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BEFORE THE ARIZONA CORPORATION COMMISSION

COMMISSIONERS

- KRISTIN K. MAYES - Chairman
- GARY PIERCE
- PAUL NEWMAN
- SANDRA D. KENNEDY
- BOB STUMP

IN THE MATTER OF THE APPLICATION OF
 UNS ELECTRIC, INC. FOR THE ESTABLISHMENT
 OF JUST AND REASONABLE RATES AND
 CHARGES DESIGNED TO REALIZE A
 REASONABLE RATE OF RETURN ON THE FAIR
 VALUE OF THE PROPERTIES OF UNS ELECTRIC,
 INC. DEVOTED TO ITS OPERATIONS
 THROUGHOUT THE STATE OF ARIZONA

DOCKET NO. E-04204A-09-0206

**STAFF'S NOTICE OF FILING
SURREBUTTAL TESTIMONY**

Staff of the Arizona Corporation Commission ("Staff") hereby files the Surrebuttal Testimony of Dr. Thomas H. Fish; David C. Parcell; W. Michael Lewis; William C. Stewart; and Kenneth C. Rozen of the Utilities Division.

RESPECTFULLY SUBMITTED this 15th day of January 2010.

Arizona Corporation Commission
DOCKETED

JAN 15 2010

DOCKETED BY

Maureen A. Scott, Senior Staff Counsel
 Wesley Van Cleve, Attorney
 Legal Division
 Arizona Corporation Commission
 1200 West Washington Street
 Phoenix, Arizona 85007
 (602) 542-3402

Original and thirteen (13) copies
 of the foregoing filed this 15th
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Docket Control
 Arizona Corporation Commission
 1200 West Washington Street
 Phoenix, Arizona 85007

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1 Copies of the foregoing mailed
this 15th day of January 2010 to:

2 Michael W. Patten
3 Roshka, DeWulf & Patten, PLC
4 One Arizona Center
400 East Van Buren, Suite 800
Phoenix, Arizona 85004

5 Philip J. Dion
6 Michelle Livengood
7 UniSource Energy Services
One South Church Avenue
Tucson, Arizona 85701

8 Daniel W. Pozefsky, Chief Counsel
9 Residential Utility Consumer Office
1110 West Washington, Suite 220
10 Phoenix, Arizona 85007

11 Timothy M. Hogan
12 Arizona Center for Law in the Public Interest
202 East McDowell Road, Suite 153
Phoenix, Arizona 85004

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**SURREBUTTAL
TESTIMONY
OF**

DR. THOMAS H. FISH, Ph.D.

DAVID C. PARCELL

W. MICHAEL LEWIS

WILLIAM C. STEWART

KENNETH C. ROZEN

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JANUARY 15, 2010

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IN THE MATTER OF THE APPLICATION OF)
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THE PROPERTIES OF UNS ELECTRIC, INC.)
DEVOTED TO ITS OPERATIONS)
THROUGHOUT THE STATE OF ARIZONA.)

DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

THOMAS H. FISH, PH.D.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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SCHEDULES
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The Surrebuttal Testimony of Thomas H. Fish, Ph.D.

Schedule	Description
	Revenue Requirement
THF A-1	Computation of Increase in Gross Revenue Requirement
	Rate Base
THF B-1	Original Cost, RCND, and Fair Value Rate Base
THF B-2	Pro Forma Adjustments to Original Cost Rate Base
	Operating Income Adjustments
THF C-1	Adjusted Test Year Income
THF C-2	Income Pro Forma Adjustments

**EXECUTIVE SUMMARY
UNS ELECTRIC INC.
DOCKET NO. E-04204A-09-0206**

My Surrebuttal Testimony addresses the following issues raised by UNS Electric, Inc. (“UNS Electric” or “Company”) witnesses in their Rebuttal Testimony:

- The Company’s proposed revenue requirement.
- Adjustments to test year data.
- Rate base
- Test year revenues and expenses

My findings and recommendations for each of these areas are as follows:

- The Company is proposing an increase in gross revenue requirement of \$13,500,000 which represents a weighted average cost of capital of 10.38 percent (of which 1.34 percent is fair value adjustment). I identified an operating income deficiency of \$4,594,246 and an increase in gross revenue requirement of \$7,517,565 in my Direct Testimony. As a result of my analysis and evaluation of the Company’s Rebuttal Testimony and information provided by Staff witness Parcell, I am modifying my identified operating income deficiency to \$4,631,859 and my recommended increase in gross revenue requirement to \$7,579,110 which represents a weighted average cost of capital of 8.4 percent (plus a fair value adjustment of 1.5 percent on the increment in fair value rate base over original cost rate base).
- The following are adjustments to UNS Electric’s proposed original cost and fair value rate base from Staff’s Direct Testimony and reflecting modifications resulting from Staff’s Surrebuttal Testimony:

Summary of Staff Adjustments to Rate Base		Surrebuttal Testimony Original Cost	Direct Testimony Original Cost	Surrebuttal Testimony Fair Value	Direct Testimony Fair Value
Description	Increase (Decrease)	Increase (Decrease)	Increase (Decrease)	Increase (Decrease)	Increase (Decrease)
Remove post test-year plant in service	(\$7,263,614)	(\$7,263,614)	(\$7,263,614)	(\$7,263,614)	(\$7,263,614)
Cash working capital – lead/lag study	\$61,025	(\$61,025)	\$61,025	(\$61,025)	(\$61,025)
Total of Staff Adjustments	(\$7,202,589)	(\$7,324,639)	(\$7,202,589)	(\$7,324,639)	(\$7,324,639)
UNS Proposed Rate Base	\$175,818,913	\$175,818,913	\$265,152,067	\$265,152,067	\$265,152,067
Staff Proposed Rate Base	\$168,616,324	\$168,494,274	\$257,949,478	\$257,827,428	\$257,827,428

- The following adjustments to UNS Electric's proposed revenues, expenses and net operating income should be made:

Description	Direct Testimony Increase (Decrease)	Surrebuttal Testimony Increase (Decrease)
Incentive Compensation PEP	(\$132,159)	(\$132,159)
Incentive Compensation SERP	(\$102,142)	(\$102,142)
Payroll Tax Expense PEP	(\$10,110)	(\$10,110)
Call Center Expense	(\$281,581)	(\$99,476)
Industry Association Dues	(\$40,792)	(\$4,763)
Legal Expense	(\$58,722)	(\$27,359)
Fuel Expense	(\$75,798)	(\$75,798)
Rate Case Expense	(\$66,667)	(\$66,667)
CARES Expense (Revenue Shortfall)	\$61,797	\$61,797
Bad Debt Expense	(\$105,487)	\$105,487
Depr. & Property tax for Post TY PIS	(\$442,526)	(\$442,526)
Income Tax	\$481,859	(\$48,747)
Adjusted Operating Income per UNS Electric	\$10,003,347	\$10,003,347
Adjusted Operating Income per Staff	\$10,899,270	\$10,871,910

1 **INTRODUCTION**

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

3 A. My name is Thomas H. Fish. I am President of Ariadair Economics Group. My business
4 address is 1020 Fredericksburg Road, Excelsior Springs, Missouri 64024.

5
6 **Q. What is the purpose of your Surrebuttal Testimony?**

7 A. The purpose of my Surrebuttal Testimony is to rebut portions of the Rebuttal Testimony
8 of UNS Electric, Inc. ("UNS Electric", "Company" or "UNSE") witnesses Michael J.
9 DeConcini, Dallas J. Dukes, D. Bentley Erdwurm, Kentton C. Grant and Thomas A.
10 McKenna. The areas I will address include rate base/revenue requirement, the Black
11 Mountain Generating Station proposed acquisition treatment, Purchased Power and Fuel
12 Adjustment Clause, and Fuel and Purchased Power Policies.

13
14 **Q. Did you revise your Schedules as a result of your analysis and review of information
15 provided by the Company in its Rebuttal Testimony?**

16 A. Yes. These Revised Schedules are attached to this Testimony. They are Schedules THF
17 A-1, THF B-1, THF B-2, THF C-1, and THF C-2.

18
19 **MICHAEL J. DECONCINI**

20 **Black Mountain Generating Station ("BMGS")**

21 **Q. What does the Company request regarding the Black Mountain Generating Station?**

22 A. The Company requests the Commission to pre-authorize inclusion of the BMGS in rate
23 base after it has been purchased. It proposes a purchase price equal to the total cost net
24 depreciation and a revenue-neutral rate classification that would go into effect only upon
25 acquisition of BMGS by the Company.

26

1 **Q. In its previous case, did the Company request financing authority to acquire BMGS?**

2 A. Yes. The Company requested and received financing authority to acquire BMGS in its
3 last rate case.

4
5 **Q. Did the Company acquire the BMGS?**

6 A. No.

7
8 **Q. Why not?**

9 A. The Company claimed that even with the financing authority it did not have the financial
10 strength to acquire the BMGS.

11
12 **Q. Are you testifying that the Company should not purchase the BMGS?**

13 A. No. That is a decision to be made by Company management. In fact, as I mentioned in
14 my Direct Testimony, the Commission urged the Company to acquire BMGS. I agree
15 with the Commission's determination in the last case that the Company should pursue
16 purchase of BMGS if it decides that is in the best interest of its customers and owners.

17
18 **Q. Mr. DeConcini states at page 4 of his Rebuttal Testimony that "Staff argues that the
19 Company chose not to acquire BMGS and that, since it does not own the facility, it
20 should not be included in rate base." Is this a fair statement of Staff's position?**

21 A. To a degree. Staff does not accept that the BMGS should be included in rate base before
22 all facts regarding the purchase are known. After the purchase has been made, then the
23 request for inclusion of BMGS in rate base should be made. At that time, the Commission
24 could be expected to have the necessary facts to make a determination. At this time, prior
25 to the purchase, the Commission may not have all the necessary information. In the last
26 case, in addition to urging the Company to pursue the possible acquisition of BMGS, the
27 Commission was very clear that approval of financing did not imply pre-approval of the

1 purchase. At page 78, lines 23-27, of Decision No. 70360, the Commission stated:
2 “However, approval of the financing set forth herein does not constitute or imply approval
3 or disapproval by the Commission of any particular expenditure of the proceeds derived
4 thereby for purposes of establishing just and reasonable rates.”

5
6 **Q. What reason does the Company provide for requesting pre-approval of inclusion of
7 BMGS in rate base.**

8 A. Company witness DeConcini testified that the Company was unable to buy the BMGS
9 after the last case and acquisition of an asset the size of the BMGS would have a very
10 detrimental impact on the Company’s financial position and credit profile.

