Staff and RUCO are biased and produce unreasonably low equity costs.

3. The Inputs Chosen by Staff Depress the Results Produced By Its DCF Models.

The basic formulation of the constant growth DCF model is quite simple and is recognized by all of the parties' witnesses:

$$K = \frac{D_1}{P_0} + g$$

See e.g., Rigsby Dt. at 8; Ramirez Dt. at 14-15. Under this formula, there are two components, *dividend yield*, which is the expected annual dividend (D_1) divided by the price of the stock (P_0), and *dividend growth*, which is the expected rate of future dividend growth (g). Under the constant growth version of the model, a company is assumed to have a constant earnings retention rate and its earnings are expected to grow at a constant rate. *Id.* The FERC 1-step DCF model is a constant growth model, as explained by Dr. Zepp. Zepp Dt. at 22-23. Consequently, both Arizona Water and Staff (as well as RUCO) have used this common DCF model to estimate the cost of equity for the same six, publicly traded water utilities. However, the inputs used by Staff to implement this model vary significantly from those used by FERC.

Arizona Water and Staff also presented estimates based on a multi-stage DCF model. Both multi-stage models use the same dividend yield, but assume that dividend growth will occur in multiple stages, as opposed to being constant. The FERC 2-step DCF model, for example, assumes that dividend growth will occur in two stages; initial or near-term growth and terminal growth. Zepp Dt. at 35-36. The FERC recognizes that investment firms often use more complex three-stage models in which the first and second growth stages could be as long as 20 years and final stage growth is equal to the long-term growth rate of the economy. *Id.* However, the FERC prefers to use a two-stage model that is less complicated and involves less subjective judgment. *Id.* at 36. The multi-stage DCF model that Staff uses is similar to the FERC 2-step model, and contains two growth stages. Ramirez Dt. at 23-25 (describing Staff's multi-stage DCF model). As shown below, however, the inputs selected by Staff also depress the results of this model.

a. Staff's Use of "Spot" Stock Prices Depresses the Result Produced by Both of Its DCF Models.

The first important difference between the FERC and Staff is that the FERC uses a six-month average of dividend yields. Zepp Dt. at 29.[12] Staff, in contrast, relies on "spot" stock prices, i.e., the price of each water utility's stock on a particular day, to compute the dividend yield. Ramirez Dt. at 15.

In his Rebuttal Testimony, Dr. Zepp adopted Staff's "spot" price method, and in restating Staff's constant growth DCF estimate, he used the dividend yields Mr. Ramirez calculated in his Direct Testimony using spot stock prices. Zepp Rb. at 12-13 and Rebuttal Tables 5 and 6. The resulting equity cost estimate was 11.5%. *Id.* In his Surrebuttal Testimony, however, the stock prices selected by Mr. Ramirez resulted in a dividend yield of only 3.0%, depressing his DCF equity cost estimates to 8.8% (constant growth) and 9.3% (multi-stage), which Mr. Ramirez then rounded down to arrive at an average DCF equity cost estimate of only 9.0%. Ramirez Sb., Schedules AXR-5 and

[12] RUCO similarly uses an eight-week average of stock prices to calculate the dividend yield in its DCF model estimate. Rigsby Dt. at 21; Tr. at 158-59 ("it leaves a little too much to chance if you rely on stock prices for one day").

AXR-8.[13] Notably, in surrebuttal testimony filed by Mr. Ramirez just 20 days earlier in the Chaparral City Water Company rate case, Mr. Ramirez chose stock prices that produced an average dividend yield of 3.3% - a difference of 30 basis points (10%). Zepp Rj. at 7; Tr. at 108. See also Surrebuttal Testimony of Alejandro Ramirez, Docket No. W-02113A-04-0616 (filed May 5, 2005) at 2 and Schedule AXR-8.

In short, Mr. Ramirez appears to have selected stock prices in this case that depressed his DCF equity cost estimates. Zepp Rj. at 6-7. During the hearing, Staff's witness, Mr. Fox (who adopted Mr. Ramirez's testimony), was unable to explain how Mr. Ramirez chose the stock prices used in his Surrebuttal Testimony. Tr. at 215. However, Mr. Fox did testify that Staff has certain "criteria" that it uses to select the date of the stock prices in order to avoid "spurious" price changes that impact the dividend yield calculation. *Id.*[14] Thus, Staff implicitly acknowledges that the use of spot stock prices may distort the dividend yield.

To avoid the negative bias produced by the use of spot stock prices in this case, Dr. Zepp used the FERC method to compute the dividend yield in his Rejoinder Testimony, which results in an average dividend yield of 3.2%. Zepp Rj. at 7 and Rejoinder Tables 3 and 4. That dividend yield is still below the 3.3% dividend yield computed by Mr. Ramirez in his surrebuttal testimony in the Chaparral City Water Company rate case, but is equal to the dividend yield calculated by Mr. Ramirez in his Direct Testimony in this case. Ramirez Dt., Schedule AXR-8. Given that new rates will likely be established next October, with new rates being in effect during the 2006 -

---

[13] In contrast, in his Direct Testimony, Mr. Ramirez's DCF equity cost estimates were 9.1% (constant growth) and 9.5% (multi-stage), which resulted in an average DCF estimate of 9.3%. Ramirez Dt., Schedule AXR-8.

[14] Mr. Fox stated that, under these criteria, the stock prices Staff selects should be reported for a Wednesday, as opposed to another day of the week. However, he was not aware of Staff's other criteria. *Id.*

2008 time period, Staff's dividend yields based on its spot prices are no more current than the dividend yield calculated by Dr. Zepp using the FERC method. Therefore, the dividend yield used in both the constant growth and multi-stage DCF models should be no less than 3.2%.

b. Staff's Inclusion of Historic Growth Reduces Its Constant Growth DCF Model Estimate.

Putting aside Staff's use of spot stock prices, the primary difference between the FERC and Staff approaches is that the FERC relies on forward-looking estimates of growth, while Staff gives a 50% weight to historic growth (data from 1994 to 2004). *E.g.* Zepp Rj. at 11-12; Tr. at 216-17. As shown below, Staff's historic growth rates produce unrealistic results and depress the equity cost estimate. *Id.*

In his Surrebuttal Testimony, Mr. Ramirez provides the following table showing the dividend growth rates he used in implementing the DCF model:

Type of Growth	Historic	Projected
Dividends per Share ("DPS") Growth	2.6%	3.4%
Earning per Share (EPS") Growth	4.1%	10.4%
Intrinsic (Sustainable) Growth	5.4%	8.8%
Average	**4.0%**	**7.5%**

Ramirez Sb., Schedule AXR-6 (emphasis supplied).[15] In his constant growth DCF estimate, Mr. Ramirez gives equal weight to each of the foregoing growth estimates, and computes an average dividend growth rate of 5.8%. *Id.*; Tr. at 216. Mr. Ramirez then applies the average dividend yield based on "spot" stock prices, 3.0%, to compute

[15] Staff uses the term "intrinsic" growth, while the FERC and RUCO use the term "sustainable" growth. Both terms refer to the same type of dividend growth, which is essentially based on the company's earnings multiplied by its retention ratio (*i.e.*, the percentage of earnings retained and reinvested), adjusted for changes in the company's outstanding shares of common stock. *E.g.*, Zepp Dt. at 31-32; Ramirez Dt. at 17-22; Rigsby Dt. at 14-15.

an equity cost of 8.8%. Ramirez Sb., Schedule AXR-8.

This approach masks the fact that Staff's historic dividend growth rates are extraordinarily low, and produces results that are below the cost of debt. For example, Mr. Ramirez's historic DPS growth rates for American States Water, California Water Services and Connecticut Water are 1.1%, 1.3% and 1.4%, respectively. Ramirez Sb., Schedule AXR-3. Using the spot prices and projected dividends shown on Schedule AXR-7 to compute the dividend yields for those three companies, the indicated equity cost for those three water utilities is 4.4%, 4.5% and 5.0%, respectively - well below the current cost of an investment grade bond. *See* Table attached hereto as Brief Exhibit 2. In fact, the average historic dividend growth rate shown on Schedule AXR-6 is 2.6%, and when combined with Mr. Ramirez's average dividend yield of 3.0%, results in an equity cost of only 5.6% for the entire group.[16]

The FERC, in contrast, gives a 100% weight to forward-looking estimates of growth in its 1-step (constant growth) DCF model. Zepp Rj. at 12; Zepp Dt. at 30. RUCO does so as well. *E.g.*, Rigsby Dt. at 18. The FERC considers estimates of both intrinsic (sustainable) growth and analysts' forecasts of growth. Zepp Dt. at 30; *see also* Zepp Rj., Rejoinder Tables 1-3 (updated estimate using the FERC 1-step model).

Moreover, the FERC eliminates from consideration any individual utility equity cost estimate that is not at least 40 basis points above the cost of investment grade bonds. *Id.* at 29, 35 and FERC Opinion No. 445 (attached hereto as Brief Exhibit 3) at 21 ("Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low end-return cannot be considered reliable in this case."). Thus, the FERC would not consider the unrealistic

---

[16] As discussed below, Staff also uses the geometric average growth rates, rather than the conceptually correct arithmetic average growth rates, which further lowers the average growth rate and the resulting equity cost estimate. Zepp Rj. at 12-15.

results produced by Staff's use of historic growth rates.

The FERC's use of future growth rates is theoretically sound. Under the efficient market hypothesis, "the current stock price includes investors' expectations of future returns and is the best indicator of those expectations." Ramirez Dt. at 15. See also Exhibit S-4; Tr. at 107-08. In other words, in an efficient market, stock prices fully reflect all relevant information available at that time. Zepp Dt. at 30; Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital*, 136 (1994). Thus, historical information regarding the company's performance is already embedded in the stock prices used to compute the dividend yield. Similarly, financial institutions and analysts would have considered the historic information, as well as other, more recent information, in making their forecasts. For example, *Value Line* (on which all of the parties' witnesses have relied) provides forecasts of DPS growth, EPS growth and growth in book value per share. Those forecasts already incorporate the historic information used by Staff. Zepp Dt. at 30. Therefore, giving a 50% weight to historic growth rates effectively double counts what has happened in the past. Investors are far more interested in a stock's future performance than in its performance in 1995. Relying on future growth as FERC does avoids this problem and should be adopted.

c. Staff's Multi-Stage DCF Model Also Uses Inputs That Depress the Cost of Equity.

Staff's multi-stage DCF model again relies on inputs that depress the cost of equity. First, Staff ignores its own forward-looking growth rates, using only the lowest forecasted growth rate as the initial or near-term growth rate. Mr. Ramirez provides a projected EPS growth rate of 10.4% in his Surrebuttal Testimony. Ramirez Sb., Schedules AXR-3 and AXR-6 (reproduced in table above). He also calculated a sustainable (intrinsic) growth rate of 8.7%. *Id.*, Schedules AXR-4 and AXR-6. However, in estimating growth in the first stage of his multi-stage DCF model, Mr.

Ramirez ignores his own EPS and sustainable growth estimates, and instead assumes near-term growth will be only 3.7%. Zepp Rj. at 15-16. Thus, while Mr. Ramirez uses the average of six growth rates (including extremely low historic DPS and EPS growth rates) in his constant growth DCF model, Mr. Ramirez uses only the lowest forecasted growth rate in his multi-stage DCF model, ignoring the remaining forecasted growth rates reported in his schedules.

Second, Mr. Ramirez also uses an unrealistic, three-year period for his initial growth stage, which lowers the equity cost produced by the model. *See* Ramirez Sb., Schedule AXR-7. The FERC, in contrast, appropriately assumes that it will take many years before the terminal growth rate will be the same as growth in gross domestic product ("GDP"), i.e., the economy as a whole, and gives greater weight to the estimate of near-term growth. Zepp Dt. at 37; Zepp Rj. at 16.[17]

Finally, Mr. Ramirez uses the *geometric* average annual GDP growth rate, which is 6.5%, as the terminal growth rate, rather than the conceptually correct *arithmetic* average annual GDP growth rate, which is 6.8%. Dr. Zepp explains in his Rejoinder Testimony why an arithmetic annual average is the correct ingredient to use because it takes into account variability in growth. Zepp Rj. at 12-15. Dr. Zepp also attached excerpts from two well-known texts, Richard A. Brealey and Stuart C. Myers, *Principles of Corporate Finance* (7th ed. 2003), and Ibbotson Associates, *SBBI Valuation Edition 2005 Yearbook*, discussing this point and explaining why an arithmetic average should be used. *Id.*, Rejoinder Exhibits TMZ-1 and TMZ-2. Dr. Roger Morin, in his textbook on regulatory finance, also explains why arithmetic averages should be used for forecasting, discounting and estimating the cost of capital,

---

[17] The FERC gives two-thirds weight to near-term growth and one-third weight to GDP growth. Zepp Dt. at 36.

rather than geometric averages. Morin, *supra*, at 298-300.[18]

Each of Staff's choices depresses the result produced by its multi-stage DCF model. If Staff had used the average of its three forward-looking growth rates, 7.5%, as the near-term growth rate, used the conceptually correct arithmetic GDP growth rate, 6.8%, as the terminal growth rate, and gave each growth rate equal weight, the growth rate would be 7.2%. Even if Staff's dividend yield based on "spot" stock prices were used, the indicated equity cost would be 10.2% (3.0% + 7.2%). If the FERC method of calculating the dividend yield were used instead, the indicated equity cost would be 10.4% (3.2% + 7.2%), which is the same equity cost Dr. Zepp computed using the FERC 2-step model. Zepp Rj., Rejoinder Table 3.

4. The California PUC Risk Premium Method and the Staff Capital Asset Pricing Model.

a. Staff's CAPM Estimates Substantially Understate the Cost of Equity.

Staff also relies heavily on the CAPM to support its recommended 9.1% equity return, giving its CAPM estimates a 50% weight. See Ramirez Sb. at 2 and Schedule AXR-8.[19] While this finance model is theoretically interesting, it is difficult to implement in practice and, moreover, empirical studies have shown the model is incomplete and does not account for all factors affecting the cost of equity, including size and other firm-specific risks. Tr. at 121-23.

On its face, the CAPM is deceptively simple:

Equity cost = risk free rate + [ß x market risk premium]

---

[18] As noted above, geometric averages are also used by Staff to determine forward-looking estimates of growth from past growth in dividends per share and earnings per share, which results in lower growth rates.

[19] RUCO also derives equity cost estimates using the CAPM, but relies on its DCF estimate to support its 9.44% recommendation. Rigsby Dt. at 27. Accordingly, the Company will focus on Staff's CAPM method.

E.g., Ramirez Dt. at 26. Thus, the CAPM requires three basic inputs: (1) beta ("ß"), which measures a security's volatility in relation to that of the market (i.e., the security's market risk); (2) the risk-free rate ("R_f"), which is the return an investor expects to earn on a theoretical "riskless" investment; and (3) the average market return ("R_m"), from which the market risk premium (R_m - R_f) is calculated. *See, e.g.*, Morin, *supra*, at 301-304 (conceptual background) and 307-315 (CAPM application). For example, if the risk-free rate (R_f) is 6.0% and the market return (R_m) is 16.0%, the market risk premium is 10.0% (16.0% - 6.0%). In that example, the CAPM equity cost estimates for Firms A, B and C would be 12.0%, 14.0% and 16.0%, respectively, corresponding to their respective betas of 0.60, 0.80 and 1.00.

Despite the apparent simplicity of the CAPM, however, the model's use in estimating Arizona Water's equity cost is problematic in several significant respects. The first application problem is the selection of a beta. Staff uses the betas estimated by *Value Line* for the six publicly traded water utilities in its sample group to compute an average beta of 0.68. Ramirez Dt. at 28; Ramirez Sb. Schedule AXR-5. Staff then assumes Arizona Water, which is *not* publicly traded and has *no* estimated beta, has the same estimated beta as the average of the sample group's betas. Staff does not provide a credible basis for this assumption. As discussed below, Arizona Water is more risky than the larger, publicly traded utilities in the sample group, and would have a beta closer to 1.0, which would result in a higher equity cost estimate. *E.g.*, Zepp Rb. at 28-29; Zepp Rj. at 25.

