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Attorneys for Arizona Water Company

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AZ CORP COMMISSION
DOCUMENT CONTROL

Arizona Corporation Commission
DOCKETED
SEP 15 2004
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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 **NOTICE OF FILING OF CORRECTED TESTIMONY OF THOMAS M. ZEPP AND PAGE OMITTED FROM BILL COUNT**

On September 8, 2004 Arizona Water Company, an Arizona corporation (the "Company"), filed its application for an order approving certain adjustments to its rates and charges for utility service provided by the Company's Western Group, which includes five separate water systems in Arizona. In support of its application, the Company filed, among other things, the direct testimony of Thomas M. Zepp.

This week, the Company discovered that it inadvertently omitted some attachments that should have been filed with Dr. Zepp's direct testimony. For that reason, the Company is filing with this Notice a separate (Dr. Zepp's testimony as filed on September 8 was included in a bound volume with the testimony of other Company witnesses) bound volume of Dr. Zepp's direct testimony that includes the previously omitted schedules. Dr. Zepp's testimony is otherwise unchanged.

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The Company has also discovered that a page was inadvertently omitted from its bill count that was also filed with its application on September 8. The omitted page concerned four inch meters in the White Tank system. The Company is filing with this Notice the omitted page, which should be included with the original bill count, and, for the benefit of the Staff and other parties, all of the pages from the bill count for the White Tank system, including the previously omitted page. The bill count is otherwise unchanged.

RESPECTFULLY SUBMITTED this 15th day of September, 2004.

ARIZONA WATER COMPANY

By: Robert W. Geake

Robert W. Geake
Vice President and General Counsel
ARIZONA WATER COMPANY
Post Office Box 29006
Phoenix, Arizona 85038-9006

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Attorneys for Applicant
Arizona Water Company

An original and thirteen (13) copies of the foregoing, together with the separately bound attachments and direct testimony referenced therein, were filed this 15th day of September, 2004 with:

Docketing Supervisor
Docket Control Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

A copy of the foregoing, together with the document referenced therein, were delivered this 15th day of September, 2004 to:

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

ORIGINAL

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

Christopher Kempley, Chief Counsel
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

By: Robert W. Geake

ORIGINAL

1/07/04 SYSTEM: 044 WHITE TANK
12.07.25 METER SIZE: 4 INCH

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451J-.

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS PASSING THRU BLOCK	ALL BILLS: M GALLONS	ALL BILLS: PERCENT
.0	0	0	.00	.0	.0	.0	.0	.00
.1	0	0	.00	.0	.0	.0	.0	.00
.2	0	0	.00	.0	.0	.0	.0	.00
.3	0	0	.00	.0	.0	.0	.0	.00
.4	0	0	.00	.0	.0	.0	.0	.00
.5	0	0	.00	.0	.0	.0	.0	.00
.6	0	0	.00	.0	.0	.0	.0	.00
.7	0	0	.00	.0	.0	.0	.0	.00
.8	0	0	.00	.0	.0	.0	.0	.00
.9	0	0	.00	.0	.0	.0	.0	.00
1.0	0	0	.00	.0	.0	.0	.0	.00
1.2	0	0	.00	.0	.0	.0	.0	.00
1.4	0	0	.00	.0	.0	.0	.0	.00
1.6	0	0	.00	.0	.0	.0	.0	.00
1.8	0	0	.00	.0	.0	.0	.0	.00
2.0	0	0	.00	.0	.0	.0	.0	.00
2.5	0	0	.00	.0	.0	.0	.0	.00
3.0	0	0	.00	.0	.0	.0	.0	.00
3.5	0	0	.00	.0	.0	.0	.0	.00
4.0	0	0	.00	.0	.0	.0	.0	.00
4.5	0	0	.00	.0	.0	.0	.0	.00
5.0	0	0	.00	.0	.0	.0	.0	.00
6.0	0	0	.00	.0	.0	.0	.0	.00
7.0	0	0	.00	.0	.0	.0	.0	.00
8.0	0	0	.00	.0	.0	.0	.0	.00
9.0	0	0	.00	.0	.0	.0	.0	.00
10.0	0	0	.00	.0	.0	.0	.0	.00
12.0	0	0	.00	.0	.0	.0	.0	.00
14.0	0	0	.00	.0	.0	.0	.0	.00
16.0	0	0	.00	.0	.0	.0	.0	.00
18.0	0	0	.00	.0	.0	.0	.0	.00
20.0	0	0	.00	.0	.0	.0	.0	.00
25.0	0	0	.00	.0	.0	.0	.0	.00
30.0	0	0	.00	.0	.0	.0	.0	.00
35.0	0	0	.00	.0	.0	.0	.0	.00
40.0	0	0	.00	.0	.0	.0	.0	.00
50.0	0	0	.00	.0	.0	.0	.0	.00
60.0	0	0	.00	.0	.0	.0	.0	.00
70.0	0	0	.00	.0	.0	.0	.0	.00
80.0	0	0	.00	.0	.0	.0	.0	.00
90.0	0	0	.00	.0	.0	.0	.0	.00
100.0	0	0	.00	.0	.0	.0	.0	.00
120.0	0	0	.00	.0	.0	.0	.0	.00
140.0	0	0	.00	.0	.0	.0	.0	.00
160.0	0	0	.00	.0	.0	.0	.0	.00
200.0	0	0	.00	.0	.0	.0	.0	.00
250.0	0	0	.00	.0	.0	.0	.0	.00
300.0	0	0	.00	.0	.0	.0	.0	.00
400.0	0	0	.00	.0	.0	.0	.0	.00
500.0	0	0	.00	.0	.0	.0	.0	.00

TOTAL BILLS	0
TOTAL USAGE	.0
AVG GALLONS/BILL	0
AVERAGE CUSTOMERS	0

This page was inadvertently omitted from September 8, 2004 filing.

1/07/04 SYSTEM: 044 WHITE TANK
12.07.25 METER SIZE: 5/8 INCH

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451D-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE BLS ENDING IN BLOCK	CUMMULATIVE USE BLS PASSING THRU BLOCK	ALL BILLS M GALLONS	ALL BILLS PERCENT
.0	202	15,014	100.00	.0	.0	.0	.0	.00
.1	88	14,812	98.65	8.8	8.8	1,472.4	1,481.2	.76
.2	57	14,724	98.07	11.4	20.2	2,933.4	2,953.6	1.51
.3	51	14,667	97.69	15.3	35.5	4,384.8	4,420.3	2.26
.4	50	14,616	97.35	20.0	55.5	5,826.4	5,881.9	3.01
.5	55	14,566	97.02	27.5	83.0	7,255.5	7,338.5	3.76
.6	42	14,511	96.65	25.2	108.2	8,681.4	8,789.6	4.50
.7	56	14,469	96.37	39.2	147.4	10,089.1	10,236.5	5.24
.8	54	14,413	96.00	43.2	190.6	11,487.2	11,677.8	5.98
.9	48	14,359	95.64	41.4	232.0	12,879.9	13,111.9	6.71
1.0	55	14,311	95.32	55.0	287.0	14,256.0	14,543.0	7.44
1.2	86	14,256	94.95	93.9	380.9	17,004.0	17,384.9	8.90
1.4	112	14,170	94.38	151.4	532.3	19,681.2	20,213.5	10.35
1.6	118	14,058	93.63	183.4	715.7	22,304.0	23,019.7	11.78
1.8	117	13,940	92.85	205.0	920.7	24,881.4	25,802.1	13.21
2.0	134	13,823	92.07	253.3	1,174.0	27,378.0	28,552.0	14.61
2.5	321	13,689	91.17	738.2	1,912.2	33,420.0	35,332.2	18.08
3.0	371	13,368	89.04	1,040.4	2,952.6	38,991.0	41,943.6	21.47
3.5	406	12,997	86.57	1,341.3	4,293.9	44,068.5	48,362.4	24.75
4.0	477	12,591	83.86	1,813.3	6,107.2	48,456.0	54,563.2	27.93
4.5	505	12,114	80.68	2,166.6	8,273.8	52,240.5	60,514.3	30.97
5.0	566	11,609	77.32	2,710.5	10,984.3	55,215.0	66,199.3	33.88
6.0	1,019	11,043	73.55	5,653.7	16,638.0	60,144.0	76,782.0	39.30
7.0	1,024	10,024	66.76	6,695.3	23,333.3	63,000.0	86,333.3	44.18
8.0	920	9,000	59.94	6,916.7	30,250.0	64,640.0	94,890.0	48.56
9.0	838	8,080	53.82	7,151.1	37,401.1	65,178.0	102,579.1	52.50
10.0	777	7,242	48.23	7,363.4	44,764.5	64,650.0	109,414.5	56.00
12.0	1,191	6,465	43.06	13,108.9	57,873.4	63,288.0	121,161.4	62.01
14.0	900	5,274	35.13	11,704.7	69,578.1	61,236.0	130,814.1	66.95
16.0	752	4,374	29.13	11,280.6	80,858.7	57,952.0	138,810.7	71.04
18.0	576	3,622	24.12	9,794.0	90,652.7	54,828.0	145,480.7	74.46
20.0	465	3,046	20.29	8,853.2	99,505.9	51,620.0	151,125.9	77.35
25.0	803	2,581	17.19	17,926.1	117,432.0	44,450.0	161,882.0	82.85
30.0	497	1,778	11.84	13,623.7	131,055.7	38,430.0	169,485.7	86.74
35.0	371	1,281	8.53	12,008.4	143,064.1	31,850.0	174,914.1	89.52
40.0	242	910	6.06	9,052.5	152,116.6	26,720.0	178,836.6	91.53
50.0	282	668	4.45	12,534.3	164,650.9	19,300.0	183,950.9	94.14
60.0	136	386	2.57	7,304.9	171,955.8	15,000.0	186,955.8	95.68
70.0	83	250	1.67	5,363.4	177,319.2	11,690.0	189,009.2	96.73
80.0	46	167	1.11	3,405.4	180,724.6	9,680.0	190,404.6	97.45
90.0	37	121	.81	3,149.1	183,873.7	7,560.0	191,433.7	97.97
100.0	21	84	.56	1,973.0	185,846.7	6,300.0	192,146.7	98.34
120.0	25	63	.42	2,717.6	188,564.3	4,560.0	193,124.3	98.84
140.0	19	38	.25	2,496.9	191,061.2	2,660.0	193,721.2	99.15
160.0	6	19	.13	895.0	191,956.2	2,080.0	194,036.2	99.31
200.0	6	13	.09	1,097.4	193,053.6	1,400.0	194,453.6	99.52
250.0	2	7	.05	426.1	193,479.7	1,250.0	194,729.7	99.66
300.0	2	5	.03	545.8	194,025.5	900.0	194,925.5	99.76
400.0	2	3	.02	639.8	194,665.3	400.0	195,065.3	99.83
500.0	0	1	.01	.0	194,665.3	500.0	195,165.3	99.88
99999.9	1	1	.01	725.9	195,391.2	.0	195,391.2	100.00

TOTAL BILLS	15,014
TOTAL USAGE	195,391.2
AVG GALLONS/BILL	13,014
AVERAGE CUSTOMERS	1,251

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451J-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS PASSING THRU BLOCK	CUMMULATIVE USE: ALL BILLS M GALLONS	CUMMULATIVE USE: ALL BILLS PERCENT
.0	4	183	100.00	.0	.0	.0	.0	.00
.1	1	179	97.81	.1	.1	17.8	17.9	.22
.2	1	178	97.27	.2	.3	35.4	35.7	.44
.3	1	177	96.72	.3	.6	52.8	53.4	.66
.4	0	176	96.17	.0	.6	70.4	71.0	.88
.5	1	176	96.17	.5	1.1	87.5	88.6	1.10
.6	0	175	95.63	.0	1.1	105.0	106.1	1.32
.7	0	175	95.63	.0	1.1	122.5	123.6	1.53
.8	0	175	95.63	.0	1.1	140.0	141.1	1.75
.9	0	175	95.63	.0	1.1	157.5	158.6	1.97
1.0	0	175	95.63	.0	1.1	175.0	176.1	2.19
1.2	2	175	95.63	2.3	3.4	207.6	211.0	2.62
1.4	1	173	94.54	1.4	4.8	240.8	245.6	3.05
1.6	2	172	93.99	3.0	7.8	272.0	279.8	3.47
1.8	1	170	92.90	1.7	9.5	304.2	313.7	3.89
2.0	0	169	92.35	.0	9.5	338.0	347.5	4.31
2.5	4	169	92.35	9.0	18.5	412.5	431.0	5.35
3.0	4	165	90.16	11.5	30.0	483.0	513.0	6.37
3.5	4	161	87.98	12.9	42.9	549.5	592.4	7.35
4.0	3	157	85.79	11.5	54.4	616.0	670.4	8.32
4.5	6	154	84.15	25.4	79.8	666.0	745.8	9.26
5.0	1	148	80.87	4.7	84.5	735.0	819.5	10.17
6.0	6	147	80.33	34.5	119.0	846.0	965.0	11.98
7.0	7	141	77.05	46.9	165.9	938.0	1,103.9	13.70
8.0	7	134	73.22	52.6	218.5	1,016.0	1,234.5	15.33
9.0	4	127	69.40	33.9	252.4	1,107.0	1,359.4	16.88
10.0	3	123	67.21	29.5	281.9	1,200.0	1,481.9	18.40
12.0	10	120	65.57	108.6	390.5	1,320.0	1,710.5	21.23
14.0	7	110	60.11	90.0	480.5	1,442.0	1,922.5	23.87
16.0	10	103	56.28	146.9	627.4	1,488.0	2,115.4	26.26
18.0	1	93	50.82	17.0	644.4	1,656.0	2,300.4	28.56
20.0	0	92	50.27	.0	644.4	1,840.0	2,484.4	30.84
25.0	12	92	50.27	274.3	918.7	2,000.0	2,918.7	36.23
30.0	4	80	43.72	107.8	1,026.5	2,280.0	3,306.5	41.05
35.0	9	76	41.53	295.4	1,321.9	2,345.0	3,666.9	45.52
40.0	9	67	36.61	343.3	1,665.2	2,320.0	3,985.2	49.47
50.0	11	58	31.69	482.9	2,148.1	2,350.0	4,498.1	55.84
60.0	8	47	25.68	448.3	2,596.4	2,340.0	4,936.4	61.28
70.0	14	39	21.31	918.2	3,514.6	1,750.0	5,264.6	65.36
80.0	6	25	13.66	442.0	3,956.6	1,520.0	5,476.6	67.99
90.0	3	19	10.38	255.8	4,212.4	1,440.0	5,652.4	70.17
100.0	2	16	8.74	182.6	4,395.0	1,400.0	5,795.0	71.94
120.0	2	14	7.65	207.4	4,602.4	1,440.0	6,042.4	75.01
140.0	2	12	6.56	250.4	4,852.8	1,400.0	6,252.8	77.63
160.0	1	10	5.46	145.6	4,998.4	1,440.0	6,438.4	79.93
200.0	0	9	4.92	.0	4,998.4	1,800.0	6,798.4	84.40
250.0	2	9	4.92	431.3	5,429.7	1,750.0	7,179.7	89.13
300.0	1	7	3.83	296.5	5,726.2	1,800.0	7,526.2	93.43
400.0	3	6	3.28	1,000.5	6,726.7	1,200.0	7,926.7	98.41
500.0	3	3	1.64	1,328.4	8,055.1	.0	8,055.1	100.00

TOTAL BILLS	183
TOTAL USAGE	8,055.1
AVG GALLONS/BILL	44,017
AVERAGE CUSTOMERS	15

1/07/04 SYSTEM: 044 WHITE TANK
12.07.25 METER SIZE: 1 1/2 INCH

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451J-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE BLS ENDING IN BLOCK	CUMMULATIVE USE BLS PASSING THRU BLOCK	ALL BILLS M GALLONS	ALL BILLS PERCENT
.0	0	0	.00	.0	.0	.0	.0	.00
.1	0	0	.00	.0	.0	.0	.0	.00
.2	0	0	.00	.0	.0	.0	.0	.00
.3	0	0	.00	.0	.0	.0	.0	.00
.4	0	0	.00	.0	.0	.0	.0	.00
.5	0	0	.00	.0	.0	.0	.0	.00
.6	0	0	.00	.0	.0	.0	.0	.00
.7	0	0	.00	.0	.0	.0	.0	.00
.8	0	0	.00	.0	.0	.0	.0	.00
.9	0	0	.00	.0	.0	.0	.0	.00
1.0	0	0	.00	.0	.0	.0	.0	.00
1.2	0	0	.00	.0	.0	.0	.0	.00
1.4	0	0	.00	.0	.0	.0	.0	.00
1.6	0	0	.00	.0	.0	.0	.0	.00
1.8	0	0	.00	.0	.0	.0	.0	.00
2.0	0	0	.00	.0	.0	.0	.0	.00
2.5	0	0	.00	.0	.0	.0	.0	.00
3.0	0	0	.00	.0	.0	.0	.0	.00
3.5	0	0	.00	.0	.0	.0	.0	.00
4.0	0	0	.00	.0	.0	.0	.0	.00
4.5	0	0	.00	.0	.0	.0	.0	.00
5.0	0	0	.00	.0	.0	.0	.0	.00
6.0	0	0	.00	.0	.0	.0	.0	.00
7.0	0	0	.00	.0	.0	.0	.0	.00
8.0	0	0	.00	.0	.0	.0	.0	.00
9.0	0	0	.00	.0	.0	.0	.0	.00
10.0	0	0	.00	.0	.0	.0	.0	.00
12.0	0	0	.00	.0	.0	.0	.0	.00
14.0	0	0	.00	.0	.0	.0	.0	.00
16.0	0	0	.00	.0	.0	.0	.0	.00
18.0	0	0	.00	.0	.0	.0	.0	.00
20.0	0	0	.00	.0	.0	.0	.0	.00
25.0	0	0	.00	.0	.0	.0	.0	.00
30.0	0	0	.00	.0	.0	.0	.0	.00
35.0	0	0	.00	.0	.0	.0	.0	.00
40.0	0	0	.00	.0	.0	.0	.0	.00
50.0	0	0	.00	.0	.0	.0	.0	.00
60.0	0	0	.00	.0	.0	.0	.0	.00
70.0	0	0	.00	.0	.0	.0	.0	.00
80.0	0	0	.00	.0	.0	.0	.0	.00
90.0	0	0	.00	.0	.0	.0	.0	.00
100.0	0	0	.00	.0	.0	.0	.0	.00
120.0	0	0	.00	.0	.0	.0	.0	.00
140.0	0	0	.00	.0	.0	.0	.0	.00
160.0	0	0	.00	.0	.0	.0	.0	.00
200.0	0	0	.00	.0	.0	.0	.0	.00
250.0	0	0	.00	.0	.0	.0	.0	.00
300.0	0	0	.00	.0	.0	.0	.0	.00
400.0	0	0	.00	.0	.0	.0	.0	.00
500.0	0	0	.00	.0	.0	.0	.0	.00