11
12 **Q. Does Staff take issue with the Company’s determination of the financial impact of
13 the acquisition?**

14 A. Yes. Staff witness Parcell addressed that issue in his Testimony.

15
16 **Q. At page 5 of his Rebuttal Testimony, Mr. DeConcini lists the benefits of purchasing
17 BMGS. Does Staff disagree with the benefits?**

18 A. Staff has no reason to disagree with Management’s determination of the possible benefits
19 of the acquisition. Company management must weigh the benefits and costs of ownership
20 in making its determination to purchase the BMGS or to continue with the Purchased
21 Power agreement regarding BMGS or to pursue other sources of power.

22
23 **Q. If the Company chooses not to purchase the BMGS, will it lose that source of power?**

24 A. It is my understanding that the purchased power agreement with UniSource Energy
25 Development (“UED”) will continue if the Company does not purchase the plant.
26

1 **CWIP**

2 **Q. Does Mr. DeConcini take issue with Staff's recommendation to reject UNS Electric's**
3 **request to include CWIP in rate base?**

4 A. Yes. Although the Company called the CWIP adjustment "post test-year non-revenue
5 producing plant in service" in Direct Testimony, during the test year it was CWIP. Now
6 Mr. DeConcini is referring to it as "non-revenue post-test year plant" and it was still
7 CWIP during the test year.

8
9 **Q. Has the Commission addressed inclusion of CWIP in the Company's rate base**
10 **before?**

11 A. Yes. In the Company's last rate case the Commission rejected both the request to include
12 CWIP in rate base and the request to include Post Test-Year Plant in rate base. In
13 Decision No. 70360, the Commission referred to the Decision in UNS Gas's rate case,
14 Decision No. 70011, where it rejected the Company's requests to include CWIP in rate
15 base, its request to include Post Test-Year Plant in rate base, and its request to not deduct
16 customer advances from rate base.

17
18 **Q. Do you agree with the Commission's decisions in those two cases?**

19 A. Yes.

20
21 **Q. Are there situations where including CWIP or Post Test-Year Plant in rate base is**
22 **necessary and beneficial?**

23 A. In my opinion there are situations where the use of these tools by the Commission is both
24 advisable and beneficial. In my review of past Commission Decisions, it appears that
25 small water companies find themselves in serious financial straits from time to time and
26 the use of these tools has been beneficial in these cases. In other rare situations, other
27 utilities may find themselves in serious financial trouble and require the use of these tools

1 by the Commission. For example, if construction costs of a nuclear generating unit get out
2 of control then the use of CWIP may be useful for maintaining the financial viability of
3 the Utility. In the instant situation, however, I do not believe inclusion of Post Test-Year
4 Plant in rate base is warranted or beneficial.

5
6 **Purchased Power and Fuel Adjustment Clause ("PPFAC")**

7 **Q. Does the Company offer additional reasons for changing the interest rate on PPFAC**
8 **over- and under-collected balances?**

9 A. Only that the Company will continue to procure fuel and purchased power in a prudent
10 manner if it is allowed to use the 3-month LIBOR rate plus 1 percent as the interest rate on
11 PPFAC over- and under-collected balances.

12
13 **Q. Does this assurance remove the possible disincentive to strive for a zero bank**
14 **balance?**

15 A. In my opinion, it does not.

16
17 **Q. What costs are included in the PPFAC?**

18 A. In Decision No. 70360, the Commission determined that only fuel and purchased power
19 costs recorded in FERC Accounts 501, 547, 555, and 565 should be flowed through the
20 PPFAC. The Commission determined that the recovery of "other" expenses through the
21 PPFAC should be denied.

22
23 **Q. As part of your analysis in this proceeding, did you review the expense included in**
24 **the PPFAC?**

25 A. Yes.

1 **Q. Did the Company include expenses other than those allowed by the Commission?**

2 A. I did not identify any non-permissible expenses in the PPFAC as a result of my analysis.
3 In addition, I asked the Company if any non-permissible expenses had been included in
4 the PPFAC and they assured me that none had.

5
6 **Q. Does the Company incur expenses associated with credit support for its acquisition
7 of wholesale power?**

8 A. Yes.

9
10 **Q. Did the Company remove those expenses in calculating its revenue requirement?**

11 A. The Company does not offer a pro forma adjustment to remove those expenses from its
12 revenue requirement. They were not included in the PPFAC for recovery.

13
14 **Fuel and Purchased Power Policies**

15 **Q. Mr. DeConcini, at page 11 of his Rebuttal Testimony, suggests that Staff's
16 recommendation to strengthen the relationship between fuel contract management
17 and procurement is related to the acquisition of back-up diesel fuel for the Valencia
18 units. Is this what you were referring to?**

19 A. No. The recommendation is not related to diesel fuel. This recommendation is actually
20 connected to the recommendation for periodic audits on the procurement of fuel and
21 purchased power that I discuss on page 63 of my Direct Testimony. My review of the
22 Company's data request responses and my visit with Company personnel in Tucson
23 regarding the prudence of PPFAC procedures and policies indicate to me that the
24 Company's PPFAC policies and procedures are, overall, well organized and efficient.
25 There does appear, however, to be somewhat of a disconnect between the identification
26 and acquisition process of a source of purchased power and the actual procurement of the
27 power within the framework of each contract. In my opinion, although I did not identify

1 specific problems as a result of my analysis, a periodic connection of the procurement
2 process and the source agreement could strengthen this area. Also, as Mr. DeConcini
3 noted in response to Staff data request STF 3.135, the Company had no audit reports
4 issued in 2007 or 2008 related to the procurement of fuel and purchased power.
5 Therefore, periodic audits of this relationship could serve to further strengthen this area.

6
7 **Q. Mr. DeConcini, at page 12 of his Rebuttal Testimony, states that the Company does**
8 **not have any interstate pipeline capacity and implies that all gas procurement for the**
9 **Company is by UNS Gas. Do you agree?**

10 A. UNS Electric does not have interstate pipeline capacity and, as I discussed in my Direct
11 Testimony, UNS Gas provides natural gas to the Company. However, the Company does
12 hedge gas, and it does this with the use of financial swing products because the actual
13 physical gas is supplied by UNS Gas. When hedging, UNS Electric is hedging price risk
14 through the use of fixed price financial swing gas.

15
16 **Q. Are there characteristics of the months of August, September, and October which**
17 **make them especially important in hedging operations involving natural gas?**

18 A. Yes. Those months represent the hurricane season. Hurricanes in the Gulf of Mexico
19 disrupt the production of natural gas and can result in significant price swings. This extra
20 risk translates into extra hedging costs. During my visit to Tucson, UNS Electric
21 personnel expressed concern regarding the implication of the UNS Gas case for additional
22 hedging costs if hedging is required to be undertaken during these months. Their position
23 was that situations could arise where the cost and risk relationships were such that hedging
24 during these months would be beneficial but there could also be situations where hedging
25 would not be beneficial. In light of this expressed concern, and I consider it a legitimate
26 concern, I made the recommendation to consider hedging, rather than require it, during
27 these months.

1 **DALLAS J. DUKES**

2 **CWIP**

3 **Q. Did Company witness Dukes address your position regarding Post Test-Year Plant**
4 **in Service in his Rebuttal Testimony?**

5 A. Yes. At page 8 of his Rebuttal Testimony, Mr. Dukes states that Staff's position is wrong.
6 His reasoning is essentially the same as presented by Mr. DeConcini. However, Mr.
7 Dukes includes a discussion of previous Commission Decisions which he believes support
8 the Company's request.

9
10 **Q. Do you agree with Mr. Dukes' analysis?**

11 A. No. I disagree with Mr. Dukes' analysis for the same reasons given above in my response
12 to Mr. Deconcini's discussion of this issue. With respect to the previous Decisions
13 referred to by Mr. Dukes, it is my understanding that the Commission evaluates each case
14 on its own merits, and the facts of the cases of these water companies are different than in
15 the instant case. I addressed these cases in my Direct Testimony.

16
17 **Working Capital**

18 **Q. Did you propose a pro forma adjustment with respect to the Company's working**
19 **capital?**

20 A. I proposed two adjustments. First, since Staff's pro forma adjustments were different than
21 the Company's pro forma adjustment, an adjustment for this difference was required.
22 Second, the Company made an error in its calculations as identified in footnote 3 of my
23 Direct Testimony.

24
25 **Q. What was the result of the two adjustments?**

26 A. The result was to increase rate base by \$61,025.

27

1 **Operating Income Adjustments**

2 **Incentive Compensation Expense**

3 **Q. Did Mr. Dukes disagree with your pro forma adjustment for Performance**
4 **Enhancement Plan (“PEP”) cost?**

5 A. Yes. First, he suggested that the PEP expense Staff used was incorrect because it was
6 taken from the Company’s Federal Energy Regulatory Commission (“FERC”) Form 1.
7 He stated that FERC Form 1 overstated PEP expenses and that Staff should have used a
8 smaller PEP value. He did not, however, provide any meaningful evidence that the FERC
9 Form 1 expense was incorrect and that the Company was preparing a corrected FERC
10 Form 1. If he makes this revision to FERC Form 1, Staff would consider using the smaller
11 PEP value in its analysis.

12
13 Second, Mr. Dukes argues that the fact that incentive pay benefits both owners and
14 ratepayers is no reason for owners to share the cost of the program with ratepayers. He
15 then compares incentive pay to payroll expense. Incentive pay, of course, is distinctively
16 different compared to payroll expense. Incentive pay is earned over and above base pay,
17 and its purpose is to induce greater efficiency and productivity from employees than
18 payroll expense alone. This extra reward for above normal productivity makes this cost
19 unique and subject to separate treatment. Normal payroll expenses are a normal and
20 ongoing cost of providing service. Incentive pay is designed as a reward for extraordinary
21 and above normal service and benefit to the Company and as such its cost should be borne
22 by the parties that enjoy the above normal service and benefit, the Company’s owners and
23 ratepayers.

1 **Q. Does Mr. Dukes agree with your proposed pro forma adjustment to remove**
2 **Supplemental Executive Retirement Plan (“SERP”) expenses?**

3 A. No. The SERP program is an incentive program for UniSource officers that exceeds
4 Internal Revenue Service retirement guidelines. Staff does not argue that the program be
5 eliminated only that the cost not be recovered from ratepayers.