The second application problem concerns the selection of the appropriate risk-free rate. Staff uses the average yield on 5, 7 and 10-year Treasury securities for its risk-free rate. Ramirez Dt. at 27. This choice is theoretically unsound and reduces the equity cost estimate. Staff justifies its use of intermediate-term Treasuries on the basis that most investors hold securities for a five to 10-year period. Ramirez Dt. at 27, n. 8.

Regardless of an investor's holding period, however, a corporation has an indefinite life. Therefore, in valuing the stock of a corporation, the investor's holding period is irrelevant.

> The horizon of the chosen Treasury security should match the horizon of whatever is being valued. When valuing a business that is being treated as a going concern, the appropriate Treasury security should be that of long-term Treasury bond. Note that the horizon is a function of the investment, not the investor.

Zepp Rb. at 22, *quoting* Ibbotson Associates, *SBBI Valuation Edition, 2005 Yearbook 57*. The use of an intermediate-term Treasury security implicitly assumes that the corporation will dissolve after the investor's holding period has ended, rendering the stock worthless. This is not a realistic assumption.

Moreover, although Staff has used an average of intermediate-term Treasury rates as the risk-free rate, Staff has used the long-term Treasury rate to estimate the market risk premium, which creates an improper mismatch. Zepp Rj. at 17-18. As explained, the market risk premium is equal to the average market return less the risk-free rate. By substituting the higher, long-term Treasury rate in calculating the market risk premium, the market risk premium is lowered, reducing the CAPM equity cost estimate by 40 to 60 basis points. *Id.* Mr. Fox acknowledged this error during the hearing. Tr. at 179-83.

Finally, Staff uses two different methods of estimating the market risk premium. First, Staff uses the historic market risk premium reported by Ibbotson Associates for the period 1926 - 2003, which results in a risk premium of 7.6%. Ramirez Dt. at 29. Second, Staff uses an extremely volatile method of estimating the current market risk premium that involves the use of the DCF model. *Id. See also* Zepp Rb. at 25; Zepp Rj. at 19 ("Because the method is so unstable, it allows ACC Staff to pick and chose the *Value Line* data used in the analysis and depress the cost of equity if it chooses to do so.").

The inputs Staff uses in implementing the CAPM produce results that run counter to CAPM theory and contradict Mr. Ramirez's testimony, as shown below. Mr. Ramirez testifies that, according to the CAPM, "the cost of equity moves in the same direction as interest rates." Ramirez Dt. at 7. Mr. Ramirez also testifies that beta measures a stock's market or systematic risk, and that a company's unique risk is irrelevant to investors. *Id.* at 10. Finally, he testifies that investors "require a greater return for bearing risk." *Id.* at 25. Thus, according to the CAPM, as interest rates and the estimated beta increase, the cost of equity increases.

Staff's CAPM estimates, however, move in the opposite direction of both interest rates and beta risk. Two years ago, in Arizona Water's Eastern Group rate case, Staff presented CAPM equity cost estimates using the same methods based on the same six publicly traded water utilities, and on a sample group of 10 publicly traded gas companies. *See* Decision No. 66849 at 21. Staff's risk-free rate, average beta estimated by Value Line and resulting CAPM estimates were as follows:

	Risk-Free Rate	Value Line Beta	CAPM Estimate
Sample Water Utilities	3.3%	0.59	9.2%
Sample Gas Utilities	3.3%	0.69	10.3%

See Direct Testimony of Joel M. Reiker, Docket No. W-01445A-02-0619 (filed July 8, 2003), Schedules JMR-7 and JMR-18. At that time, Mr. Reiker maintained "the cost of equity to the sample gas companies is approximately 100 basis points higher than the cost of equity to the sample water companies based on the difference in risk." *Id.* at 26 (italics in original). *See also* Decision No. 66849 at 21.

By comparison, in this case, the average beta of the water utilities sample group increased to 0.68 - virtually the same level as the gas companies' sample in the Eastern Group case - and the risk-free rate used by Staff increased by 70 basis points.

Incredibly, Staff's CAPM model produces the same result:

	Risk-Free Rate	Value Line Beta	CAPM Estimate
Western Group- Staff Surrebuttal	4.0%	0.68	9.2%

Ramirez Sb., Schedule AXR-8. Moreover, after Mr. Ramirez's Surrebuttal Testimony was filed, *Value Line* published updated betas for the water utilities in Staff's sample group, and the average beta increased to 0.71 (Zepp Rj. at 17), indicating greater risk and an even higher equity cost.

Comparing current interest rates, Value Line's estimated betas, and the result produced by Staff's CAPM model in the Eastern Group case with the data in this case, one would expect the indicated equity cost to increase by over 150 basis points. *See* Zepp Rb. at 10-12 (discussing increases in interest rates and beta estimates relative to Staff's recommended equity return). First, Staff's risk-free rate is 70 basis points higher. Further, the increase in the sample group's average beta should increase the CAPM equity cost estimate by at least 100 basis points, according to Mr. Reiker's testimony. Thus, one would certainly expect Staff's CAPM estimate in this case to exceed 10%. Instead, it is only 9.2% - the same as Staff's CAPM estimate in the Eastern Group rate case. Again, something is clearly wrong with Staff's methods and inputs.

Putting aside the foregoing application problems, empirical studies show that the value for the risk-free rate in the standard CAPM model is higher than Treasury rates. Zepp Rj. at 21. For example, Dr. William Sharpe, who was awarded the Nobel Prize for his role in developing the CAPM in the 1960s, has reported that the return on the "zero beta" asset (i.e., the risk-free rate) is significantly higher than the average returns on Treasury securities. *Id., citing* William F. Sharpe, *Investments 401* (1985). Recent empirical studies of the CAPM have also shown that the returns estimated for low beta stocks (like the water utility sample group) are too low relative to required returns for average risk stocks. Tr. at 121-22.

This research is summarized in an article published last year by Drs. Eugene Fama and Kenneth French, who have studied the CAPM for a number of years and have written extensively about its shortcomings. Eugene F. Fama and Kenneth R. French, "*The Capital Asset Pricing Model: Theory and Evidence*," 18 Journal of Economic Perspectives 25-46 (Summer 2004). They conclude:

> [F]inance textbooks often recommend using the Sharpe-Linter CAPM risk-return relation to estimate the cost of equity capital. The prescription is to estimate a stock's market beta and combine it with the risk-free interest rate and the average market risk premium to produce an estimate of the cost of equity. . . . But empirical work, old and new, tells us the relation between beta and average return is flatter than predicted by the Sharpe-Linter version of the CAPM. As a result, CAPM estimates of the cost of equity for high beta stocks are too high (relative to historical average returns) and estimates for low beta stocks are too low (Friend and Blume 1970). . . .
>
> We continue to teach the CAPM as an introduction to the fundamental concepts of portfolio theory and asset pricing, to be built on by more complicated models like Merton's (1973) ICAPM. But we also warn students that despite its seductive simplicity, the CAPM's empirical problems probably invalidate its use in applications.

Id. at 43-44.[20] *See also* Morin, *supra,* at 321-334 (discussing conceptual and empirical problems with the CAPM, and recommending the addition of company-specific risk, including the utility's size, to provide more accurate equity cost estimates); Brealey and Myers, *supra*, at 210 ("Stocks of small companies, and stocks with high book values relative to market prices, appear to have risks not captured by the CAPM.").

---

[20] Dr. Fama is a professor of finance at the University of Chicago Graduate School of Business. Dr. French is a professor of finance at Dartmouth College Tuck School of Business.

In short, Staff's CAPM estimate is badly flawed and fails to accurately estimate the current equity cost for Staff's sample group. Staff's CAPM estimate uses inputs that depress the cost of equity, and fails to properly take into account empirical studies, as discussed above, indicating that the risk-free rate is higher than the rate on long-term Treasury bonds for low beta stocks like the sample water utilities.

b. The California PUC Risk Premium Method Is Preferable to the CAPM.

The California PUC staff, in contrast, does not use the CAPM, and instead uses the Risk Premium method to estimate the cost of equity. Zepp Dt. at 5-6 and 40-45 (describing the California PUC staff's methods). Under the Risk Premium method, the risk premium is directly estimated by comparing authorized and actual returns on equity with the current yield of investment grade bonds or other debt instruments. *Id.* at 38-39, quoting Morin, *supra*, at 269. As Dr. Zepp explains, the California PUC has relied on this approach in water utility rate proceedings for many years. *Id.* at 6. The Risk Premium approach is simpler and easier to implement than the CAPM. For example, there is no need to estimate betas or market risk premiums, and there is no reason to determine if "beta risk" is the only risk of relevance to investors holding shares of water utilities. *Id.* at 6 and 39. Consequently, regulatory commissions use the Risk Premium approach in setting rates far more frequently than the CAPM. *Id.* at 39; Tr. at 123.

The California PUC staff has determined that a good proxy for the average cost of equity for the water utilities sample is an average of their actual, earned returns on equity. Zepp Dt. at 40 and 42-43; Zepp Rj. at 8-9. That agency also uses forecasts of interest rates. Zepp Dt. at 40-42; Zepp Rj. at 8-9. To be consistent with the California PUC approach, Dr. Zepp used interest rate forecasts for the first full year (2006) in which new rates will be in affect for Arizona Water. Zepp Rj. at 9. While Staff criticizes the use of interest rate forecasts rather than current interest rates, the rates set in this proceeding will not become effective until late 2005, and will likely remain in effect until mid-2008. Staff's use of April 2005 interest rates effectively assumes that interest rates will not change in 2006 and in subsequent years, when in fact interest rates have been at unusually low levels and have been increasing. Zepp Rj. at 9-10. The California PUC staff recognizes this problem, and therefore incorporates interest rate forecasts into its model. *Id.*[21]

Using the California PUC Risk Premium approach, and based on updated data, the indicated cost of equity for the water utility sample is 10.5%. Zepp Rj. at 8 and Rejoinder Table 6. That equity cost is consistent with the cost of equity indicated by the FERC 1-step DCF model (10.4%) and the FERC 2-step DCF model (10.2 %). *See id.*, Rejoinder Tables 3 and 4. It is also consistent with the current equity return of the water utilities sample group, 10.5%, and less than the equity returns forecast for that group of companies during 2006, 10.8%. Exhibits A-19 and A-20. Notably, those estimated equity costs do not take into account Arizona Water's additional risks.

5. RUCO Has Substituted Its Witness' Subjective Views for Market Data in Its DCF Model, Reducing the Estimate.

RUCO recommends an equity return of 9.44% based on the result of Mr. Rigsby's DCF analysis. Rigsby Dt. at 6. As noted above, Mr. Rigsby has used the constant growth DCF model to estimate the cost of equity for a sample group of publicly traded water utilities, American States Water, Aqua America and California Water Service. *Id.* at 17. Mr. Rigsby selected those three utilities because he believes they "face the same types of risk that Arizona Water faces" (*id.*), and Value Line provides "forward-looking information (i.e. long-term estimates on return on common

[21] Dr. Zepp also notes that Staff has relied on forecasts of interest rates in the past. Zepp Dt. at 41 (giving examples).

equity and share growth)" for those utilities (*id.* at 18). *See also* Tr. at 155-56.

This forward-looking information is necessary because Mr. Rigsby has used the sustainable growth method to estimate dividend growth. Rigsby Dt. at 14-15; Tr. at 161-62. This method combines expected growth from a company's future retained earnings and expected future growth from sales of common stock above book value. Zepp Dt. at 30-33. Notably, there is no disagreement regarding the basic formula used to derive the sustainable growth rate:

$$g = br + sv,$$

where "b" is the company's earnings retention ratio, "r" is the expected return on common equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate, e.g., the portion of the new stock financing that will inure to the benefit of the company's shareholders. Zepp Dt. at 31. *See also* Morin, *supra*, at 157-61 (explaining the sustainable growth method). *Compare* Rigsby Dt. at 14-15.[22]

Unfortunately, Mr. Rigsby failed to use the information reported in his schedules, and substituted his own subjective views for that information in estimating dividend growth, resulting in an unreasonably low equity cost estimate. Zepp Rb. at 37-39. The primary problem with RUCO's dividend growth estimate is found in Mr. Rigsby's external "sv" growth rate. First, Mr. Rigsby's average estimate of the stock financing rate, "s," (i.e., growth in the number of shares), is substantially understated when compared to the recent and forecasted stock financing rates reported in Mr. Rigsby's Schedule WAR-5:

---

[22] Notably, both Mr. Rigsby and Dr. Zepp acknowledge that Dr. Myron Gordon developed this concept of growth, which is explained in his text, *The Cost of Capital to a Public Utility* (1974). Rigsby Dt. at 14; Zepp Dt. at 31.

	Past Growth (1999-2003)	Forecasted Growth (2003-2008)	Estimated by Mr. Rigsby
American States	3.14%	4.55%	1.25%
California Water	6.95%	6.32%	1.75%
Aqua America	3.69%	1.55%	1.00%
Average	**4.59%**	**4.14%**	**1.33%**

Zepp Rb. at 32 and Rebuttal Table 15. Although Mr. Rigsby generally discusses the approach he used in his testimony, he has not provided any basis for ignoring the actual and forecasted stock financing rates reported in his own schedules. *See* Rigsby Dt. at 19-20; Rigsby Sb. at 31-32. During the hearing, Mr. Rigsby acknowledged that he used "subjective judgment" to estimate future share growth, rather than the actual data presented in his schedules to support his recommendation. Tr. at 174.

Moreover, in estimating the "v" in "sv" growth, Mr. Rigsby again substituted his subjective view for market data, opining that "the market prices of a utility's common stock will tend to move toward book value, or a market-to-book ratio of 1.0, if regulators allow a rate of return that is equal to the cost of capital." Rigsby Dt. at 15. *See* Zepp Rb. at 38-39; Zepp Dt. at 32-33. Based on this assumption, Mr. Rigsby substituted a different formula for the formula developed by Dr. Gordon and used by the FERC (as well as by Staff). *Compare* Rigsby Dt. at 15 and Schedule WAR-4 at 2 *with* Zepp Dt. at 31.

However, there is no evidence that the market prices of the utilities' stock will move toward book value. First, the average market-to-book ratios for water utilities followed by *AUS Utilities Reports* have been above 1.0 since at least 1991. Zepp Rb. at 39. Moreover, as shown in Exhibit A-23, the market-to-book ratios of the three water utilities used by Mr. Rigsby have been increasing since 1997. *See also* Zepp Rj. at 30 and Rejoinder Exhibits TMZ-3 (chart depicting the average of the market-to-book ratios of Mr. Rigsby's sample water utilities since 1991); Exhibit R-3 (workpaper containing Dr. Zepp's chart with supporting data from *AUS Utilities Reports*).

Mr. Rigsby testifies that during the past two years, the stock prices of his sample water utilities have been increasing. Rigsby Dt. at 47-49. For example, Mr. Rigsby testifies that "[o]ver the past two years there have been no substantial changes in dividend payouts but stock prices have increased." *Id.* at 47. He also testifies that "the differences in dividend yields for the three water companies included in both Dr. Zepp's proxy and my proxy are attributed to the increase in stock prices since Dr. Zepp's [direct] testimony was filed." *Id.* at 49. In fact, the stock prices of the three water utilities in Mr. Rigsby's sample have continued to increase during 2005. *Compare* Rigsby Dt. at 48 (stock prices used by Mr. Rigsby to calculate dividend yield) *with* Ramirez Sb., Schedule 5 (stock prices at May 11, 2005).[23]

Dr. Zepp restated RUCO's constant growth DCF model estimate in two different ways, both of which are consistent with the FERC 1-step (constant growth) model. First, in his Rebuttal Testimony, Dr. Zepp used RUCO's dividend yields, adjusted "br" growth using the FERC's formula to recognize that *Value Line* computes returns on equity on year-end equity, and corrected RUCO's estimate of "vs" growth, which results in an equity cost of 10.9%. Zepp Rb. at 39 and Rebuttal Tables 15 and 16. In his Rejoinder Testimony, Dr. Zepp restated RUCO's DCF analysis using analysts' forecasts of growth instead of sustainable growth (based on Mr. Rigsby's discussion on

[23] During the hearing, RUCO presented an exhibit containing three charts prepared by Mr. Rigsby (which were attached to Mr. Rigsby's Surrebuttal Testimony) along with daily stock prices and the average annual book value per share for the three water utilities. However, as Dr. Zepp testified, Mr. Rigsby failed to adjust the book values for the result of stock splits. Tr. at 111-19 and 127-30. There is simply no evidence that the market-to-book ratios of RUCO's sample water utilities are moving toward 1.0. Tr. at 118.

page 31 of his Surrebuttal Testimony that his growth rates are comparable to analysts forecasts of growth), which produces an equity cost of 10.54%. Zepp Rj. at 29 and Rejoinder Table 11. These equity cost estimates are based on Mr. Rigsby's data, but using the inputs preferred by the FERC rather than Mr. Rigsby's subjective views, and are again consistent with the results produced by the FERC DCF models and the California PUC Risk Premium methods.