TOTAL BILLS	0
TOTAL USAGE	.0
AVG GALLONS/BILL	0
AVERAGE CUSTOMERS	0

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451J-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE BLS ENDING IN BLOCK	CUMMULATIVE USE BLS PASSING THRU BLOCK	ALL BILLS M GALLONS	ALL BILLS PERCENT
.0	0	24	100.00	.0	.0	.0	.0	.00
.1	0	24	100.00	.0	.0	2.4	2.4	.08
.2	0	24	100.00	.0	.0	4.8	4.8	.16
.3	0	24	100.00	.0	.0	7.2	7.2	.24
.4	0	24	100.00	.0	.0	9.6	9.6	.33
.5	0	24	100.00	.0	.0	12.0	12.0	.41
.6	0	24	100.00	.0	.0	14.4	14.4	.49
.7	0	24	100.00	.0	.0	16.8	16.8	.57
.8	0	24	100.00	.0	.0	19.2	19.2	.65
.9	0	24	100.00	.0	.0	21.6	21.6	.73
1.0	0	24	100.00	.0	.0	24.0	24.0	.82
1.2	0	24	100.00	.0	.0	28.8	28.8	.98
1.4	0	24	100.00	.0	.0	33.6	33.6	1.14
1.6	0	24	100.00	.0	.0	38.4	38.4	1.31
1.8	0	24	100.00	.0	.0	43.2	43.2	1.47
2.0	0	24	100.00	.0	.0	48.0	48.0	1.63
2.5	0	24	100.00	.0	.0	60.0	60.0	2.04
3.0	0	24	100.00	.0	.0	72.0	72.0	2.45
3.5	2	24	100.00	6.3	6.3	77.0	83.3	2.83
4.0	0	22	91.67	.0	6.3	88.0	94.3	3.21
4.5	0	22	91.67	.0	6.3	99.0	105.3	3.58
5.0	1	22	91.67	4.6	10.9	105.0	115.9	3.94
6.0	0	21	87.50	.0	10.9	126.0	136.9	4.66
7.0	1	21	87.50	6.7	17.6	140.0	157.6	5.36
8.0	0	20	83.33	.0	17.6	160.0	177.6	6.04
9.0	0	20	83.33	.0	17.6	180.0	197.6	6.72
10.0	0	20	83.33	.0	17.6	200.0	217.6	7.40
12.0	0	20	83.33	.0	17.6	240.0	257.6	8.76
14.0	1	20	83.33	12.2	29.8	266.0	295.8	10.06
16.0	1	19	79.17	15.1	44.9	288.0	332.9	11.32
18.0	0	18	75.00	.0	44.9	324.0	368.9	12.55
20.0	0	18	75.00	.0	44.9	360.0	404.9	13.77
25.0	0	18	75.00	.0	44.9	450.0	494.9	16.83
30.0	2	18	75.00	58.3	103.2	480.0	583.2	19.83
35.0	0	16	66.67	.0	103.2	560.0	663.2	22.55
40.0	1	16	66.67	38.0	141.2	600.0	741.2	25.21
50.0	5	15	62.50	221.6	362.8	500.0	862.8	29.34
60.0	1	10	41.67	51.6	414.4	540.0	954.4	32.46
70.0	0	9	37.50	.0	414.4	630.0	1,044.4	35.52
80.0	0	9	37.50	.0	414.4	720.0	1,134.4	38.58
90.0	0	9	37.50	.0	414.4	810.0	1,224.4	41.64
100.0	0	9	37.50	.0	414.4	900.0	1,314.4	44.70
120.0	1	9	37.50	105.8	520.2	960.0	1,480.2	50.34
140.0	0	8	33.33	.0	520.2	1,120.0	1,640.2	55.78
160.0	1	8	33.33	141.9	662.1	1,120.0	1,782.1	60.61
200.0	2	7	29.17	396.5	1,058.6	1,000.0	2,058.6	70.01
250.0	0	5	20.83	.0	1,058.6	1,250.0	2,308.6	78.51
300.0	0	5	20.83	.0	1,058.6	1,500.0	2,558.6	87.02
400.0	3	5	20.83	967.4	2,026.0	800.0	2,826.0	96.11
500.0	2	2	8.33	914.4	2,940.4	.0	2,940.4	100.00

TOTAL BILLS	24
TOTAL USAGE	2,940.4
AVG GALLONS/BILL	122,517
AVERAGE CUSTOMERS	2

1/01/04 SYSTEM: 044 WHITE TANK
12.07.25 METER SIZE: 3 INCH

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL4510-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS PASSING THRU BLOCK	CUMMULATIVE USE: ALL BILLS M GALLONS	CUMMULATIVE USE: ALL BILLS PERCENT
.0	0	24	100.00	.0	.0	.0	.0	.00
.1	0	24	100.00	.0	.0	2.4	2.4	.05
.2	0	24	100.00	.0	.0	4.8	4.8	.10
.3	0	24	100.00	.0	.0	7.2	7.2	.14
.4	0	24	100.00	.0	.0	9.6	9.6	.19
.5	0	24	100.00	.0	.0	12.0	12.0	.24
.6	0	24	100.00	.0	.0	14.4	14.4	.29
.7	0	24	100.00	.0	.0	16.8	16.8	.33
.8	0	24	100.00	.0	.0	19.2	19.2	.38
.9	0	24	100.00	.0	.0	21.6	21.6	.43
1.0	0	24	100.00	.0	.0	24.0	24.0	.48
1.2	0	24	100.00	.0	.0	28.8	28.8	.57
1.4	0	24	100.00	.0	.0	33.6	33.6	.67
1.6	0	24	100.00	.0	.0	38.4	38.4	.76
1.8	0	24	100.00	.0	.0	43.2	43.2	.86
2.0	0	24	100.00	.0	.0	48.0	48.0	.95
2.5	0	24	100.00	.0	.0	60.0	60.0	1.19
3.0	0	24	100.00	.0	.0	72.0	72.0	1.43
3.5	0	24	100.00	.0	.0	84.0	84.0	1.67
4.0	0	24	100.00	.0	.0	96.0	96.0	1.91
4.5	0	24	100.00	.0	.0	108.0	108.0	2.15
5.0	0	24	100.00	.0	.0	120.0	120.0	2.39
6.0	0	24	100.00	.0	.0	144.0	144.0	2.86
7.0	0	24	100.00	.0	.0	168.0	168.0	3.34
8.0	0	24	100.00	.0	.0	192.0	192.0	3.82
9.0	1	24	100.00	9.0	9.0	207.0	216.0	4.30
10.0	0	23	95.83	.0	9.0	230.0	239.0	4.75
12.0	0	23	95.83	.0	9.0	276.0	285.0	5.67
14.0	0	23	95.83	.0	9.0	322.0	331.0	6.58
16.0	0	23	95.83	.0	9.0	368.0	377.0	7.50
18.0	0	23	95.83	.0	9.0	414.0	423.0	8.41
20.0	0	23	95.83	.0	9.0	460.0	469.0	9.33
25.0	0	23	95.83	.0	9.0	575.0	584.0	11.62
30.0	0	23	95.83	.0	9.0	690.0	699.0	13.90
35.0	0	23	95.83	.0	9.0	805.0	814.0	16.19
40.0	0	23	95.83	.0	9.0	920.0	929.0	18.48
50.0	0	23	95.83	.0	9.0	1,150.0	1,159.0	23.05
60.0	2	23	95.83	118.3	127.3	1,260.0	1,387.3	27.59
70.0	1	21	87.50	64.5	191.8	1,400.0	1,591.8	31.66
80.0	4	20	83.33	297.2	489.0	1,280.0	1,769.0	35.19
90.0	0	16	66.67	.0	489.0	1,440.0	1,929.0	38.37
100.0	1	16	66.67	94.8	583.8	1,500.0	2,083.8	41.45
120.0	1	15	62.50	106.8	690.6	1,680.0	2,370.6	47.15
140.0	1	14	58.33	124.9	815.5	1,820.0	2,635.5	52.42
160.0	1	13	54.17	140.7	956.2	1,920.0	2,876.2	57.21
200.0	2	12	50.00	376.8	1,333.0	2,000.0	3,333.0	66.29
250.0	2	10	41.67	422.1	1,755.1	2,000.0	3,755.1	74.69
300.0	3	8	33.33	841.3	2,596.4	1,500.0	4,096.4	81.48
400.0	2	5	20.83	661.4	3,257.8	1,200.0	4,457.8	88.66
500.0	1	3	12.50	422.0	3,679.8	1,000.0	4,679.8	93.08
99999.9	2	2	8.33	1,347.9	5,027.7	.0	5,027.7	100.00

TOTAL BILLS	24
TOTAL USAGE	5,027.7
AVG GALLONS/BILL	209,488
AVERAGE CUSTOMERS	2

1/01/04 SYSTEM: 044 WHITE TANK
12.07.25 METER SIZE: 4 INCH

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451J-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS PASSING THRU BLOCK	CUMMULATIVE USE: ALL BILLS M GALLONS	CUMMULATIVE USE: ALL BILLS PERCENT
.0	0	0	.00	.0	.0	.0	.0	.00
.1	0	0	.00	.0	.0	.0	.0	.00
.2	0	0	.00	.0	.0	.0	.0	.00
.3	0	0	.00	.0	.0	.0	.0	.00
.4	0	0	.00	.0	.0	.0	.0	.00
.5	0	0	.00	.0	.0	.0	.0	.00
.6	0	0	.00	.0	.0	.0	.0	.00
.7	0	0	.00	.0	.0	.0	.0	.00
.8	0	0	.00	.0	.0	.0	.0	.00
.9	0	0	.00	.0	.0	.0	.0	.00
1.0	0	0	.00	.0	.0	.0	.0	.00
1.2	0	0	.00	.0	.0	.0	.0	.00
1.4	0	0	.00	.0	.0	.0	.0	.00
1.6	0	0	.00	.0	.0	.0	.0	.00
1.8	0	0	.00	.0	.0	.0	.0	.00
2.0	0	0	.00	.0	.0	.0	.0	.00
2.5	0	0	.00	.0	.0	.0	.0	.00
3.0	0	0	.00	.0	.0	.0	.0	.00
3.5	0	0	.00	.0	.0	.0	.0	.00
4.0	0	0	.00	.0	.0	.0	.0	.00
4.5	0	0	.00	.0	.0	.0	.0	.00
5.0	0	0	.00	.0	.0	.0	.0	.00
6.0	0	0	.00	.0	.0	.0	.0	.00
7.0	0	0	.00	.0	.0	.0	.0	.00
8.0	0	0	.00	.0	.0	.0	.0	.00
9.0	0	0	.00	.0	.0	.0	.0	.00
10.0	0	0	.00	.0	.0	.0	.0	.00
12.0	0	0	.00	.0	.0	.0	.0	.00
14.0	0	0	.00	.0	.0	.0	.0	.00
16.0	0	0	.00	.0	.0	.0	.0	.00
18.0	0	0	.00	.0	.0	.0	.0	.00
20.0	0	0	.00	.0	.0	.0	.0	.00
25.0	0	0	.00	.0	.0	.0	.0	.00
30.0	0	0	.00	.0	.0	.0	.0	.00
35.0	0	0	.00	.0	.0	.0	.0	.00
40.0	0	0	.00	.0	.0	.0	.0	.00
50.0	0	0	.00	.0	.0	.0	.0	.00
60.0	0	0	.00	.0	.0	.0	.0	.00
70.0	0	0	.00	.0	.0	.0	.0	.00
80.0	0	0	.00	.0	.0	.0	.0	.00
90.0	0	0	.00	.0	.0	.0	.0	.00
100.0	0	0	.00	.0	.0	.0	.0	.00
120.0	0	0	.00	.0	.0	.0	.0	.00
140.0	0	0	.00	.0	.0	.0	.0	.00
160.0	0	0	.00	.0	.0	.0	.0	.00
200.0	0	0	.00	.0	.0	.0	.0	.00
250.0	0	0	.00	.0	.0	.0	.0	.00
300.0	0	0	.00	.0	.0	.0	.0	.00
400.0	0	0	.00	.0	.0	.0	.0	.00
500.0	0	0	.00	.0	.0	.0	.0	.00

TOTAL BILLS	0
TOTAL USAGE	.0
AVG GALLONS/BILL	0
AVERAGE CUSTOMERS	0

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL451J-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE BLS ENDING IN BLOCK	CUMMULATIVE USE BLS PASSING THRU BLOCK	ALL BILLS M GALLONS	ALL BILLS PERCENT
.0	0	0	.00	.0	.0	.0	.0	.00
.1	0	0	.00	.0	.0	.0	.0	.00
.2	0	0	.00	.0	.0	.0	.0	.00
.3	0	0	.00	.0	.0	.0	.0	.00
.4	0	0	.00	.0	.0	.0	.0	.00
.5	0	0	.00	.0	.0	.0	.0	.00
.6	0	0	.00	.0	.0	.0	.0	.00
.7	0	0	.00	.0	.0	.0	.0	.00
.8	0	0	.00	.0	.0	.0	.0	.00
.9	0	0	.00	.0	.0	.0	.0	.00
1.0	0	0	.00	.0	.0	.0	.0	.00
1.2	0	0	.00	.0	.0	.0	.0	.00
1.4	0	0	.00	.0	.0	.0	.0	.00
1.6	0	0	.00	.0	.0	.0	.0	.00
1.8	0	0	.00	.0	.0	.0	.0	.00
2.0	0	0	.00	.0	.0	.0	.0	.00
2.5	0	0	.00	.0	.0	.0	.0	.00
3.0	0	0	.00	.0	.0	.0	.0	.00
3.5	0	0	.00	.0	.0	.0	.0	.00
4.0	0	0	.00	.0	.0	.0	.0	.00
4.5	0	0	.00	.0	.0	.0	.0	.00
5.0	0	0	.00	.0	.0	.0	.0	.00
6.0	0	0	.00	.0	.0	.0	.0	.00
7.0	0	0	.00	.0	.0	.0	.0	.00
8.0	0	0	.00	.0	.0	.0	.0	.00
9.0	0	0	.00	.0	.0	.0	.0	.00
10.0	0	0	.00	.0	.0	.0	.0	.00
12.0	0	0	.00	.0	.0	.0	.0	.00
14.0	0	0	.00	.0	.0	.0	.0	.00
16.0	0	0	.00	.0	.0	.0	.0	.00
18.0	0	0	.00	.0	.0	.0	.0	.00
20.0	0	0	.00	.0	.0	.0	.0	.00
25.0	0	0	.00	.0	.0	.0	.0	.00
30.0	0	0	.00	.0	.0	.0	.0	.00
35.0	0	0	.00	.0	.0	.0	.0	.00
40.0	0	0	.00	.0	.0	.0	.0	.00
50.0	0	0	.00	.0	.0	.0	.0	.00
60.0	0	0	.00	.0	.0	.0	.0	.00
70.0	0	0	.00	.0	.0	.0	.0	.00
80.0	0	0	.00	.0	.0	.0	.0	.00
90.0	0	0	.00	.0	.0	.0	.0	.00
100.0	0	0	.00	.0	.0	.0	.0	.00
120.0	0	0	.00	.0	.0	.0	.0	.00
140.0	0	0	.00	.0	.0	.0	.0	.00
160.0	0	0	.00	.0	.0	.0	.0	.00
200.0	0	0	.00	.0	.0	.0	.0	.00
250.0	0	0	.00	.0	.0	.0	.0	.00
300.0	0	0	.00	.0	.0	.0	.0	.00
400.0	0	0	.00	.0	.0	.0	.0	.00
500.0	0	0	.00	.0	.0	.0	.0	.00

TOTAL BILLS	0
TOTAL USAGE	.0
AVG GALLONS/BILL	0
AVERAGE CUSTOMERS	0

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* METER TOTALS *

SCHEDULE H-5 -BL4510-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE BLS ENDING IN BLOCK	CUMMULATIVE USE BLS PASSING THRU BLOCK	ALL BILLS M GALLONS	ALL BILLS PERCENT
.0	0	0	.00	.0	.0	.0	.0	.00
.1	0	0	.00	.0	.0	.0	.0	.00
.2	0	0	.00	.0	.0	.0	.0	.00
.3	0	0	.00	.0	.0	.0	.0	.00
.4	0	0	.00	.0	.0	.0	.0	.00
.5	0	0	.00	.0	.0	.0	.0	.00
.6	0	0	.00	.0	.0	.0	.0	.00
.7	0	0	.00	.0	.0	.0	.0	.00
.8	0	0	.00	.0	.0	.0	.0	.00
.9	0	0	.00	.0	.0	.0	.0	.00
1.0	0	0	.00	.0	.0	.0	.0	.00
1.2	0	0	.00	.0	.0	.0	.0	.00
1.4	0	0	.00	.0	.0	.0	.0	.00
1.6	0	0	.00	.0	.0	.0	.0	.00
1.8	0	0	.00	.0	.0	.0	.0	.00
2.0	0	0	.00	.0	.0	.0	.0	.00
2.5	0	0	.00	.0	.0	.0	.0	.00
3.0	0	0	.00	.0	.0	.0	.0	.00
3.5	0	0	.00	.0	.0	.0	.0	.00
4.0	0	0	.00	.0	.0	.0	.0	.00
4.5	0	0	.00	.0	.0	.0	.0	.00
5.0	0	0	.00	.0	.0	.0	.0	.00
6.0	0	0	.00	.0	.0	.0	.0	.00
7.0	0	0	.00	.0	.0	.0	.0	.00
8.0	0	0	.00	.0	.0	.0	.0	.00
9.0	0	0	.00	.0	.0	.0	.0	.00
10.0	0	0	.00	.0	.0	.0	.0	.00
12.0	0	0	.00	.0	.0	.0	.0	.00
14.0	0	0	.00	.0	.0	.0	.0	.00
16.0	0	0	.00	.0	.0	.0	.0	.00
18.0	0	0	.00	.0	.0	.0	.0	.00
20.0	0	0	.00	.0	.0	.0	.0	.00
25.0	0	0	.00	.0	.0	.0	.0	.00
30.0	0	0	.00	.0	.0	.0	.0	.00
35.0	0	0	.00	.0	.0	.0	.0	.00
40.0	0	0	.00	.0	.0	.0	.0	.00
50.0	0	0	.00	.0	.0	.0	.0	.00
60.0	0	0	.00	.0	.0	.0	.0	.00
70.0	0	0	.00	.0	.0	.0	.0	.00
80.0	0	0	.00	.0	.0	.0	.0	.00
90.0	0	0	.00	.0	.0	.0	.0	.00
100.0	0	0	.00	.0	.0	.0	.0	.00
120.0	0	0	.00	.0	.0	.0	.0	.00
140.0	0	0	.00	.0	.0	.0	.0	.00
160.0	0	0	.00	.0	.0	.0	.0	.00
200.0	0	0	.00	.0	.0	.0	.0	.00
250.0	0	0	.00	.0	.0	.0	.0	.00
300.0	0	0	.00	.0	.0	.0	.0	.00
400.0	0	0	.00	.0	.0	.0	.0	.00
500.0	0	0	.00	.0	.0	.0	.0	.00