6
7 **Q. What is the basis for Mr. Dukes’ position?**

8 A. First, that it is not fair for one group of employees to receive retirement pay that is funded
9 in rates and not for another group of employees to receive the same treatment. Second, he
10 states at page 21, lines 19-20, that “It (SERP) simply keeps those individuals whose
11 compensation level exceeds deductibility levels equal to those individuals whose
12 compensation does not.” Apparently Mr. Dukes believes that employees whose
13 compensation levels are \$40,000 per year are equal in compensation to employees whose
14 compensation levels exceed \$750,000 per year.

15
16 **Q. Do you agree with Mr. Dukes’ arguments?**

17 A. No.

18
19 **Rate Case Expense**

20 **Q. Did Mr. Dukes agree with your proposal to limit the Company’s rate case expense to**
21 **\$100,000 per year?**

22 A. No. Mr. Dukes argues that the Company’s actual rate case expense is higher than
23 comparable Company expenses because the Company must compensate Tucson Electric
24 Power Company (“TEP”) for the use of TEP personnel, there is a significant amount of
25 discovery, and numerous internal personnel, outside counsel and consultants are required.
26 In addition, because of the variety of issues involved, it does not make sense to develop its
27 own rate case team.

1 **Q. Do you agree with Mr. Dukes' arguments to recover extra rate case expense?**

2 A. No. Mr. Dukes offers no additional justification for increasing rate case expense.

3
4 **Membership Dues Expense**

5 **Q. Did the Company incur membership dues for Edison Electric Institute ("EEI")?**

6 A. In its work papers supporting its pro forma adjustment, the Company provides a copy of
7 an invoice in the amount of \$125,029 from EEI dated 12/12/07 for the year 2008 sent to
8 TEP. This invoice was paid quarterly. Another invoice was sent to TEP from EEI on
9 12/12/07 for regular activities for the year 2008 in the amount of \$314,244. Another was
10 sent to TEP from EEI dated 4/2/08 in the amount of \$28,000. No invoices for
11 membership dues were sent to UNSE from EEI.

12
13 **Q. Did UNS Electric pay membership dues to EEI?**

14 A. A memo from Sharon Feltz to Mina Briggs was provided by the Company dated 3/2/08.
15 Ms. Feltz asked whether UNSE should have been charged a part of the regular \$314,244
16 member dues. Ms. Briggs replied that UNS Electric should have been charged \$10,000.
17 In its work papers, the Company says that it paid a total of \$12,000 EEI dues and removed
18 \$1,628 of those in its pro forma adjustment, leaving a total of \$11,172 of EEI dues in
19 revenue requirement. However, there is no record of payment by UNSE of the \$12,000 in
20 the work papers, there is no record of an invoice from EEI to UNSE for membership dues
21 in the work papers, and there is no record of membership of UNSE in EEI in the work
22 papers.

23
24 **Q. Did the Company incur this expense during the test year?**

25 A. No. The Company made a posting error, and the amount was not included in revenue
26 requirement for the test year.

1 **Q. Did UNSE receive an invoice from EEI for EEI membership dues?**

2 A. There is no record in the work papers that UNSE received an invoice from EEI for EEI
3 membership dues as a member of EEI.

4
5 **Q. If the Company is not a member of EEI and is not entitled to the benefits of
6 membership should it be paying EEI dues?**

7 A. No.

8
9 **Q. Have you revised your adjustment for Industry Association Dues?**

10 A. Yes. I have reduced my adjustment for Industry Association Dues from \$40,792 to \$4,763
11 as shown on page 1 of Schedule THF C-2.

12

13 **Call Center Expense**

14 **Q. Company witness Dukes alleges that Staff used an incorrect amount for 2006 test
15 year Call Center expenses in making your Call Center pro forma adjustment. Did
16 you use an incorrect amount?**

17 A. No. Staff used the Call Center information pointed to by the Company. In its response to
18 Staff data request STF 5.3, the Company stated that calendar year 2006 information had
19 been provided in the last case and it saw no reason to provide that same information in this
20 case. The available information the Company referred to was the information Staff used
21 in its adjustment. The data referred to by Mr. Dukes were not provided until the Company
22 filed its Rebuttal Testimony.

23

24 **Q. Were the data recently provided by the Company more relevant than the
25 information you originally relied on?**

26 A. Yes.

27

1 **Q. Did this more recent data affect your proposed pro forma adjustment?**

2 A. Yes. I used the more recent data in my proposed pro forma adjustment. I have reduced
3 my adjustment for Call Center Expense from \$281,581 to \$99,476. This modification is
4 reflected in the attached Schedules.

5
6 **Bad Debt Expense**

7 **Q. Did the Company err in the calculation of its bad debt expense?**

8 A. Yes.

9
10 **Q. What was the error the Company made in deriving its bad debt expense?**

11 A. It understated its bad debt expense by \$105,487.

12
13 **Q. How was the Company able to understate its bad debt expense by \$105,487?**

14 A. Company Schedule C-2 page 3 of 4 shows a bad debt expense pro forma adjustment of
15 \$436,441 and the page total includes this amount. The actual bad debt expense for the test
16 year was about \$1.2 million. The Company normalized the bad debt expense by
17 calculating the average bad debt ratio to gross revenue for the years 2006, 2007, and 2008.
18 The Company then multiplied that ratio by test year adjusted retail revenues rather than
19 gross revenue. The three-year bad debt ratio should have been multiplied by gross retail
20 revenues and that value subtracted from actual bad debt expense to derive the normalized
21 bad debt pro forma adjustment.

22
23 **Q. Have you revised your adjustment for Bad Debt Expense?**

24 A. Yes. I have reversed my \$105,487 adjustment for Bad Debt Expense as shown on page 2
25 of Schedule THF C-2.

26

1 **Outside Legal Expense**

2 **Q. Did Company witness Dukes address your outside legal expense pro forma**
3 **adjustment in his Rebuttal Testimony?**

4 A. Yes.

5
6 **Q. Did Mr. Dukes express concern regarding your selection of years in the three-year**
7 **average outside legal expense values you used?**

8 A. Yes. In his proposed pro forma adjustment, Mr. Dukes used the 2005, 2006 and 2007
9 adjusted outside legal expense values in his calculations. I used the 2005, 2006 and 2008
10 outside legal expense values in my calculations because the 2007 outside legal expense is
11 an outlier compared to the other years and would have a biasing effect on the result.

12
13 **Q. What were the three-year average outside legal expense values?**

14 A. The three-year average outside legal expense value calculated by the Company was
15 \$138,263.69 and the three-year average outside legal expense value calculated by Staff
16 was \$87,552.94, shown in Schedule THF C-8 in my Direct Testimony. These average
17 values, when compared to the test year amount resulted in a pro forma adjustment by Mr.
18 Dukes of \$109,433.80 and by Staff of \$58,722. Therefore, Staff's adjustment to the
19 proposed Company pro forma adjustment is a reduction of the difference, or \$50,962.

20
21 **Q. In your opinion, what is the reason for the difference in the value of the pro forma**
22 **outside legal expense adjustment?**

23 A. In my opinion, the difference is due to the selection of the years to use for normalization.
24 The 2007 adjusted value is the highest of the four years, 2005 through 2008, and the
25 adjusted 2008 value is the smallest. The Company chose the highest value, and Staff
26 chose the smallest value.
27

1 **Q. Is there another normalization technique that the Commission could consider?**

2 A. Yes. For normalization purposes a three-year period is frequently used. In this situation,
3 however, because of the extreme values, I recommend that the Commission consider a
4 four-year normalization period that includes all values 2005 through 2008. In this way,
5 the two extreme values might be expected to cancel each other out and result in a more
6 representative value.

7
8 **Q. Did you make that four-year calculation?**

9 A. Yes. The attached Schedules include a recommended pro forma adjustment based on a
10 four-year normalization period, 2005 through 2008, for outside legal expenses. I have
11 reduced my adjustment for Legal Expense from \$58,722 to \$27,359.

12
13 **Fleet Fuel Expense**

14 **Q. Did the Company propose an adjustment to its fleet fuel expense?**

15 A. Not in its original filing. However, in the Rebuttal Testimony of Mr. Dukes, the Company
16 agreed to normalize fleet fuel expense over three years.

17
18 **Q. In your opinion, is this new proposal by the Company appropriate?**

19 A. In my opinion, the change recommended by the Company is much better and more
20 *indicative* of ongoing fleet fuel expense than the test year values. The fuel costs for the
21 test year were at a historic high and have not continued at that level. Therefore, although
22 the Company's new proposed test year fuel expense is better than the Company's original
23 proposal, it is biased by including the extreme test year value. Staff's proposal is much
24 more indicative of reasonably expected ongoing fleet fuel expenses.

25

1 **D. BENTLEY ERDWURM**

2 **Q. Did you propose a pro forma adjustment to remove the Company's proposed pro**
3 **forma increase in test year revenue related to Customer Assistance Residential**
4 **Energy Support ("CARES") customers?**

5 A. Yes.

6
7 **Q. Does the Company disagree with your proposed CARES pro forma revenue**
8 **adjustment?**

9 A. Yes. In his Rebuttal Testimony, Company witness Erdwurm argues that the Company's
10 proposed pro forma adjustment of \$61,797 is necessary for the Company to recover its
11 revenue requirement.

12
13 **Q. What is the basis for the Company's disagreement with your pro forma CARES**
14 **revenue adjustment?**

15 A. Company witness Erdwurm, at page 13 of his Rebuttal Testimony, states that the
16 Company did not correctly calculate CARES customer annualization and CARES weather
17 normalization so the adjustment is necessary to correct for that error.

18
19 **Q. Did Mr. Erdwurm provide any support that the annualization and normalization**
20 **mistakes amounted to a cost of \$61,797?**

21 A. No.

22
23 **Q. Do you agree that Mr. Erdwurm's calculation error resulted in a \$61,797**
24 **understatement of revenue?**

25 A. No. There does not appear to be any support to this guess.
26

1 **KENTTON C. GRANT**

2 **BMGS**

3 **Q. What position does Company witness Grant take with respect to your**
4 **recommendation for the Commission to not accept the Company's BMGS request?**

5 A. Mr. Grant states that the Company cannot finance BMGS without some assurance from
6 the Commission for timely rate relief. He goes on to point out that the Company does not
7 have sufficient cash flow, even with its requested rate relief, to service the additional
8 capital required to purchase the BMGS.

9
10 **Q. Will the proposed rate restructuring change its cash flow?**

11 A. My understanding is that the rate restructuring will be revenue neutral. Therefore, the
12 total cash flowing into the Company from its retail operations will be the same in either
13 case. The use of that cash will be different. Acquisition of the BMGS could be expected
14 to increase cash used for servicing the capital required for the acquisition and reduce cash
15 expended under the BMGS Purchased Power agreement. However, if revenue neutrality
16 is to be maintained, total cash in and out should not be affected.