6. Arizona Water Is Riskier Than the Publicly Traded Water Utilities and Requires a Higher Equity Return.

All of the estimates of the cost of equity discussed above are based on information available for six (or, in the case of RUCO, three) publicly traded water utilities. The analyses employed by Staff and RUCO assume that Arizona Water has the same risk as the risk presented by the average of their sample groups. In reality, Arizona Water faces more risk than the sample groups of publicly traded water utilities and therefore has a higher cost of equity.

The particular rate-setting system in Arizona creates significant risks that the sample water utilities do not face.[24] The United States Supreme Court has stated that the particular rate-setting system to which a utility is subject affects investment risk:

> [T]he impact of certain rates can only be evaluated in the context of the system under which they are imposed. One of the elements always relevant to setting the rate under *Hope* [*Natural Gas*] is the return investors expect given the risk of the enterprise. . . . The risks a utility faces are in large part defined by the rate methodology because utilities are virtually always public monopolies dealing in an essential service, and so relatively immune to the usual market risks.

---

[24] Only one of the six publicly traded water utilities, American States Water, has operations in Arizona. Exhibit A-19. However, American States Water's principal subsidiary is Southern California Water Company, which supplies water to 75 communities in 10 California counties. *Id.* That utility's Arizona subsidiary, Chaparral City Water Company, in contrast, serves approximately 12,000 customers in Fountain Hills.

> Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions.

Duquesne Light Co., 488 U.S. at 314-15. *See also* Morin, *supra*, at 38-39 (discussing regulatory risk and stating that "[r]egulation can increase business risk if it does not provide adequate returns and/or if it does not provide the utility with the opportunity to earn a fair rate of return.").

The Company's witnesses have identified a number of different aspects of Arizona's rate-setting system that increase risk. For example, Arizona uses an historic test year with limited pro forma adjustments. In contrast, approximately 30 states, including California (in which American States Water, California Water Service and SJW Corp. operate), use future test years, or partially projected test years, to better reflect future costs and to match plant, revenues and expenses on a going-forward basis. Zepp Dt. at 17; Exhibit A-36 at 14. For example, in Chaparral City Water Company's pending rate case, Staff has opposed including in rate base the expansion of a surface water treatment plant, which cost in excess of $2 million and was placed in service less than three months outside the test year. *See* Direct Testimony of Jamie R. Moe, Docket No. W-02113A-04-0616 (filed March 22, 2005) at 7-10.

The impact of using an historic test year is increased by the Commission's legal inability to authorize rate adjustments outside of general rate case in which the "fair value" of the utility's plant and property is determined. *Residential Utility Consumer Office v. Ariz. Corp. Comm'n*, 199 Ariz. 588, 20 P.3d 1169 (App. 2001). In that case, the Commission authorized a surcharge allowing a water utility to recover a known increase in the cost of purchasing CAP water. *Id.* at 590, 20 P.3d at 1171. In addition, the Commission ordered the water utility to file a rate application within six months, and made the revenues collected under the surcharge subject to "true-up" during the rate proceeding. *Id.* Nevertheless, the court held that the surcharge could not be classified as an automatic adjustment mechanism or as an interim rate, and held that the surcharge violated Arizona law. *Id.* at 591-93, 20 P.3d 1172-74. These legal constraints do not exist in other states, including California, where various types of balancing accounts, advice letter filings and other streamlined procedures under which costs can be recovered outside a general rate case are generally allowed. Zepp Dt. at 17.

Moreover, in this case, Staff and RUCO both challenge the Western Group systems' PPAMs and PWAMs, as previously discussed. Again, many jurisdictions, including California, routinely authorize automatic adjustment mechanisms, which help to stabilize the utility's earnings by allowing increases in purchased power, purchased water and other operating expenses beyond the utility's control to be promptly recovered. *Residential Utility Consumer Office*, 199 Ariz. at 592, 20 P.3d at 1173; Zepp Dt. at 18-19. Arizona Water's PPAMs and PWAMs are similar to adjustment mechanisms available to the water utilities in the parties' sample group, and reduce risk for those utilities. Zepp Dt. at 18. Consequently, the elimination of the adjustment mechanisms for the Company's Eastern Group systems in Decision No. 66849 made Arizona Water more risky than the sample water utilities, and if the recommendations of Staff and RUCO are adopted in this case, that risk will further increase. Zepp Dt. at 18-20.[25]

---

[25] Dr. Zepp performed a study of the impact of rate adjustment mechanisms used in California on investment risk several years ago. *Id.* at 19-20. There, the California Office of Ratepayer Advocates proposed a modification of the balancing account mechanism used to recover unexpected changes in the cost of purchased water, purchased power and pump taxes. Dr. Zepp's study showed that the proposed modification of the balancing account mechanism increased through required equity returns for California water utilities by at least 75 basis points. *Id.* at 19. Notably, the balancing account mechanism was modified, not eliminated. *Id.*

The additional risk created by Arizona's particular rate-setting system is also shown by Arizona Water's inability to promptly obtain recovery of its CAP-related costs. As previously discussed, at the end of the test year, December 31, 2003, Arizona Water's deferred M&I capital charge balance exceeded $5 million. There is no dispute that Arizona Water has been required to pay M&I capital charges annually to CAWCD in order to retain its CAP subcontracts for Casa Grande, Coolidge and White Tank. Tr. at 1095-96 and 1103-04. Mr. Carlson explained that Staff recognizes M&I capital charges as a legitimate expense, and further testified that the Company had acted prudently in paying those charges to retain its rights to CAP water. Tr. at 1327-29. Thus, even though the Company has made annual payments that are required to retain its rights to CAP water, and Staff agrees that the Company acted prudently in doing so, the Company has been unable to begin recovering those costs.

Arizona Water also faces additional risk in complying with the new maximum contaminant level ("MCL") for arsenic imposed by the Environmental Protection Agency. Mr. Garfield has explained the impact that the new arsenic MCL will have on both the Western Group systems and the Company as a whole, which testimony is not challenged. Garfield Dt. at 6-9. There is no disagreement that the cost to construct and operate arsenic treatment facilities and related plant will be substantial. On a company-wide basis, the Company may be required to finance as much as $30 million, while experiencing increases in operating expenses that exceed $5 million. Garfield Dt. at 7-8; Kennedy Dt. at 11-15; Zepp Dt. at 21. Mr. Kennedy explains that the Company will be required to issue in excess of $15 million in new long-term debt in connection with this project. Kennedy Rb. at 13. While the Commission has authorized a cost recovery mechanism for arsenic-related costs, that mechanism is not designed to allow full cost recovery. Decision No. 66400 (Oct. 14, 2003) at 20. *See also* Zepp Dt. at 21-22. A large construction budget of this nature, which requires substantial external financing, creates additional risk. Morin, *supra* at 43-44; Zepp Dt. at 22. This risk is increased by Arizona Water's small size and limited access to the capital markets. Zepp Dt. at 25-26.

Finally, an inverted block rate design was adopted in the Company's Eastern Group rate case, and both Staff and RUCO have proposed inverted-block rate designs in this case. As discussed in the following section of this brief, the primary purpose of an inverted block rate design is to encourage water conservation by charging more for water at higher usage levels. As a result, this type of rate design causes revenue instability and may prevent a water utility from earning its authorized rate of return:

> Inverted-block rates can result in revenue erosion and instability. Since the intent of this rate alternative is to reduce consumption, some change in revenue should be expected. Reductions in revenue and consumption could cause an increase in system average costs. . . . Changes in customer water use magnify the revenue impacts since the changes take place at the higher rates of the inverted-block rate structure. Sufficient revenues under this alternative tend to be uncertain because the rates frequently do not correspond to the utility's costs.

American Water Works Association, *Alternative Rates* 18 (1992). *See also* Zepp Dt. at 23. Neither Staff nor RUCO have conducted a billing analysis or study of the impacts of their proposed rate designs, nor have they proposed any adjustment to test year revenues to take into account the reduction in revenues that is likely to occur. Kennedy Rb. at 14-19; Kennedy Rj. at 5-8.

Arizona Water's risks are exacerbated by the lack of uniform regulatory standards and policies and precedents to guide the rate-setting process in Arizona. Staff's accounting witness, Mr. Carlson, who has been employed by the Commission for 14 years and has participated in over 125 prior cases, emphasized during the hearing that the Commission "has no policies except to explore every issue case by case." Tr. at 1249. *See also* Tr. at 1304 ("I am saying the Commission has no policies.") and 1304-05 (same). Mr. Carlson also explained that the Commission's position on a particular issue, as stated in a formal decision, may well change the next time that issue is addressed by the agency: "In one case a decision would be one way; in the next case it would be the exact opposite. Doesn't [sic] necessarily mean the first was wrong. It just means certain things have changed." Tr. at 1250. This type of regulatory environment, where no uniform agency standards and policies exist, and issues are relitigated and may be decided differently in each case, as Mr. Carlson emphasized, is precisely the type of risk that, according to the United States Supreme Court must be considered in establishing a fair equity return. *Duquesne Light*, 488 U.S. at 314-15.

These factors increase the Company's risk, and thus, its required return on equity by at least 50 basis points above the equity cost for the sample water utilities. Zepp Dt. at 23. That adjustment is supported by the Company's most recent bond issue, which had a cost of debt that was 37 basis points above the cost of A-rated bonds and 49 basis points above the cost of AA-rate bonds. Zepp Dt. at 24; Zepp Rb. at 27. All of the water utilities in RUCO's sample group currently have bond ratings of A or higher, as do five of the six water utilities in Staff's sample group. Exhibit A-20. This known market information clearly indicates that Arizona Water is riskier than the sample water utilities and supports the need to give Arizona Water a risk premium that takes into account that additional risk. It is not appropriate to simply assume, as Staff and RUCO do, that all water utilities possess the same risk or that the various risk factors listed above, (which are supported by evidence and cannot be legitimately disputed), would not affect the return expected by an investor. *Duquesne Power*, 488 U.S. at 314-15.

VII. RATE DESIGN.

A. Summary of the Parties' Positions.

Arizona Water's Western Group systems have a very straight-forward, cost-of-service based rate design, which has been approved by the Commission in prior rate cases. *E.g.*, Decision No. 64282 (Northern Group) at 21-23; Decision No. 58120 (all systems) at 24. Each system has a monthly minimum charge based on meter size rather than on the type of customer receiving service, and a uniform commodity rate for all gallons sold. Kennedy Dt. at 24. This type of rate design is recognized as having a number of advantages, including the following:

- Simplicity – uniform rates are easily understood and implemented, and other utility functions (including the design of rates) are simplified.
- Equity – uniform rates are generally considered equitable because all customers pay the same unit price for general water service, avoiding the appearance of large-volume customers subsidizing small-volume customers or vice versa.
- Revenue Stability – uniform rates provide utilities with greater revenue stability in comparison to inverted-block rates and other more complex rate designs, resulting in a more predictable and dependable revenue stream.
- Conservation – uniform rates facilitate conservation because customer bills vary directly with the level of water usage, providing a price signal to customers.
- Implementation – uniform rates are easily implemented, avoiding the difficulty and expense associated with detailed cost allocations necessary to implement more complex rate designs.

American Water Works Association, *Principles of Water Rates, Fees, and Charges* 87 (5th ed. 2000) (hereinafter "AWWA *Manual M1*").

Arizona Water is proposing several minor changes to its present rate design. First, the Company is proposing to eliminate the 1,000 gallons of "free" water currently included in the monthly minimum charge as a conservation measure. Kennedy Dt. at 27; Tr. at 598. The same change was approved for the Company's Northern Group and Eastern Group systems. Decision No. 64282 at 21-22; Decision No. 66849 (Eastern Group) at 24. The Company is also proposing to increase its monthly minimum charges based on meter multiples, i.e., equivalent meter capacity ratios. Tr. at 673-75. The same adjustment was approved in the Northern Group and Eastern Group rate cases.

Decision No. 64282 at 23; Decision No. 66849 at 24 and n. 5. Because Arizona Water is proposing to maintain its existing, uniform commodity rate design, a cost of service study or similar analysis is not required and would provide little assistance in designing rates. The Company was not required to file such a study in its Northern Group and Eastern Group rate cases. Kennedy Dt. at 24.[26]

The other parties, in contrast, are recommending dramatic changes to the Company's rate design. Staff is proposing an inverted-block rate structure, under which customers on 5/8 x 3/4-inch meters would have three commodity rate blocks (including an initial "lifeline" rate block), while all customers on larger size meters would have two commodity rate blocks. *See* Ludders Sb., Schedules REL-16 (Casa Grande), REL-12 (Stanfield), REL-15 (Coolidge) and REL-12 (Ajo). Staff also proposes graduated break-over points between commodity rate blocks that increase as meter size increases. *Id.*

In developing its inverted-block rate design, Staff did not prepare a cost of service study or similar analysis, did not perform a billing analysis evaluating the impacts of its rate design on customers, and did not analyze possible consumption and revenue impacts caused by its rate design. Kennedy Rb. at 15 and Staff's Responses to Data Requests 2-14, 2-15 and 2-16 (attached hereto as Brief Exhibit 4); Tr. at 1262-65. Instead, as explained below, Staff's rate design is subjective and unsupported by credible evidence.

RUCO also proposes an inverted-block rate design, but it is more simplistic and,

[26] The Company is also requesting approval of a revised service charge tariff, which simply extends the service charges approved for the Northern Group and Eastern Group systems to the Western Group systems, so that a single service charge tariff will be applicable to all Company systems. Kennedy Dt. at 28; Exhibit A-17, Schedule H-8. None of the parties have raised any objection to the revised service charge tariff in this case. *See* Ludders Dt. at 15.

as discussed below, even more problematic. RUCO proposes two inverted commodity rate blocks, with a single break-over point at 4,000 gallons for all meter sizes. Coley Dt. at 26. That break-over point is approximately 6,000 gallons below the average level of consumption by customers receiving service on 5/8 x 3/4-inch meters for all five Western Group systems. *Id.* Like Staff, RUCO failed to perform a cost of service study or similar analysis, did not conduct a billing analysis evaluating the impacts of its proposed rate design on customers, and did not analyze the impact of its rate design on water consumption and revenues. Kennedy Rb. at 25 and RUCO's Responses to Data Requests 2.12, 2.13 and 2.14 (attached hereto as Brief Exhibit 5). For its part, the City did not propose a rate design.

B. Staff's Rate Design is Badly Flawed and Should be Rejected.

Staff, as the party proposing dramatic changes to Arizona Water's rate design, bears the burden of supporting its rate design by credible, competent evidence. Staff has not done so. As stated, Staff has not conducted even a rudimentary billing analysis or bothered to evaluate the impact of its rate design on consumption. In fact, during the hearing, Mr. Carlson (who adopted Mr. Ludders' pre-filed testimony) admitted that Staff's approach to designing rates is subjective and done on a case-by-case basis. *E.g.*, Tr. at 1268-71. Staff's admittedly "subjective" and "case-by-case" approach, which is unsupported by any study or analysis, violates fundamental rate design principles.

Moreover, Staff refuses to recognize that the primary purpose of an inverted-block rate design is to encourage water conservation and, therefore, it will adversely impact Arizona Water's ability to earn its authorized rate of return. The American Water Works Association explains:

> Increasing block rate structures tend to result in more revenue volatility than other rate structures (i.e., decreasing and uniform block rates). This revenue volatility is because an increasing block rate anticipates recovering a proportionately greater percentage of the customer class's

> revenue requirement at higher levels of consumption. These higher levels of consumption tend to be more subject to variations in seasonal weather and, when coupled with a higher unit pricing, customers tend to curtail consumption in these higher consumption blocks. As a result, a utility implementing an increasing block rate structure is advised to have a good understanding of the distribution of water demand by customer class and of price elasticity of demand.