TOTAL BILLS	0
TOTAL USAGE	.0
AVG GALLONS/BILL	0
AVERAGE CUSTOMERS	0

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS PASSING THRU BLOCK	ALL BILLS M GALLONS	ALL BILLS PERCENT
.0	0	0	.00	.0	.0	.0	.0	.00
.1	0	0	.00	.0	.0	.0	.0	.00
.2	0	0	.00	.0	.0	.0	.0	.00
.3	0	0	.00	.0	.0	.0	.0	.00
.4	0	0	.00	.0	.0	.0	.0	.00
.5	0	0	.00	.0	.0	.0	.0	.00
.6	0	0	.00	.0	.0	.0	.0	.00
.7	0	0	.00	.0	.0	.0	.0	.00
.8	0	0	.00	.0	.0	.0	.0	.00
.9	0	0	.00	.0	.0	.0	.0	.00
1.0	0	0	.00	.0	.0	.0	.0	.00
1.2	0	0	.00	.0	.0	.0	.0	.00
1.4	0	0	.00	.0	.0	.0	.0	.00
1.6	0	0	.00	.0	.0	.0	.0	.00
1.8	0	0	.00	.0	.0	.0	.0	.00
2.0	0	0	.00	.0	.0	.0	.0	.00
2.5	0	0	.00	.0	.0	.0	.0	.00
3.0	0	0	.00	.0	.0	.0	.0	.00
3.5	0	0	.00	.0	.0	.0	.0	.00
4.0	0	0	.00	.0	.0	.0	.0	.00
4.5	0	0	.00	.0	.0	.0	.0	.00
5.0	0	0	.00	.0	.0	.0	.0	.00
6.0	0	0	.00	.0	.0	.0	.0	.00
7.0	0	0	.00	.0	.0	.0	.0	.00
8.0	0	0	.00	.0	.0	.0	.0	.00
9.0	0	0	.00	.0	.0	.0	.0	.00
10.0	0	0	.00	.0	.0	.0	.0	.00
12.0	0	0	.00	.0	.0	.0	.0	.00
14.0	0	0	.00	.0	.0	.0	.0	.00
16.0	0	0	.00	.0	.0	.0	.0	.00
18.0	0	0	.00	.0	.0	.0	.0	.00
20.0	0	0	.00	.0	.0	.0	.0	.00
25.0	0	0	.00	.0	.0	.0	.0	.00
30.0	0	0	.00	.0	.0	.0	.0	.00
35.0	0	0	.00	.0	.0	.0	.0	.00
40.0	0	0	.00	.0	.0	.0	.0	.00
50.0	0	0	.00	.0	.0	.0	.0	.00
60.0	0	0	.00	.0	.0	.0	.0	.00
70.0	0	0	.00	.0	.0	.0	.0	.00
80.0	0	0	.00	.0	.0	.0	.0	.00
90.0	0	0	.00	.0	.0	.0	.0	.00
100.0	0	0	.00	.0	.0	.0	.0	.00
120.0	0	0	.00	.0	.0	.0	.0	.00
140.0	0	0	.00	.0	.0	.0	.0	.00
160.0	0	0	.00	.0	.0	.0	.0	.00
200.0	0	0	.00	.0	.0	.0	.0	.00
250.0	0	0	.00	.0	.0	.0	.0	.00
300.0	0	0	.00	.0	.0	.0	.0	.00
400.0	0	0	.00	.0	.0	.0	.0	.00
500.0	0	0	.00	.0	.0	.0	.0	.00

TOTAL BILLS	0
TOTAL USAGE	.0
AVG GALLONS/BILL	0
AVERAGE CUSTOMERS	0

ARIZONA WATER COMPANY
BILL COUNT
TEST YEAR 2003

* SYSTEM TOTALS *

SCHEDULE H-5 -BL4510-

USAGE BLOCK M GAL	# OF BILLS IN BLOCK	CUM BLS THRU BLOCK NUMBER	CUM BLS THRU BLOCK PERCENT	TOTAL USE OF BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS ENDING IN BLOCK	CUMMULATIVE USE: BLS PASSING THRU BLOCK	CUMMULATIVE USE: ALL BILLS M GALLONS	CUMMULATIVE USE: ALL BILLS PERCENT
.0	206	15,245	100.00	.0	.0	.0	.0	.00
.1	89	15,039	98.65	8.9	8.9	1,495.0	1,503.9	.71
.2	58	14,950	98.06	11.6	20.5	2,978.4	2,998.9	1.42
.3	52	14,892	97.68	15.6	36.1	4,452.0	4,488.1	2.12
.4	50	14,840	97.34	20.0	56.1	5,916.0	5,972.1	2.82
.5	56	14,790	97.02	28.0	84.1	7,367.0	7,451.1	3.52
.6	42	14,734	96.65	25.2	109.3	8,815.2	8,924.5	4.22
.7	56	14,692	96.37	39.2	148.5	10,245.2	10,393.7	4.92
.8	54	14,636	96.01	43.2	191.7	11,665.6	11,857.3	5.61
.9	48	14,582	95.65	41.4	233.1	13,080.6	13,313.7	6.30
1.0	55	14,534	95.34	55.0	288.1	14,479.0	14,767.1	6.98
1.2	88	14,479	94.98	96.2	384.3	17,269.2	17,653.5	8.35
1.4	113	14,391	94.40	152.8	537.1	19,989.2	20,526.3	9.71
1.6	120	14,278	93.66	186.4	723.5	22,652.8	23,376.3	11.06
1.8	118	14,158	92.87	206.7	930.2	25,272.0	26,202.2	12.39
2.0	134	14,040	92.10	253.3	1,183.5	27,812.0	28,995.5	13.72
2.5	325	13,906	91.22	747.2	1,930.7	33,952.5	35,883.2	16.97
3.0	375	13,581	89.08	1,051.9	2,982.6	39,618.0	42,600.6	20.15
3.5	412	13,206	86.63	1,360.5	4,343.1	44,779.0	49,122.1	23.23
4.0	480	12,794	83.92	1,824.8	6,167.9	49,256.0	55,423.9	26.22
4.5	511	12,314	80.77	2,192.0	8,359.9	53,113.5	61,473.4	29.08
5.0	568	11,803	77.42	2,719.8	11,079.7	56,175.0	67,254.7	31.81
6.0	1,025	11,235	73.70	5,688.2	16,767.9	61,260.0	78,027.9	36.91
7.0	1,032	10,210	66.97	6,748.9	23,516.8	64,246.0	87,762.8	41.51
8.0	927	9,178	60.20	6,969.3	30,486.1	66,008.0	96,494.1	45.64
9.0	843	8,251	54.12	7,194.0	37,680.1	66,672.0	104,352.1	49.36
10.0	780	7,408	48.59	7,392.9	45,073.0	66,280.0	111,353.0	52.67
12.0	1,201	6,628	43.48	13,217.5	58,290.5	65,124.0	123,414.5	58.38
14.0	908	5,427	35.60	11,806.9	70,097.4	63,266.0	133,363.4	63.08
16.0	763	4,519	29.64	11,442.6	81,540.0	60,096.0	141,636.0	66.99
18.0	577	3,756	24.64	9,811.0	91,351.0	57,222.0	148,573.0	70.28
20.0	465	3,179	20.85	8,853.2	100,204.2	54,280.0	154,484.2	73.07
25.0	815	2,714	17.80	18,200.4	118,404.6	47,475.0	165,879.6	78.46
30.0	503	1,899	12.46	13,789.8	132,194.4	41,880.0	174,074.4	82.34
35.0	380	1,396	9.16	12,303.8	144,498.2	35,560.0	180,058.2	85.17
40.0	252	1,016	6.66	9,433.8	153,932.0	30,560.0	184,492.0	87.27
50.0	298	764	5.01	13,238.8	167,170.8	23,300.0	190,470.8	90.09
60.0	147	466	3.06	7,923.1	175,093.9	19,140.0	194,233.9	91.87
70.0	98	319	2.09	6,346.1	181,440.0	15,470.0	196,910.0	93.14
80.0	56	221	1.45	4,144.6	185,584.6	13,200.0	198,784.6	94.03
90.0	40	165	1.08	3,404.9	188,989.5	11,250.0	200,239.5	94.71
100.0	24	125	.82	2,250.4	191,239.9	10,100.0	201,339.9	95.23
120.0	29	101	.66	3,137.6	194,377.5	8,640.0	203,017.5	96.03
140.0	22	72	.47	2,872.2	197,249.7	7,000.0	204,249.7	96.61
160.0	9	50	.33	1,323.2	198,572.9	6,560.0	205,132.9	97.03
200.0	10	41	.27	1,870.7	200,443.6	6,200.0	206,643.6	97.74
250.0	6	31	.20	1,279.5	201,723.1	6,250.0	207,973.1	98.37
300.0	6	25	.16	1,683.6	203,406.7	5,700.0	209,106.7	98.91
400.0	10	19	.12	3,269.1	206,675.8	3,600.0	210,275.8	99.46
500.0	6	9	.06	2,664.8	209,340.6	1,500.0	210,840.6	99.73
99999.9	3	3	.02	2,073.8	211,414.4	.0	211,414.4	100.00

TOTAL BILLS	15,245
TOTAL USAGE	211,414.4
AVG GALLONS/BILL	13,868
AVERAGE CUSTOMERS	1,270

ARIZONA WATER COMPANY

Docket No. W-01445A-04-0650

2004 RATE HEARING EXHIBIT NO. ___

For Test Year Ending 12/31/03

CORRECTED

DIRECT TESTIMONY & EXHIBITS

OF

Thomas M. Zepp

TABLE OF CONTENTS

ARIZONA WATER

Direct Testimony of

Thomas M. Zepp

I. <u>INTRODUCTION AND QUALIFICATIONS</u>

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. My name is Thomas M. Zepp. My business address is Suite 250, 1500 Liberty Street, S.E., Salem, Oregon 97302.

Q. WHAT IS YOUR PROFESSION AND BACKGROUND?

A. I am an economist and Vice President of Utility Resources, Inc., a consulting firm. I received my Ph.D. in Economics from the University of Florida. Prior to jointly establishing our consulting firm in 1985, I was a consultant at Zinder Companies from 1982-1985 and a senior economist on the staff of the Oregon Public Utility Commission between 1976-1982. Prior to 1976, I taught business and economics courses at the graduate and undergraduate levels.

I have been deposed or testified on various topics before regulatory commissions, courts and legislative committees in 22 states, before two Canadian regulatory authorities and before four Federal agencies. In addition to cost of capital studies, I have testified as to incremental costs of energy and telecommunications services, determined values of utilities' properties and have presented rate design testimony.

Q. WHAT COST OF CAPITAL STUDIES HAVE YOU PREPARED?

A. I have prepared and submitted studies or testified on cost of capital and other financial issues before the Interstate Commerce Commission, Bonneville Power Administration, and courts or regulatory agencies in Alaska, Arizona, California, Hawaii, Idaho, Illinois, Kentucky, Montana, Nevada, New Mexico, Oregon, Tennessee, Utah, Washington and Wyoming.

My studies and testimony have included consideration of the financial health and fair rates of return for Arizona Water in past cases and for Nevada Bell Telephone, Illinois Bell Telephone, General Telephone of the Northwest, Pacific Northwest Bell, US West, Anchorage Municipal Light & Power, Pacific Power & Light, Portland General Electric, Commonwealth Edison, Northern Illinois Gas, Iowa-Illinois Gas and Electric, Puget Sound Power & Light, Idaho Power, Cascade Natural Gas, Mountain Fuel Supply, Northwest Natural Gas, Arizona-American Water Company, California-American Water Company, California Water Service, Dominguez Water Company, Hawaii-American Water Company, Kentucky-American Water Company, Mountain Water Company, New Mexico-American Water Company, Oregon Water Company, Paradise Valley Water Company, Park Water Company, San Gabriel Valley Water Company, Southern California Water Company, Tennessee-American Water Company and Valencia Water Company. I have also prepared estimates of the appropriate rates of return for a number of hospitals in Washington, a large insurance company, and U.S. railroads.

Q. DO YOU HAVE OTHER PROFESSIONAL EXPERIENCE RELATED TO COST OF CAPITAL ISSUES?

A. Yes. My article, "Utility Stocks and the Size Effect - Revisited," was published in *The Quarterly Review of Economics and Finance*, Vol. 43, Issue 3 (Autumn 2003) 578-582. Also, I published an article "Water Utilities and Risk," in *Water: The Magazine of the National Association of Water Companies*, Vol. 40, No. 1 (Winter 1999), and was an invited speaker on the topic of risk of water utilities at the 57th Annual Western Conference of Public Utility Commissioners in June 1998. I presented a paper entitled "Application of the Capital Asset Pricing

Model in the Regulatory Setting" at the 47th Annual Southern Economic Association Conference and published an article entitled "On the Use of the CAPM in Public Utility Rate Cases: Comment" in *Financial Management* (Autumn 1978) 52-56. While on the staff of the Oregon Public Utility Commission, I established a sample of over 500,000 observations of common stock returns and measures of risk and conducted a number of studies related to the use of various methods to estimate cost of equity for utilities. I was invited to Stanford University to discuss that research.

II. PURPOSE OF TESTIMONY, BASIC PRINCIPLES, SUMMARY AND CONCLUSIONS

Q. WHAT IS THE SUBJECT OF YOUR TESTIMONY IN THIS PROCEEDING?

A. Arizona Water ("Arizona Water" or "the Company") has asked me to estimate its cost of equity and the fair rate of return on common equity. My study is based on data available to investors in June 2004.

Q. HOW IS YOUR TESTIMONY ORGANIZED?

A. In this Section II, the concept of a fair rate of return and a summary of my analysis is presented.

In Section III, the general risks of water utility common stocks and specific additional risks faced by Arizona Water are discussed. I explain why the Company's cost of equity should be increased by at least 50 basis points above the cost of equity for samples of water utilities used to determine benchmark estimates of the cost of equity to account for added risk resulting from Arizona's particular rate-setting system, from losing its Purchased Water Adjustment Mechanism ("PWAM") and Purchased Power Adjustment Mechanism ("PPAM") previously available in its Eastern Group systems, from inverted rates recently imposed in the Eastern Group, and from continuing risk of not recovering all of its required costs to meet new federal arsenic maximum contaminant level ("MCL") requirements. I also discuss other risks faced by Arizona Water that Arizona Corporation Commission Utilities Division Staff ("Staff") challenged in Docket No. W-01445A-02-0619 ("Arizona Water's last GRC"), but at the Company's request, do not propose a risk premium to account for such risks in this case.

Section IV provides an overview and perspective on what one should expect the fair rate of return to be in 2005 and 2006, the initial period when new rates for Arizona Water will be approved, and develops my discounted cash flow ("DCF") equity cost estimates. In making my DCF equity cost estimates, I have recognized that the Administrative Law Judges and subsequently the Arizona Corporation Commission (the "Commission" or "ACC") relied exclusively on estimates of the cost of equity made by Staff in Arizona Water's last GRC, and in Arizona-American Water Company, Decision No. 67093, Docket No. WS-01303A-02-0867, et al. I have acknowledged that fact by determining my DCF equity cost estimates with methods used by the Federal Energy Regulatory Commission ("FERC") instead of methods I presented in those cases. The extremely low DCF equity cost estimates adopted by the Commission for water utilities in 2004 depended on the way Staff implemented the capital asset pricing model ("CAPM") and DCF model based on interest rates and data in 2003. While I believe the methods the FERC uses to implement the DCF model are conservative and may understate the cost of equity, the FERC approaches are based upon many years of deliberations and are clearly superior to the approaches taken by Staff in 2003.

Section V presents equity cost estimates based on the risk premium approach. In the two Commission water utility cases listed above, Staff relied upon the original version of the CAPM to make its risk premium equity cost estimates. To make my risk premium equity cost estimates, I rely on the methods and data the California Public Utilities Commission Staff ("CPUC Staff") has used for many years to make risk premium equity cost estimates for water utilities. These risk premium estimates are transparent and straightforward, and they do not depend on the many choices and assumptions required to implement the original version of the CAPM. In my opinion, equity cost estimates based on the risk premium method and data relied upon by the CPUC Staff are clearly superior to risk premium equity cost estimates based on the original version of CAPM that the Staff relied on in 2003.

Section VI presents a summary of the equity cost estimates based on the FERC DCF approaches and the CPUC Staff risk premium approaches. I also present additional information on past Commission decisions that corroborates my equity cost estimates. This information shows that since December 2001, Staff's revised methods of estimating the cost of equity have caused a substantial decrease in equity cost estimates when compared to the equity returns authorized by the Commission during the previous 10-year period.

Q. HAVE YOU PREPARED ANY TABLES AND ATTACHMENTS TO ACCOMPANY YOUR TESTIMONY?

A. Yes. I have prepared 15 tables and three attachments that support my testimony.

Q. PLEASE PROVIDE SOME PERSPECTIVE AND AN OVERVIEW OF THE ISSUES YOU ADDRESS IN YOUR TESTIMONY.

A. Investors can choose to invest in many different types of assets with varying degrees of risk. Those investments might be in real estate, or gold, or collections of fine art, or financial assets. The financial assets run the gamut from relatively low risk assets such as Treasury securities and somewhat higher risk investment grade corporate bonds to relatively high-risk shares of common stocks. As the level of risk increases, investors require higher expected returns. Common stocks of utilities are generally more risky and thus require higher returns than investment grade bonds, which are secured debt instruments with fixed repayment terms. Operating expenses, interest on debt and repayment of principal take precedence over payments to common stock holders, and thus it is the common equity shareholder of the utility who bears the greatest risk of receiving expected returns. Conceptually,

$$\text{Required return for common stock} = \text{Return on a risk-free asset} + \text{risk premium}$$

where the risk premium required for common stocks will be higher than it is for investment grade bonds.

Regulators generally set rates to recover a utility's costs of service. One of those costs of service is the cost of common equity, the required return for the utility's common stock. Rates that give a utility a reasonable opportunity to earn the cost of equity are fair to customers of the utility. Such rates are also fair to owners of the utility because the cost of equity is equal to returns expected to be earned by other companies of comparable risk, is high enough to attract capital, and allows the utility to maintain its financial integrity.

Q. HAS THE U.S. SUPREME COURT SET FORTH ANY STANDARDS THAT APPLY TO EQUITY RETURNS?

A. Yes. In 1923, the U.S. Supreme Court set forth the following standards in *Bluefield Waterworks & Improvement Co. v. Public Utility Commission of West Virginia,* 262 U.S. 679 (1923):

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs

> for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

262 U.S. at 692-93.

In *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591 (1944), the U.S. Supreme Court stated the following regarding the return to owners of a company:

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 603.