17
18 **Q. Is the Company asking for additional rate relief upon its proposed acquisition of**
19 **BMGS?**

20 A. Mr. Grant seems to be implying that the Company will seek additional rate relief upon
21 acquisition of BMGS. Company witnesses, including Mr. Grant, have stated that the
22 acquisition of BMGS is revenue neutral. That is, they claim that upon acquisition of
23 BMGS the Company would restructure their rates but that the revenue impact from either
24 the current or restructured rates would be the same.

1 **PPFAC**

2 **Q. Does Mr. Grant offer reasons to recover wholesale credit costs in the PPFAC?**

3 A. Yes. First, he proposes, at page 27 of his Rebuttal Testimony, that these costs are directly
4 related to the fuel and wholesale power procurement function. Second, the level of credit
5 support will vary depending upon the size of the Company's payable balances and the
6 market value of forward energy purchases committed to by the Company.

7
8 **Q. In your opinion, are these reasons sufficient justification to include wholesale credit
9 costs in PPFAC?**

10 A. No.

11
12 **Q. Has the Commission demonstrated a pattern of allowing other costs in the PPFAC?**

13 A. No. It is my understanding that the Commission has not done so. In Decision No. 69663,
14 Arizona Public Service was not permitted to include broker's fees in its PSA and in
15 Decision No. 70360 UNSE was not permitted to include other costs such as broker's fees,
16 credit costs, and legal fees in its PPFAC.

17
18 **Fair Value Rate of Return**

19 **Q. Did Company witness Grant indicate that Staff understated its proposed revenue
20 requirement?**

21 A. Yes. At page 12 and 13 of his Rebuttal Testimony Company witness Grant stated that a
22 mathematical error was made that resulted in Staff understating the Company's revenue
23 requirement by \$633,000.

1 **Q. What did Mr. Grant cite as the cause of the error?**

2 A. Mr. Grant stated that there was a typographical error in Mr. Parcell's testimony which
3 suggested a fair value rate of return of 5.99 percent rather than 6.14 percent caused the
4 alleged revenue understatement.

5
6 **Q. Did a possible typographical error in Mr. Parcell's testimony result in an
7 underestimate of Staff's determination of the Company's revenue requirement?**

8 A. No.

9
10 **Q. What was the basis for the Company's determination that an error associated with
11 the FVROR had caused the understatement of Staff's determination of UNSE's gross
12 revenue requirement?**

13 A. It is my understanding that the basis was a typo in a table at page 57 of Mr. Parcell's
14 Direct Testimony. The table, as it appeared, was:

15
16

<u>Capital Item</u>	<u>Percent</u>	<u>Cost</u>	<u>Return</u>
Long-Term Debt	36.45%	7.05%	2.57%
Common Equity	30.76%	10.00%	3.08%
FVRB Increment	32.79%	1.50%	0.34%
Total	100.00%		5.99%

17
18
19
20
21

22 The highlighted return on Fair Value Rate Base ("FVRB") Increment of 0.34 percent is a
23 typographical mistake that resulted in a (highlighted) total return of 5.99 percent. The
24 correct value is shown as:

Capital Item	Percent	Cost	Return
Long-Term Debt	36.45%	7.05%	2.57%
Common Equity	30.76%	10.00%	3.08%
FVRB Increment	32.79%	1.50%	0.49%
Total	100.00%		6.14%

Mr. Grant multiplied the difference in total return (0.15 percent) times FVRB and determined that an addition to gross revenue requirement of \$633,000 was required. This conclusion is not correct.

Q. Why isn't Mr. Grant's analysis and conclusion correct?

A. Mr. Parcell was addressing the Company's capital cost and its capital structure. Consider the following table based on the table on page 57 of Mr. Parcell's Direct Testimony:

Dollar				
Capital Item	Percent	Amount	Cost	Return
Long-Term Debt	36.45%	\$93,978,098	7.05%	2.57%
Common Equity	30.76%	\$79,307,717	10.00%	3.08%
FVRB Increment	<u>32.79%</u>	<u>\$84,541,634</u>	1.50%	<u>0.49%</u>
Total	100.00%	\$257,827,428		6.14%

Note that the dollar amount for FVRB Increment calculated on the basis of the information in the table is \$84,541,634. The actual increment of FVRB over Original Cost Rate Base, from Schedule THF A-1, is \$89,333,154. Therefore, the correct percent for the FVRB Increment is $\$89,333,154 / \$257,827,428 = 34.65$ percent. Mr. Parcell's table was based on the Company's capital structure which understated the 1.5 percent

1 component by about \$5m and overstated the 8.4 percent debt and equity components by
2 the same amount. The result was an illusionary overstatement of FVROR by .15 percent.

3
4 Using the proper rate base values results in the following FVROR:

5

	Dollar		Dollar	
Capital Item	Amount	Cost	Cost	Return
Debt & Equity	\$168,494,273	8.40%	\$14,153,519	5.49%
FVRB Increment	<u>\$89,333,154</u>	1.50%	<u>\$ 1,339,997</u>	<u>0.52%</u>
Total	\$257,827,428		\$15,493,516	6.01%

6
7
8
9
10
11

12 **Q. What do you conclude with respect of your review of Mr. Grant's criticism of your**
13 **gross revenue requirement?**

14 A. There is no understatement of the Company's gross revenue requirement as determined by
15 Staff. My determination of the Company's gross revenue requirement and its return on
16 fair value rate base is consistent with Mr. Parcell's cost of capital analysis. Mr. Grant
17 simply erred in confusing capital structure with rate base.

18
19 **Q. Why did you use values from Staff's Direct Testimony in your analysis above rather**
20 **than your revised Surrebuttal values?**

21 A. For consistency purposes. The use of the Direct Testimony values allows for proper
22 comparison of the numbers used by Mr. Grant, Mr. Parcell, and myself. The conclusion is
23 valid for both the Direct and Surrebuttal situations, i.e., there is no inconsistency between
24 Mr. Parcell's and my analyses in our Direct or Surrebuttal Testimonies.

1 **THOMAS A. MCKENNA**

2 **Q. Does Company witness McKenna address your recommendation regarding UNSE's**
3 **proposed acquisition and treatment of the BMGS?**

4 A. Yes.

5
6 **Q. Does Mr. McKenna offer additional reasons why the Company should be authorized**
7 **to use its proposed rate base and ratemaking treatment of BMGS?**

8 A. No. Mr. McKenna simply restates the position of the Company with respect to this issue.

9
10 **Q. Do you have additional comments regarding this issue?**

11 A. No. The comments I offered above are relevant to Mr. McKenna's proposed justification
12 for implementation of the Company's proposal.

13
14 **Q. Would you summarize your conclusions with respect to your determination of the**
15 **Company's operating income deficiency and change in gross revenue requirement?**

16 A. I identified an operating income deficiency of \$4,594,246 and an increase in gross revenue
17 requirement of \$7,517,565 in my Direct Testimony. As a result of my analysis and
18 evaluation of the Company's Rebuttal Testimony and information provided by Staff
19 witness Parcell, I am modifying my identified operating income deficiency to \$4,631,859
20 and my recommended increase in gross revenue requirement to \$7,579,110 which
21 represents a weighted average cost of capital of 8.4 percent (plus a fair value adjustment
22 of 1.50 percent on the increment in fair value rate base over original cost rate base).

23
24 **Q. Does that conclude your testimony?**

25 A. Yes.

Line No.	Description	(a) Company Original Cost	(b) Staff Original Cost	(c) Company RCND	(d) Staff RCND	(e) Company Fair Value	(f) Staff Fair Value	Line No.
1	Adjusted Rate Base	\$175,818,913	\$168,616,324	\$354,485,222	\$347,282,633	\$265,152,067	\$257,949,478	1
2	Adjusted Operating Income	\$10,003,347	\$10,871,910	\$10,003,347	\$10,871,910	\$10,003,347	\$10,871,910	2
3	Current Rate of Return (2/1)	5.69%	6.45%	2.82%	3.13%	3.77%	4.21%	3
4	Required Operating Income Plus Fair Value (Line 6)	\$18,253,668	\$14,163,771 \$15,503,789	\$18,253,668	\$14,163,771 \$14,163,771	\$18,253,668	\$14,163,771 \$15,503,789	4
5	Weighted Average Cost of Capital Fair Value Adjustment*	9.04%	8.40%	5.15%	4.08%	6.88%	6.01%	5
6	Required Rate of Return	1.34%	\$1,338,987	5.15%	\$0	6.88%		6
7	Operating Income Deficiency							7
8	Gross Revenue Conversion Factor	\$8,250,321	\$4,631,859	\$8,250,321	\$3,291,861	\$8,250,321	\$4,631,859	8
9	Increase in Gross Revenue Requirement	1,6363	1,6363	1,6363	1,6363	1,6363	1,6363	9
10		\$13,500,000	\$7,579,110	\$13,500,000	\$5,386,472	\$13,500,000	\$7,579,110	10

Supporting Schedules
 Columns (a), (c), and (e) Company Schedule A-1
 Line 1, columns b, d, & f From Staff Schedule THF B-1
 Line 2, columns b, d, & f From Staff Schedule THF C-1
 *Staff fair value adjustment is equal to Staff witness Parcel Fair Value return midpoint (0% - 3%, or 1.5%) x difference between fair value and original cost rate base.