AWWA, *Manual M1* at 100. Staff, in contrast, has done nothing to evaluate the impacts of its rate design on the Company, and has assumed (with no evidence) that its rates will not affect customers' water demand.

Staff proposes to create at least one, and in most cases two, discounted commodity rate blocks, in which water would be priced *below* the system's *existing* commodity rate:

Water System	Discount in 1st Block	Discount in 2nd Block
Casa Grande	36%	26%
Stanfield	34%	7%
White Tank	53%	17%
Coolidge	51%	9%
Ajo	18%	-1%

Ludders Sb., Schedules REL-16 (Casa Grande), REL-12 (Stanfield), REL-15 (White Tank), REL-15 (Coolidge) and REL-12 (Ajo). In every case except Ajo, every commodity rate proposed by Staff is less than the existing commodity rate, and in many cases, it is substantially less.

The initial rate block, in which the commodity rate is heavily discounted, would be available only to customers on 5/8 x 3/4-inch meters, the Company's largest customer group. *See* Exhibit A-17, Schedule H-2 (analysis of revenue by meter size, listing average number of customers). By proposing a commodity rate applicable to usage in the initial block that is substantially less than the Company's existing commodity rates, a large subsidy is created, which must be paid by customers on larger meters. Kennedy Rb. at 22-23. As Mr. Kennedy explains, Staff is effectively proposing what is often called a "lifeline" rate: "Lifeline rates are often thought of as providing a minimal amount of water at a reduced cost to all customers, independent of income level or ability to pay." AWWA, *Manual M1* at 129.

No study or analysis was performed by Staff to support its "lifeline" rate, and it is not discussed in Staff's pre-filed testimony. Mr. Carlson explained that Staff has an internal policy, developed by "some of the chief accountants," under which a discounted rate is provided for the first 3,000 to 4,000 gallons (depending on the utility) of "nondiscretionary" water use each month. Tr. at 1301-04. According to Mr. Carlson, this policy is not in writing (and therefore not available to the regulated community); however, Staff always follows it. Tr. at 1309. In contrast, in Arizona Water's Eastern Group rate case, Staff proposed a discounted commodity rate for the first 3,000 gallons of use (although the discount was only 20%), and the Commission rejected it. Decision No. 66849 at 25. *See also* Exhibit A-40 (Direct Testimony of John S. Thornton, discussing Staff's proposed "lifeline" rate). More recently, Staff proposed a discounted commodity rate for the first 4,000 gallons of usage applicable to customers using 5/8 x 3/4-inch meters. *Rio Rico Utilities*, Decision No. 67279 (Oct. 5, 2004) at 19. The Commission rejected Staff's rate design, explaining "we are reluctant to adopt Staff's proposed first tier rate for residential 5/8 inch meters, which is lower than the current commodity rate and appears to have the result of shifting a greater proportion of the rate increase to larger meter sizes." *Id.* at 19.

The impact of the subsidy created by Staff's discounted, "nondiscretionary use" block is exacerbated by the discounted commodity rates Staff proposes for the second block. With the sole exception of Ajo, Staff's proposed commodity rates in the second block are all less than the Company's existing commodity rates. In the most extreme case, Casa Grande, the second block's commodity rate is discounted by 26%, a percentage that is greater than the "lifeline" rate discount that Staff proposed, and which the Commission rejected, in the Eastern Group case. Again, this is an extreme change that is unsupported by any study or analysis.

Large-volume users must pay the subsidy created by Staff's discounted commodity rates in the first and second blocks. In other words, recovery of the Company's revenue requirement will be shifted into the upper commodity rate block, creating revenue volatility and making it likely that the Company will be unable to earn its authorized rate of return. Exhibit A-39 graphically depicts how Staff's rate design shifts revenue responsibility from smaller to larger-size meters in Casa Grande. With the exception of customers served by 8-inch meters, approximately 60% of water use by customers on meters 1-inch or larger is priced at the *highest* third block rate of $2.00 per 1,000 gallons, while usage in the first and second commodity rate blocks would be priced at $1.00 and $1.15 per 1,000 gallons, respectively.

Mr. Carlson acknowledged during cross examination that Staff's commodity rate blocks are designed based on the *existing* water use patterns, and that the revenue produced by usage in the third or highest block is required to produce Arizona Water's revenue requirement. Tr. at 1286 ("The third tier is designed to put you at [the] revenue requirement.") and 1287 ("The idea is that we use the existing usage patterns to design the recovery over the three tiers, not one of them, not two of them, but all three."). In other words, in designing rates, Staff has assumed no change in water use will occur if its rate design is adopted. This ignores both the purpose of inverted-block rates – water conservation – and the impact of water conservation on the Company's ability to collect revenues sufficient to actually earn its authorized rate of return.

There are now decades of studies demonstrating that water use is relatively responsive to rate changes. Kennedy Rb. at 16-18; Kennedy Rj. at 5-6; Exhibit S-21.

For example, in the most current edition of its *Manual of Water Supply Practices*, the American Water Works Association states:

> The consequences of omitting price elasticity from the rate design process are becoming increasingly important. Evidence suggests that the price sensitivity of water use increases with the increase in real water rates. It is difficult to provide practical benchmarks for assessing how much effort should be expended on developing price elasticity price estimates for a given service area. Where it is not cost-effective for water utilities to conduct demand studies, results of existing research can be used to develop benchmarks for estimating the usage effects of rate changes.

AWWA, *Manual M1* at 160. The American Works Association also states:

> [P]rice elasticity for different customer classes must be considered. For example, the usage patterns for large users are generally more price-elastic than the patterns of residential customers. Eliminating volume discounts (e.g., replacing declining block rates with a single uniform rate) may trigger a substantial usage response. Large users may reduce their use through efficiency improvements or bypassing the water utility for their own supply, resulting in revenue instability and revenue shortfalls. Revenue problems may be exacerbated if price elasticity is excluded from the rate-setting process.

Id. at 159. As shown by Exhibit A-39, the customers in Casa Grande that will be most impacted by Staff's inverted-block rate design are large users, i.e., customers on larger-sized meters. Numerous studies have shown that those customers are more responsive to price changes, and are most likely to adjust their usage, resulting in under-collection of revenues. *See* AWWA *Manual M1* at 158; Exhibit S-21 at 88-89.

Similarly, Beecher, Mann, Hegazy and Sanford warn in their report, *Revenue Effects of Water Conservation and Conservation Pricing:& Issues and Practices* (NRRI 1994), which Staff introduced during the hearing (Exhibit S-21):

> The implications of omitting price elasticity from the rate design process are becoming more critical. Some emerging evidence suggests that the price sensitivity of water demand may be increasing over time (with increasing real prices) and that conservation programs can influence the shape or

nature of the water demand curves.

Exhibit S-21 at 95. In this case, Mr. Kennedy provided Staff with water price elasticity estimates from a draft report prepared by the Governor's Drought Task Force, and offered to work with Staff in developing an elasticity adjustment. Staff chose to ignore Mr. Kennedy. Kennedy Rb. at 17 and Exhibit RJK-R3; Tr. at 655.

In addition to relying on authorities such as the American Water Works Association and the National Regulatory Research Institute (Exhibit S-21), Arizona Water performed an analysis of the impact of inverted-block rates on its own customers' water usage. In Decision No. 66849, the Commission, while rejecting Staff's rate design, imposed a three-tier inverted-block rate design on each of the eight systems in the Company's Eastern Group without any price elasticity adjustment. This circumstance provided a unique opportunity to evaluate the impact of inverted-block rates on water usage. As discussed in the Introduction, Arizona Water has 18 regulated water systems organized in three different groups; the Northern Group, the Eastern Group and the Western Group. The water systems are located in eight different counties throughout Arizona as shown on the map found on page 6 of Exhibit CCG-8. However, following the issuance of Decision No. 66849, only the eight systems in the Eastern Group had an inverted-block rate design. The remaining systems have a uniform commodity rate.

As Mr. Kennedy explains in his pre-filed testimony, the Company accumulated billing data for the Eastern Group systems, beginning with April 2004, the first full month the new Eastern Group rates were in effect, through March 2005. Kennedy Rb. at 18; Tr. at 684. Over the period, consumption per customer decreased 7.00% though revenue per customer increased 12.23%, resulting in a price elasticity of .57. Kennedy Rb. at 18 and Exhibit RJK-R4. That estimate is very similar to the results of various price elasticity studies reported in Exhibit S-21, including a study of changes in residential water demand in Tucson, in which short-run elasticity was estimated to be .5. Tr. at 678-79.

While consumption per customer decreased in the Eastern Group systems, during the same period consumption *increased* in the Northern and Western Group systems, providing additional support for Mr. Kennedy's price elasticity estimate. Tr. at 685. It was suggested during Mr. Kennedy's cross-examination that unusually high amounts of precipitation in late 2004 and early 2005 caused the Eastern Group systems' change in consumption. However, the exhibits presented by Staff on this point (Exhibits S-34 through S-36) contain statewide precipitation and other weather-related data. That data would apply equally to the Company's Northern and Eastern Group systems, where consumption per customer increased during the April 2004 through March 2005 period.

In sum, there are now decades of studies demonstrating the price elasticity of water demand, and as a result, customer water use will decrease in response to price increases. In this case, Arizona Water demonstrated that fact by evaluating the impact of the inverted-block rates approved in Decision No. 66849 for its Eastern Group systems, and comparing the change in consumption to consumption by customers served by the Company's remaining systems during the same time period. Moreover, respected authorities such as the American Water Works Association state that price elasticity is an important issue and should be considered in designing rates.

Staff (as well as RUCO) simply refuses to acknowledge that rates impact water demand, and assumes that the imposition of inverted block rates – which are intended to encourage water conservation – will have no impact on water usage. In fact, Mr. Carlson testified that Staff is not aware of inverted-block rates ever resulting in reductions in water use. Tr. at 1311. If that is the case, then there is no reason to impose inverted-block rates on the Western Group systems, particularly in view of the advantages provided by uniform commodity rates, summarized above. Conversely, if an inverted- block rate design is imposed, the Company's test year revenues should be adjusted to reflect the impact of that rate design using the methodology presented by Mr. Kennedy on A-26.

C. RUCO's Inverted-Block Rate Design Should Also be Rejected.

RUCO's inverted-block rate design is simplistic and even more seriously flawed than Staff's rate design because it applies the same blocking factors to *all* meter sizes. As explained, RUCO proposes a single break-over point of 4,000 gallons for all customers. Consequently, all consumption below 4,000 gallons is priced at a lower, discounted rate:

Water System	Discount in 1st Block
Casa Grande	36%
Stanfield	44%
White Tank	56%
Coolidge	18%
Ajo	9%

Rigsby Dt. (Exhibit R-30), Schedule WAR-17 (Casa Grande) and Schedule WAR-17 (Stanfield); Coley Dt., Schedule TJC-17 (Ajo), Schedule TJC-17 (Coolidge) and Schedule TJC-17 (White Tank).

This approach is very similar to Staff's rate design, effectively creating a "lifeline" rate applicable to the first 4,000 gallons of monthly consumption. However, because RUCO proposes to use the *same* break-over points for all customers, regardless of meter size, RUCO's proposed rate design is more extreme, and would have an even greater impact on customers served by larger-sized meters. As the following table shows, Casa Grande customers using larger-sized meters will have a much larger percentage of their usage fall into RUCO's upper commodity rate block.

Meter Size	Average Monthly Use	Percentage of Use in 2nd Rate Block
5/8-inch	10,666	62.5%
1-inch	31,339	87.2%
2-inch	170,216	97.7%
3-inch	353,507	98.9%
4-inch	1,177,280	99.7%
6-inch	2,780,484	99.9%
8-inch	394,083	99.0%

Kennedy Rj. at 8 (data for Casa Grande system). Obviously, this is not a conservation-oriented rate design, because virtually all of the usage by customers on larger-sized meters will fall into the upper rate block, even if the customer conserves. For those customers, RUCO's rate design is no different than a uniform commodity rate. In short, RUCO's rate design is simply a way of shifting revenue recovery to customers on larger-sized meters.

RUCO's rate design witness, Mr. Coley, suggests that this rate design is "non-discriminatory," presumably because all customers, regardless of meter size, must pay the same price per 1,000 gallons of water. Tr. at 1007. In reality, this rate design does discriminate against customers on larger sized meters, who are forced to pay more than their cost of service:

> Increasing block rates are not a one-size-fits-all solution. Systemwide application of a single increasing block rate structure is likely to result in cost-of-service inequities, especially to commercial and industrial customers with relatively constant consumption patterns (low peak demands but high total usage). These customers may not impose costs on a water system proportional to the costs implied by increasing block rates.

AWWA, *Manual M1* at 99-100. In the Rio Rico Utilities' rate case, RUCO proposed a similar rate design, with two commodity rate blocks and a single break-over point for all meter sizes. Decision No. 67279 at 18-19. The Commission rejected that rate design because, like Staff's "nondiscretionary use" block, it "does not create an equitable sharing of the rate increase." Decision No. 67279 at 18-19. The Commission should again reject RUCO's rate design in this case.

VIII. MISCELLANEOUS ISSUES.

A. Arsenic Cost Recovery Mechanism.

Three of the Company's Western Group systems will require arsenic treatment. Kennedy Dt. at 10; Whitehead Dt. at 7-8. Accordingly, Arizona Water is requesting approval of an ACRM that would allow the company to recover capital costs and certain specified recoverable O&M directly related to the construction and continued operation of facilities required to comply with the new arsenic maximum contaminant level of 10 parts per billion. Kennedy Dt. at 15-17. The ACRM requested herein is the same arsenic cost adjustment mechanism already approved by the Commission for the Company's Northern and Eastern Group systems. Decision No. 66400 (Northern Group); Decision No. 66849 (Eastern Group).

RESPECTFULLY SUBMITTED this 1st day of August, 2005.

FENNEMORE CRAIG

By________________________
Norman D. James
Jay L. Shapiro
3003 North Central Ave., Suite 2600
Phoenix, Arizona 85012

and

Robert W. Geake
3805 Black Canyon Highway
Phoenix, Arizona 85015-5351
Attorneys for Arizona Water Company

ORIGINAL and 13 copies of the foregoing
delivered for filing this 1st day of August, 2005, to:

Docket Control
Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

COPY hand-delivered this 1st day of August, 2005, to:

Teena Wolfe
Administrative Law Judge
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Timothy J. Sabo
Staff Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ 85007

Dan Pozefsky
Chief Counsel
Residential Utility Consumer Office
1110 West Washington, Suite 220
Phoenix, AZ 85007

Copy sent by electronic mail to:

Joan S. Burke
Osborn Maledon, P.A.
2929 North Central Avenue, Ste. 2100
Phoenix, AZ 85012
Attorneys for the City of Casa Grande

Marvin S. Cohen
Sacks Tierney
4250 North Drinkwater Blvd.
4th Floor
Scottsdale, AZ 85261
Attorneys for Pivotal Group, Inc.

A copy of the foregoing via U.S. mail
this 1st day of August, 2005 to:

K. Scott McCoy
City Attorney
City of Casa Grande
510 E. Florence Blvd.

Casa Grande, AZ 85222

Jeffery W. Crockett
Deborah R. Scott
Snell & Wilmer
One Arizona Center
400 East Van Buren
Phoenix, AZ 85004
Attorneys for Pivotal Group, Inc.

By: Mary L House

1687652.3/12001.189

BRIEF
EXHIBIT 1

ARIZONA WATER COMPANY
Western Group
Docket No. W-01445A-04-0650
Witness (es) Hubbard

Data Request No. RUCO 1.10
Rate Case Expense: Please provide the following information regarding rate case expense:
a) How much is allocated to each system? Please list separately.
b) Provide copies of all rate case expense invoices received to date.
Please update on a going forward basis as additional invoices are received.

Response To Data Request No. RUCO 1.10 b), 2nd Supplement

b) The total amount of rate case expenses that have been invoiced since March 31, 2005 applicable to the Western Group proceeding is $168,744.64. Invoices in support of this amount are attached. The rate case expenses recorded or invoiced as of July 15, 2005 total $226,815.36. The Company expects to update this data response in conjunctions with the filing of its reply brief in this proceeding.