Q. ARE THERE OTHER CONSIDERATIONS THAT SHOULD BE RECOGNIZED?

A. Yes. In determining an appropriate return, consideration must be given to the specific risks created by the nature and degree of regulation to which the utility is subject, in addition to examining general economic and financial data for utilities. The Arizona Constitution, Arizona appellate court decisions, and the Commission's policies and practices create a particular rate-setting system that limits the ability of Arizona utilities to earn a fair return on the value of their property devoted to public service. For example, in Arizona there are limitations on out-of-period adjustments that are more restrictive than general rate case procedures available to water utilities in the sample I use to determine benchmark equity costs estimates.

Arizona Water also faces the risk that it will have unexpected costs in the period in which new rates are in effect but will not be able to recover such unexpected costs without a costly and lengthy general rate case. This particular rate setting system increases risk and thus requires the Commission to authorize higher rates of return on common equity ("ROE") than would be the case in jurisdictions such as California, which use forecasted or projected test periods and allow utilities to implement surcharges and other mechanisms to recover unexpected costs without going through a general rate case.

Additionally, Arizona Water has higher risk because the Commission has eliminated the Company's PPAM and PWAM in the Eastern Group and approved inverted block rate structures for those water systems to encourage water conservation. These added risks should be recognized when setting the fair rate of return for the Company.

Q. WHAT ARE THE IMPLICATIONS OF THESE ADDED RISKS IN THE DETERMINATION OF A FAIR RATE OF RETURN FOR ARIZONA WATER?

A. The added risks are important to customers and equity investors of Arizona Water. From the perspective of customers, the cost of equity is another cost of service, and customers' rates should cover that cost just as rates should cover other costs of service. The rates customers pay should provide a reasonable opportunity, but not a guarantee, for Arizona Water to earn that cost of equity.

From the perspective of equity owners, the added risks require rates and rate adjustment mechanisms that provide a reasonable opportunity to earn a return for its equity investors that maintains the utility's financial integrity, is commensurate with returns on investments in other enterprises having corresponding risks, and is sufficient to attract capital on reasonable terms. As I discuss further below, Arizona Water is more risky than the water utilities sample I rely upon to determine benchmark estimates of the cost of equity and thus its required common equity return is higher.

Q. PLEASE SUMMARIZE YOUR TESTIMONY?

A. My findings and recommendations are the following:

1. The cost of common equity faced by Arizona Water is greater than the cost of common equity that faces my water utilities sample:
   (a) The Company faces risk that stems from the use of an historical test year with limited opportunities for out-of-period adjustments.
   (b) The ACC eliminated its PPAM and PWAM in the Eastern Group. Such purchased power cost and purchased water cost adjusters are similar to ones available to the water utilities sample and thus Arizona Water is now more risky than the water utilities sample.
   (c) The Company's arsenic treatment cost recovery mechanism ("ACRM") does not provide the opportunity to recover all reasonable costs of meeting the new federal arsenic MCL.

(d) Arizona Water faces risk due to the Commission's proposed policy that Staff consider the appropriateness of an inverted three-tiered commodity rate structure for all water company rate cases to encourage reductions in water use, which may destabilize and reduce revenues.

(e) Based on the risks discussed in (a), (b), (c) and (d) that are greater for Arizona Water than for the water utilities sample, the Company has an equity cost that is at least 50 basis points higher than the benchmark water utilities.

(f) Arizona Water is also more risky than the water utilities sample because it is smaller and has more limited financial flexibility than the sample companies. The Company, however, is not requesting an additional risk premium to account for these added risks in this proceeding.

2. The market cost of common equity faced by the benchmark water utilities falls in a range of 10.2% to 11.4% at this time:

- Conservative estimates of the cost of equity derived with DCF methods used by the FERC indicate the cost of equity for the benchmark water utilities falls in a range of 10.2% to 10.4%;
- Costs of equity derived from methods and data used by the CPUC Staff to determine risk premium equity costs for water utilities indicate the cost of equity for benchmark water utilities falls in the range of 10.6% to 11.4%.
- Past Commission decisions for water and gas utilities indicate an average cost of equity of 11.0%. Given new risks faced by Arizona Water, the authorized ROE should be higher than 11.0%.

3. Based on the risks of the rate-setting system in Arizona, loss of the Eastern Group adjustment mechanisms that allowed the Company to recover changes in the costs of purchased power and purchased water, an ACRM that does not offer an opportunity to recover all reasonable costs and the risk created by the Commission's proposed policy for an inverted rate design, I recommend an ROE of 11.25% be authorized for Arizona Water in this case. My recommendation is slightly below the mid-point of my estimated cost of equity range. (See Summary Table 15.)

III. RISKS OF WATER UTILITIES AND ARIZONA WATER

Q. AS A PRELIMINARY MATTER, PLEASE DISCUSS THE SAMPLE OF WATER UTILITIES YOU HAVE USED IN YOUR DCF ANALYSIS.

A. My sample of water utilities is composed of American States Water, Aqua America (formerly named Philadelphia Suburban), California Water Service Group, Connecticut Water Service, Middlesex Water and SJW Corp., which are the water utilities the Staff relied upon to determine benchmark equity costs in two general rate cases for Class A water utilities in 2003. Table 1 lists bond ratings, operating revenues and net plant for the six water utilities as reported by C. A. Turner Utility Reports in June 2004.

Q. DO YOU HAVE ANY GENERAL CONCERNS WITH THE DATA AVAILABLE TO MAKE DCF EQUITY COST ESTIMATES FOR WATER UTILITIES?

A. Yes. Table 2 shows premiums that investors in water utilities have received when water utilities were either acquired or merged with other firms. At the time mergers or acquisitions were completed, investors received premiums that ranged between 35% and 55% over market values. Value Line has advised investors to expect such acquisitions and mergers to continue and to expect prices from an acquisition to be as much as four times book value. (See

Attachment 1) As a result, it is reasonable to expect that investors have bid up prices for all water utility stocks to some extent to reflect the probability they may be acquired at a premium, which lowers the result produced by the DCF model.

Table 3 confirms this has happened. It shows that common stock prices for the water utilities in the sample have had an annual average percentage increase during the last five years that exceeded annual average percentage increases in dividends per share ("DPS"), earnings per share ("EPS") and book value per share. The annual average increase in common stock prices also exceeds an average of analysts' forecasts of future growth in EPS. With the constant growth DCF model, *in equilibrium*, book values, common stock prices, EPS and DPS would grow at the same rate. If investors have bid up those stock prices in anticipation that some of the utilities may be targets for favorable mergers or acquisitions, dividend yields will have been bid down and expected future growth rates may not reflect the anticipated higher future prices. In such a situation, application of the constant growth DCF model may produce negatively biased estimates of the cost of equity for water utilities.

Q. DO YOU HAVE OTHER CONCERNS WITH MAKING DCF EQUITY COSTS FOR UTILITIES IN THE ACC STAFF SAMPLE?

A. Yes. There are no forecasts of forward-looking growth for either Connecticut Water Service or SJW Corp at this time. Staff has used past DPS growth, past EPS growth and past sustainable growth (Staff calls sustainable growth "intrinsic growth") as part of its measure of growth to be used in the DCF model. If an average of those measures of growth for Connecticut Water Service is adopted to make an equity cost estimate, that equity cost estimate would be 200 basis points *below* the cost of investment grade debt expected during 2005 which, of course, is not at all realistic. Table 3 shows past DPS growth has been 1.1%

and past EPS growth has been 3.1% for Connecticut Water Service. Past growth from retained earnings has been 3%. Adding an average of those growth rates to an average of the high and low dividend yields of 3.1% (see Table 4) produces an indicated equity cost of *only 5.6%* ((3.1% x 1.024) + 2.4%), which is not credible when the cost of Baa bonds is expected to be 7.6% during 2005 and even higher during 2006, when the Company's new rates will be in effect. (See Table 9) Various institutions that report investor analysts' forecasts of growth (shown in Table 7) do not report such forecasts for Connecticut Water Service at this time. For my implementation of the FERC DCF approach, I assume investors expect Connecticut Water Service to have growth equal to the average growth expected for other water utilities. This is the approach Staff took in past cases such as the recent Arizona-American Water case.

SJW Corp. poses the same problem. If an average of past growth in DPS, EPS and growth indicated by past retained earnings are used to estimate growth, SJW Corp. has an indicated equity cost that is 90 basis points below the expected cost of investment grade bonds in 2005 and thus is not realistic. Table 3 shows past DPS growth has been 3.9% and past EPS growth has been 1.1% for SJW Corp. Past growth from retained earnings has been 5.1%. Adding an average of those growth rates to an average of the high and low dividend yields of 3.2% (see Table 4) produces an indicated equity cost of *only 6.7%* ((3.2% x 1.034) + 3.4%), which is not credible when the cost of Baa bonds is expected to be 7.6% during 2005 and even higher during 2006. Various institutions that report investor analysts' forecasts of growth (shown in Table 7) do not report such forecasts for SJW Corp. at this time. For my implementation of the FERC DCF approach, I assume investors expect SJW Corp. to have growth equal to the average growth expected for other water utilities. Again, Staff has used the same flawed approach in past cases.

Q. **DO YOU HAVE THE SAME CONCERNS WITH INCLUDING CONNECTICUT WATER SERVICE AND SJW CORP. IN THE RISK PREMIUM EQUITY COST ANALYSES?**

A. No. In those risk premium analyses, the data problems with the application of the DCF model are not an issue.

Q. **IN GENERAL, DOES A WATER UTILITY FACE MORE RISK WHEN IT HAS TO MAKE ADDITIONAL INVESTMENTS TO MEET STATE AND FEDERAL WATER QUALITY STANDARDS AND OTHER REGULATORY MANDATES?**

A. Yes. First, expected or unexpected requirements for additional capital spending means the water utilities have to request rate increases more often and for larger percentage increases in order to maintain fair rates of return. Regulatory procedures are expensive, time consuming, increase uncertainty, and raise doubts in investors' minds that regulators will authorize high enough rates and/or rate adjustment mechanisms to enable the water utilities to earn fair rates of return. This increases uncertainty about future returns and thus increases risk.

Second, investors are concerned that regulators will delay inclusion of new plant in rate base or not allow part of the dollars invested or operating costs to be recovered. In Arizona, because there are limitations on out-of-period adjustments, investments may not only be challenged but also may not be allowed in rate base because they are not considered appropriate out-of-period adjustments. If such investments are challenged and there is any chance that the Commission will disallow part of the dollars invested or will delay recovery of the costs of those investments, risk increases. From an investor's point of view, it is the *potential* for such disallowances, delays or exclusion from consideration in setting new rates that increases risk. If additional investments were never required there would be no potential disallowances, delays or possible exclusions and investor concerns would never arise; but, with the need for increased investments, uncertainty arises and the risk increases.

With the need for a rate increase, delay in setting new rates as well as uncertainty related to what those rates will be increases risk above the level of risk faced by water utilities that can expect new rates to better match future costs of service and have less delay in obtaining rate increases.

Q. HAVE YOU STUDIED THE IMPACT OF FINANCING REQUIREMENTS ON THE RISK AND COSTS OF CAPITAL FACED BY UTILITIES?

A. Yes, I have. Several years ago, before recent events in western power markets occurred, I conducted a study of expected differences in bond costs and common equity costs that faced electric utilities with different financing requirements. I found that utilities with above average financing requirements required an ROE that was approximately 80 basis points higher than was required by an average utility. Higher financing requirements pushed up bond costs, too.

Q. DOES THE RATE SETTING SYSTEM USED IN ARIZONA POSE ANY SPECIFIC RISKS TO ARIZONA WATER THAT REQUIRES THE AUTHORIZED ROE TO BE SET ABOVE THE MARKET COST OF EQUITY FOR YOUR WATER UTILITIES SAMPLE?

A. Yes, it does. In its *Duquesne* decision, the U. S. Supreme Court stated:

> [T]he impact of certain rates can only be evaluated in the context of the system under which they are imposed . . . . 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.

Duquesne Light Company v. Barasch, 488 U.S. 299, 314-15 (1989). Two state-specific factors in Arizona make Arizona Water more risky than the utilities in the water utilities sample I rely upon to determine benchmark cost of equity estimates. One factor is the legal constraint on Arizona water utilities that limits their ability to obtain rate relief outside of general rate cases. The Arizona Constitution, as interpreted in recent court decisions, limits the ability of Arizona utilities to utilize adjustment mechanisms, advice letter filings and other streamlined procedures to obtain recovery of costs outside a general rate case, in contrast to many other jurisdictions. For example in *RUCO v. Arizona Corporation Commission*, 199 Ariz. 588, 20 P.3d 1169 (App. 2001), the court held the Commission violated the Arizona Constitution because it authorized a water utility to implement a surcharge to recover increased purchased water costs without finding the utility's "fair value." These limitations on obtaining rate relief in Arizona make it more risky for Arizona Water to do business than utilities in the states that permit utilities to implement surcharges and other cost recovery mechanisms outside a general rate case.

Second, even in a general rate case, Arizona requires the use of historic test years with limitations on the amount of out-of-period adjustments. This process creates another state-specific factor that increases risk and thus required ROEs for utilities in Arizona. Other states, such as California, use future test years or partially projected test years to better reflect future costs and to match plant, expenses and revenues on a going-forward basis. Such constraints on the determination of new rates in a general rate case make it difficult to construct rates that allow Arizona Water to recover the costs of service it will actually incur during the period when new rates are put in place.

These risks increase Arizona Water's required return on equity above the level required by water utilities that operate in states that do not have such limitations imposed, either by law or by agency policy, on the rate setting system. Under the *Duquesne* decision, the additional risk associated with the particular rate setting system must be compensated with an ROE that is higher than would be appropriate for the utilities in the water utilities sample. Because rate relief in Arizona is generally limited to decisions made during general rate cases, there are unavoidable delays in receiving such rate relief. If it takes the same amount of time for Arizona Water to obtain rate relief as it did in Arizona Water's last GRC and in Arizona-American Water's recent rate case, it will be late 2005 or even early 2006 before new rates for Arizona Water go into effect.

Q. DOES ARIZONA WATER FACE OTHER ADDITIONAL RISKS NOT FACED BY UTILITIES IN THE WATER UTILITY SAMPLE?

A. Yes. Arizona Water faces risk that unavoidable purchased water and purchased power costs in its Eastern Group systems will not be recovered and risk that costs to treat arsenic that are not recognized by its ACRM will not be recovered.

Generally, changes in purchased water and purchased power costs are beyond the control of Arizona Water. In the Eastern Group rate case, Staff recommended elimination and subsequently the Commission eliminated Arizona Water's PPAMs and PWAMs in the Eastern Group systems. The PPAMs and the PWAMs are similar to cost adjusters available to the water utilities in the water utilities sample. Such adjusters reduce risk for the water utilities sample and thus the elimination of the PPAMs and PWAMs in the Company's Eastern Group systems by the Commission has made Arizona Water more risky than the sample water utilities. Such risk is heightened by the fact that Arizona Public Service has filed for increases in electric rates that Arizona Water must pay to provide service to its customers but the magnitude of such rate increases on the Company's operations is not known. Without the PPAM, such rate increases – that are beyond the control of Arizona Water, but approved by the Commission – pose a risk to Arizona Water that other water utilities with adjusters similar to the PPAM would not have.

Q. HAVE YOU STUDIED THE IMPACT OF RATE ADJUSTMENT MECHANISMS THAT MITIGATE THE IMPACT OF CHANGES IN COSTS BEYOND THE CONTROL OF WATER UTILITIES ON REQUIRED RETURNS OF EQUITY?

A. Yes, I have. In California, prior to November 2001, unexpected outlays for purchased water, purchased power and pump taxes were booked to balancing accounts and ultimately either refunded to customers or collected from customers in the future independent of an earnings test. The California Office of Ratepayer Advocates ("ORA") proposed a modification of the balancing account mechanism that would continue the balancing accounts, but base recovery of unexpected higher costs on an earnings test. I conducted company-specific simulation analyses of the ORA proposal for three California water utilities and found the cost adjustment mechanisms reduce utilities' costs of equity without placing any added burden on ratepayers.[1] My studies showed that the proposed modification of the balancing account procedures increased required ROEs by at least 75 basis points.[2] These negative impacts on expected ROEs were the result of just a proposed modification of the balancing account mechanisms, not elimination of them. Arizona Water's increased risk due to loss of PPAMs and PWAMs for the Eastern Group is more severe than the change in balancing

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[1] There is no added burden if ratepayers are expected to pay their actual costs of service. A balancing account recovers or refunds only <u>unexpected</u> costs of water or power.

[2] My study indicated increases in required ROEs of 75 basis points for California Water Service, 90 basis points for Southern California Water and 110 basis points for San Gabriel Valley Water Company.

accounts in California, and clearly shows that Arizona Water's risk and required ROE has increased as a result of the Staff recommendation and Commission decision to eliminate PPAMs and PWAMs altogether for some of the Company's systems.

Q. **YOU ALSO MENTIONED THE RISK ARIZONA WATER FACES WITH RESPECT TO RECOVERY OF ARSENIC-RELATED TREATMENT COSTS. DOESN'T ARIZONA WATER HAVE AN ACRM THAT OFFSETS THAT RISK?**

A. No, it does not. EPA's new arsenic MCL of 10 parts per billion ("ppb") requires Arizona Water to make substantial new investments in non-revenue producing facilities which would otherwise not be required and are not required by water utilities in other geographic areas that do not need to remove arsenic from their sources of water. Arizona Water does not have an ACRM approved for its systems in the Western Group, and even for those systems that are covered by an ACRM, the provisions of the ACRM limit the deferral period of recoverable O & M costs, excludes other costs and allows only two filings per system. This does not offset the risk.

Q. **PLEASE DISCUSS THE SITUATION IN THE WESTERN GROUP.**

A. Currently there is no ACRM approved for systems in the Western Group. This raises serious risks for Arizona Water because the investments in arsenic treatment plant for systems in this Group represent 55%, 187% and 37% of the adjusted rate bases for three of those systems and the annual operating and maintenance ("O&M") costs net of taxes to operate those facilities represent 92%, 173% and 129% of the adjusted net operating incomes of those systems. Mr. Kennedy provides more detail on these capital costs and O&M requirements. The Company has filed for an accounting order that would allow it to defer these costs. But even if its request is approved, the Company will be unable to make an ACRM filing until 2006 when the plant must be in place to meet federal treatment requirements. This places a severe financial burden on the Company to finance the Western Group arsenic treatment plant facilities for 12 to 24 months before recovery of these costs could even begin.