Line No.	Description	(a) Company Adjusted Original Cost Rate Base	(b) OCRB Staff Adjustments	(c) OCRB as Adjusted by Staff	(d) Company RCND	(e)* RCND Staff Adjustments	(f) RCND as Adjusted by Staff	(g)** Company Fair Value Rate Base	(h)** Staff Fair Value Rate Base	Line No
1	Gross Utility Plant in Service	\$454,177,170	\$7,263,614	\$446,913,556	\$844,301,155	\$7,263,614	\$837,037,541	\$649,239,162	\$641,975,548	1
2	Less: Accumulated Depreciation	193,348,359	0	\$193,348,359	\$367,590,759	\$0	\$367,590,759	\$280,469,559	\$280,469,559	2
3	Net Utility Plant in Service	260,828,810	7,263,614	\$253,565,196	\$476,710,396	\$7,263,614	\$469,446,782	\$368,769,603	\$361,505,989	3
4	Citizens Acquisition Discount	(93,273,341)	0	(\$93,273,341)	(\$130,469,005)	\$0	(\$130,469,005)	(\$111,871,173)	(\$111,871,173)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,878,317)	0	(\$20,878,317)	(\$27,773,948)	\$0	(\$27,773,948)	(\$24,325,132)	(\$24,325,132)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	(\$72,397,024)	(\$102,695,057)	\$0	(\$102,695,057)	(\$87,546,041)	(\$87,546,041)	6
7	Total Net Utility Plant	188,431,786	7,263,614	\$181,168,172	\$374,015,339	\$7,263,614	\$366,751,725	\$281,223,563	\$273,959,949	7
8	Customer Advances for Construction	(12,605,744)	0	(\$12,605,744)	(\$17,555,056)	\$0	(\$17,555,056)	(\$15,080,400)	(\$15,080,400)	8
9	Customer Deposits	(4,064,671)	0	(\$4,064,671)	(\$4,064,671)	\$0	(\$4,064,671)	(\$4,064,671)	(\$4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	(\$2,028,227)	(\$3,996,158)	\$0	(\$3,996,158)	(\$3,012,192)	(\$3,012,192)	10
11	Total Deductions	(18,898,641)	0	(\$18,898,641)	(\$25,615,885)	\$0	(\$25,615,885)	(\$22,157,263)	(\$22,157,263)	11
12	Allowance for Working Capital	6,085,768	(61,025)	\$6,146,793	\$6,085,768	(\$61,025)	\$6,146,793	\$6,085,768	\$6,146,793	12
13	Regulatory Assets	0	0	\$0	0	0	0	0	0	13
14	Regulatory Liabilities	0	0	0	0	0	0	0	0	14
15	Total Rate Base	\$175,818,913	\$7,202,589	\$168,616,324	\$354,485,222	\$7,202,589	\$347,282,633	\$285,152,067	\$287,949,478	15

Supporting Schedules
 Column A and D from Company filing
 Column B and E from THF B-2
 *For Column (e) test year OCRB and RCND adjustments have the same value for Post test year PIS and Working Capital so no separate THF B-2 equivalent Schedule is required for RCND
 **Fair Value rate base, columns (g) and (h) are derived as an average of OCRB and RCND

Line No.	Description	(a) Company Actual End of TY	(b) Staff Adjustments (a)	(c) Staff Adjusted at End of TY	Line No.
1	Gross Utility Plant in Service	\$454,177,170	\$7,263,614	\$446,913,556	1
2	Less: Accumulated Depreciation	193,348,359	0	193,348,359	2
3	Net Utility Plant in Service	260,828,811	7,263,614	253,565,197	3
4	Citizens Acquisition Discount	(93,273,341)	0	(93,273,341)	4
5	Less: Accum. Amort. - Citizens Acq. Discount	(20,876,317)	0	(20,876,317)	5
6	Net Citizens Acquisition Discount	(72,397,024)	0	(72,397,024)	6
7	Total Net Utility Plant	188,431,787	7,263,614	181,168,173	7
8	Customer Advances for Construction	(12,605,744)	0	(12,605,744)	8
9	Customer Deposits	(4,064,671)	0	(4,064,671)	9
10	Accumulated Deferred Income Taxes	(2,028,227)	0	(2,028,227)	10
11	Total Deductions	(18,698,642)	0	(18,698,642)	11
12	Allowance for Working Capital	6,085,768	(61,025)	6,146,793	12
13	Regulatory Assets	0	0	0	13
14	Regulatory Liabilities	0	0	0	14
15	Total Original Cost Rate Base	<u>\$175,818,913</u>	<u>\$7,202,589</u>	<u>\$188,616,324</u>	15

Supporting Schedules
(a) B-2, Pg. 2

Recap Schedules
B-1

Line No.	Description	Post-Test Year Non- Revenue Plant in Service	Working Capital	Total Page Adjustments	Line No.
1	Gross Utility Plant in Service	\$7,263,614		\$7,263,614	1
2	Less: Accumulated Depreciation				2
3	Net Utility Plant in Service	7,263,614		7,263,614	3
4	Citizens Acquisition Discount				4
5	Less: Accum. Amort. - Citizens Acq. Discount				5
6	Net Citizens Acquisition Discount				6
7	Total Net Utility Plant	7,263,614		7,263,614	7
8	Customer Advances for Construction				8
9	Customer Deposits				9
10	Accumulated Deferred Income Taxes				10
11	Total Deductions				11
12	Allowance for Working Capital		\$61,025	61,025	12
13	Regulatory Assets				13
14	Regulatory Liabilities				14
15	Total Original Cost Rate Base	\$7,263,614	\$61,025	\$7,324,639	15

Supporting Schedules
 B3, B4

Line No.	Description	Company Unadjusted (a)	Company Pro Forma Adjustments (b)	Company	Staff Adjustments	Staff Adjusted	Line No.
1	Operating Revenues	\$181,638,915	(\$22,358,469)	\$159,280,446	\$61,797	\$159,342,243	1
2	Electric Retail Revenues	10,168,115	(10,168,115)	0	0	0	2
3	Sales for Resale	3,103,658	(1,458,039)	1,645,619	0	1,645,619	3
4	Other Operating Revenue	194,910,688	(33,984,623)	160,926,065	61,797	160,987,862	4
	Total Operating Revenues						
5	Operating Expenses	143,362,723	(32,059,158)	111,303,565	0	111,303,565	5
6	Fuel, Purchased Power & Transmission	21,569,849	(2,144,234)	19,425,615	(412,987)	19,012,628	6
7	Other Operations and Maintenance Expense	14,429,415	(194,193)	14,235,222	0	14,235,222	7
8	Depreciation and Amortization	3,680,634	156,415	3,837,049	(442,526)	3,394,523	8
9	Taxes Other than Income Taxes	2,081,685	39,582	2,121,267	48,747	2,170,014	9
10	Income Taxes	185,124,306	(34,201,588)	150,922,718	(806,766)	150,115,952	10
	Total Operating Expenses						
11	Operating Income	9,786,382	\$216,985	\$10,003,347	\$688,563	\$10,871,910	11
12	Other Income and Deductions	322,168					
13	Allowance for Equity Funds	76,881					
14	Other - Net	399,049					
	Total Other Income and Dedu						
15	Income Before Interest Expense	10,185,431					
16	Interest Expense	6,546,248					
17	Interest on Long-Term Debt	57,412	(1)				
18	Other Interest Expense	(181,815)					
19	Allowance for Borrowed Funds	6,421,845					
	Total Interest Expense						
20	Net Income Available for Common Stock	\$3,763,586					

(1) Includes reclassification of \$160,200 for Customer Deposit Interest Expense From Other Interest Expense to Other O&M Expense.

Line No.	Description	Incentive Compensation Adj PEP	Incentive Compensation Adj SERP	Payroll Tax Expense, PEP incentive	Call Center Expense Adj	Industry Association Dues	Legal Expense	Total Page Adjustments
1	Operating Revenues							
2	Electric Retail Revenues	\$0	\$0	\$0	\$0	\$0	\$0	\$0
3	Sales for Resale	0	0	0	0	0	0	0
4	Other Operating Revenue	0	0	0	0	0	0	0
	Total Operating Revenues	0	0	0	0	0	0	0
	Operating Expenses							
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	132,159	102,142	10,110	99,476	4,763	27,359	376,009
7	Depreciation and Amortization	0	0	0	0	0	0	0
8	Taxes Other than Income Taxes	0	0	0	0	0	0	0
9	Income Taxes	0	0	0	0	0	0	0
10	Total Operating Expenses	132,159	102,142	10,110	99,476	4,763	27,359	376,009
11	Operating Income	(\$132,159)	(\$102,142)	(\$10,110)	(\$99,476)	(\$4,763)	(\$27,359)	(\$376,009)

Line No	Description	Fuel Expense Adjustment	Rate Case Expense	C.A.R.E. Expense	Bad Debt Expense	Depreciation and Property Tax for Post-TY Non-Rev Plant in Service	Normalized Income Tax Corrected*	Normalized Income Tax for pro forma adjustment corrections**	Total Page Adjustments	Total Adjustment
1	Operating Revenues									
2	Electric Retail Revenues	\$0	\$0	\$61,797	\$0	\$0	\$0	\$0	\$61,797	\$61,797
3	Sales for Resale	0	0	0	0	0	0	0	0	0
4	Other Operating Revenue	0	0	0	0	0	0	0	0	0
	Total Operating Revenues	0	0	61,797	0	0	0	0	61,797	61,797
	Operating Expenses									
5	Fuel, Purchased Power & Transmission	0	0	0	0	0	0	0	0	0
6	Other Operations and Maintenance Expense	75,798	66,667	0	(105,487)	0	0	0	36,978	412,987
7	Depreciation and Amortization	0	0	0	0	313,599	0	0	313,599	313,599
8	Taxes Other than Income Taxes	0	0	0	0	128,927	0	0	128,927	128,927
9	Income Taxes	0	0	0	0	0	124,178	(172,925)	(48,747)	(48,747)
10	Total Operating Expenses	75,798	66,667	0	(105,487)	442,526	124,178	(172,925)	430,757	806,766
11	Operating Income	(\$75,798)	(\$66,667)	\$61,797	\$105,487	(\$442,526)	(\$124,178)	\$172,925	(\$368,960)	(\$744,969)

Supporting Schedules

Schedules THF C-3 through THF C-13

*Adjusted operating income before income taxes of \$13,502,396 less synchronized interest of \$6,436,481 times the effective tax rate of .38598

The normalized income tax expense is \$2,727,302 vs Company pro forma of \$2,124,267. Staff incremental adjustment should be \$606,035, a net change of \$124,176

**Based on adjusted operating income after changes in pro forma adjustments which produce operating income before income tax of \$13,069,751 less synchronized interest of \$6,441,851 times the effective tax rate of .38,598%. This results in a normalized income tax expense of \$2,554,377 vs. corrected level of \$2,727,302, a net change of (\$172,925)

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF)
UNS ELECTRIC, INC. FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF UNS ELECTRIC, INC.)
DEVOTED TO ITS OPERATIONS)
THROUGHOUT THE STATE OF ARIZONA.)
_____)

DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206

My Surrebuttal Testimony responds to certain parts of the Rebuttal Testimonies of UNS Electric, Inc.'s ("UNS Electric" or "Company") witnesses Pritz and Grant. I first respond to Ms. Pritz's Rebuttal Testimony on the issue of Cost of Common Equity. I demonstrate that her criticisms on my Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and Comparable Earnings methodologies and conclusions are without merit. I also explain why her "recalculations" of my DCF and CAPM analyses are not proper, but rather represent her attempts to apply her improper inputs into my analyses.