BRIEF EXHIBIT 2

STAFF'S CONSTANT GROWTH DCF MODEL RESULTS USING HISTORICAL DATA TO ESTIMATE DIVIDEND GROWTH[1]

	Amer. States	Cal. Water	Aqua Amer.	Conn. Water	Middlesex	SJW Corp.
DPS Growth – 1994-2004	1.1%	1.3%	5.8%	1.4%	2.3%	3.8%
EPS Growth – 1994-2004	2.2%	1.8%	9.3%	2.5%	0.9%	7.8%
Intrinsic Growth – 1994-2003	3.8%	4.1%	11.0%	3.5%	5.1%	5.0%
Average Growth	2.4%	2.4%	8.7%	2.5%	2.8%	5.5%
Dividend Yield	3.3%	3.2%	1.9%	3.6%	3.6%	2.7%
Staff Equity Cost Estimate	**5.7%**	**5.6%**	**10.6%**	**6.1%**	**6.4%**	**8.2%**

Moody's Baa Industrial Bonds	6.02%
Prime Interest Rate	6.00%

Staff Average – 7.1%

Staff Average without Aqua America – 6.4%

[1] Based on Surrebuttal Testimony of Alejandro Ramirez, Schedules AXR-3 (Growth in Earnings and Dividends), AXR-4 (Intrinsic Growth), and Schedule AXR-7 (Multi-Stage DCF Estimates). Dividend Yield (D_1/P_0) computed from data in Schedule AXR-7. Bond yields and prime interest rate reported in Federal Reserve Statistical Release H.15 (May 16, 2005) for May 11, 2005 (the date of Staff's spot stock prices).

BRIEF
EXHIBIT 3

92 FERC ¶ 61,070

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO. 445

Southern California Edison Company

Docket Nos. ER97-2355-000, ER98-1261-000 and ER98-1685-000

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND
REVERSING IN PART, INITIAL DECISION

Issued: July 26, 2000

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

OPINION NO.445

Southern California Edison Company

Docket Nos. ER98-2355-000 ER98-1261-000 and ER98-1685-000

OPINION AND ORDER
AFFIRMING IN PART, VACATING IN PART, AND
REVERSING IN PART, INITIAL DECISION

APPEARANCES

Gary A. Morgans, Bruce J. Barnard, Michael D. Mackness, Jennifer Key, and Edward Twomey for Southern California Edison Company;

Bonnie S. Blair for Cities of Anaheim, Azusa, Banning, Colten and Riverside, California;

Alan I. Robbins, Elisa J. Grammar, and Mark D. Urban for California Department of Water Resources;

Arnold Fieldman, Channing D. Strother, and David B. Brearley for the City of Vernon;

Harvey Y. Morris and Peter Arth, Jr., for Public Utilities Commission of the State of California;

Edward Berlin, David Ruben, and Michael Ward for California Independent System Operator Corporation;

Lisa G. Dowden and Sarah Weinberg for Northern California Power Agency;

Mark D. Parizio for Pacific Gas and Electric Company;

Michael Yuffee and Joel Newton for Sacramento Municipal Utility District;

James D. Pembroke, Wallace L. Duncan, Michael Postar, Lisa Gast, and Diana Mahmud for Transmission Agency of Northern California, The Metropolitan Water District of Southern California, Modesto Irrigation District, City of Santa Clara, California City of Redding, California, M-S-R Public Power Agency, and Trinity County Public Utility District; and

Linda Lee, Stanley A. Berman, Jo Ann Scott, Janet Jones, Laura K. Sheppeard, and Richard L. Miles for the trial staff of the Federal Energy Regulatory Commission

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: James J. Hoecker, Chairman;
William L. Massey, Linda Breathitt,
and Curt Hébert, Jr

Southern California Edison Company — Docket Nos. ER97-2355-000, ER98-1261-000, and ER98-1685-000

OPINION NO.445

OPINION AND ORDER AFFIRMING IN PART, VACATING IN PART, AND REVERSING IN PART, INITIAL DECISION

(Issued July 26, 2000)

I. Introduction

This case is before the Commission on exceptions to an Initial Decision issued March 31, 1999.[1] For the reasons set forth below, we will affirm in part, vacate in part, and reverse in part, the Initial Decision.

II. Procedural Background

On March 31, 1997, Southern California Edison Company (SoCal Edison) filed, in Docket No. ER97-2355-000, a Transmission Owner (TO) Tariff, for utility-specific rates to be charged for transmission service on its facilities under the operational control of the California Independent System Operator (California ISO). In the same filing, SoCal Edison also submitted a Distribution Access (DA) Tariff for transmission service over its distribution facilities that are not part of the California ISO grid. In an order issued by

[1]Southern California Edison Company, 86 FERC ¶ 63,014 (1999) (Initial Decision).

the Commission on December 17, 1997,[2] we accepted SoCal Edison's TO and DA Tariffs, for filing, suspended them, and permitted them to become effective, subject to refund, on the date the California ISO began operation. We also set the proposed tariffs for hearing.

On December 31, 1997, SoCal Edison filed, in Docket No. ER98-1261-000, proposed revisions to its TO Tariff to add a surcharge of $.00009/kWh for a one-year period, to recover $6.7 million in costs associated with its abandoned Devers-Palo Verde 2 project. On January 29, 1998, SoCal Edison filed, in Docket No. ER98-1685-000, proposed revisions to its TO Tariff to correct what it claimed were computational errors and omissions in the development of the rates set for hearing in the December 17 Order. In separate orders issued by the Commission on February 25, 1998,[3] and March 30, 1998,[4] we set SoCal Edison's proposed tariff revisions for hearing and consolidated these filings with SoCal Edison's pending proceeding in Docket No. ER97-2355-000.[5]

Prior to hearing, a number of issues initially set for hearing were resolved. First, the rate-effective period applicable to SoCal Edison's proposed cost-based rates for ancillary services was narrowed by the Commission's ruling in Docket No. ER98-2843-001, in which we granted market-based rate authority to all entities providing ancillary services in California, effective November 3, 1998.[6] As such, SoCal Edison's proposed cost-based rates for ancillary services is this proceeding are only for a locked-in period, April 1, 1998 through November 2, 1998. In addition, the parties filed a stipulation with

---

[2]Pacific Gas and Electric Company, et al., 81 FERC ¶ 61,323 (1997) (December 17 Order), order on reh'g, 82 FERC ¶ 61,324 (1998).

[3]California Independent System Operator Corporation, et al., 82 FERC ¶ 61,174 (1998).

[4]San Diego Gas & Electric Company, et al., 82 FERC ¶ 61,324 (1998).

[5]On February 6, 1998, the Chief Administrative Law Judge severed issues concerning non-rate terms and conditions from rate issues, and assigned the SoCal Edison's TO Tariff and DA Tariff filing to the Presiding Judge. See Pacific Gas & Electric Company, et al., 82 FERC ¶ 63,010 (1998).

[6]AES Redondo Beach, L.L.C., et al., 85 FERC ¶ 61,123 (1998) (AES).

the Presiding Judge, which the Presiding Judge accepted, fully resolving six issues originally set for hearing.[7]

An evidentiary hearing on all remaining issues commenced on September 15, 1998. Following the hearing and the filing of initial and reply briefs, the Presiding Judge issued the Initial Decision. Briefs on exceptions were filed by SoCal Edison, the Commission's trial staff (trial staff), the California ISO, the Department of Water Resources of the State of California (DWR). Briefs opposing exceptions were filed by SoCal Edison, trial staff, DWR, the Northern California Power Agency (NCPA), the Cities of Anaheim, Azusa, Banning, Colton, and Riverside, California (Cities), the Public Utilities Commission of the State of California (California Commission), and the City of Vernon (Vernon).

IV. Discussion

A. Issues Identified and Resolved by the Initial Decision

The Initial Decision identified and resolved 17 issues. Of these issues, we will summarily affirm Issue Nos. 1-3, 5, 8, 11-12, 14-15, and 17; and vacate as moot Issue Nos. 9-10, and 13, in part. The remaining issues (Issue Nos. 4, 6-7, 13, and 16) are discussed below.

B. Summary Affirmance Issues

No party excepted to the Presiding Judge's disposition of Issues Nos. 1-3, 5, 14-15, and 17. Specifically, the Presiding Judge ruled (and no party now contests) that: (1) SoCal Edison's reliance on a 45-day cash working capital allowance in rate base is reasonable, subject to the adjustments discussed elsewhere in the Initial Decision (Issue No. 1); (2) SoCal Edison's claimed rate base for plant held for future use, Account 105, (Issue No. 2),[8] and for construction work in progress, Account 107, (Issue No. 3), should be addressed in a compliance filing to be made by SoCal Edison to demonstrate that SoCal Edison's Account 105 and Account 107 costs do not recover costs already included

---

[7]Initial Decision, 86 FERC at 65,136 (citing the following issues: abandoned plant; rate base adjustments; South Georgia adjustments; depreciation; revenue credits for wholesale transmission and power sales agreements; and the divisor for wholesale and access charges).

[8]Our ruling includes the requirement that SoCal Edison's compliance filing must demonstrate that such plant is not also recorded in Account 101.

in Account 101, electric plant in service; (3) the California Commission's proposal for the disposition of refunds to retail customers should be followed, in the event a lower transmission revenue requirement than that proposed by SoCal Edison is found just and reasonable (Issue No. 5); (4) the term of the TO Tariff may be superceded by the new California ISO Tariff, but in any event, does not need not be addressed in this proceeding (Issue No 14); (5) SoCal Edison's load dispatching expenses included in Account 561 are incurred by SoCal Edison for the benefit of all users of the transmission system and should therefore be allowed, as claimed (Issue No. 15); and (6) Vernon's proposal allowing ratepayers to recover a share of the gains realized by SoCal Edison from the sale of its oil and gas generating plants was not supported and should be rejected (Issue No. 17).

We find that the Presiding Judge's rulings on these issues were well reasoned and fully supported by the record. Accordingly, these rulings are hereby summarily affirmed. We also summarily affirm the ruling of the Presiding Judge: (1) accepting rolled-in rates for the TO Tariff wholesale access charge (Issue No. 8); (2) rejecting the proposal for time-of-use transmission rates (Issue No. 11); and (3) accepting the DA Tariff rate design (Issue No. 12). We find that the Initial Decision properly decided these issues on the grounds set forth in the Initial Decision. We therefore deny the exceptions on these issues asserted by SoCal Edison (as to Issue No. 8) and DWR (as to Issue Nos. 11-12).

C. Vacated Issues

We will vacate the Initial Decision as to those issues concerning membership rights and incentives to join the California ISO (Issue Nos. 9, 10, and 13).[9] On March 31, 2000, in Docket No. ER00-2019-000, the California ISO filed Amendment No. 27 to its tariff to address these issues. Amendment No. 27 proposes a new methodology for recovering, through a Transmission Access Charge (TAC), the embedded cost of transmission facilities comprising the California ISO-controlled grid. In our order issued May 31, 2000, we accepted for filing, suspended, and set for hearing the proposed TAC methodology and related tariff revisions.[10] Given these changed circumstances, the issues litigated in this proceeding relating to parties joining the California ISO are rendered moot. Therefore, we will vacate the Initial Decision

---

[9]These incentives include, among other things, removal of the self-sufficiency test, which in turn eliminates the Non-Self Sufficiency Access charge.

[10]See California Independent System Operator Corp., 91 FERC 61,205 (2000). We also held the hearing in abeyance pending efforts at settlement and established settlement judge procedures.

regarding these issues, specifically, the appropriate billing determinants to be used for SoCal Edison's Non-Self Sufficient Access charge (Issue No. 9), whether a monthly versus an hourly rate should be used for SoCal Edison's Non-Self Sufficient Access charge (Issue No. 10), and all issues relating to customer credits for participating transmission owners (Participating TOs) (Issue No. 13).[11]

D. Whether the Presiding Judge Properly Determined that Non-Participating TOs Should Receive Credits for their Customer-Owned Transmission Facilities

Initial Decision

At hearing, Vernon and Cities (collectively Municipals) argued that as non-Participating TOs they should receive network customer credits against their Access Charges for their transmission facilities that are integrated with SoCal Edison's transmission system. Prior to restructuring, the creation of the California ISO, and SoCal Edison's filing of its TO Tariff, the Municipals were receiving an implicit credit for their customer-owned transmission facilities under their Intergrated Operating Agreements (IOAs) through hub and spoke pricing. In late 1996 and early 1997, as a result of the California restructuring process, the parties negotiated Restructuring Agreements, creating the current Transmission Service Agreements (TSAs), and terminated the IOAs. Under the TSAs, Municipals still pay for transmission solely within SoCal Edison's 230 kV hub network and not for SoCal Edison's spokes which generally parallel Municipals' transmission facilities. At hearing, Municipals argued that after their TSAs expire it will be unfair to take service under the TO Tariff using rolled-in pricing.[12]

SoCal Edison, the California ISO, and trial staff disagreed, relying on Florida Municipal Power Agency v. Florida Power & Light Company[13] and Orders Nos. 888 and 888-A. These parties argued that the Municipals' facilities are not integrated with the California ISO-controlled grid, which now includes SoCal Edison's transmission facilities, and therefore network customer credits should be denied. They further argued

[11] That portion of Issue No. 13 which addresses credits for non-participating TO's has not been rendered moot. The exceptions raised with respect to this issue, therefore, are addressed below.

[12] The TSA expiration dates differ for each agreement, with some TSAs terminating as early as December 31, 2002.

[13] 67 FERC ¶ 61,167 (1994) (FMPA), reh'g denied, 74 FERC ¶ 61,006 (1996).

that the only relevant test for integration under the restructured California ISO framework is if the California ISO has operational control and scheduling rights for the use of the transmission facilities.

The Presiding Judge rejected these arguments and found that the Municipals' facilities provide substantial support to the California ISO-controlled grid and that the Municipals act functionally as network service customers, meeting the Commission's requirements for network customer credits. On the matter of whether the Municipals should receive a network customer credit as Non-Participating TOs, the Presiding Judge found that the elimination of the implicit credits with the expiration of the TSAs would be unjust and unreasonable. The Presiding Judge ruled that SoCal Edison must modify the proposed wholesale wheeling access charge to permit the Municipals to pay hub-only costs instead of rolled-in costs once their TSAs expire.

Exceptions

SoCal Edison, the California ISO and trial staff filed exceptions. SoCal Edison and trial staff argue that the rates and term of the TSAs were the result of negotiation by the affected parties for the purpose of implementing restructuring, and that the Initial Decision has the effect of improperly extending these existing agreements beyond their negotiated contract terms. SoCal Edison also argues that the Presiding Judge's ruling on this issue undermines the ruling accepting rolled-in rates by making exceptions for the Municipals. Finally, SoCal Edison contends that the continuation of the TSAs beyond their negotiated terms unduly discriminates against the other users of the transmission system, including SoCal Edison's retail customers, who will have to pay higher rates when the current TSAs expire for the same service. [14]

The California ISO adds that because no party to this proceeding proposed continuation of the sub-functional (hub and spoke) rates, they were not a subject of discussion during the hearing, and there is no record evidence of the impact of such rates on other market participants. The California ISO concludes that under these circumstances, the justness and reasonableness of these rates was unsupported.

Cities and Vernon oppose these exceptions. Cities states that the Initial Decision does not extend the Cities' current contract rights, nor does the Initial Decision rely on the TSAs in reaching the conclusion that credits for the Municipals are appropriate. Cities argue that the Presiding Judge's findings were based on proper ratemaking principles and are independent of the contractual arrangements embodied in the TSAs and Restructuring

[14] SoCal Edison's Brief on Exceptions, at pp. 62-65.

Agreements. Vernon adds that SoCal Edison has proposed a new rate methodology in this proceeding which the Presiding Judge modified to grant customer credits. Vernon also disagrees with the assertions made by SoCal Edison and trial staff that the Presiding Judge has extended the existing contracts beyond their negotiated term, stating that the Presiding Judge's determination has only modified the proposed rates to incorporate the previous TSA's sub-functional rates.

Discussion

Although we have vacated the issue of customer credits for Participating TOs due to the ISO's TAC filing, in Docket No. ER00-2019-000, specifically the proposal to eliminate the non-self sufficiency test, [15] we will discuss here the issue of customer credits for non-Participating TOs.