Q. DOES THE ACRM APPROVED FOR THE NORTHERN AND EASTERN GROUPS FULLY MITIGATE RISK?

A. No. The ACRM is limited in scope and does not provide Arizona Water with an opportunity for full cost recovery. For many months, the Company, Staff and RUCO attempted to reach an agreement concerning an appropriate ACRM. The Company estimated that, on a company-wide basis, it would have to finance nearly $30 million to construct arsenic treatment facilities and related plant, and would experience increases in O&M costs of more than $5 million. For comparison, the Company's total capitalization was approximately $70 million when those estimates were made and the increased O&M costs were 74% of total 2003 operating income. Consequently, there was general agreement that some sort of cost recovery mechanism was needed. Nevertheless, it was difficult to obtain an agreement with Staff, and no agreement was ever reached with RUCO.

In Decision No. 66400 (October 14, 2003), the ACRM was approved for the Northern Group. In that Decision, the Commission found that

> . . . the agreement between Staff and Arizona Water will enable the Company to recover *a portion* of additional O&M expenses associated with arsenic treatment facilities, whether those facilities are constructed and operated by Arizona Water or by a third party pursuant to a lease agreement. However, the *recovery of O&M*

> *expenses is confined to specific and narrowly defined costs* in order to enable Staff and other parties to more easily audit expenditures incurred by the Company for the treatment facilities. Decision No. 66400 at 20 (emphasis added).

The Commission acknowledged that the ACRM was not designed to give Arizona Water an opportunity for full cost recovery. Arsenic treatment cost recovery is limited to a narrowly defined set of costs. In addition, the Commission required that Arizona Water's rate of return for the affected systems could not exceed the authorized rate of return established in Decision No. 64282. Decision No. 66400 at 17-18. In Arizona Water's last GRC, the Commission approved a similar ACRM for the Eastern Group systems. Decision No. 66849 at 31.

From a risk standpoint, the new arsenic MCL has a much greater impact on water utilities in Arizona than on water utilities in the water utilities sample in other parts of the United States where the natural occurrences of arsenic in water supplies are minimal. The ACRM for the Northern and Eastern Groups mitigates some of the risk of placing and operating new facilities required to meet the federal arsenic standard, but was not designed to allow full recovery of those costs. Given the short time before the deadline for compliance with the federal arsenic standard and the time necessary to make an ACRM filing, assuming approval of a Western Group ACRM in this proceeding, it may not be possible for Arizona Water to recover similar costs for its Western Group systems. Thus, while some of the risk of meeting the new arsenic standard has been mitigated with the ACRM, risk remains, and Arizona Water has more risk than water utilities in the water utilities sample that do not have to make such additional investments and incur such additional O&M costs.

Q. ARE THERE ANY OTHER ASPECTS OF ARIZONA WATER'S RATE SETTING SYSTEM THAT INCREASE RISK?

A. Yes. In the past several years, the Commission has placed increased emphasis on water conservation, and water utilities have been required to implement inverted block rate structures, which are intended to cause customers to use less water. Inverted block rates were an issue in Arizona Water's last GRC, and in its Eastern Group, Arizona Water now has rates based on an inverted block rate design. As a result, Arizona Water is more risky than water utilities that have rates that more closely conform to the costs of providing service.

Because the primary objective of this type of water rate design is to reduce water use, the adoption of inverted block rates creates additional risk. Inverted block rates may cause revenue erosion and instability. American Water Works Association, *Alternative Rates* (1992) 18. At a minimum, it is reasonable to expect some reduction in water use, and therefore a reduction in the utility's revenues, which may prevent it from earning its rate of return. However, the magnitude of these reductions is often difficult to predict. This uncertainty makes it more difficult to develop rates that allow the utility a reasonable opportunity to recover its cost of service, including its cost of equity. This uncertainty creates additional risk that increases Arizona Water's required return on equity.

Q. DO YOU HAVE AN OPINION ABOUT HOW MUCH THE RISK POSED BY THE RATE SETTING SYSTEM IN ARIZONA, THE INADEQUATE RECOVERY OF COSTS BY THE ACRM, THE ELIMINATION OF THE PPAMS AND PWAMS IN THE EASTERN GROUP SYSTEMS, AND THE INVERTED RATES INCREASES ARIZONA WATER'S REQUIRED ROE?

A. Yes. These factors increase the Company's risk and thus its required ROE by at least 50 basis points above the ROE required by the benchmark water utilities.

Q. IS THERE EVIDENCE THAT CORROBORATES THE NEED FOR SUCH A RISK PREMIUM ?

A. Yes, there is. The utilities in the water utilities sample used to determine equity costs are rated by Moody's or S&P at either A or AA. (See Table 1). At the time the cost of the Company's last bond issue was set, it 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-rated bonds. The cost of equity for a utility is undeniably higher than its incremental cost of debt. If the common equity cost risk premium above the cost of debt for Arizona Water is the same as the common equity risk premium above the cost of debt for the water utilities sample, this factual evidence sets the floor under the common equity risk premium required for Arizona Water. Arizona Water, however, has additional common equity risks than the sample water utilities and thus the expected risk premium will be higher than the floor of 37 to 49 basis points. Given the higher risks of Arizona Water that were discussed above, 50 basis points provides a conservative value for that required equity cost risk premium above the cost of equity for the water utilities sample.

Q. DOES ARIZONA WATER FACE OTHER RISKS?

A. Yes. Arizona Water is more risky than the water utilities sample because it is smaller than the average utility in the water utilities sample and has less financial flexibility than those publicly traded utilities.

Smaller companies – and smaller water utilities in particular – are more risky than larger companies. Staff used the original version of the CAPM to determine equity costs in Arizona Water's last general rate case. Thirty years after that original version of CAPM was developed, new scholarly studies[3] found

[3] Beta is the measure of risk in the original CAPM. Eugene Fama and Kenneth French found that even after accounting for differences in beta risk among companies, smaller companies are generally more risky than larger ones. "Industry Costs of Equity," 43 *Journal of Financial Economics* (1997) pp. 153-193.

that version of the CAPM is incomplete and that the size of a company needs to be included in models that explain risk and required returns for common stocks. Thus, if other risk factors are the same, smaller companies require higher equity returns than do larger companies. I published an article in *The Quarterly Review of Economics and Finance* ("Utility Stocks and the Size Effect - Revisited," Vol. 43, Issue 3, Autumn 2003, 578-582) that provides specific evidence that the stocks of small water utilities, like Arizona Water, are more risky than the stocks of larger water utilities, such as those in the water utilities sample. The California PUC also conducted a study that showed smaller water utilities are more risky than larger ones.[4] Even so, the Company is not including an additional risk premium for size in this proceeding, though I believe it would be justified in doing so.

Q. DOES ARIZONA WATER'S LIMITED FINANCIAL FLEXIBILITY INCREASE ITS RISK?

A. Yes. Arizona Water does not have access to the public equity and bond markets that are available to the utilities in the water utilities sample. This lack of financing flexibility increases risk for Arizona Water because it has no choice but to rely on retained earnings, short-term debt, and privately placed bonds to provide the capital necessary to finance the utility plant improvements and additions required to treat arsenic and otherwise assure the quality and reliability of water service. By contrast, utilities in the water utilities sample with publicly traded common equity and bonds have the flexibility to issue shares of common

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In chapter 7 of *Stocks, Bonds, Bills and Inflation, 2004 Yearbook Valuation Edition,* Ibbotson Associates report that when betas are properly estimated, betas are larger for small companies than for larger companies. They also find that even after accounting for differences in beta risk, small firms require an additional risk premium over and above the added risk premium indicated by differences in beta risk.

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

equity to keep their capital structures in balance and raise additional capital from external sources. For example, in its *First Quarter Report to Shareholders*, Middlesex Water stated:

> On May 14, 2004, the Company [Middlesex] closed on the offering of 700,000 shares of its Common Stock. The Company also granted the underwriters an over-allotment option to purchase an additional 100,000 shares. We intend to use the net proceeds to repay most of our outstanding short-term borrowings.

A Note from the President, May 15, 2004, First Quarter Report to Stockholders, Middlesex Water Company. Arizona Water does not have the option to issue common stock to the public to repay its outstanding short-term borrowings or obtain equity capital from the public for any other purpose. This lack of financing flexibility is of special concern to Arizona Water because the Company must make relatively large investments. As with the risk premium for size, the Company is not including a risk premium for this additional risk in this proceeding.

IV. OVERVIEW AND DCF EQUITY COST ESTIMATES

Q. DO YOU HAVE ANY GENERAL OBSERVATIONS THAT PUT YOUR EQUITY COST ESTIMATES IN PERSPECTIVE?

A. Yes. Equity costs move in the same direction as interest rates. In 2003, Treasury rates dropped to the lowest level in close to 40 years. From 1964 to 2002, annual average yields on 10-year Treasury securities, for example, ranged from 4.19% to 13.92%. For the 10-year period ending in 2002, the annual averages of 10-year Treasury rates ranged from 4.61% to 7.09%. By contrast, in 2003, that annual average was only 4.01%.

At present, however, interest rates, and thus costs of equity for Arizona Water, are rising and expected to continue rising. As of June 14, 2004, the 10-year Treasury rate reported by the Federal Reserve was 4.89% and the June 2004 Blue Chip long term consensus forecast for the 10-year Treasury rate for 2005 was 5.6%, rising to 5.9% in 2006. *Value Line* forecasts of Treasury rates made in May 2004 also indicate that interest rates are increasing and expected to be higher in 2005 and 2006 than they are today and much higher than they were in 2003. (See Table 9.) Recently, the Federal Reserve has twice increased its target rate for short-term interest rates for the first time in several years. Most analysts expect further increases. Based on interest rate forecasts alone, the Commission should anticipate reasonable estimates of the cost of equity for water utilities to be higher today than in 2003.

Q. PLEASE PROVIDE AN OVERVIEW OF YOUR DCF EQUITY COST ESTIMATES.

A. An ROE for Arizona Water that is fair to ratepayers, yet still provides a satisfactory return for investors, is the Company's cost of equity. To estimate that cost of equity, the analyst requires market data that reveals investors' required returns, but such data are not available for Arizona Water. It is not publicly traded, and there is no "pure play" company that is perfectly comparable to Arizona Water. Equity costs based on data for the sample of water utilities, however, are for companies that provide the same service and thus provide a useful starting point in the determination of Arizona Water's cost of equity.

I determine DCF equity costs for water utilities based on the two methods the FERC uses to determine DCF equity costs in different situations. When the FERC determines an equity cost for an electric utility, it uses a "one-step" model. Conceptually, the one-step model is the same as the constant growth DCF model the Staff employed in Arizona Water's last GRC. When the FERC determines equity costs for gas transmission companies, it uses a "two-step" DCF model. The two-step model is conceptually the same as the multi-stage DCF equity model Staff presented in that same proceeding.[5]

Q. PLEASE EXPLAIN THE DCF METHOD OF ESTIMATING THE COST OF EQUITY.

A. The constant growth DCF model computes the cost of equity as the sum of an expected dividend yield ("D_1/P_0") and an expected long-term average dividend growth rate ("g"). The expected dividend yield is computed as the ratio of next period's expected dividend ("D_1") divided by the current stock price ("P_0"). Generally, the constant growth model is computed with formula (1) or (2):

(1) Equity Cost $= D_0/P_0 \times (1+g) + g$

(2) Equity Cost $= D_1/P_0 + g$

where D_0/P_0 is the current dividend yield and D_1/P_0 is found by increasing the current yield by the growth rate. The DCF model is derived from the valuation model shown in equation 3 below:

(3) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + \ldots + D_n/(1+k)^n$,

where k is the cost of equity; n is a very large number; P_0 is the current stock price, $D_1, D_2, \ldots D_n$ are the cash flows expected to be received in periods 1, 2, . . . n, respectively. Equation (3) can be re-written to show that the current price (P_0) is also equal to

(4) $P_0 = D_1/(1+k) + D_2/(1+k)^2 + P_2/(1+k)^2$,

where P_2 is the price expected to be received at the end of the second period. When the multi-stage DCF model is used to estimate the cost of equity, it is assumed investors expect different rates of growth in the initial period and

[5] Direct Testimony of Joel M. Reiker, Docket No. W-01445A-02-0619, Schedule JMR-6.

subsequent period.

If the future price (P_2) included a premium, the price the investor would pay today in anticipation of receiving that premium would increase. Table 2 reports premiums investors have recently received from mergers and acquisitions. Attachments 1 and 2 to this testimony explain why such premiums are expected to continue. If investors expect that a water utility is a potential merger/acquisition candidate they will bid its stock price up to the present value of the future price expected from the merger/acquisition to reflect that probability. In such a situation, the dividend yield would be lower and thus either the constant growth (one-step) DCF model or the multi-stage (two-step) DCF model may understate the cost of equity. In making my DCF equity cost estimates below, I do not account for this bias in the DCF equity cost estimates, and thus my DCF equity cost estimates are conservative.

Q. PLEASE BEGIN WITH YOUR DCF ESTIMATES BASED ON THE FERC ONE-STEP MODEL. HOW DOES FERC IMPLEMENT THAT MODEL?

A. The FERC implements the one-step (or constant growth) DCF model by initially combining the lowest and highest dividend yields for individual utilities in the sample during the most recent six month period with two estimates of forward-looking growth to estimate a range of DCF equity costs for the utilities in its sample. Next, the FERC eliminates from consideration any of those equity cost estimates that imply the cost of equity is below the cost of investment grade bonds. Then the FERC determines a range of equity costs for the sample and a mid-point of that range to determine the cost of equity. This method is fully discussed in *Southern California Edison Company*, Opinion No. 445, 92 F.E.R.C. 61,070 (2000). This opinion is included as Attachment 3 to this testimony. More recent FERC decisions refer back to the *Southern California Edison* decision. For example, see FERC findings in *Midwest Independent Transmission System Operator*, 100 F.E.R.C. 61,292 (2002).

Q. HOW DID YOU COMPUTE CURRENT DIVIDEND YIELDS?

A. The FERC one-step method determines a range of dividend yields based on the lowest and the highest dividend yields during the last six months. Table 4 reports those dividend yields for the water utilities sample.

Q. WHAT GROWTH RATES ARE CONSIDERED IN THE FERC ONE-STEP METHOD?

A. The FERC considers estimates of both sustainable growth (growth Staff has called "intrinsic growth") and analysts' forecasts of growth. I agree with the choice of growth estimates relied upon by the FERC. The DCF model requires estimates of growth that investors expect in the future. No weight should be given to historical measures of growth. Logically, financial institutions and analysts would have taken such past information into account, and other more recent information, when they make their forecasts for the future.[6] To the extent that past, recorded results provide useful indications of future growth prospects, the forecasts would already incorporate the past and any further recognition of the past will double-count what has already occurred. When there is no estimate of forward-looking growth for a utility in the water utilities sample, I have followed the method Staff adopted in the past and assumed investors expect the growth for that utility to equal the average of growth rates for the other water utilities in the sample, as explained above.

[6] See David A. Gordon, Myron J. Gordon and Lawrence I. Gould, "Choice Among Methods of Estimating Share Yield," *Journal of Portfolio Management* (Spring 1989). 50-55. Gordon, Gordon and Gould found that a consensus of analysts' forecasts of earnings per share growth for the next five years provides a more accurate estimate of growth required in the DCF model than three different historical measures of growth. They explain that this result makes sense because analysts would take into account such past growth as indicators of future growth as well as any new information.

Q. WHAT IS SUSTAINABLE GROWTH?

A. Sustainable growth is derived by combining expected growth from future retained earnings and expected future growth from sales of common stock above book value. The FERC defines sustainable growth as follows:

> 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 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.

Southern California Edison, 92 F.E.R.C. at p. 61,269, citing *Connecticut Light and Power Co.* 45 F.E.R.C. 62,370 at p. 62,161, n. 15 (1988). The retention ratio "b" is equal to (1 - the ratio of dividends divided by earnings) and the equity accretion rate "v" is equal to (1 - (book value divided by market value)). Myron Gordon developed this concept of growth in his book, *The Cost of Capital to a Public Utility* (Michigan State University 1974). Gordon explains why "sv" growth can be expected when market prices exceed book value but why "sv" growth is not expected to come into play when market prices are below book values.

Q. HOW DO YOU ESTIMATE EXPECTED "br" GROWTH?

A. Investors' expectations of what the retention ratio and the expected ROE will be in the future determine this portion of expected sustainable growth. Multiplying "b" times "r" gives the estimate of future sustainable growth from retained earnings. Investors look for measures of future growth when pricing stocks. When the data are available, I have used *Value Line* projections of future ROEs, future DPS and future EPS to make the forecasts of "br" growth. The available estimates of "br" growth are reported in Table 5 as well as the average "br" for those water utilities.

Q. HAVE YOU ESTIMATED "sv" GROWTH FOR THE WATER UTILITIES SAMPLE?

A. Yes. My estimates of "sv" growth for the water utilities are presented in Table 6. I have used Value Line projections of new issues of shares of common stock to estimate "s." The estimates of "v" are based on reported book values and respective averages of the prices used to compute the dividend yields. Some of the utilities in the water utilities sample have sold stock at prices in excess of book value in recent years and have thus achieved "sv" growth. Knowledgeable investors would expect such growth in the future. Available forecasts indicate investors expect some of the sample water utilities to issue more shares of stock over time. Thus there will be a positive "s" term in "sv" growth. Also, the average market-to-book ratio for the sample of water utility stocks is over 2.0. Unless stock prices drop to less than half of their current values, there will be a positive "v" for the foreseeable future.

Q. DOES THE FERC SPECIFICALLY INCLUDE ESTIMATES OF "sv" GROWTH IN THE ESTIMATES OF SUSTAINABLE GROWTH?

A. Yes, it does.

Q. DO MARKET-TO-BOOK RATIOS GREATER THAN 1.0 IMPLY INVESTORS EXPECT THE UTILITIES IN THE WATER UTILITIES SAMPLE TO EARN BOOK RETURNS ON EQUITY GREATER THAN THE COSTS OF EQUITY?

A. No. There are many reasons investors may bid up market prices for stocks above book values other than an expectation that a water utility will earn more than its cost of equity. Investors may expect a city or some other public entity to condemn all or part of a water utility and that the public entity will be required by the court to pay the utility the fair market value for it. Water utilities' assets typically have a value based on reproduction cost that is well in excess of book value. I have testified on the values of water utility properties and electric utility properties in various court cases in California, Utah and Oregon. Based on my experience, in situations where only a portion of the utility is being condemned, valuations based on both reproduction cost new less depreciation and the income approach indicate utility property has a value well in excess of book value. Investors would be aware that courts may award potential condemnation values well in excess of book values even if the utility earns no more than its cost of equity.