I next respond to Mr. Grant's Rebuttal Testimony on the issues of: 1) Ability of UNS Electric to earn its Cost of Capital; and 2) Rate of Return on Fair Value Rate Base. Regarding the first issue, my response is that regulation only provides the Company with the opportunity to earn a fair rate of return; it does not provide a guarantee. On the second issue, I disagree with Mr. Grant's interpretation of the Commission's recent decisions concerning the proper methodologies to determine the Fair Value Rate of Return. I further demonstrate that my proposed Fair Value Rate of Return proposal is consistent with past Commission decisions.

1 **INTRODUCTION**

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

3 A. My name is David C. Parcell. I am President and Senior Economist of Technical
4 Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond,
5 Virginia 23219.

6

7 **Q. Are you the same David C. Parcell who filed direct testimony on behalf of the**
8 **Utilities Division Staff ("Staff") earlier in this proceeding?**

9 A. Yes, I am.

10

11 **Q. What is the purpose of your current testimony?**

12 A. My current testimony is Surrebuttal Testimony in response to the Rebuttal Testimonies of
13 UNS Electric Inc. ("UNS Electric" or "Company") witnesses Martha B. Pritz and Kentton
14 C. Grant. I also updated my cost of capital analyses in this Surrebuttal Testimony.

15

16 **Q. What aspects of Ms. Pritz's and Mr. Grant's Rebuttal Testimonies do you respond to**
17 **in this Surrebuttal Testimony?**

18 A. My Surrebuttal Testimony responds to the following general areas of Ms. Pritz's and Mr.
19 Grant's Rebuttal Testimonies:

20

21 Cost of Common Equity (Ms. Pritz);

22 Ability of UNS Electric to Earn its Cost of Capital (Mr. Grant); and

23 Fair Value Rate of Return ("FVROR") (Mr. Grant).

1 **COST OF COMMON EQUITY**

2 **Q. Ms. Pritz claims, on pages 1 and 2, that your cost of equity cost recommendation “is**
3 **low due to the use of inappropriate inputs in several of the methods upon which he**
4 **(you) relies.” What is your response to this assertion?**

5 A. I believe that my cost of equity recommendation is appropriate for UNS Electric at this
6 time. This cost of equity recommendation is based upon the results of my Discounted
7 Cash Flow (“DCF”), Capital Asset Pricing Model (“CAPM”), and Comparable Earnings
8 (“CE”) analyses and has been performed in a similar fashion to my recent testimonies
9 before this Commission. I note that my 10.0 percent recommendation matches the cost of
10 equity that the Commission found appropriate for UNS Electric in its most recent
11 proceeding (i.e., Docket No. E-04204A-06-0783). There has been no demonstration that
12 the cost of capital has increased since the 2007 proceeding of UNS Electric.

13
14 **DCF Issues**

15 **Q. On pages 2-3, Ms. Pritz criticizes your DCF analyses and she characterizes some of**
16 **your growth estimates as “weak sets of data as indications of dividend growth.”**
17 **What is your response to this assertion?**

18 A. Ms. Pritz first takes issue with my use of historic data as one of several sources of growth
19 projections. She next takes issue with my use of retention growth (both historic and
20 prospective) as a growth indicator. What is implicit in her criticism is that her preferred
21 short-term growth rates (i.e., exclusive use of analysts’ forecasts of earnings per share
22 growth) is all that is appropriate. I have previously noted in my direct testimony (pages
23 42-45) why it is improper to exclusively rely on earnings per share (“EPS”) forecasts and
24 also that such an exclusive reliance is not reflective of investor expectations.

1 Ms. Pritz attempts to justify her exclusive reliance on analysts' forecasts of EPS growth on
2 her belief that "analysts providing forward-looking growth estimates will have already
3 considered historical growth in determining the outlook for a company." This viewpoint
4 is not a sufficient reason to assume that investors ignore historic growth and focus
5 exclusively on analysts' forecasts. It should be apparent, based upon the experience of the
6 past two years, that analysts have not been accurate in projecting EPS and, further, any
7 investors who were unfortunate enough to have exclusively relied on such forecasts would
8 have been sorely disappointed with their investment performance. In any event, recent
9 performance of analysts' estimates would give investors even more reason to consider
10 other growth indicators in making their investment decisions.

11
12 I further note that the preponderance of financial information provided to investors, both
13 by individual companies and investment services such as Value Line, is historic data. It is
14 neither realistic nor accurate to maintain that all of this information is ignored by
15 investors, but this is what Ms. Pritz is maintaining.

16
17 **Q. Ms. Pritz provides indications, on pages 2 and 3, reflecting her position of what your**
18 **DCF results would be if you had not considered historic growth and retention growth**
19 **in your analyses. Are these results meaningful?**

20 **A.** No, they are not. These results simply reflect her attempt to substitute her proposal (i.e.,
21 exclusive use of analysts' estimates of EPS growth) into my DCF analyses. This is not
22 proper and not an accurate portrayal of my DCF analyses.

1 **Q. On page 5, Ms. Pritz claims that her use of historical gross domestic product**
2 **("GDP") growth is proper. What is your response to this?**

3 A. I note, first of all, that Ms. Pritz maintains that short-term growth (in a DCF context)
4 should only reflect prospective data, whereas long-term growth should only use historic
5 data. This position is internally inconsistent. As I noted in my Direct Testimony (pages
6 45-47) prospective GDP growth is about 4.5 percent, well below that 6.5 percent level she
7 uses.

8
9 In addition, Ms. Pritz's rebuttal testimony on page 5 implies that her 6.5 percent long-term
10 growth rate reflects GDP projections. However, this is largely not the case, as she
11 averages GDP estimates with other and higher growth rates, such as EPS projections and
12 the "outlook for the electric utility industry."

13
14 **CAPM Issues**

15 **Q. Ms. Pritz further maintains, on pages 7-9, that your use of both geometric and**
16 **arithmetic means in your CAPM analysis is not proper. What is your response to**
17 **this?**

18 A. It is apparent that investors have access to both types of returns, and correspondingly use
19 both types of returns, when they make investment decisions. In fact, it is noteworthy that
20 mutual fund investors regularly receive reports on their own funds, as well as prospective
21 funds they are considering investing in, that show only geometric returns. In fact, the
22 Securities and Exchange Commission requires that returns be reported this way. Based on
23 this, I find it difficult to accept Ms. Pritz's position that only arithmetic returns are
24 considered by investors and, thus, only arithmetic returns are appropriate in a CAPM
25 context. I note that I provided additional comments on this point in my Direct Testimony.

1 **Q. Has this Commission recently made a finding as to whether it is appropriate to use**
2 **geometric as well as arithmetic returns in this context?**

3 A. Yes, it has. In Decision No. 70360 (UNS Electric Docket No. E-04204A-06-0783) the
4 Commission specifically stated (page 43) that it agreed with the use of geometric returns
5 in this manner: "We agree with the Staff that it is appropriate to consider the geometric
6 returns in calculating a comparable company CAPM because to do otherwise would fail to
7 give recognition to the fact that many investors have access to such information for
8 purposes of making investment decisions." Therefore, the Company's position also
9 conflicts with recent Commission orders on this issue.

10
11 **Q. Ms. Pritz indicates her belief, on pages 7-8, that "income returns" (which she uses) is**
12 **superior to "total returns" (which you use). What is your response to this?**

13 A. I addressed this issue in my Direct Testimony on page 48.
14

15 **Q. On pages 9-10, Ms. Pritz claims to have recalculated your CAPM cost of equity**
16 **results. Is this a proper exercise?**

17 A. No, it is not. Ms. Pritz's "recalculations" are simply her attempt to interject her CAPM
18 components into my analyses. Such recalculations are incorrect and improper.
19

20 **Comparable Earnings Issues**

21 **Q. Ms. Pritz also criticizes your comparable earnings analyses on page 6. What is your**
22 **response to this position?**

23 A. I disagree with Ms. Pritz. The book value of UNS Electric's capital, including common
24 equity, is used to determine the Company's cost of capital. It is only natural that the
25 returns on book value of equity (i.e., comparable earnings analyses) is an appropriate
26 mechanism for estimating the cost of equity.

1 **Q. Ms. Pritz also implies, on page 6, that market-to-book ratios do not indicate investor**
2 **acceptance of earned returns. Is she correct?**

3 A. No, she is not. Stock prices – one component of the market-to-book ratio – reflect all
4 relevant information. For public utilities, the return on equity is a major component of the
5 rate-setting process and clearly is reflected in stock prices, and thus market-to-book ratios.
6 I also note that I consider expected returns on equity in my comparable earnings analysis.
7

8 **ABILITY OF UNS ELECTRC TO EARN ITS COST OF CAPITAL**

9 **Q. Mr. Grant devotes several pages of his Rebuttal Testimony to his assertion that UNS**
10 **Electric will not likely earn the cost of capital authorized in this proceeding. Is this a**
11 **proper criticism of your Direct Testimony?**

12 A. I do not believe it is proper rebuttal to my testimony. Mr. Grant seems to be taking the
13 position that the cost of capital authorized by a commission should be regarded as a
14 “guarantee” but this is not the case. Utility investors have no more “right” to a guaranteed
15 return than do its ratepayers to a “right” to employment, maintenance of their housing
16 values, and an increasing value of their retirement accounts and other investments.
17

18 **RATE OF RETURN ON FAIR VALUE RATE BASE**

19 **Q. Mr. Grant maintains, on page 10, that your FVROR recommendation to apply a zero**
20 **percent return to the Fair Value Increment amounts to a “backing in” method of**
21 **assigning a FVROR. Do you agree with his assessment?**

22 A. No, I do not. My proposal specifically recognizes the value of the Fair Value Rate Base
23 (“FVRB”) increment and applies the actual cost of this capital (which is zero) to it. As
24 such, I believe this proposal specifically recognizes and utilizes the FVRB in establishing
25 rates.
26

1 **Q. Mr. Grant also claims, on pages 10-11, that since the Commission did not adopt your**
2 **FVROR proposal in the Chaparral City remand proceeding (Docket No. W-02113A-**
3 **04-0616) that your proposal has been “rejected.” What is your response to this?**

4 A. It is my reading of the Chaparral City Remand Order¹ by the Commission that a similar
5 procedure to what I recommended was adopted. I also note that the Commission stated in
6 its Chaparral City Remand Order “we also believe that Staff’s method is an appropriate
7 way to adjust the Weighted Average Cost of Capital associated with the Original Cost
8 Rate Base (“OCRB”) for use with the FVRB, as it is based on sound economic and
9 financial theory.” (Decision No. 70441 at p. 37) In the UNS Gas and UNS Electric cases,
10 the Commission did adopt my recommendation. Finally I note that the FVROR proposal
11 of Chaparral City was the same as that proposed by UNS Gas and UNS Electric in their
12 2007 rate proceedings (Docket Nos. G-04204A-06-0463 and E-04204A-06-0783), namely
13 that the original cost rate of return (“OCROR”) be applied to the level of FVRB. In all
14 three of these cases, the Commission did not adopt the Chaparral City/UNS Gas &
15 Electric position.