FMPA, Order No. 888, and Order 888-A, all require that for facilities to be considered integrated, the transmission provider must be able to provide transmission service to itself or other transmission customers over these facilities As of the start-up of the California ISO, SoCal Edison no longer served as the transmission provider. Under these circumstances, until and unless the Municipals join the California ISO and turn over control of their facilities to the California ISO, the California ISO can have no operational control over Municipals' facilities. If the California ISO has no operational control over these facilities, it can not use them to provide transmission service to its customers. In fact, the California ISO would not even be able to transmit power over the customer facilities to the Municipals.

The Presiding Judge's ruling gives the benefit of California ISO membership without assigning any corresponding responsibilities to the Municipals. The result of this ruling is that other users of the California ISO grid would pay for the implicit credit, but would not be able to use the facilities. In addition, the Presiding Judge's ruling would require the rolled-in rate for other users to be modified each time a TSA expires, creating a lack of uniformity in rates over several years. In order for the Municipals to receive credits for their facilities, they must join the California ISO and thereby allow scheduling and control of the facilities by the transmission provider.

In addition, we find that the Presiding Judge improperly applied the terms and conditions of a negotiated contract to the proposed wholesale wheeling access charge. As noted by Cities' witness, the parties "mutually agreed in the Restructuring Agreements to terms and conditions under which the IOAs would terminate and the Cities will make the

---

[15] See section C supra.

transition to independent operation in the restructured market". [16] The terms and conditions of the Restructuring Agreements were negotiated as a package with the expectation that the Municipals would eventually be able to operate independently. The Presiding Judge's ruling acts to sever the expiration term of the contract from the other terms and conditions mutually agreed upon by the parties, and would have the effect of abrogating the parties' agreement, without a reasonable basis for doing so. Therefore, we reverse the Presiding Judge's ruling that the implicit credit contained in the TSA's should be continued in the wholesale wheeling access charge.

E. Whether the Presiding Judge Properly Determined SoCal Edison's Rate of Return on Common Equity

Initial Decision

The Initial Decision declined to adopt the rate of return on common equity (ROE) proposed by SoCal Edison (11.6 percent) or trial staff (8.71 percent). The Initial Decision also accepted, in part, and rejected, in part, the methodologies used by these parties for calculating their respective ROEs. Based on the Presiding Judge's application of a two-stage discounted cash flow (DCF) formula which the Presiding Judge found to be consistent with the Commission's recent precedents in natural gas pipeline company cases, [17] the Presiding Judge calculated an ROE for SoCal Edison of 9.68 percent.

The Initial Decision found that the ROE recommendations made by SoCal Edison and trial staff differed significantly, due to the differing methodologies advanced by these parties to calculate SoCal Edison's ROE. These differences included: (1) trial staff's stand alone analysis of SoCal Edison versus SoCal Edison's analysis of a proxy group; (2) trial staff's use of a DCF analysis alone versus SoCal Edison's reliance on a DCF/risk premium analysis; (3) SoCal Edison's reliance on the gross domestic product (GDP) for the long-term growth factor in the DCF analysis versus trial staff's use of DRI industry data; and (4) the use or rejection of adjustments based on flotation costs and risk assessments.

---

[16] Vernon's Brief Opposing Exceptions, at pp. 43-44.

[17] Initial Decision, 86 FERC at 65,143, citing Williston Basin Interstate Pipeline Company, 50 FERC ¶ 61,284 (1990) (Williston), vacated on other grounds, 931 F.2d 948 (D.C. Cir. 1991); Northwest Pipeline Corporation, 79 FERC ¶ 61,309 (Opinion No. 396-B), reh'g denied, 81 FERC ¶ 61,036 (1997) (Opinion No. 396-C); and Transcontinental Gas Pipe Line Corporation, 80 FERC ¶ 61,157 (1997) (Opinion No. 414), reh'g, 84 FERC ¶ 61,084 (1998) (Opinion No. 414-A).

The Presiding Judge concluded that in performing the DCF analysis in this case, the proxy group advanced by trial staff was appropriate because it is the Commission's preferred approach for natural gas pipeline companies and because "[t]he same logic should apply to electric companies." [18] The Presiding Judge also held that a DCF analysis rather than a risk premium analysis, or a combination thereof, was appropriate because, among other reasons, it was consistent with Commission policy In addition, the Presiding Judge accepted the use of the Institutional Brokers Estimation System (IBES) growth projections for the short-term growth factor in the DCF model and held that SoCal Edison's recommended use of GDP data, as a long-term growth factor, was appropriate because it was consistent with the Commission's rulings in Williston and Opinion No. 396-B. [19] Finally, the Presiding Judge chose the median return from the zone of reasonableness of the proxy group of companies he relied on to calculate his ROE, without an adjustment for flotation costs, based on his assessment of SoCal Edison's business and financial risks.

Exceptions

Exceptions were filed by SoCal Edison and trial staff. SoCal Edison argues that the Presiding Judge's ROE of 9.68 percent "fails to reflect the significant risks that [SoCal Edison] faces in the restructured electric utility environment, and reduces [SoCal Edison's] ROE substantially below levels previously allowed by the [California Commission] on the same assets for the same service." [20] SoCal Edison also claims that in addition to the DCF model, use of a risk premium analysis is appropriate because: (1) it is widely used and relied upon; and (2) the bond yields, on which the analysis is based, reflect investors' perceptions on a forward-looking basis.

SoCal Edison also objects to the Presiding Judge's rejection of its proxy group. SoCal Edison states that the companies included in trial staff's proxy group, which the Presiding Judge relied upon, have a lower risk profile than SoCal Edison. SoCal Edison also takes issue with the Presiding Judge's reliance on the Commission's natural gas pipeline precedents for the weighting to be given the short and long-term dividend growth rates, as used in the DCF formula to calculate "g." While in these precedents, the

---

[18] Id. at 65,141.

[19] The Presiding Judge also determined that the short-term growth component should be given a two-thirds weight, and the long-term component a one-third weight, consistent with the Commission's recent natural gas pipeline company cases.

[20] SoCal Edison's Brief on Exceptions, at 7.

Commission gave a two-thirds weighting to short-term growth and a one third weighting to long-term growth, SoCal Edison claims that the Presiding Judge failed to explain why this same weighting would be appropriate in the case of an electric utility.

Trial staff asserts as error the Presiding Judge's decision not to use the long-range growth forecast of the electric industry's return on total capital, as published by Data Resources Inc. (DRI), for the long-term projection of growth in the DCF model. Trial staff also asserts as error the Presiding Judge's failure to consider company-specific data in the form of a stand-alone DCF in determining SoCal Edison's ROE.

Order Establishing Further Procedures

On September 17, 1999, the Commission issued an "Order Establishing Further Procedures On Issue Of Rate of Return on Common Equity." [21] In the September 17 Order, the Commission held that it would be in the public interest to consider additional arguments in this proceeding on the issue of SoCal Edison's ROE "[i]n light of the possible risks associated with the transfer of operational control of facilities to the California ISO, and the potential increase, since the end of the hearing, in the number of public utilities that face similar risks. . . ." The September 17 Order permitted interested parties to file initial and reply comments on these issues. [22]

Initial Comments

Initial Comments were timely filed by the California Electricity Oversight Board (Board); trial staff; the California Commission; the Sacramento Municipal Utility District (SMUD); and SoCal Edison. In addition, a motion for leave to file initial comments one day out of time was filed by Pacific Gas and Electric Company (PG&E), and motions for late intervention and comments were filed by Edison Electric Institute (EEI), the Electricity Consumers Resources Council (ELCON) and the American Iron and Steel Institute (AISI); and the Midwest ISO Participants (ISO Particpants). [23]

---

[21]Southern California Edison Company, 88 FERC ¶ 61,254 (1999) (September 17 Order).

[22]As required by the September 17 Order, Initial Comments were filed on November 1, 1999. Reply Comments were filed December 1, 1999.

[23]Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2000), we will grant the unopposed motions to intervene filed by EEI,

(continued...)

SoCal Edison submits an updated ROE analysis, in its comments, in which it updates both its DCF study as well as its two risk premium analyses. These updated analyses are based on data for the period April 1999 through September 1999 and support, in SoCal Edison's view, an ROE in this case of at least 11.6 percent. SoCal Edison explains that this recommended ROE is based on the high end of the zone of reasonableness indicated by SoCal Edison's DCF analysis and is supported by a finding that SoCal Edison faces significant risks attributable to its joining the California ISO.

In assessing the risks it faces, SoCal Edison asserts that other industries that have experienced similar unbundling and partial deregulation should be studied, including the telecommunications and natural gas pipeline industries. SoCal Edison states that in these industries, there is clear evidence that unbundling one component of a previously integrated company can increase the risk attributable to the other components of the company's business. SoCal Edison also argues that in setting its ROE in this case, the Commission should consider the broader policy issue it discussed in the RTO proceeding, i.e., the option of using ROEs to give electric utilities an incentive to make investments in new transmission facilities.

ISO Participants, PG&E, and EEI argue that higher ROEs for the electric utility industry as a whole are necessary because in the restructured market, electric utilities face an increased risk of non-recovery of their transmission revenue requirements. EEI points out that while higher ROEs may mean higher direct costs for consumers, it will mean an avoidance of the far more significant indirect costs that could be incurred if utilities are not given the proper incentives to participate fully in the restructured market. ISO Participants add that the DCF analyses of integrated electric utilities may not reflect the risks associated with RTOs because the earnings growth forecasts for vertically integrated companies do not reflect transmission-only growth forecasts, nor do they reflect the increased financial and operational risks associated with joining an RTO. PG&E asserts that there are significant regulatory risks associated with a transfer of jurisdiction from the California Commission to the Commission, and that an exclusive reliance on a DCF analysis using electric utilities as a proxy group significantly understates the risks that SoCal Edison faces, because the electric utilities that comprise this proxy group are undergoing so much change at the present time.

Trial staff, the California Commission, the Board, ELCON, and AISI assert a different position on these issues. Trial staff argues that there is no evidence that SoCal

---

[23](...continued)
ELCON, AISI, and the ISO Participants. We will also accept the initial comments filed one day out of time by PG&E.

Edison has become exposed to any new risks following the close of the record in this case, and suggests that SoCal will fully recover its stranded generation costs and plans to make significant new generation investments. Trial staff also cites evidence that the stock value of SoCal Edison's parent has and will continue to out-perform the electric utility averages. In addition, trial staff states that SoCal Edison itself has performed well since the advent of retail unbundling and intends to make substantial investments in its transmission and distribution network.[24]

The California Commission and the Board state that any increased risks facing SoCal Edison as a result of its participation in the California ISO were fully addressed by the California legislature in Assembly Bill 1890 (AB 1890), and that SoCal Edison retains the right to file section 205 rate cases at the Commission to recover its transmission revenue requirements.

ELCON, AISI and SMUD agree with the general thrust of these arguments. They argue that SoCal Edison's risks have been significantly reduced since its restructuring, and that its credit rating will actually improve as a result of its membership in the ISO, given its ability to recover its stranded costs. However, because an immediate reduction in ROEs for other utilities may act as a disincentive to their membership in RTOs, ELCON and AISI support the allowance of a grace period, during which utilities joining RTOs will be permitted to retain their current ROEs. SMUD argues that an artificially-inflated ROE is contrary to sound, cost-based ratemaking practices, and believes that SoCal Edison does not have increased risk associated with its participation in the California ISO.

Reply Comments

Reply comments were timely filed by ELCON; SoCal Edison; SMUD; the Metropolitan Water District of Southern California (Metropolitan); the California Commission; and trial staff. Trial staff and SMUD note, in their reply comments, that many of the arguments raised by SoCal Edison and others, in support of raising SoCal Edison's ROE in this case, address issues which have no bearing on the issues identified by the Commission in the September 17 Order. Trial staff further points out that other

---

[24]Trial staff does note, however, that following the close of the record in this case, changes in the financial markets have occurred, which would justify an increased ROE for SoCal Edison over the figure advanced by trial staff at hearing. Specifically, the 8.71 percent return initially recommended by trial staff should be adjusted upward to 9.47 percent, based on the updated data on which trial staff relies and the same methodology previously utilized by trial staff's witness.

issues raised by these parties may have a bearing on other utilities or other industries, but have not been shown to have a bearing on the electricity market in California, or on SoCal Edison, specifically. Trial staff also takes issue with SoCal Edison's argument that the California ISO has no financial incentive in maximizing the company's profits. Trial staff claims that this risk, if it existed, would already be reflected in investors' expectations. Metropolitan also asserts that this risk is overstated and that it overlooks the many benefits conferred upon SoCal Edison as a result of its membership in the California ISO.

The California Commission also disputes SoCal Edison's claim that it risks less growth in its regulated business. The California Commission notes that SoCal Edison's own president has forecasted a substantial growth in its service territory. The California Commission also disputes SoCal Edison's claim that a higher ROE is necessary in order to further expand the transmission grid, pointing to other cases approving lower ROEs for utilities who are nonetheless pursuing expansion projects.

In its reply comments, Metropolitan urges the Commission to set SoCal Edison's ROE in this case based solely on SoCal Edison's electric transmission business. Metropolitan also urges the Commission not to use the instant proceeding to announce any new policies regarding appropriate ROEs for utilities who voluntary join an RTO pursuant to Order No. 2000. Metropolitan points out that because the California ISO was not voluntarily established, it does not fit the new paradigm contemplated by Order No. 2000. SMUD concurs with Metropolitan on this point.

ELCON takes issue with EEI's conclusion that restructuring will enhance the risk faced by transmission owners. ELCON asserts, to the contrary, that restructured transmission services, because they will be regulated, will continue to qualify for a fair ROE. ELCON also states that in a restructured environment, transmission owners will no longer be burdened by the substantial risks associated with generation.

SoCal Edison's reply comments take issue with the contention that it is seeking a premium ROE as a reward for its having joined the California ISO. SoCal Edison argues that the ROE it is seeking is fully commenserate with the risks it faces. SoCal Edison also takes issue with those comments addressing such issues as retail restructuring, generation, distribution and stranded cost recovery. SoCal Edison asserts that the issue for review, pursuant to the September 17 Order, are not these issues, but the risk that California ISO membership imposes on SoCal Edison's transmission business.

Discussion

The record in this proceeding was reopened for the purpose of considering additional evidence and arguments on ROE. As noted above, numerous comments were received, including the submission of revised DCF analyses by SoCal Edison and trial staff, and new DCF analyses submitted by SMUD and PG&E. These parties developed their ROE recommendations using either a DCF or a risk premium analysis or a combination of the two. The DCF analyses submitted in the supplemental record are similar to both the DCF analyses submitted by SoCal Edison and trial staff in the original proceeding and the DCF analysis adopted by the Presiding Judge. Each of these analyses relies on a weighted averaging of a short-term and a long-term growth rate, and purports to comply with the Commission's two-step DCF methodology, as set forth in Opinion No. 396-B.

The Commission, to date, has not expressly addressed the differing approaches taken in setting ROEs for gas pipelines and for electric utilities. This proceeding, however, presents the Commission with its first opportunity to calculate an ROE for an electric utility company where the positions advocated by the parties, and the record evidence contains both short-term and long-term growth data, consistent with our latest formulation of a two-step DCF methodology for natural gas pipeline companies. [25] The issue presented here, therefore, is whether the Commission's preferred DCF methodology for natural gas pipeline companies should be applied, without variation, to an electric utility company, in place of the Commission's standard, constant growth DCF model, previously relied upon by the Commission in calculating an ROE for an electric utility company. [26]

As noted above, the Presiding Judge applied the two-step DCF model currently used by the Commission in natural gas pipeline cases, reasoning, among other things, that

---

[25]See, e.g., note 10 supra. The Commission's preferred approach in both gas pipeline and electric utility proceedings, is to use a DCF methodology to calculate the ROE. As discussed below, however, the two policies have diverged in how they determine the appropriate growth rate used in the DCF model.