Q. ARE THERE OTHER REASONS?

A. Yes. Investors may anticipate a merger or acquisition that produces premium prices similar to those reported in Table 2, which have been well above book values. With such anticipated sale prices well above book values, a water utility would also be priced above book value even if the water utility made no more than its cost of equity. There are other reasons as well.[7]

Q. WHERE DO YOU REPORT YOUR ESTIMATE OF AVERAGE SUSTAINABLE GROWTH?

A. That value is developed in Table 5.

Q. IS THERE ANOTHER INDICATOR OF FUTURE GROWTH THAT THE FERC RELIES UPON WHEN IT IMPLEMENTS THE ONE-STEP DCF APPROACH?

A. Yes. The other estimates of forward-looking growth relied upon by the FERC

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[7] An Oregon Public Utility Commission staff witness listed the following six reasons a market price could exceed book value even if the utility was expected to earn its authorized ROE: (1) public utility commissions do not issue orders simultaneously in all jurisdictions, (2) not all of a company's earnings are regulated, (3) regulatory expenses, revenue and rate base adjustments may cause accounting returns to differ from those calculated on a rate case basis, (4) actual sales do not equal sales assumed in a rate case, (5) market expected ROEs change frequently while rate case authorized ROEs do not, and (6) regulated subsidiaries constitute only a piece of a holding company pie. Testimony of John Thornton in Oregon Docket UM 903 (filed November 9, 1998).

are analysts' forecasts of future five-year EPS growth. Table 7 reports analysts' five-year forecasts of EPS growth reported by a number of financial institutions and the average of those analysts' forecasts. The first two columns of Table 7 show analysts' consensus forecasts of future EPS growth rates reported by Zacks and Thomson First Call that were available for the utilities in the water utilities sample. The third column shows available analysts' growth forecasts for the same water utilities that are reported in the S&P Earnings Guide. Column 4 shows forecasts of EPS growth reported by Value Line at April 30, 2004. The average of analysts' forecasts of growth is 7.0%. For my implementation of the FERC one-step method, I have used the average of these analysts' forecasts of growth for each of the utilities when such forecasts were available. If forecasts were not available, I followed Staff's past practice of assuming investors expect the missing growth rate to equal the average growth expected for the other water utilities in the sample, as explained previously.

Q. HOW DID YOU UTILIZE THIS INFORMATION ON DIVIDEND YIELDS AND ESTIMATED FUTURE GROWTH TO MAKE YOUR BENCHMARK DCF ESTIMATES WITH THE FERC ONE-STEP METHOD?

A. I adopted the approach shown in Table 4. First, adjusted high and low dividend yields were computed for each of the utilities by increasing the current dividend yields shown in column "a" by one-half the average of the two estimates of growth presented in columns "c" and "d". The FERC method increases the current dividend by only one-half of the expected future growth and thus produces a value for D_1/P_0 that is conceptually only six months (instead of one full year) into the future. In my view this results in conservative estimates of the cost of equity, but I have adopted this method in my implementation of the FERC one-step approach because the FERC uses that method.

Next, I computed the low equity cost estimates shown in column "e" of Table 4 for each of the utilities by combining the lowest estimate of growth for each utility with the respective low estimates of the adjusted dividend yield. The equity cost estimates in column "f" were then made by combining the highest estimate of growth with the high dividend yields.

The last step of the FERC one-step method is to estimate the mid-point of the indicated equity cost range as the benchmark cost of equity. Both the mid-point and the average of the various equity cost estimates are 10.2%. This equity cost for the sample understates the Company's cost of equity because Arizona Water is more risky for the reasons discussed above.

Q. DID YOU CONSIDER ALL TWELVE EQUITY COST ESTIMATES WHEN YOU DETERMINED THE MIDPOINT OF THE EQUITY COST RANGE?

A. Yes, I did. As I mentioned above when I described the one-step method, the FERC deletes any individual utility equity cost estimate that is not at least 40 basis points above the cost of investment grade bonds. Based on the estimates made here, none of the indicated costs of equity is that small and thus none was deleted from the range used to determine the mid-point equity cost for the benchmark sample.

Q. PLEASE TURN TO YOUR IMPLEMENTATION OF THE FERC'S TWO-STEP APPROACH. HOW DOES THE TWO-STEP APPROACH DIFFER FROM THE ONE-STEP APPROACH?

A. The FERC two-step approach differs from the one-step approach in that it assumes that investors will expect terminal growth to be different than initial growth. In deriving its two-step approach, the FERC recognized that investment houses use more complex three-stage models in which the first and second stages could have a length of possibly 20 years and the final stage growth is the long-term growth rate of the economy. The FERC also noted that determining the length of such stages requires judgment on the part of the analyst. In Opinion 396-B, the FERC expressed its preference for the simpler two-step model that, in effect, combined the first two stages of the more complicated three-stage model used by investment houses. *Northwest Pipeline Company*, 79 F.E.R.C. 61,309 (1997). The FERC specifically rejected the use of the "investment house approach" in which a complicated three-stage model that required solving for the ROE with an iterative process was used to determine ROE. FERC stated such models are not only complicated but require judgments as to how long initial growth will continue, and whether the transitional growth rate would decline (increase) towards the terminal growth rate slowly, quickly or at a steady rate.

Q. HOW DOES THE FERC DETERMINE GROWTH WITH THE TWO-STEP MODEL?

A. The FERC adopts analysts' forecasts of EPS growth as the growth rate in the first stage, forecasted growth of Gross Domestic Product ("GDP") for growth for the final stage and took an average of those growth rates to compute growth for the two-step model. More recently, in *Southern California Edison*, the FERC indicated it gives a weight of two-thirds to analysts' forecasts of growth and a weight of one-third to GDP growth to compute that average growth rate. *Southern California Edison*, 92 F.E.R.C. at 61, 257 and n.19 (citing *Northwest Pipeline Company*).

Q. HOW DOES THE FERC TWO-STEP MODEL DIFFER FROM THE MULTI-STAGE DCF APPROACH PRESENTED BY STAFF IN THE 2003 ARIZONA WATER AND ARIZONA-AMERICAN WATER CASES?

A. Conceptually, the multi-stage DCF model presented by Staff in water utility rate cases in 2003 is similar to the FERC two-step model, but the choices made by Staff to implement the model lead to significantly lower estimated costs of equity. Both the FERC and Staff assumed terminal growth should ultimately be assumed to equal GDP growth. The distinction between the Staff multi-stage analysis and the FERC two-step method can be boiled down to two significant differences. First, the FERC assumes the initial period before reaching terminal growth is much longer than the four or five years that Staff assumed in its multi-stage model. FERC wisely assumes it will take many years before the terminal growth for a utility will be the same as growth in GDP. Second, the FERC assumes investors rely on EPS growth in the longer, initial period, when they price common stocks. The FERC approach correctly recognizes that it is earnings that permit dividends to be paid and thus bases growth in its longer, initial period on EPS growth, not short-term DPS growth used by Staff in its model.

Q. WHERE DO YOU REPORT YOUR TWO-STEP EQUITY COST ESTIMATE?

A. It is reported in Table 8. In preparing this estimate, I have relied on spot prices instead of an average of prices. Staff has indicated its preference for spot prices.[8] The values for the DCF dividend yield (D_1/P_0) are based on the FERC convention of increasing current dividends by only one-half the growth rate. As I indicated in my discussion of the one-step approach, it is my view that this method of computing dividend yields produces very conservative estimates of the cost of equity. Consistent with the FERC two-step approach described in the *Northwest Pipeline Company* opinion, the initial growth rates are the analysts'

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[8] It is my view that average dividend yields are preferred to spot yields when making DCF equity cost estimates. To eliminate an issue with Staff, the numbers in Table 8 are closing prices at the time this testimony was written.

forecasts of growth. (See Table 4.) The terminal growth rate I have relied upon is 6.5%, which is the estimate of the long-term growth in GDP relied upon by Staff in Arizona Water's last GRC and in Arizona-American Water's recent rate case. That growth rate provides a conservative estimate of the long-term estimate of GDP growth. The more appropriate growth estimate to use in this analysis would be the long-term arithmetic average growth rate of 6.8%. The 6.5% value is the long-term geometric average and thus understates the forward-looking growth required by investors.[9] Therefore, the smaller GDP growth value of 6.5% in my analysis is very conservative. Based on the FERC two-step approach, the indicated cost of equity for the water utilities sample is 10.4%. Because Arizona Water is more risky, its cost of equity is at least 50 basis points higher.

V. RISK PREMIUM EQUITY COST ESTIMATES

Q. PLEASE TURN TO YOUR RISK PREMIUM EQUITY COST ESTIMATES FOR WATER UTILITIES. CAN YOU PROVIDE AN OVERVIEW OF THE RISK PREMIUM METHOD OF ESTIMATING THE COST OF EQUITY?

A. Yes. Under the risk premium approach, the risk premium is directly estimated by comparing authorized and actual returns on equity with the current yields of investment grade bonds or other debt instruments:

> The risk premium method of determining the cost of equity, sometimes referred to as the "stock-bond-yield spread method" or the "risk positioning method," or again the "bond-

[9] This issue is discussed in Ibbotson Associates, *SBBI 2003 Yearbook* 100-101. The geometric average is used to report what has happened not what is expected to happen and only applies for the future if year-to-year growth in GDP is not expected to fluctuate. If GDP growth varies – even slightly – from year to year in the future, the past GDP growth will not be realized if the geometric average is used to set the growth. If year-to-year variation is the same as in the past, the required growth rate is the arithmetic average growth rate.

> yield plus risk-premium" method, recognizes that common equity capital is more risky than debt from an investor's standpoint, and that investors require higher returns on stocks than on bonds to compensate for the additional risk. The general approach is relatively straightforward: First, determine the historical spread between the return on debt and the return on equity. Second, add this spread to the current debt yield to derive an estimate of current equity return requirements.
>
> The risk premium approach to estimating the cost of equity derives its usefulness from the simple fact that while equity return requirements cannot be readily quantified at any given time, the returns on bonds can be assessed precisely at every instant in time. If the magnitude of the risk premium between stocks and bonds is known, then this information can be used to produce the cost of common equity. This can be accomplished retrospectively using historical risk premiums or prospectively using expected risk premiums.

Roger A. Morin, *Regulatory Finance: Utilities' Cost of Capital* (1994) at 269. The risk premium approach is a simpler and less subjective approach. There is no need to estimate betas or current expected market risk premiums, as required in implementing the CAPM, and there is no reason to determine if "beta risk" is the only risk of relevance to investors holding shares of water utilities. For these reasons, regulatory commissions use the risk premium approach in setting rates far more frequently than the CAPM.

Q. WHAT ARE THE SOURCES FOR YOUR RISK PREMIUM ESTIMATES?

A. The sources are the methods and data presented by the CPUC Staff in various general rate cases. I have made three risk premium analyses.

Q. EXPLAIN YOUR FIRST ANALYSIS.

A. My first analysis is an update of the method presented by CPUC Staff in California-American Water Company's Los Angeles district rate case (Docket No. A 03-07-036) in January 2004. The only difference in my first analysis and the one relied upon by CPUC Staff in that case is the updated forecasts of interest rates. CPUC Staff has used this risk premium approach to determine costs of equity in numerous cases during the last three years. Under this approach, CPUC Staff adopted annual averages of actual realized ROEs for the six water utilities in my sample as proxies for the costs of equity for the period 1993-2002, subtracted contemporaneous Treasury rates from those equity cost proxies to determine annual average risk premiums, then added the 5-year and the 10-year averages of those risk premiums to forecasts of the respective Treasury rates to determine an equity cost range.

Q. WHAT HAVE YOU DONE TO UPDATE THE CPUC STAFF'S RISK PREMIUM ANALYSIS?

A. I have updated the CPUC Staff's analysis by updating the forecasts of the Treasury rates with an average of Treasury rate forecasts for the period 2005-2006 made by Blue Chip and Value Line. This is the only change from the risk premium analysis CPUC Staff presented in Table 2-7 of its Cost of Capital Report for California-American Water Company in Docket No. A 03-07-036. The interest rate forecasts I have relied upon to make this update are averages of Blue Chip's consensus forecast of interest rates for 2005 and 2006 reported in June 2004 and Value Line's most recent quarterly forecasts of interest rates made May 28, 2004. I report those Treasury rate forecasts and forecasts for Baa bond rates in Table 9.

Q. HAS ACC STAFF RELIED UPON FORECASTS OF INTEREST RATES IN ANALYSES OF EQUITY COSTS IN PAST CASES?

A. Yes, it has. For example, in Docket No. U-1656-91-134, Staff relied upon Blue Chip Financial forecasts of interest rates, Gross National Product ("GNP") and inflation during the next year to describe the economic environment that influenced its cost of capital estimates. Testimony of Linda A. Jaress, dated December 2, 1991, at 9-11. Also, in testimony dated April 19, 1993, Docket No. U-1303-92-286, ACC Staff relied upon Blue Chip forecasts of interest rates for the first quarter of the following year to determine the appropriate level of interest rates for the determination of costs of equity. Supplemental Testimony of J. David Daer, at 6. Relying on forecasts of interest rates to determine costs of equity is not a new concept to ACC Staff. Therefore, the fact that the CPUC Staff method relies on forecasts of interest rates to determine costs of equity is not unusual.

Q. WHY HAVE YOU USED INTEREST RATE FORECASTS FOR THE PERIOD 2005 TO 2006 IN YOUR ANALYSIS?

A. I have used this period because it is the period in which Arizona Water's new rates will first be put into place. August 2005 is the earliest the new rates could be approved and put in place. But based on the amount of time it has recently taken to complete rate cases in Arizona, it could be as late as 2006 before new rates are in place. The CPUC Staff method relies upon forecasts of interest rates for the future periods when new rates for the utility will be in place. To be consistent with the CPUC Staff approach, it is appropriate to adopt forecasts of interest rates for the period when Arizona Water's new rates will be in place.

Q. WHY NOT USE CURRENT RATES FOR TREASURY SECURITIES?

A. There are two reasons. First, the CPUC Staff does not use current rates and thus to be consistent with the CPUC Staff approach, forecasted rates should be adopted. Second, the goal is to determine the cost of capital for Arizona Water when new rates are in effect, not the cost of capital 18 months before such new rates are approved.

The Commission Staff provided evidence in the recent Arizona-American Water case that showed forecasts of interest rates reported by Blue Chip were sometimes higher and sometimes lower than the interest rates that actually occurred and that the projected interest rates were, on average, lower than the actual interest rates that subsequently occurred.[10] CPUC Staff has determined that such forecasts of interest rates are preferred to using current interest rates as proxies for future rates. Current interest rates are also sometimes higher and sometimes lower than interest rates during future periods. It is especially inappropriate to adopt current interest rates as proxies for future interest rates when those current interest rates are close to 40-year lows and are expected to increase.

Q. WHAT IS THE RESULT OF THIS ANALYSIS?

A. This analysis indicates the cost of equity for the water utilities sample falls in a range of 10.6% to 10.9%, as shown on Table 10. Arizona Water's indicated cost of equity is at least 50 basis points higher because it is more risky.

Q. TURN TO YOUR SECOND RISK PREMIUM ANALYSIS. HOW DOES IT DIFFER FROM THE FIRST ANALYSIS?

A. In that analysis, CPUC Staff chose to use earned ROEs instead of authorized ROEs as the proxies for the costs of equity in its analysis. If regulators attempt

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[10] Direct Testimony of Joel M. Reiker, Docket No. WS-01303A-02-0867, et al., at 49

to authorize ROEs that are equal to the utilities' costs of equity, and adopt rates and rate adjustment mechanisms that give those utilities a reasonable opportunity to earn those authorized ROEs, on average, earned as well as authorized ROEs might provide proxies for the costs of equity. The second risk premium analysis adopts authorized ROEs instead of earned ROEs as the proxies for the costs of equity in the risk premium analysis. This change is the only change from the first risk premium analysis.

Q. WHAT ARE THE RESULTS OF THE SECOND RISK PREMIUM ANALYSIS?

A. Table 11 presents the results of this second analysis. This analysis indicates the cost of equity for the water utilities sample falls in a range of 11.0% to 11.4%. The indicated cost of equity range for Arizona Water is at least 11.5% to 11.9% because it is more risky. During the period of the study, on average, utilities in the water utilities sample earned less than their authorized ROEs, and thus it is expected that this second risk premium analysis will indicate a higher equity cost range than was found in the first risk premium analysis.

Q. TURN TO YOUR THIRD RISK PREMIUM ANALYSIS. WHAT DATA HAVE YOU USED TO PREPARE THIS ANALYSIS?

A. In a number of cases, the CPUC Staff has adopted averages of realized ROEs for samples of water utilities as proxies for costs of equity. My third risk premium analysis is based on averages of realized ROEs for water utilities samples that the CPUC Staff adopted as proxies for the costs of equity, Baa bond yields reported by the Federal Reserve, and the expectation that when bond costs decrease, equity costs will also decrease, but by less. In effect, the risk premium increases as interest rates decrease. This expectation is generally consistent with the theoretical work of Gordon and Halpern, "Bond Share Yield Spreads Under Uncertain Inflation," *American Economic Review*, Vol. 66, No. 4

(September 1976) 559-565. It is also consistent with empirical studies such as a 1989 study conducted by Staff at the Oregon Public Utility Commission and a statement by the CPUC in decisions in 1997 (D.97-12-089) and 2002 (D.02-11-027) that its practice is to adjust ROEs for energy utilities by one-half to two-thirds of the change in the benchmark interest rate.

Q. PLEASE EXPLAIN THIS RISK PREMIUM ESTIMATE.

A. I followed the three-step procedure shown in Table 12. Panel A of Table 12 shows earned ROEs for samples of publicly traded water utilities for the period 1985 to 2002. CPUC Staff adopted these ROEs as proxies for the costs of equity for water utilities in San Gabriel Valley Water Company's 1995 rate case (Table 3-4 A95-09-010), in California-American Water Company's 2003 rate case (Table 2-7, A02-09-030), and in San Gabriel Valley Water Company's 2003 rate case (Table 2-7, A02-11-044). Lines 19 and 20 of Panel A of Table 12 show the average risk premium increased from 2.12% to 3.13% as the average Baa rate decreased from 10.48% to 7.99%. This result indicates that, on average, returns for water utilities dropped by 59 basis points for each 100-basis point drop in the Baa bond rate. Thus, on average, the risk premium increased by 41 basis points for every 100-basis point drop in the Baa bond rate. (See line 22 of Panel A of Table 12.) This result is consistent with equity costs moving in the same direction as interest rates, but by less.

Q. DID YOU USE THE DATA IN PANEL A TO ESTIMATE THE COST OF EQUITY FOR ARIZONA WATER?

A. Yes. First, I recognized that the relationship between risk premiums and interest rates implies the following:

Risk premium = constant - slope x Baa bond rate.

Then, in Panel A, I solved for the slope in this equation by dividing the difference in risk premiums by the difference in bond rates (shown on line 21). Next, in Panel B, I solved for the constant in the equation that is consistent with the derived slope, the most recent average risk premium of 3.13% for the period 1993-2002, and the average Baa rate of 7.99% for the period 1993-2002.