16
17 **Q. On pages 12-13, Mr. Grant maintains there is a mathematical error in your FVROR**
18 **calculation and states that the correction of this “increases Staff’s proposed revenue**
19 **requirement by \$633,000.” What is your response to these assertions?**

20 A. Mr. Grant is correct, on page 12, that my FVROR (as shown on page 57) should have
21 stated 6.14 percent rather than 5.99 percent. However, this correction does not impact
22 Staff’s proposed revenue requirement.

23

¹ See, *In The Matter of the Application of Chaparral City Water Company, an Arizona Corporation, for a Determination of the Current Fair Value of its Utility Plant and Property and for Increases in its Rates and Charges for Utility Service Based Thereon.* Docket No. W-02113A-04-0616. Opinion and Order, Decision No. 70441 (July 28, 2008).

1 **Q. Why is it the case that this correction does not impact Staff's proposed revenue**
2 **requirement?**

3 A. Mr. Grant's claim (i.e., that the difference between a 5.99 percent FVROR and a 6.14
4 percent FVROR) results in a \$633,000 impact on Staff's proposed revenue requirement is
5 based upon an assumption on his part that Utilities Division Staff witness Fish used the
6 5.99 percent number in developing the revenue requirement. This is not the case.

7
8 Dr. Fish did not use the 5.99 percent per se when developing his proposed revenue
9 requirement. Rather, he developed his value for the fair value return by multiplying my
10 proposed 1.50 percent return on the FVRB increment, or the difference between the fair
11 value rate base and original cost rate base (see Dr. Fish's direct testimony, Schedule THF
12 A-1). As a result, the mathematic error on my page 57 was not carried through by Dr.
13 Fish to the Staff's revenue requirement, as stated by Mr. Grant.

14
15 **Q. Aside from this correction of your "mathematical error" on page 57 of your Direct**
16 **Testimony, do you have any additional comments on the FVROR calculation you are**
17 **proposing in this proceeding?**

18 A. Yes, I do. As I was in the process of reviewing my FVROR calculation, as shown on
19 pages 54 and 57 of my Direct Testimony, I discovered that I had not properly developed
20 the capital structure ratios to be used in the FVROR consistent with Staff's calculations in
21 most other cases. I have subsequently corrected this, which is shown on Schedule 15 of
22 my Surrebuttal Testimony. As a result, my recommendation is that the Commission adopt
23 a FVROR of 6.01 percent.

1 **Q. Please describe Schedule 15.**

2 A. The top portion of Schedule 15 shows how the 6.14 percent (as corrected) FVROR was
3 developed in my Direct Testimony. As this indicates, I developed the capital structure
4 ratios by combining the dollars as long-term debt, common equity and FVRB Increment
5 and calculating the respective percentages of each of the three items.

6
7 The problem I discovered with this process is that I was combining dollars of capital items
8 (for long-term debt and common equity) with dollars of rate base (for FVRB Increment).
9 Since the rate base and capital for UNS Electric (as well as most utilities) do not precisely
10 match, the FVROR which I recommended in my Direct Testimony (i.e., 6.14 percent) was
11 slightly different than the ultimate FVROR in Staff witness Dr. Fish's return on FVRB
12 (i.e., 6.01 percent).

13
14 However, the proper way to develop the capital structure ratios for the FVROR calculation
15 is to equate the capital structure percentages (for long-term debt and common equity) to
16 the dollar values of original cost rate base. I did this on the bottom portion of Schedule
17 15. Here I applied the percentages of long-term debt and common equity (as shown in the
18 development of the total cost of capital in Schedule 1 of my Direct Testimony) to the
19 dollar value of OCRB to develop dollars of long-term debt and common equity that equate
20 to OCRB. This is then combined with the dollar value of the FVRB Increment to develop
21 a capital structure that equates to the value of FVRB. I then applied the cost rates of long-
22 term debt (7.05 percent), common equity (10.00 percent) and FVRB Increment (1.50
23 percent) to the percentages to develop a FVROR that properly matches the value of
24 FVRB. This produces a FVROR of 6.01 percent, which should have been my
25 recommendation.
26

1 **Q. Does this correction impact Staff's revenue requirement?**

2 A. No, it does not. As I indicated previously, Dr. Fish did not directly use my proposed
3 FVROR number in his calculation of the revenue requirement, but rather directly used the
4 1.50 percent FVRB Increment cost to arrive at a return on the FVRB. I have developed
5 Schedule 15 to clarify the method by which the FVROR should be viewed in a cost of
6 capital context.

7

8 **UPDATES**

9 **Q. Have you updated your cost of capital analyses?**

10 A. Yes, I have. My Direct Testimony utilized financial market data as of October of 2009.
11 My DCF and CAPM analyses employed stock prices and interest rates for the three-month
12 period July-September of 2009.

13

14 My updated analyses consider financial data through early January 2010 and incorporates
15 stock prices and interest rates for the three-month period October-December 2009. I have
16 also used the most recent editions of Value Line and analysts' forecasts of EPS in my
17 updated analyses. My updated analyses also reflect a minor correction to my analyses that
18 was identified in the Rebuttal Testimony of UNS Electric.

19

20 I have prepared a complete set of schedules to my exhibit. Any schedules that have been
21 revised are identified as "updated."

22

23 **Q. What is the impact of your cost of capital updates?**

24 A. The table below identifies the impacts of my updates:

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DCF Analyses

	<u>Original Analyses</u>		<u>Updated Analyses</u>	
	<u>Proxy Group</u>	<u>Pritz Group</u>	<u>Proxy Group</u>	<u>Pritz Group</u>
Mean	10.1%	9.5%	9.8%	9.2%
Median	9.6%	9.4%	10.1%	9.4%
Mean				
Low	8.6%	8.2%	8.0%	8.0%
High	12.3%	11.7%	13.0%	11.9%
Median				
Low	8.9%	7.4%	7.9%	6.9%
High	11.8%	11.6%	13.9%	11.3%

CAPM Analyses

	<u>Original Analyses</u>		<u>Updated Analyses</u>	
	<u>Proxy Group</u>	<u>Pritz Group</u>	<u>Proxy Group</u>	<u>Pritz Group</u>
Mean	8.3%	7.6%	8.2%	7.9%
Median	8.3%	8.0%	8.2%	7.9%

Based upon these updates, I conclude that the cost of capital for UNS Electric remains at the 10.0 percent level I derived in my Direct Testimony.

Q. Does this conclude your Surrebuttal Testimony?

A. Yes, it does.

**UNS ELECTRIC INC
 TOTAL COST OF CAPITAL**

Item	Percent	Cost	Weighted Cost
Long-Term Debt	54.24%	7.05%	3.82%
Common Equity	45.76%	9.50% - 10.50%	4.35% - 4.80%
Total	100.00%		8.17% - 8.63%
			8.40% With 10.0% ROE

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un- employment Rate	Consumer Price Index	Producer Price Index
1975 - 1982 Cycle					
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
1983 - 1991 Cycle					
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
1992 - 2001 Cycle					
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	6.1%	4.5%	1.6%	0.0%
1999	4.8%	4.3%	4.2%	2.7%	2.9%
2000	4.1%	4.2%	4.0%	3.4%	3.6%
2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
Current Cycle					
2002	1.8%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	3.1%	3.3%	5.1%	3.4%	5.4%
2006	2.7%	2.3%	4.6%	2.5%	1.1%
2007	2.1%	1.5%	4.6%	4.1%	6.2%
2008	0.4%	-2.2%	5.8%	0.1%	-0.9%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	1.2%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	3.6%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.1%	1.7%	4.8%	5.6%	12.8%
2008					
1st Qtr.	-0.7%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	1.5%	-0.4%	5.4%	7.6%	14.0%
3rd Qtr.	-2.7%	-3.2%	6.1%	2.8%	-0.4%
4th Qtr.	-5.4%	-6.7%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-6.4%	-11.6%	8.1%	2.4%	-1.2%
2nd Qtr.	-0.7%	-12.9%	9.3%	3.2%	8.8%
3rd Qtr.	2.8%	-9.5%	9.6%	2.4%	1.6%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
1975 - 1982 Cycle							
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
1983 - 1991 Cycle							
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
1992 - 2001 Cycle							
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
Current Cycle							
2002	4.67%	1.62%	4.61%		[1] 7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003						
Jan	4.25%	1.17%	4.05%	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%	6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%	6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%	6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%	6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%	6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%	6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%	6.45%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%	6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%	6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%	6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%	6.18%	6.27%	6.61%
2004						
Jan	4.00%	0.89%	4.15%	6.06%	6.15%	6.47%
Feb	4.00%	0.82%	4.08%	6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%	5.93%	5.97%	6.12%
Apr	4.00%	0.84%	4.35%	6.33%	6.35%	6.48%
May	4.00%	1.04%	4.72%	6.66%	6.62%	6.75%
June	4.00%	1.27%	4.75%	6.36%	6.46%	6.64%
July	4.25%	1.35%	4.50%	6.08%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%	5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%	5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%	5.74%	5.94%	6.17%
Nov	5.00%	2.08%	4.19%	5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%	5.78%	5.92%	6.10%
2005						
Jan	5.25%	2.32%	4.22%	5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%	5.56%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%	5.76%	5.83%	6.01%
Apr	5.75%	2.78%	4.34%	5.69%	5.84%	5.95%
May	6.00%	2.86%	4.41%	5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%	5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%	5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%	5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%	5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%	5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%	5.58%	5.86%	6.18%
Dec	7.25%	3.89%	4.47%	5.55%	5.80%	6.14%
2006						
Jan	7.50%	4.20%	4.42%	5.60%	5.75%	6.08%
Feb	7.50%	4.41%	4.57%	5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%	5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%	6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%	6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%	6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%	6.13%	6.37%	6.61%
Aug	8.25%	4.96%	4.88%	5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%	5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%	5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%	5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%	5.62%	5.81%	6.06%
2007						
Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
Apr	8.25%	4.85%	4.69%	5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%	5.88%	5.99%	6.23%
June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
Oct	7.50%	3.87%	4.53%	6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%	5.67%	5.87%	6.27%
Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
2008						
Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.50%
Mar	5.25%	1.38%	3.51%	5.95%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%	5.98%	6.28%	6.82%
May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
June	5.00%	1.50%	4.10%	6.19%	6.38%	6.83%
July	5.00%	1.72%	4.01%	6.13%	6.40%	6.87%
Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.88%
Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%	6.96%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.88%
Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
2009						
Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%	6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%	6.13%	6.20%	7.30%
July	3.25%	0.19%	3.66%	5.53%	5.97%	6.87%
Aug	3.25%	0.18%	3.58%	5.33%	5.71%	6.36%
Sept	3.25%	13.00%	3.40%	5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%	5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%	5.33%	5.64%	6.18%

Note: Moody's has not published Aaa utility bond yields since 2001.