[26]See, e.g., Southern California Edison Company, 56 FERC ¶ 61,003 (Opinion No. 362), order on reh'g, 56 FERC ¶ 61,117 (1991) (Opinion No. 362-A); Connecticut Light & Power Co., 43 FERC ¶ 61,508 (1988), Jersey Central Power & Light Co., 77 FERC ¶ 61, 001 (1996), Southwestern Public Service Co., 83 FERC ¶ 61,138 (1998), Appalachian Power Co., 83 FERC ¶ 61,335 (1998) (Appalachian), and Consumers Energy Co., 85 FERC ¶ 61,100 (1998).

the precedents applicable under Natural Gas Act are equally applicable to a case decided under the Federal Power Act. [27] Rather than adopting this approach, however, we believe that significant differences exist in the electric utility industry and the natural gas pipeline industry which warrant the continued use of different growth rates in the DCF models for each. Accordingly, we will not adopt the Initial Decision's ROE of 9.68 percent and the natural gas pipeline company methodology on which it relies. Instead, we will approve an ROE for SoCal Edison of 11.60 percent, based on the Commission's standard constant growth DCF model, as applied below. Should circumstances in the industry change, in the future, we will reevaluate our methodology, as necessary.

In Opinion No. 396-B, we gave four reasons why the long-term growth of the United States economy as a whole is a reasonable proxy for the long-term growth rate of all firms, including regulated firms in the gas business. [28] First, the record in that case showed that as companies reach maturity over the long-term, their growth slows, and their growth rate will approach that of the economy as a whole. Second, it is reasonable to expect that, over the long-run, a regulated firm will grow at the rate of the average firm in the economy. Third, the purpose of using the DCF model approved in Opinion No. 396-B was to approximate the rate of return an investor would reasonably expect from a pipeline company, and no evidence in that record indicated that investors relied upon any of the alternative long-term growth approaches suggested by the parties in that proceeding. Fourth, each of the witnesses in Opinion No. 396-B used the long-term growth of the economy as a whole as confirmation or support for their analyses.

We find that our rationale in Opinion No. 396-B does not support the use of GDP data in developing a growth rate estimate in this proceeding. Unlike the gas pipeline industry, which was nearly through with major restructuring at the time we issued Opinion No. 396-B, on June 11, 1997, the electric industry is just beginning a significant new phase of its restructuring. In particular, SoCal Edison had just begun to restructure from a vertically integrated utility when it made its filing in the instant proceeding. [29] In addition, in contrast to the growth estimates that underlay the two-step approach for gas pipelines, the current growth rate estimates for SoCal Edison are not two to three times

---

[27]Initial Decison, 86 FERC at 65,141.

[28]Opinion No. 396-B, 79 FERC at 62,382-83.

[29]SoCal Edison notes, moreover, that the transmission assets which are the subject of this proceeding, were state-regulated assets, until only recently, earning an 11.6 percent ROE. See SoCal Edison's Brief Opposing Exceptions, at p.4.

greater than GDP.[30] Moreover, the use of a two-step approach in natural gas pipeline company cases is supported by the fact that two large investment firms, Merrill Lynch and Prudential Securities, use the long-term growth of the economy as a whole in their analyses of gas pipeline companies. However, Prudential Securities indicates that it treats electric utilities differently from all of the other industrial companies when estimating growth rates.[31]

Trial staff also notes a number of significant differences between the electric and gas industries.[32] Specifically, trial staff notes that gas pipeline companies are similar to other industrial companies in that they have low dividend payout ratios (i.e., low dividend yields) and that they reinvest a high proportion of their earnings into their businesses to promote future growth.[33] By comparison, electric utilities typically have much higher dividend payout ratios (i.e., high dividend yields) as compared to most other industrial companies, including most gas pipeline companies. As a result, electric utilities reinvest less than a third of their earnings.[34]

This distinction between the two industries is critical, because retained earnings are a key source of dividend growth. The higher payout ratios attributable to electric

---

[30]See, e.g., Ozark Gas Transmission System, 68 FERC ¶ 61,032 at 61,104-05 (1994) (Ozark) (growth estimates ranging from 8.81 percent to 15.2 percent and GDP estimates of 5.4 percent); Williston Basin Interstate Pipeline Company, 72 FERC ¶ 61,074 at 61,387 (1995) (growth estimates ranging from 8 to 15 percent and GDP estimates of 5.37 percent and 6.33 percent); and Opinion No. 414-A, 84 FERC at 61,427-7 (growth estimates ranging from 8 percent to 15 percent and GDP estimates of 5.45 percent). By comparison, the IBES growth estimate for SoCal Edison is 5.87 percent. See trial staff's Reply Comments, Att. D-1, at p. 1. GDP estimates range from 4.41 percent to 5.2 percent. See Exh. SCE-97, at pp. 5-7.

[31]See Exh. S-2, Schedule 14, at pp. 1-4.

[32]Trial staff's Brief on Exceptions, at pp. 19-21.

[33]Trial staff also points out that industrial companies, on average, had a payout ratio of 29 percent for the period 1994-97 and a forecasted payout ratio of 24 percent for 2002. Exh. S-2, Schedule No. 15, at p. 2. Gas pipelines had a payout ratio of 45 percent for the period 1993-97 and a forecasted payout ratio of 30 percent for 2002. Id., Schedule No. 13.

[34]Electric utilities had an average payout ratio of 71 percent for the period 1993-97, and a forecasted payout ratio of 68 percent for 2002. Id.

utilities cause these companies to have significantly lower expected dividend growth rates than most other industrial companies (including most gas pipeline companies). For example, the record in this case indicates that while the internal growth rate of gas pipelines averaged 6.05 percent from 1993 to 1997, and is projected to be 9.16 percent in 2002, the internal growth rate of electric utilities averaged only 2.51 percent over the same period, and is projected to be 3.86 percent in 2002. [35] While retention ratios for the electric utility industry, as a whole, are projected to increase slightly, in the future, as noted above, the rate of retention is still significantly lower than the average gas pipeline company. For all these reasons, we find that it would be premature, at this time, to incorporate GDP in the DCF model applicable to an electric utility company.

Nor are we convinced that trial staff's proposed use of DRI data is a reliable source for projecting growth, in this case, for SoCal Edison. Trial staff argues that because the DRI data on which it relies is closely related to total return on common equity, it is both more appropriate than GDP for projecting dividend growth for electric utilities and more likely to be used by investors. However, as the Presiding Judge found, DRI's estimate of return on total capital may be depressed by its anticipated write-offs of stranded costs that are incorporated into its forecasts. [36] Moreover, trial staff has not demonstrated that its DRI projection of growth in total capital equates to the measure of "g" on which the DCF model relies, i.e., growth in dividends per share, as we discuss below.

In the past, we have consistently applied a one-step, constant growth DCF model for calculating ROEs for electric utilities. The DCF methodology determines the ROE by summing the dividend yield (with an adjustment for the quarterly payment of dividends) and expected growth rate. The resulting formula is $D/P(1+.5g) + g = k$, where "D/P" is the dividend yield, "g" is the sustainable growth rate of dividends per share, and "k" is the resulting ROE. The sustainable growth rate is calculated by the following formula: $g = br + sv$, where "b" is the expected retention ratio, "r" is the expected earned rate of return on common equity, "s" is the percent of common equity expected to be issued annually as new common stock, and "v" is the equity accretion rate. [37]

Based on the evidence submitted by trial staff in its Initial Comments, we can calculate an ROE for SoCal Edison using this one-step, constant growth DCF

---

[35]See id., Schedule Nos. 10 and 13. A company's internal growth rate is computed as the product of its retention rate and its earned return on equity.

[36]Initial Decision, 86 FERC at 65,142; See also Exh. SCE-55, at p. 9.

[37]Connecticut Light & Power Co., 45 FERC ¶ 61,370 at 62,161, n. 15. (1988).

methodology. We turn first to the growth rate, of "g." From Value Line's growth projections for SoCal Edison's parent company, Edison International, a payout ratio can be calculated by dividing forecasted dividends per share by forecasted earnings per share. The payout ratio, for 1999, is 55.38 percent (based on Value Line's forecasts of dividends per share of $1.08, and earnings per share of $1.95); 52.68 percent for 2000 (based on Value Line's forecasts of dividends per share of $1.08, and earnings per share of $2.05), and 52.73 percent for 2003 (based on Value Line's forecasts of dividends per share of $1.16, and earnings per share of $2.20). The average forecasted payout ratio is 53.6 percent. Consequently, the retention ratio, "b," which is 1 minus the payout ratio, is 46.40 percent.

Value Line also forecasts a return on book value for Edison International, the "r" in the "br+sv" equation. For both 1999 and 2000, that return is expected to be 12.5 percent. It is expected to be 11.5 percent for 2003. The average forecasted "r" is 12.17 percent. However, these are forecasted year-end returns which must be adjusted by the growth in common equity for the period to derive an average yearly return. The average yearly return ("r") is thus 12.52 percent. [38]

Because Edison International is not issuing any new common stock, the external growth rate "sv," in the br+sv model, in this case, is zero.

Consequently, "g" may be calculated as "b" (.4640) times "r" (.1252), for a forecasted growth rate of 5.81 percent. By comparison, the IBES growth forecast for Edison International is 5.87 percent. [39] Using both projections, we will frame the zone of reasonableness in this case by combining the average low dividend yield for the six-month period ending August 1999 (3.96 percent), with the low growth rate (5.81 percent) and the average high dividend yield for this period (4.51 percent) with the high growth rate (5.87 percent). [40] The resulting zone of reasonable returns, as adjusted for the quarterly payments of dividends, is 9.89 percent to 10.51 percent.

---

[38] In 1998, SoCal Edison's common equity ratio was 37.4 percent, with total capital of $13.6 billion (the equity component was $5.1 billion). For 2003, Value Line forecasts an equity ratio of 46 percent, with total capital of $14.8 billion (the equity component is $6.8 billion). Therefore, the growth in common equity ("G") is 5.9 percent. The adjustment factor -- 2(1+G)/(2+G) is 1.0287, which is applied to the year-end "r".

[39]Trial staff's Initial Comments, Att. D, at p. 1.

[40]Appalachian, 83 FERC at 62,350.

The Supreme Court has provided guidance in two often cited decisions regarding the range of allowed returns that may be permitted in a particular case. In Bluefield Water Works & Improvement Co. v. Public Service Commission of West Virginia,[41] the Court stated that the approved return should be "reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties."[42] In a subsequent case, FPC v. Hope Natural Gas Co.,[43] the Court provided additional guidance on this issue:

> From the investor or company point of view, it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. The return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital.[[44]]

Applying these guidelines, we will measure the zone of reasonable returns indicated by the above analysis against a group of proxy companies having corresponding risks. A number of alternative proxy groups were proposed in this case by SoCal Edison, trial staff, SMUD, and PG&E. In the original proceeding and its Initial Comments, SoCal Edison relied on a proxy group of 13 companies with operating revenues of over $1 billion, and a bond rating of "A" or "A+." In its Initial Comments, SoCal Edison also developed an alternative proxy group, based on two criteria: companies located in states in which electric restructuring is at a comparable level to SoCal Edison's own restructuring, and companies having comparable bond ratings.[45] Trial staff, by contrast, chose its four-company proxy group based on the following criteria: (1) bond ratings of "AA-" to "A+"; (2) nuclear generation equal to at least 17 percent of total generation; (3)

---

[41]262 U.S. 679 (1923) (Bluefield).

[42]Id. at 693.

[43]320 U.S. 591 (1944) (Hope).

[44]Id. at 603.

[45]SoCal Edison's alternative proxy group consists of Allegheny Energy Inc., MDU Resources Group, New England Electric System, PG&E, Pacificorp, and Sempra Energy.

a Standard & Poors (S&P) business profile of average or above; (4) $3 billion or more in total revenues, for 1996; and (5) an exclusion of any utility involved in any merger activity.

SMUD also calculated a zone of reasonableness based on a six company proxy group and the following seven criteria: (1) common stock actively traded on the open market and reported in the Wall Street Journal; (2) 80 percent of 1998 operating revenues derived from electric utility operations; (3) consistent financial history lasting for at least the last five years; (4) the exclusion of any utility involved in any merger activity or other significant structural change; (5) nuclear energy operations comprising less than 20 percent of generation fuel base; (6) companies paying dividends for the last ten years; and (7) companies whose non-utility revenues are equal to 15 percent, or less, of total operating revenues. PG&E calculated its proposed ROE utilizing a group of natural gas local distribution companies as a proxy group.

The Presiding Judge adopted trial staff's proxy group and we will do the same for the purpose of confirming our DCF analysis for SoCal Edison. As such, we will reject the proxy groups proposed by SoCal Edison, SMUD, and PG&E. As noted by the Presiding Judge, SoCal Edison's 13 company proxy group is based on overly-broad selection criteria without any emphasis on finding companies that are comparable in risk to SoCal Edison. SoCal Edison's alternative proxy group is a closer fit, however, it too lacks the detailed risk analysis of trial staff's comparable group. Several of the companies included by SMUD in its proxy group are insufficient in size relative to SoCal Edison. In addition, unlike SoCal Edison, five of the companies in SMUD's proxy group have no nuclear facilities. Finally, we will reject PG&E's proposed proxy group, given the significant differences between the gas industry and the electric utility industry, as discussed above.

Trial staff's proxy group, by contrast, includes comparable risk companies that are similar to SoCal Edison in size, business profile, and level of nuclear generation. Moreover, two of the four companies in trial staff's proxy group are currently in a Commission-approved ISO -- PG&E and the Constellation Energy Group (the parent company of Baltimore Gas & Electric Company). Thus trial staff's comparable group is the best proxy group to apply the standards enunciated in Bluefield and Hope.

In calculating our comparison group ROE, we will use the same "br + sv" formula, applied above, and the same Value Line source material relied upon above to calculate

SoCal Edison's individual zone of reasonableness. [46] In addition, we will corroborate the calculated growth rate with the forecasted IBES growth rate to set the high and low end of the zone of reasonableness. The results are summarized in the table below:

	avg. low dividend	avg. high dividend	growth rate (br + sv) [47]	growth rate (IBES)	zone of reasonableness
PG&E	3.63	3.88	4.70	6.153 [48]	8.42 - 10.15
Constellation	5.63	6.16	4.10	3.85	9.59 - 10.39
Duke	3.74	4.14	7.60	8.13	11.48 - 12.44
Southern	4.81	5.35	5.28	5.85	10.22 - 11.36

An adjustment to this data is appropriate in the case of PG&E's low-end return of 8.42 percent, which is comparable to the average Moody's "A" grade public utility bond yield of 8.06 percent, for October 1999. [49] Because investors generally cannot be expected to purchase stock if debt, which has less risk than stock, yields essentially the same return, this low end-return cannot be considered reliable in this case. Therefore, excluding this single outlier, the resulting zone of reasonableness for the comparable companies is 9.59 percent to 12.44 percent. The midpoint return is 11.02 percent.

We will next consider where, within this zone of reasonable returns, SoCal Edison's ROE should be set. In making this determination, it is necessary to measure the business and financial risks faced by SoCal Edison relative to the overall risks attributable to the appropriate proxy group of companies. As noted above, a substantial body of evidence has been presented in this case arguing for and against the relative riskiness of a utility transferring its transmission assets to an ISO. In addition, SoCal Edison, trial staff, and SMUD attempted to quantify the potential risks associated with SoCal Edison's

---

[46] See trial staff's Initial Comments, Att. D-1, at pp. 12-15.

[47] Both Constellation and Duke are forecasted to issue stock.

[48] Exh. SCE-104, at p. 14 (containing a corrected forecasted growth rate of eight percent rather than 39 percent for the one analyst that was excluded from trial staff's calculation).

[49] Exh. SCE-104, at p. 31.

transfer of assets to the California ISO. However, much of this evidence was disputed by one party or another, or was speculative. In addition, much of the evidence submitted by the parties in their Initial Comments and Reply Comments was tied only tangentially to SoCal Edison.

The revised and updated DCF analyses submitted by SoCal Edison, trial staff and SMUD reflect updated investor expectations for SoCal Edison, which are based on more than a year's worth of operating practice by the California ISO. Given the conflicting evidence in this case on the issue of risk, we find that the updated financial data relied upon above is the best quantifiable measure of the investment communities' current risk assessment for SoCal Edison.

SoCal Edison argues that its risks exceed those of the proxy group based, among other things, on the rating of the comparable group's senior secured debt. Except for two of the five Southern Company subsidiaries, which have the same S&P bond rating as SoCal Edison, the rest of the companies in this proxy group are rated "AA-". [50] SoCal Edison's zone of reasonableness (9.89 - 10.51 percent) places SoCal Edison at the lower end of the zone of reasonableness of the comparable companies. This would be a reasonable result, if SoCal Edison was less risky than the comparable companies. However, based on the higher bond ratings of the comparable companies, we find that SoCal Edison is more risky than the comparison group. Therefore, the appropriate ROE for SoCal Edison should be above the midpoint of returns indicated for the comparison group. Therefore, we will establish SoCal Edison's ROE at the midpoint of the upper half of the zone of reasonableness. [51] That zone is 11.02 - 12.44 percent with a midpoint of 11.73. However, because this return exceeds SoCal Edison's own request, we will adjust the indicated return downward to 11.60 percent.