Q. HOW DID YOU USE THAT RESULT TO ESTIMATE THE COST OF EQUITY?

A. I combined the slope of -0.41 and the constant of 6.39% derived in Panel B of Table 12 with the forecast of 7.68% for Baa bond rates during 2005-2006 reported in Table 9, to derive the current risk premium of 3.3%. Adding this current risk premium to the forecasted Baa rate of 7.68%, the indicated cost of equity for the sample of water utilities is 10.9%. Again, the indicated cost of equity for Arizona Water is higher than 10.9% because it is more risky than the sample water utilities. (See Table 12, Panel C.)

Q. WHAT IS SHOWN IN TABLE 13?

A. Table 13 is the same as Table 12 but uses 10-year Treasury rates to conduct the risk premium analysis instead of Baa bond rates. In testimony filed in 2003 in Arizona-American Water's rate case, Staff claimed Baa rates should not be used in a risk premium analysis because such rates include default risk premiums.[11] I subsequently provided evidence showing that Baa rates provided better forecasts of equity costs than Treasury rates and explained that Staff's contention had no merit if investors require the same default risk premium today as in the past.[12] I have prepared Table 13 to show that the choice of interest rates to conduct this risk premium analysis is not an important issue. Whether Treasury rates or corporate bond rates are used in this analysis, the equity cost

[11] Direct Testimony of Joel M. Reiker, Docket No. WS-01303A-02-0867, et al., at 50-52.

[12] Rebuttal Testimony of Thomas M. Zepp, Docket No. WS-01303A-02-0867, et al., at 21-23 and Rebuttal Tables 2 and 3.

estimate for the water utilities sample rounds to the same number, 10.9%.

VI. CONCLUSIONS

Q. PLEASE SUMMARIZE YOUR EQUITY COST ESTIMATES.

A. The Commission adopted Staff's estimates of costs of equity in Arizona Water's last GRC and in Arizona-American Water Company's recent rate case without giving any consideration to estimates I provided or restatements of Staff estimates that showed the costs of equity for those water utilities were much higher. In response, I have prepared equity cost estimates in this case that are not based on the methods I have presented in past cases (even though I believe my methods are theoretically sound and provided reasonable results), but instead are based on the methods and inputs relied upon by the FERC to determine DCF equity costs and by the staff of the CPUC to determine risk premium equity cost estimates.

A straightforward application of the FERC one-step and two-step DCF approaches indicates an equity cost range of 10.2% to 10.4% for the water utility sample. These DCF equity cost estimates probably understate the cost of equity for water utilities for two reasons. First, some water utilities' stock prices may be bid up in anticipation of a favorable buyout or merger. In such a situation, dividend yields drop but growth rates do not fully reflect expected future growth in cash flows. Second, the FERC method determines conservative measures of equity costs by increasing the dividend to determine D_1/P_0 that is only six months into the future instead of a full year. I explained why unique risks faced by Arizona Water require that it be authorized an ROE at least 50 basis points higher than the appropriate ROE for the sample water utilities. Thus, the conservative DCF estimates based on the FERC DCF equity cost approaches and the premium for the Company's additional risk indicate Arizona Water's equity cost falls in a range of 10.7% to 10.9%.

I have also used methods and data the CPUC staff has used to determine equity costs with the risk premium approach. Those estimates indicate the cost of equity for the water utility sample falls in a range of 10.6% to 11.4% and the cost of equity for Arizona Water falls in a range of 11.1% to 11.9%. Combined, all of the DCF and risk premium approaches indicate the cost of equity for the water utility sample falls in a range of 10.2% to 11.4% with an average of 10.8%, and Arizona Water's equity cost falls in a range of 10.7% to 11.9% with an average of 11.3%. Based on these equity cost estimates, I recommend Arizona Water be authorized an ROE of 11.25%, an ROE slightly below the average of my equity cost estimates. I have prepared Table 15, in which this information has been summarized.

Q. IS THERE OTHER INFORMATION THAT CORROBORATES YOUR ESTIMATES AND RECOMMENDATIONS?

A. Yes. Current Staff has devised ways to implement the CAPM and DCF models that, after accounting for differences in the level of interest rates, produce equity cost estimates that are much lower than this Commission authorized prior to December 2001. Table 14 lists nine decisions for large water and gas utilities in Arizona and concurrent 10-year Treasury rates. Adding the average risk premium above 10-year Treasury rates of 5.43% to the current forecast of Treasury rates indicates an ROE consistent with past orders of 11.0%. Arizona Water, however, faces higher risk today because it must comply with more stringent state and federal regulations than those that existed in the past and has added risk of recovering arsenic treatment costs. Thus, my recommended ROE of 11.25% is in line with the average of past ACC determinations of equity costs prior to December 2001.

The past decisions also put in perspective recent Staff recommended ROEs of close to 9.0% for Arizona Water and Arizona-American Water Company and an even lower recommendation of 8.0% for Rio Rico Utilities (*Rio Rico Utilities, Inc.*, Docket No. WS-02676A-03-0434). Implementation of finance models that lead to such low ROEs are inconsistent with ROEs this Commission authorized before the Staff revised the methods it uses to determine equity costs in 2001.

Q. IS THERE OTHER EVIDENCE THAT AN 11.25% ROE IS REASONABLE TODAY?

A. Yes. On May 7, 2003, when Staff prepared its direct testimony in the Arizona-American Water rate case, the yield on 10-year Treasury securities was 3.8%, while Staff determined the average equity cost for its sample of water utilities was 9.2%.[13] The earliest new rates will be in place for Arizona Water is 2005 when 10-year Treasury rates are forecasted to be 5.45% (see Table 9). Based on a simple change in interest rates of 165 basis points, Staff's determination of a 9.2% ROE in May 2003 now supports an equity cost of 10.85% for the water utilities sample. Including 50 basis points to compensate Arizona Water for being more risky than the sample of water utilities Staff used to determine its equity cost, the comparable equity cost estimate of Arizona Water is not less than 11.35% at this time, which is in line with my recommended ROE of 11.25% for Arizona Water.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes.

1582066.1/12001.187

[13] Direct Testimony of Joel M. Reiker, Docket No. WS-01303A-02-0867, et al., at 23, n. 11.

Arizona Water Company

Table 1

Selected Characteristics of Water Utilities

		% Water Revenues[a/]	S&P Bond Rating[a/]	Moody's Bond Rating[a/]	Operating Revenues[a/] ($ millions)	Net Plant[a/] ($ millions)
1	American States	88%	A-	A2	$212.6	$545.7
2	Aqua America	92%	AA-	NR	$386.5	$1,629.6
3	California Water	97%	NR	A2	$286.1	$672.2
5	Connecticut Water Service	92%	A	NR	$51.1	$189.0
4	Middlesex Water	87%	A+	NR	$65.0	$212.3
6	SJW Corp	97%	NR	NR	$153.0	$274.2
	Arizona Water	100%	NR	NR	$37.5	$157.1

Source: C.A. Turner Utility Reports, June 2004.

6/29/2004

Arizona Water Company

Table 2

Premiums Received by Investors from Recent
Mergers and Acquisitions of Water Utilities

Company	Approximate Date of Acquisition or Merger	Price Prior to Announcement	Value at Time of Merger or Acquisition	Basis	Premium
United Water Resources	July 2000	$23.13	$35.30	cash	53%
E-Town	Year-end 2000	$50.38	$68.00	cash	35%
Dominguez	May 2000	$22.75	$33.75	stock	48%
Consumers Water	March 1999	$21.38	$33.10	stock	55%
American Water Works	January 2003	$34.00	$46.00	cash	35%
Average Premium					45%

6/29/2004

Arizona Water Company

Table 3

Comparison of Past and Future Estimates of Growth for the Water Utilities Sample

		Five-year average annual changes				Average Future
		Price[a]	Book Value[b]	DPS[b]	EPS[b]	EPS Growth[c]
1	American States Water	8.8%	4.6%	0.9%	6.2%	5.2%
2	Aqua America, Inc.	9.5%	9.0%	6.2%	9.6%	9.4%
3	California Water Service	0.5%	0.2%	1.1%	-6.0%	6.8%
5	Connecticut Water Service	11.4%	4.8%	1.1%	3.1%	na
4	Middlesex Water	11.2%	4.3%	2.8%	4.0%	6.7%
6	SJW Corporation	9.1%	3.7%	3.9%	1.1%	na
	Average for DCF sample	8.4%	4.4%	2.7%	3.0%	7.0%

Sources:
a/ Change in average of high and low prices for 1999 to 2003.
b/ Annual Reports to Stockholders or *Value Line* for 1998-2002.
c/ Source Table 7.

6/29/2004

Arizona Water Company

Table 4

FERC One-Step (Constant Growth) Discounted Cash Flow Model

		6 Mo. Div. Yield		Adjusted Div. Yield		Growth Rates		Implied Cost of Equity		
		Low	High	Low	High	br+sv	Analysts' Forecasts	Low		High
		a		b		c	d	e		f
1	American States Water Co.	3.3%	4.2%	3.4%	4.4%	7.6%	5.2%	8.6%	-	11.9%
2	Aqua America Inc.	2.1%	2.9%	2.2%	3.0%	7.7%	9.4%	9.8%	-	12.4%
3	California Water Service Group	3.8%	4.4%	3.9%	4.5%	4.2%	6.8%	8.1%	-	11.3%
4	Connecticut Water Service	2.8%	3.4%	2.8%	3.5%	6.5%	7.0%	9.3%	-	10.5%
5	Middlesex Water Company	3.0%	3.5%	3.1%	3.6%	6.5%	6.7%	9.6%	-	10.3%
6	SJW Corp.	2.7%	3.6%	2.8%	3.7%	6.5%	7.0%	9.3%	-	10.7%
	Average	2.9%	3.7%	3.0%	3.8%	6.5%	7.0%			
	Full range of equity cost estimates							8.1%		12.4%
	Midpoint of range								10.2%	

Notes and Sources

a/ Six-month average dividend yields for December 2003 to May 2004.

b/ Six-month dividend yield adjusted for one-half years' growth.

c/ Based on averages of projections made by *Value Line Investment Survey* (April 30, 2004) if available. See Table 5.
use ACC Staff method and adopt the average for the utilities that are available.

d/ Average of analysts' forecasts for growth. See Table 7.

e/ Sum of lowest growth rate and lowest adjusted dividend yield.

f/ Sum of highest growth rate and highest adjusted dividend yield.

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Table 5

Estimates of Sustainable Growth for the Water Utilities Sample

		Retention Ratios	Estimated Future ROE	Forecast of br[a,b] Growth	sv Growth[c]	Average Sustainable Growth
1	American States Water Co.	0.52	11.5%	6.2%	1.4%	7.6%
2	Aqua America Inc.	0.48	11.0%	5.4%	2.2%	7.7%
3	California Water Service Group	0.44	7.0%	3.1%	1.1%	4.2%
4	Connecticut Water Service[d]					6.5%
5	Middlesex Water Company[d]					6.5%
6	SJW Corp.[d]					6.5%
	Average	0.48	9.8%	4.9%	1.8%	6.5%

Notes and Sources:
_a/ FERC method: br growth based on *Value Line* forecasts of DPS, EPS and ROE for the period 2007-2009 published April 30, 2004.
_b/ FERC method: br growth adjusted for year-end ROE forecast by Value Line.
_c/ Estimated sv growth derived in Table 6.
_d/ Growth estimate is average for other water utilities.

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Table 6

Estimates of "sv" Growth for the Water Utilities Sample

		Stock Financing Rate (s)[a] (a)	Market to Book Ratio[b] (b)	v (c)	sv growth (d)
1	American States Water Co.	3.43%	1.70	0.41	1.42%
2	Aqua America Inc.	3.51%	2.76	0.64	2.24%
3	California Water Service Group	2.33%	1.94	0.49	1.13%
4	Connecticut Water Service				na
5	Middlesex Water Company				na
6	SJW Corp.				na
	Average	3.09%	2.14	0.51	1.60%

Notes and Sources:
a/ From Value Line data reported April 30, 2004.
b/ Based on average of prices in Table 4 and book values in 2003.

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Table 7

Analysts' Forecasts of Future Five-Year Earnings Growth for the Water Utilities Sample

		Zacks[a/]	Thomson First Call[a/]	S&P[b/]	Value Line[c/]	Average
1	American States Water Co.		3.0%	3.0%	9.5%	5.2%
2	Aqua America Inc.	8.9%	10.0%	9.0%	9.5%	9.4%
3	California Water Service Grour	8.3%	4.0%	4.0%	11.0%	6.8%
4	Connecticut Water Service					7.0%
5	Middlesex Water Company	6.0%	7.0%	7.0%		6.7%
6	SJW Corp.					7.0%
	Column average	7.7%	6.0%	5.8%	10.0%	7.0%

Source:

a/ As reported on the Internet May 14 and June10, 2004.

b/ May 2004 S&P Earnings Guide for Middlesex Water. Others from June 2004 S&P Earnings Guide.

c/ Reported by *Value Line* April 30, 2004.

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Table 8

FERC Two-Step (Multi-Stage Growth) Discounted Cash Flow Model

		Spot Price[a/]	Current D_0[a/]	FERC Yield D_1/P_0	Growth Rates Near Term[b/]	Growth Rates Long Term[c/]	Growth Rates Average[d/]	Indicated Cost of Equity
		a	b	c	d	e	f	(c+ f)
1	American States Water Co.	$22.15	$0.88	4.1%	5.2%	6.5%	5.6%	9.7%
2	Aqua America Inc.	$20.35	$0.48	2.5%	9.4%	6.5%	8.4%	10.9%
3	California Water Service Group	$27.50	$1.13	4.3%	6.8%	6.5%	6.7%	11.0%
4	Connecticut Water Service	$25.06	$0.83	3.4%	7.0%	6.5%	6.8%	10.3%
5	Middlesex Water Company	$19.31	$0.66	3.5%	6.7%	6.5%	6.6%	10.2%
6	SJW Corp.	$31.90	$1.02	3.3%	7.0%	6.5%	6.8%	10.1%
	Average			3.5%	7.0%	6.5%	6.9%	10.4%

Notes and Sources:

a/ Indicated dividends and closing prices June 15, 2004. Yields based on spot prices are preferred by ACC Staff.

b/ Average of analysts' forecasts of growth or the average of available forecasts of growth.

c/ GDP growth as estimated by ACC Staff.

d/ Weight given to short-term growth rate is 67%. Source: FERC Opinion 445, note 19, Attachment 3.

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Table 9

Forecasted rates for Treasury Securities and
Baa Corporate Bonds for 2005-2006

	2005	2006	Average
10-Year Treasury Securities			
Blue Chip[a]	5.60%	5.90%	5.75%
Value Line[b]	5.30%	5.40%	5.35%
Average	5.45%	5.65%	5.55%
Long-term Treasury Securities			
Blue Chip[a]	6.10%	6.50%	6.30%
Value Line[b]	5.90%	6.00%	5.95%
Average	6.00%	6.25%	6.13%
Baa Corporate Bonds			
Blue Chip[a]	7.70%	8.00%	7.85%
Value Line[c]	7.50%	7.50%	7.50%
Average	7.60%	7.75%	7.68%

<u>Sources and Notes:</u>

_a/ Blue Chip consensus forecasts, June 2004.
_b/ *Value Line* Quarterly Forecast, May 28, 2004.
_c/ No forecast made by V*alue Line*. Assume the difference in Baa rate forecast and long-term Treasury forecasts would be the same.

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Table 10

Risk Premium Equity Cost Analysis
Realized ROEs Adopted as Equity Cost Proxies

	Return on Equity[a]	Annual Averages		Risk Premiums	
		Long-term Treasury[a]	10-Year Treasury[a]	Long-term Treasury	10-Year Treasury
1993	11.57%	6.60%	5.87%	4.97%	5.70%
1994	10.87%	7.35%	7.09%	3.52%	3.78%
1995	11.20%	6.88%	6.57%	4.32%	4.63%
1996	12.02%	6.70%	6.44%	5.32%	5.58%
1997	11.82%	6.60%	6.35%	5.22%	5.47%
1998	10.90%	5.58%	5.26%	5.32%	5.64%
1999	10.59%	5.87%	5.65%	4.72%	4.94%
2000	9.75%	5.94%	6.03%	3.81%	3.72%
2001	10.27%	5.49%	5.02%	4.78%	5.25%
2002	10.58%	5.41%	4.61%	5.17%	5.97%
	10-Year Average Premium[a]			4.71%	5.07%
	5-year Average Premium[a]			4.76%	5.10%
	Forecasted Interest Rates for 2005-2006[b]			6.13%	5.55%
	Projected Returns on Equity				
	10-Year Average			10.8%	10.6%
	5-Year Average			10.9%	10.7%

Notes and Sources:

_a/ CPUC Staff Cost of Capital Report, Table 2-7, A.03-07-036, January 2004.

_b/ Source is Table 9.

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Table 11

Risk Premium Equity Cost Analysis
Authorized ROEs Adopted as Equity Cost Proxies

	Authorized Returns on Equity[a]	Annual Averages 30-Year Treasury[b]	Annual Averages 10-Year Treasury[b]	Risk Premiums 30-Year Treasury	Risk Premiums 10-Year Treasury
1993	12.13%	6.60%	5.87%	5.53%	6.26%
1994	12.13%	7.35%	7.09%	4.78%	5.04%
1995	11.51%	6.88%	6.57%	4.63%	4.94%
1996	11.58%	6.70%	6.44%	4.88%	5.14%
1997	11.18%	6.60%	6.35%	4.58%	4.83%
1998	11.06%	5.58%	5.26%	5.48%	5.80%
1999	11.12%	5.87%	5.65%	5.25%	5.47%
2000	11.12%	5.94%	6.03%	5.18%	5.09%
2001	10.86%	5.49%	5.02%	5.37%	5.84%
2002	10.62%	5.41%	4.61%	5.21%	6.01%
	10-Year Average Premium			5.09%	5.44%
	5-year Average Premium			5.30%	5.64%
	Forecasted Interest Rates for 2005-2006[c]			6.13%	5.55%
	Projected Returns on Equity				
	10-Year Average			11.2%	11.0%
	5-Year Average			11.4%	11.2%

Notes and Sources:

_a/ CA Turner *Utility Reports,* issues for December for various years.
_b/ CPUC Staff Cost of Capital Report, Table 2-7, A.03-07-036, January 2004.
_c/ Source is Table 9.

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Table 12

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historic Data

		Earned ROE			Baa Rate		Risk Premium
1	1985	14.40%	a/		12.72%	d/	1.68%
2	1986	13.28%	a/		10.39%	d/	2.89%
3	1987	14.58%	a/		10.58%	d/	4.00%
4	1988	12.42%	a/		10.83%	d/	1.59%
5	1989	10.39%	a/		10.18%	d/	0.21%
6	1990	11.07%	a/		10.36%	d/	0.71%
7	1991	12.82%	a/		9.80%	d/	3.02%
8	1992	11.80%	b/		8.98%	d/	2.82%
9	1993	11.90%	b/		7.93%	d/	3.97%
10	1994	10.76%	b/		8.63%	d/	2.13%
11	1995	11.30%	b/		8.20%	d/	3.10%
12	1996	12.21%	b/		8.05%	d/	4.16%
13	1997	11.93%	b/		7.87%	d/	4.06%
14	1998	11.34%	b/		7.22%	d/	4.12%
15	1999	11.02%	b/		7.88%	d/	3.14%
16	2000	9.91%	b/		8.37%	d/	1.54%
17	2001	10.25%	b/		7.95%	d/	2.30%
18	2002	10.58%	c/		7.80%	d/	2.78%
19	Average 1985-1992	12.60%			10.48%		2.12%
20	Average 1993-2002	11.12%			7.99%		3.13%
21	Difference	1.48%			2.49%		-1.02%
22	Slope			0.59		-0.41	

Panel B: Solve for constant in formula (risk premium = constant - slope x Baa rate):

constant	=	risk premium	+	slope[e/]	x	Baa rate
constant	=	3.13%	+	0.41[e/]	x	7.99%
constant	=	6.39%				

Panel C: Solve for current risk premium and equity cost:

Risk Premium	=	constant	-	slope	x	Baa rate		
Risk premium	=	6.39%	-	.41	x	7.68%[f/]	=	3.3%

Estimated cost of equity = bond rate + risk premium = 10.9%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: CPUC Staff Table 2-7, Application 02-11-044 (San Gabriel Valley Water).
d/ Annual average reported by the Federal Reserve.
e/ Slope of -.41 = change in risk premium divided by change in bond rates. Derived from data derived at lines 20, 21, and 22 above.
f/ Source: Table 9.

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Table 13

Risk Premium for Water Utilities Based on Past Earned ROEs

Panel A: Historic Data

		Earned ROE			10-Year Treasury		Risk Premium
1	1985	14.40%	a/		10.62%	d/	3.78%
2	1986	13.28%	a/		7.67%	d/	5.61%
3	1987	14.58%	a/		8.39%	d/	6.19%
4	1988	12.42%	a/		8.85%	d/	3.57%
5	1989	10.39%	a/		8.49%	d/	1.90%
6	1990	11.07%	a/		8.55%	d/	2.52%
7	1991	12.82%	a/		7.86%	d/	4.96%
8	1992	11.80%	b/		7.01%	d/	4.79%
9	1993	11.90%	b/		5.87%	d/	6.03%
10	1994	10.76%	b/		7.09%	d/	3.67%
11	1995	11.30%	b/		6.57%	d/	4.73%
12	1996	12.21%	b/		6.44%	d/	5.77%
13	1997	11.93%	b/		6.35%	d/	5.58%
14	1998	11.34%	b/		5.26%	d/	6.08%
15	1999	11.02%	b/		5.65%	d/	5.37%
16	2000	9.91%	b/		6.03%	d/	3.88%
17	2001	10.25%	b/		5.02%	d/	5.23%
18	2002	10.58%	c/		4.61%	d/	5.97%
19	Average 1985-1992	12.60%			8.43%		4.17%
20	Average 1993-2002	11.12%			5.89%		5.23%
21	Difference	-1.48%			-2.54%		1.07%
22	Slope			0.58		-0.42	

Panel B: Solve for constant in formula (risk premium = constant - slope x 10 yr Treas rate):

constant	=	risk premium	+	slope-[e/]	x	10 Year Treasury rate
constant	=	5.23%	+	0.42-[e/]	x	5.89%
constant	=	7.70%				

Panel C: Solve for current risk premium and equity cost:

Risk Premium	=	constant	-	slope	x	10 yr Treasury rate		
Risk premium	=	7.70%	-	.42	x	5.55%-[f/]	=	5.4%

Estimated equity cost = bond rate + risk premium = 10.9%

Notes and Sources:

a/ Source: CPUC Staff Table 3-4, Application 95-09-010 (San Gabriel Valley Water).
b/ Source: CPUC Staff Table 2-7, Application 02-09-030 (California-American Water).
c/ Source: CPUC Staff Table 2-7, Application 02-11-044 (San Gabriel Valley Water).
d/ Annual average reported by the Federal Reserve.
e/ Slope of -.42 = change in risk premium divided by change in bond rates.
Derived from data derived at lines 20, 21, and 22 above.
f/ Source: Table 9.

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Table 14

Returns on Equity for Larger Arizona Water
Sewer and Gas Utilities Prior to December 2001
and
Indicated Current Cost of Equity

Company	Decision Number	Decision Date	Authorized ROE	Average Annual 10-Year Treasury Rate	Risk Premium
Citizens Utilities Company; Agua Fria Water Division; Sun City Water Company; Sun City Sewer Company and Sun City West Utilities Company	60172	May 7, 1997	10.50%	6.35%	4.15%
Paradise Valley Water Company	60220	May 27, 1997	11.00%	6.35%	4.65%
Far West Water Company	60437	Sept 29, 1997	11.50%	6.35%	5.15%
Saddlebrooke Utility Company	61008	July 16, 1998	11.30%	5.26%	6.04%
Paradise Valley Water Company	61831	July 20, 1999	11.00%	5.65%	5.35%
Bermuda Water Company	61854	July 21, 1999	12.00%	5.65%	6.35%
Pima Utility Company (Sewer)	62184	Jan 5, 2000	11.75%	6.03%	5.72%
Far West Water & Sewer Co. (Water)	62649	June 13, 2000	11.50%	6.03%	5.47%
Southwest Gas Corporation	64172	Oct. 30, 2001	11.00%	5.02%	5.98%
Average			11.28%	5.85%	5.43%
Equity cost indicated by forecasted 10-Year Treasury rate				5.55%	11.0%

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Table 15

Summary Table: Estimated Cost of Equity Ranges
for Benchmark Water Utilities and Arizona Water Company

	Equity Cost Estimates For Samples of Water Utilities			Estimated Equity Costs for Arizona Water Company		
DCF Analysis Based on FERC Methods:						
One Step -- Table 4		10.2%			10.7%	
Two Step -- Table 8		10.4%			10.9%	
Risk Premiums Estimates based on CPUC Methods and Data:						
Risk premium -- Table 10	10.6%	to	10.9%	11.1%	to	11.4%
Risk premium -- Table 11	11.0%	to	11.4%	11.5%	to	11.9%
Risk premium -- Table 12		10.9%			11.4%	
Estimated Range and Average Equity Cost						
Range	10.2%	to	11.4%	10.7%	to	11.9%
Average		10.8%			11.3%	
Recommended ROE					11.25%	

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Attachment 1

WATER UTILITY INDUSTRY

INDUSTRY TIMELINESS: 91 (of 94)

Large companies in the Water Utility Industry are continuing to benefit from long-term consolidation trends. In addition, small- and medium-sized water utilities are beginning to be acquired by electric and energy utilities at handsome premiums.

A cloud continues to hang over the industry, as tort litigation in California has many water utilities edgy. If juries rule against those local utilities, the fallout could be costly.

Although water utility stocks are ranked to underperform the market, they provide conservative investors an opportunity to capture good yields with less risk.

Industry Consolidation

For the most part, water utilities stand as the last true American monopoly. Water companies face little or no competition for water services in a given locale because the barriers to entry are very high. Consequently, large companies looking for earnings growth find that acquisitions are the best way to accomplish this goal. Also, acquisitions help to diversify the larger company, allowing it exposure to different geographic regions, which can be beneficial when one area of the country is struggling. Takeover targets tend to welcome this arrangement because they generally need the extra capital to replace and upgrade existing water distribution networks, since a foot of pipe that cost $1 to install a hundred years ago now costs approximately $100.

An interesting phenomenon in the Water Utility Industry is the takeovers by energy companies and electric utilities. Energy and electric utilities have much in common with water companies. All three groups plan for capital investments in distribution systems, read meters, bill customers, and deal heavily with regulators and local laws. By acquiring small- and medium-sized water utilities, these companies are creating economies of scale, while providing their shareholders with diversity and steadier revenues. Investors who hold shares of an acquisition target are poised to profit handsomely, since some purchases have been for as much as four times book value. This kind of capital-appreciation potential is unusual for this industry, which is marked by slow growth and healthy yields.

Tort Litigation

Most water companies are keeping a watchful eye on tort litigation (a civil lawsuit against a party even though no contract or law was breached) underway in California. The plaintiff's bar in that state has organized and commenced tort lawsuits against several public and private community water systems for allegedly delivering contaminated water, although the companies claim to be in full compliance with state and federal standards. The possibility that judgments could be made against water utilities even though they have broken no law is disturbing for the industry. If these cases succeed, the potential fallout could be higher costs for water utilities in order to defend these kinds of lawsuits, which could occur in other states. Also, these companies may be forced to pay large settlements. Fortunately for the industry, the California Public Utilities Commission is investigating the adequacy of existing drinking water standards and has temporarily put a stop to judicial proceedings.

Meeting Government Regulations

The Safe Drinking Water Act (SDWA), which was last amended in 1996, has provided the basis for current drinking water quality standards. It requires that the Environmental Protection Agency work with state and local authorities to select and test for five potential contaminants every five years. The amended SDWA also provided a $1 billion revolving loan fund to help local communities to install and upgrade their treatment plants to remain in compliance with drinking water purity standards. Water companies spend anywhere from 15% to 50% of their annual capital budgets to remain in compliance with the SDWA. Many of the companies made large investments to upgrade their infrastructures earlier in the decade, so capital outlays over the next 3- to 5-years should remain stable, or even decline. The need to remain in compliance with the SDWA is a primary driver for the present water utility consolidation trend.

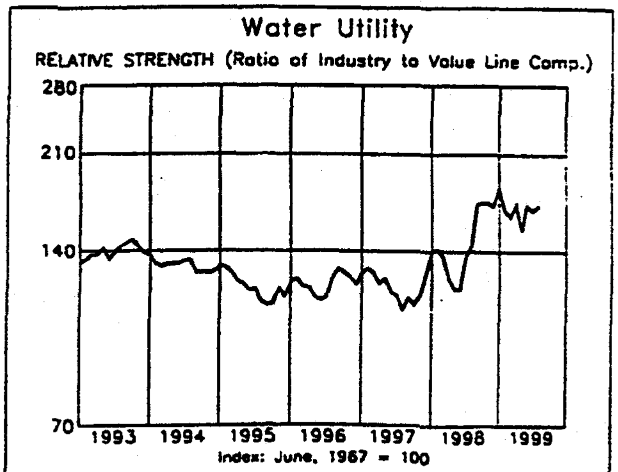
Investment Advice

The water company stocks included in this review are not timely for year-ahead investment. Conservative investors might, however, find those equities with attractive dividend-growth prospects and favorable Safety ranks a worthwhile investment, notwithstanding the aforementioned litigation.

Joseph Espaillat

Composite Statistics: Water Utility Industry

1995	1996	1997	1998	1999	2000		02-04
1639.4	1737.2	1878.0	1961.8	2275	2470	Revenues ($mill)	3020
178.0	214.8	240.2	271.0	290	315	Net Profit ($mill)	420
38.4%	39.0%	38.1%	37.1%	39.0%	39.0%	Income Tax Rate	39.0%
15.1%	7.6%	6.6%	7.4%	5.5%	6.5%	AFUDC % to Net Profit	6.5%
56.3%	56.3%	57.1%	57.2%	53.0%	52.0%	Long-Term Debt Ratio	49.0%
38.7%	39.4%	39.2%	39.5%	45.0%	46.0%	Common Equity Ratio	49.0%
4598.4	5287.2	5720.2	6200.0	6650	7070	Total Capital ($mill)	8300
5606.0	6342.8	6741.6	7294.4	7885	8280	Net Plant ($mill)	9590
6.0%	6.0%	6.2%	6.3%	6.5%	7.0%	Return on Total Cap'l	7.5%
8.9%	9.3%	9.8%	10.2%	10.5%	10.5%	Return on Shr. Equity	11.5%
9.2%	9.8%	10.3%	10.7%	11.0%	11.0%	Return on Com Equity	12.0%
2.3%	3.3%	3.6%	4.1%	3.0%	3.5%	Retained to Com Eq	4.5%
77%	68%	66%	63%	70%	70%	All Div'ds to Net Prof	60%
13.7	14.4	15.7	18.1	*Bold figures are Value Line estimates*		Avg Ann'l P/E Ratio	13.0
.92	.90	.90	.95			Relative P/E Ratio	.85
5.5%	4.6%	4.1%	3.4%			Avg Ann'l Div'd Yield	5.0%



WATER UTILITY INDUSTRY

INDUSTRY TIMELINESS: 90 (of 97)

The Water Utility Industry came under significant pressure in 2003. The majority of the companies covered in the next few pages experienced earnings declines last year, as unfavorable weather conditions resulted in weak demand for water throughout the United States.

Infrastructure costs are expected to continue to rise. As a result, further consolidation appears to be inevitable. Water utility stocks are ranked to lag the market over the next 12 months. However, conservative investors may find the risk-adjusted, total-return potential of these issues attractive.

Dampened Results

Most of the Water companies in our *Survey* were hampered by unfavorable weather conditions in 2003. *American States Water Co.* and *California Water Service Group* both most likely suffered year-over-year earnings declines because of the cool, wet-weather conditions. *Aqua America*, formerly Philadelphia Suburban Corp., however, was probably able to eke out a modest gain last year, despite the sluggish demand. (Investors should note that full-year results for each of the companies covered in this industry were not available as of the date of this issue's publication.) Although weather conditions are nearly impossible to predict, we expect more normal weather to help the Water Utility Industry rebound in 2004.

Increasingly Strict Regulations

In order to stay in compliance with the plethora of state and local regulations put in place to ensure the health levels of drinking water, the Water Utility Industry continues to face stricter purification standards. Amended in 1996, the Safe Drinking Water Act (SDWA) of 1974 authorizes the Environmental Protection Agency (EPA) to work with state and local governments to periodically test for impurities in drinking water and to regulate the levels of contaminants that are acceptable per a specified amount of water. These standards take into account the health effects of chemicals, measurement capabilities, and technical feasibility. One of the most significant contaminants that the industry screens for is arsenic, a naturally occurring substance. These laws and regulations are likely to continue to grow more stringent as the threat of bioterrorism against our water pipelines has already prompted officials to tighten regulation requirements.

Rising Infrastructure Costs

Water companies are also feeling the pressure to maintain and even to upgrade aging facilities. Indeed, many water/wastewater systems that are presently in use were built over 100 years ago and are outdated. The costs associated with replacing these systems continue to grow and, according to the EPA, are expected to venture into the hundreds of billions of dollars over the next 20 years. Given the astronomical expenses, it appears that long-term relief from the federal government is needed. Nevertheless, for now, state and local funding woes will probably leave the water companies to cover most of the expenses.

Rapid Consolidation

The rising costs associated with water purification and facility upgrades are straining many of the smaller companies in the water industry that do not have sufficient cash flow and liquidity to foot the bill for the costly improvements. Therefore, the industry has seen massive consolidation in recent years, as the smaller operations have been forced to sell to larger suitors with significantly greater capital resources. The larger utilities are benefiting from economies of scale, as well as enhanced geographic diversity. In turn, the companies are becoming less susceptible to state or region-specific problems and/or state requirements. *Aqua America*, which has been acquisition-friendly over the past few years, is on the cusp of buying Heater Utilities, which would likely increase its customer base fivefold in North Carolina.

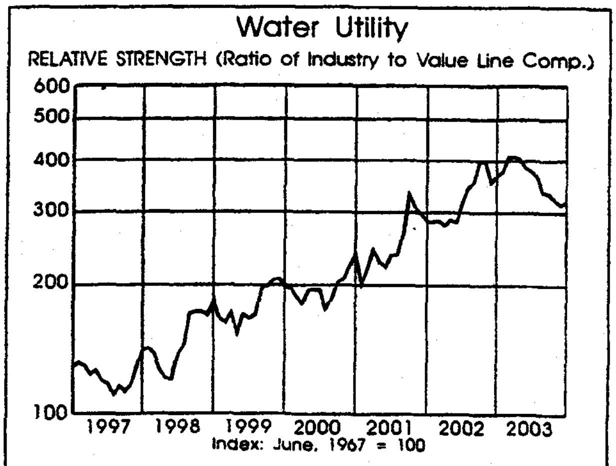
Investment Advice

Growth-minded investors ought to look elsewhere. The water company stocks in this review are not timely and offer little capital-gains appeal out to 2006-2008. However, attractive dividend yields may appeal to income-minded individuals. As always is the case, though, potential investors are advised to carefully review individual reports before making any new commitments to these issues.

Andre J. Costanza

Composite Statistics: Water Utility Industry

1999	2000	2001	2002	2003	2004		06-08
637.2	704.3	751.8	794.4	*845*	*945*	**Revenues ($mill)**	*1235*
72.4	90.9	95.4	106.6	*105*	*130*	**Net Profit ($mill)**	*190*
40.0%	41.2%	40.2%	35.8%	*41.6%*	*41.5%*	**Income Tax Rate**	*41.5%*
--	--	--	--	*Nil*	*.5%*	**AFUDC % to Net Profit**	*.5%*
51.1%	50.3%	52.4%	53.9%	*53.0%*	*51.5%*	**Long-Term Debt Ratio**	*51.0%*
48.3%	49.3%	47.2%	45.9%	*46.5%*	*48.5%*	**Common Equity Ratio**	*49.0%*
1444.7	1661.0	1840.7	1973.6	*2385*	*2545*	**Total Capital ($mill)**	*3055*
2100.3	2342.5	2532.3	2751.1	*3190*	*3370*	**Net Plant ($mill)**	*4000*
7.4%	7.0%	6.8%	7.0%	*6.5%*	*7.0%*	**Return on Total Cap'l**	*7.5%*
11.5%	10.7%	10.6%	11.2%	*9.5%*	*10.5%*	**Return on Shr. Equity**	*12.0%*
11.5%	10.6%	10.7%	11.2%	*9.5%*	*10.5%*	**Return on Com Equity**	*12.0%*
3.8%	3.6%	3.3%	3.9%	*3.0%*	*4.0%*	**Retained to Com Eq**	*5.5%*
68%	67%	69%	66%	*75%*	*65%*	**All Div'ds to Net Prof**	*54%*
19.5	18.6	22.6	21.5	*24.8*		**Avg Ann'l P/E Ratio**	*13.5*
1.11	1.21	1.16	1.17	*1.42*		**Relative P/E Ratio**	*.90*
3.5%	3.6%	[illegible]	3.1%	*3.2*		**Avg Ann'l Div'd Yield**	*3.0%*



Attachment 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

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JUL 26 2000

UNITED STATES OF AMERICA
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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

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[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

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[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

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[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

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[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.

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[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

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[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]

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[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

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[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

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[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

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[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

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[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

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[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.

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[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)

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[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
Constel-lation	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

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[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,

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[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.

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[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

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[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.

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[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.

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[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.