Use of Updated Data

Because capital market conditions may change significantly between the time the record closes and the date the Commission issues a final decision, we have consistently required the use of updated data in setting a company's ROE.[52] Here, however, the re-opened record authorized by the September 17 Order has permitted us to use current data,

---

[50]Exh. SCE-102, at p. 18.

[51]See Consumers Energy Company, 85 FERC ¶ 61,100 at 61,364 (1998).

[52]See Appalachian Power Company, 55 FERC ¶ 61,509, order on reh'g, 57 FERC ¶ 61,100 (1991), order on reh'g, 58 FERC ¶ 61,193 (1992).

making any additional updates unnecessary. Consequently, SoCal Edison's ROE will be set at 11.6 percent for the period the rates went into effect and prospectively from the date of this order until SoCal Edison files for a change in its transmission rates.

F. Whether the Presiding Judge Properly Determined the Allocation of Administrative and General Expense and General and Intangible Plant to ISO Transmission

Initial Decision

The Initial Decision found that trial staff's proposed use of labor cost ratios to allocate administrative and general (A&G) and general and intangible plant (G&I) expenses was consistent with the Commission's long-standing policy set forth in Minnesota Power and Light Company, [53] and rejected SoCal Edison's alternative proposal, which relied on a multi-factor allocator. The Initial Decision noted that under SoCal Edison's proposal, A&G and G&I costs would be assigned to generation, ISO transmission, and non-ISO business segments by grouping these costs into one of three cost attribution pools: direct, joint, or common. These costs would then be assigned to the appropriate business segment based on the attribution technique specific to that pool, with the stated objective of limiting the amounts to which general allocation formulas are applied.

The Presiding Judge rejected this approach based, in part, on the Commission's recent reaffirmation of its long-standing use of labor ratios to allocate A&G and G&I expenses. [54] The Presiding Judge also found that while the alternative allocation proposal advanced by SoCal Edison and trial staff lead to different allocations, this difference alone does not prove that one method is superior to the other, nor did it satisfy SoCal Edison's burden of showing that the Commission's existing policy is unjust and unreasonable and that its own proposal was just and reasonable. The Presiding Judge also found that SoCal Edison failed to support its own allocation of its costs, and that the timing of rate cases before this Commission and the California Commission and the restructuring of SoCal Edison's facilities and services did not support the rejection of labor ratios as the preferred allocation methodology.

[53] 4 FERC ¶ 61,268 (1978).

[54] Initial Decision, 86 FERC at 65,145, citing Portland General Electric Company, 84 FERC ¶ 61,216, at p. 62,004 (1998) and Montana Power Company, 83 FERC ¶ 61,211, at p. 61,935 (1998).

Exceptions

Exceptions were filed by SoCal Edison, in which SoCal Edison renews the arguments presented at hearing concerning the reasonableness of its proposed A&G and G&I allocation methodology. In addition, SoCal Edison states that the Presiding Judge's determination would result in significant under-recovery of its reasonably incurred transmission costs. SoCal Edison contends that the California Commission assumed that these costs would be recovered in transmission rates when the California Commission designed SoCal Edison's state jurisdictional retail rates. SoCal Edison concludes that these costs would be unrecovered due solely to the transfer of jurisdiction over retail transmission from the California Commission to this Commission resulting in an unfair denial of its legitimately-incurred costs.

Trial staff opposes SoCal Edison's exceptions, reiterating its arguments presented at hearing. The California Commission submitted comments stating that SoCal Edison's allegation that the unrecovered costs at issue would "fall through the jurisdictional cracks" is misleading. The California Commission states that Socal Edison filed for and received a resolution action from the California Commission giving SoCal Edison the opportunity to present evidence to the California Commission in order to recover these costs.

Discussions

We will affirm the Initial Decision. The majority of the arguments raised by SoCal Edison on exceptions were presented at hearing and were properly disposed of in the Initial Decision. We also find that the Presiding Judge properly applied the Commission's existing policy for allocating A&G and G&I costs. In addition, the California Commission has made clear in its comments that SoCal Edison has the opportunity, if it so chooses, to seek state jurisdictional review and potential recovery of any non-transmission costs subject to the California Commission's jurisdiction. Given this opportunity, we find that SoCal Edison's claimed inability to recover its legitimately incurred costs, due to changes in jurisdiction, is unfounded.

G. Whether the Presiding Judge Properly Determined that SoCal Edison's Projected 1998 A&G Expenses Should be Rejected in favor of the 1997 Recorded A&G Amounts, as Adjusted

Initial Decision

The Initial Decision rejected SoCal Edison's 1998, Period II test year forecasts to calculate its A&G expenses, adopting instead the California Commission's recommendation, which was based on SoCal Edison's 1997 Form No. 1 A&G data, with an adjustment to account for its divested oil and gas plants. In support of his holding, the Presiding Judge cited Commission precedent for the proposition that Period II adjustments may be based on more recent actual data. [55] The Presiding Judge also found that the use of this data was appropriate in this case given SoCal Edison's restructuring, and because SoCal Edison's Period II projections were poorly founded.

Exceptions

SoCal Edison and trial staff filed exceptions. SoCal Edison cites Commission policy for the proposition that a utility's test year projections must be accepted if found to be reasonable when made, and there is no evidence that it will produce unreasonable results. [56] SoCal Edison argues that the single fact that its 1998 Period II estimate and its 1997 data vary does not demonstrate that its test period estimate was unreasonable when made. Moreover, SoCal Edison points out that its projected 1998 A&G expense level was based on a significant reduction in its 1995 A&G expenses and was a reasonable projection of the cost reductions it anticipated.

Trial staff argues that no showing was made in this case that use of SoCal Edison's 1997 actual costs are representative of the costs that will be incurred by SoCal Edison during the rate-effective period and that these costs, in any event, would have to be adjusted to reflect future operations. Trial staff also objects to the mixing of data from different years for use of Period II data.

The California Commission opposes these exceptions, citing record evidence showing that SoCal Edison knew when they filed their 1998 Period II estimate that (1) staffing reductions decreased their A&G costs by $70 million as recorded in 1997 Form No. 1 data; (2) that the costs of certain terminated programs should be removed from the A&G projection; and (3) that use of inflation-related escalators was not accurate given the multi-year Performance Based Rate (PBR) cost-cutting measures SoCal Edison had committed to hold constant. Because SoCal Edison failed to incorporate these known changes into their projection, the California Commission supports the Presiding Judge's

---

[55]Initial Decision, 86 FERC at 65,176, citing Cleveland Electric Illuminating Company, 28 FERC ¶ 63,089 (1984) (Cleveland Electric), aff'd in relevant part, 32 FERC ¶ 61,381 at 61,858 (1985); Southern California Edison Company, 56 FERC ¶ 61,003, at 61,021-24 (1991).

[56]SoCal Edison's Brief on Exceptions, at p. 58, citing Delmarva Power & Light Company, 24 FERC ¶ 61,199 at 61,453 (1983).

finding that the estimates were not reasonable when made. In addition, the California Commission refutes SoCal Edison's interpretation of the case law, stating that in Cleveland Electric adjustments were made to the historic data because that was the only data available at the time, as opposed to this case where 1997 Form No. 1 data is available.

Discussion

None of the exceptions warrant reversing the Presiding Judge's determination in this proceeding that SoCal Edison's Period II estimate is unjust and unreasonable. The Presiding Judge's reasoning that the use of 1997 adjusted Form No. 1 data is more likely to yield just and reasonable results than SoCal Edison's poorly supported Period II estimates is well-supported by the record evidence. The approach adopted by the Presiding Judge is acceptable in this situation because of the unique facts of this case. As noted by the Presiding Judge, SoCal Edison drastically restructured and downsized its previous utility operations, divested substantial generation assets and turned over its transmission facilities to the ISO. Their escalation of 1995 A&G data in this proceeding was unwarranted given the cost cutting incentives under the PBR when SoCal Edison made its test year projections. As noted by the Presiding Judge, So Cal Edison has the burden of showing that its projections were reasonable when made, but it has not done so. Given the unique facts of this case we will affirm the Initial Decision.

H. Whether the Presiding Judge Properly Determined the Level of SoCal Edison's Cost-Based Ancillary Services Rates for the Locked-In Period, April 1, 1998 - November 2, 1998

Initial Decision

The Initial Decision found that SoCal Edison's proposed cost-based bid caps for four ancillary services for the locked-in period April 1, 1998 through November 2, 1998 [57] should not be based on the cost of SoCal Edison's oil and gas generation facilities, as proposed by SoCal Edison, but rather on SoCal Edison's hydro resources, as proposed by trial staff. The Presiding Judge further found that SoCal Edison's proposed bid caps

[57]The locked-in period was the result of the Commission's ruling in AES, 85 FERC at 61,459-65, in which the Commission granted market-based rate authority to all entities providing ancillary services in the State of California, based on our determination that cost-based bid caps in the ancillary services market were restricting supplies to these markets .

should be based on a trial staff study of 1997 FERC Form 1 data for its Hoover and Big Creek costs.

The bid caps established the maximum amount SoCal Edison could bid in the ISO's ancillary service markets during the period that the cost-based rates were in effect. SoCal Edison's filing states that these proposed rates were an interim measure to continue their existing ancillary services rates until the company completed the market study required for filing for market-based ancillary service rates. [58]

In support of its ruling, the Initial Decision noted trial staff's contention that because these facilities were divested during the period that the proposed ancillary service bid caps were in effect, the rate should be based on SoCal Edison's remaining hydro units. Even though SoCal Edison owned oil and gas-fired generation facilities through part of June 1998, trial staff maintained that SoCal Edison did not use these units for ancillary services during any part of the locked-in period. Only trial staff objected to the continued use of SoCal Edison's rates, maintaining that SoCal Edison's bid caps were in excess of the actual costs of the units that provided the services during the locked-in period.

Exceptions

On exceptions, SoCal Edison argues that its proposed ancillary services bid caps are significantly below the levels that the Commission found to be just and reasonable in AES, and are otherwise fully cost-justified. In particular, SoCal Edison notes that some of the ancillary services it provided during the relevant time period did in fact rely on SoCal Edison's oil- and gas-fired units. Moreover, SoCal Edison argues that its ancillary services sales are subject to the Commission's policy regarding off-system sales, as enunciated in Illinois Power Company, [59] which permits pricing flexibility not necessarily tied to the actual generating resource used to provide the service at issue.

In addition, SoCal Edison takes exception to various methods and calculations of cost used by trial staff to determine alternative ancillary service rates based exclusively on SoCal Edison's individual hydro units. SoCal Edison maintains that its proposed ancillary services bid caps are below costs that it experiences in providing ancillary services from its hydro resources.

[58] SoCal Edison's Transmittal Letter at 18, n. 5.

[59] 57 FERC ¶ 61,213 at 61,699 (1991) (Illinois Power).

Discussion

We find that the Presiding Judge's rejection of SoCal Edison's cost-based ancillary services bid caps, for the locked-in period, is in error. First, we agree with SoCal Edison that its proposed bid caps are cost-justified and consistent with our ruling in Illinois Power. The reasonableness of these rates, moreover, is confirmed by trial staff's own analysis, which would support a maximum rate well above SoCal Edison's proposed bid caps. [60]

We reject trial staff's contention that ancillary service bid caps must reflect the actual costs of the individual unit supplying the ancillary service at the time of sale. The ISO's ancillary services market is based on an auction mechanism in which suppliers submit hourly bids that are put in merit order, with the market clearing price paid to all bidders who are selected. As a result, during the locked-in period, all units which provide ancillary services for that hour receive the market clearing price capped at their respective cost-based bid caps. This market clearing mechanism does not comport with the theory trial staff espouses for tracking the exact costs of the actual generating unit used to supply a particular service.

Given the circumstances of this case and the state of the ISO ancillary services markets during the locked-in period, we reject the Presiding Judge's finding that trial staff's ancillary service bid caps are representative of the ceiling costs of these services during the locked-in period. For the reasons discussed above, we approve SoCal Edison's proposed ancillary service bid caps, as filed.

The Commission orders:

(A) The Initial Decision is hereby vacated in part, affirmed in part, and reversed in part, as discussed in the body of this order.

(B) The motions to intervene filed by EEI, ELCON, AISI, and the ISO Participants are hereby granted, as discussed in the body of this order.

---

[60] Trial staff calculated the unit-by-unit costs for SoCal Edison's hydro generation resources, resulting in a maximum capacity charge of \$26.02/MW/hr. See Exhibit S-4, at 16-18 and Exh. S8). In contrast, SoCal Edison's proposed ancillary services bid caps ranged from \$4.47/MW/hr to \$9.55/MW/hr. See TO Tariff and DA Tariff at Original, Sheet Nos. 74 through 78.

(C) SoCal Edison is hereby directed to file, within 45 days of the date of this order, a compliance filing addressing those matters discussed herein. However, if a request for rehearing is pending at the end of the 45 day period, the compliance filing shall be made within 15 days of the date such rehearing is disposed of by the Commission.

By the Commission.

(S E A L)

David P. Boergers

David P. Boergers,
Secretary.

BRIEF EXHIBIT 4

2-14 Did Staff perform a cost of service study or similar analysis in connection with developing its proposed rate design for each Western Group system? If your answer is in the affirmative, please provide copies of all studies, reports, work papers, published materials and other documents that Staff has used in connection with developing its proposed rate design.

Staff Response: No

Response by: Ronald Ludders

2-15 In connection with developing its proposed rate design for each Western Group system, did Staff conduct a billing analysis and study of the impacts that its proposed rate designs would have on various customers? If your answer is in the affirmative, please provide a copy of all studies, reports, work papers, published materials and other documents concerning such analysis.

Staff Response: No

Response by: Ronald Ludders

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSE TO ARIZONA WATER COMPANY'S SECOND DATA REQUESTS
Docket Nos. W-01445A-04-0650

May 9, 2005

2-16 Did Staff conduct an analysis of possible consumption and revenue impacts in connection with developing its proposed rate design for each Western Group system? If your answer is in the affirmative, please provide copies of all studies, reports, work papers, published materials and other documents relating to such analysis.

Staff Response: No

Response by: Ronald Ludders

BRIEF
EXHIBIT 5

RUCO'S RESPONSE
***

SECOND SET OF DATA REQUESTS
FROM ARIZONA WATER COMPANY
TO THE RESIDENTIAL UTILITY CONSUMER OFFICE
(Docket No. W-01445A-04-0650)

2.12 Did RUCO perform a cost of service study or similar analysis in connection with developing its proposed rate design for each Western Group system? If your answer is in the affirmative, please provide copies of all studies, reports, work papers, published materials and other documents that RUCO has used in connection with developing its proposed rate design as well as an electronic version of the study.

Response (Coley):

No.

RUCO'S RESPONSE

***

SECOND SET OF DATA REQUESTS
FROM ARIZONA WATER COMPANY
TO THE RESIDENTIAL UTILITY CONSUMER OFFICE
(Docket No. W-01445A-04-0650)

2.13 In connection with developing its proposed rate design for each Western Group system, did RUCO conduct a billing analysis and study of the impacts that its proposed rate designs would have on various customers? If your answer is in the affirmative, please provide copies of all studies, reports, work papers, published materials and other documents concerning such analysis as well as an electronic version of the study.

Response (Coley):

See RUCO's Direct Testimony TJC-19, pages 1-4, and WAR-19, pages 1-4.

RUCO'S RESPONSE

***

SECOND SET OF DATA REQUESTS
FROM ARIZONA WATER COMPANY
TO THE RESIDENTIAL UTILITY CONSUMER OFFICE
(Docket No. W-01445A-04-0650)

2.14 Did RUCO conduct an analysis of possible consumption and revenue and revenue impacts in connection with developing its proposed rate design for each Western Group system? If your answer is in the affirmative, please provide copies of all studies, reports, work papers, published materials and other document concerning such analysis as well as an electronic version of the study.

Response (Coley):

No.