Source: Council of Economic Advisors; Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
1975 - 1982 Cycle					
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
1983 - 1991 Cycle					
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988		[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
1992 - 2001 Cycle					
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
Current Cycle					
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.55%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.57%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.70	996.70	9,229.93	2.16%	1.20%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

UNISOURCE ENERGY CORPORATION
SEGMENT FINANCIAL INFORMATION
2006 - 2008
(\$millions)

Segment	Operating Revenues	Operating Income	Total Assets
	2006		
Tucson Electric Power Co	\$989 75.6%	\$216 90.0%	\$2,623 82.3%
UNS Gas	\$162 12.4%	\$13 5.4%	\$253 7.9%
UNS Electric	\$160 12.2%	\$13 5.4%	\$195 6.1%
All Other	\$14 1.1%	0.0%	\$1,038 32.6%
Unisource Energy	\$1,308	\$240	\$3,187
	2007		
Tucson Electric Power Co	\$1,071 77.6%	\$189 88.7%	\$2,573 80.8%
UNS Gas	\$151 10.9%	\$12 5.6%	\$276 8.7%
UNS Electric	\$169 12.2%	\$12 5.6%	\$231 7.3%
All Other	\$12 0.9%	0.0%	\$1,077 33.8%
Unisource Energy	\$1,381	\$213	\$3,186
	2008		
Tucson Electric Power Co	\$1,079 77.2%	\$107 73.8%	\$2,842 81.0%
UNS Gas	\$174 12.4%	\$20 13.8%	\$294 8.4%
UNS Electric	\$195 13.9%	\$12 8.3%	\$285 8.1%
All Other	\$23 1.6%	0.0%	\$1,061 30.2%
Unisource Energy	\$1,398	\$145	\$3,510

UNS Gas, TEP and UNS Electric figures do not total to Unisource Energy consolidated figures due to other activities of Unisource Energy.

**UNS ELECTRIC
CAPITAL STRUCTURE RATIOS
2003 - 2009
(\$millions)**

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	\$40,900	\$60,000	\$600
	40.3%	59.1%	0.6%
	40.5%	59.5%	
2005	\$49,900	\$60,000	\$500
	45.2%	54.3%	0.5%
	45.4%	54.6%	
2006	\$64,900	\$79,000	\$400
	45.0%	54.7%	0.3%
	45.1%	54.9%	
2007	\$79,800	\$86,000	\$400
	48.0%	51.7%	0.2%
	48.1%	51.9%	
2008	\$83,800	\$108,000	\$200
	43.6%	56.3%	0.1%
	43.7%	56.3%	
June 30, 2009	\$86,000	\$100,000	\$200
	46.2%	53.7%	0.1%
	46.2%	53.8%	

Source: Response to STF 7.2

UNISOURCE ENERGY CORP
CAPITAL STRUCTURE RATIOS
2003 - 2008
(\$millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	\$581 31.6% 31.6%	\$1,258 68.4% 68.4%	\$0 0.0%
2005	\$617 33.6% 33.7%	\$1,212 66.1% 66.3%	\$5 0.3%
2006	\$654 34.9% 35.8%	\$1,171 62.5% 64.2%	\$50 2.7%
2007	\$690 40.7% 41.0%	\$994 58.7% 59.0%	\$10 0.6%
2008	\$679 33.9% 34.1%	\$1,314 65.6% 65.9%	\$10 0.5%

Source: Unisource Energy Corporation 2008 Form 10-K.

**UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
2008
(\$millions)**

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource Energy consolidated	\$679.3 33.9% 34.1%	\$1,313.6 65.6% 65.9%	\$10.0 0.5%
UNS Gas	\$96.7 49.2% 49.2%	\$100.0 50.8% 50.8%	\$0 0.0%
UNS Electric	\$83.8 21.4% 43.7%	\$108.0 27.6% 56.3%	\$200 51.0%
TEP	\$583.6 39.0% 39.2%	\$903.6 60.4% 60.8%	\$10.0 0.7%

Source for Unisource Energy Consolidated and TEP is 2008 10-K
Source for UNS Gas and UNS Electric is Response to STF 7.2.

**PROXY GROUPS
COMMON EQUITY RATIOS**

COMPANY	2004	2005	2006	2007	2008	Average	2012-2014
Parcell Proxy Group							
Avista Corp.	41.9%	40.6%	46.3%	59.0%	51.9%	47.9%	50.0%
Hawaiian Electric Industries, Inc	51.0%	53.3%	48.6%	51.0%	52.7%	51.3%	55.0%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.0%
Pinnacle West Capital Corp.	53.3%	56.8%	51.6%	53.0%	53.2%	53.6%	50.0%
Pepco Holdings, Inc.	39.6%	42.3%	45.1%	45.9%	43.8%	43.3%	48.5%
TECO Energy, Inc.	24.9%	30.0%	35.0%	39.0%	38.5%	33.5%	41.5%
Westar Energy, Inc.	45.5%	47.2%	49.3%	48.9%	49.7%	48.1%	52.5%
Average	41.5%	43.6%	45.1%	48.0%	46.8%	45.0%	48.8%
Pritz Comparable Company Group							
ALLETE, Inc.	61.8%	60.9%	64.9%	64.4%	58.4%	62.1%	51.5%
CH Energy Group, Inc.	59.1%	58.0%	58.8%	55.2%	54.6%	57.1%	48.5%
Empire District Electric Co.	48.7%	49.0%	50.3%	49.9%	46.4%	48.9%	49.0%
Hawaiian Electric Industries	51.0%	53.3%	48.6%	51.0%	52.7%	51.3%	55.0%
MGE Energy, Inc.	62.6%	60.7%	61.3%	64.8%	63.7%	62.6%	65.0%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.0%
NorthWestern Corp.							
NSTAR	40.2%	38.6%	39.7%	40.1%	42.8%	40.3%	54.0%
Portland General Electric	58.9%	57.7%	56.6%	50.1%	53.8%	55.4%	50.5%
UIL Holdings	52.8%	52.8%	53.0%	49.2%	46.4%	50.8%	48.0%
Average	52.1%	51.8%	52.5%	51.5%	50.8%	51.8%	51.7%

Source: Value Line.

**PROXY COMPANIES
BASIS FOR SELECTION**

Company	Market Capitalization (\$ millions)	Percent Reg Elec or Gas Revenues	Common Equity Ratio	Value Line Safety	S&P Bond Rating	Moody's Bond Rating
Unisource Energy	\$975,000	84%	39%	3	NR	NR
Parcell Proxy Group						
Avista Corp.	\$1,000,000	53%	54%	3	BBB+	Baa1
Hawaiian Electric Industries, Inc.	\$1,600,000	98%	46%	3	BBB	Baa2
Northeast Utilities	\$3,600,000	81%	41%	3	BBB+	A3
Pinnacle West Capital Corp.	\$3,300,000	97%	45%	3	BBB-	Baa2
Pepco Holdings, Inc.	\$3,100,000	50%	43%	3	A-	Baa1
TECO Energy, Inc.	\$2,800,000	63%	39%	3	BBB	Baa1
Westar Energy, Inc.	\$2,300,000	71%	44%	2	BBB-	Baa2
Pritz Comparable Company Group						
ALLETE, Inc.	\$1,100,000	90%	58%	2	A-	A2
CH Energy Group, Inc.	\$750,000	49%	49%	1	A	A2
Empire District Electric Co.	\$625,000	86%	43%	3	BBB+	Baa1
Hawaiian Electric Industries	\$1,600,000	98%	46%	3	BBB	Baa2
MGE Energy, Inc.	\$850,000	59%	64%	1	AA-	Aa2
Northeast Utilities	\$4,100,000	81%	41%	3	BBB+	A3
NorthWestern Corp.						
NSTAR	\$3,400,000	80%	43%	1	AA-	A1
Portland General Electric	\$1,400,000	98%	49%	2	A	Baa1
UIL Holdings	\$775,000	100%	45%	2	NR	Baa2

Sources: AUS Utility Reports, Value Line.

**COMPARISON COMPANIES
DIVIDEND YIELD**

COMPANY	Qtr DPS	October - December, 2009			YIELD	
		DPS	HIGH	LOW		AVERAGE
Parcell Proxy Group						
Avista Corp.	\$0.21	\$0.84	\$22.44	\$18.48	\$20.46	4.1%
Hawaiian Electric Industries, Inc.	\$0.31	\$1.24	\$21.55	\$17.64	\$19.60	6.3%
Northeast Utilities	\$0.24	\$0.95	\$26.48	\$22.20	\$24.34	3.9%
Pinnacle West Capital Corp.	\$0.53	\$2.10	\$37.96	\$31.08	\$34.52	6.1%
Pepco Holdings, Inc.	\$0.27	\$1.08	\$17.51	\$14.24	\$15.88	6.8%
TECO Energy, Inc.	\$0.20	\$0.80	\$16.71	\$13.45	\$15.08	5.3%
Westar Energy, Inc.	\$0.30	\$1.20	\$22.30	\$18.91	\$20.61	5.8%
Average						5.5%
Pritz Comparable Company Group						
ALLETE, Inc.	\$0.44	\$1.76	\$35.29	\$32.23	\$33.76	5.2%
CH Energy Group, Inc.	\$0.54	\$2.16	\$45.57	\$39.54	\$42.56	5.1%
Empire District Electric Co.	\$0.32	\$1.28	\$19.36	\$17.78	\$18.57	6.9%
Hawaiian Electric Industries	\$0.31	\$1.24	\$21.55	\$17.64	\$19.60	6.3%
MGE Energy, Inc.	\$0.37	\$1.47	\$36.97	\$33.41	\$35.19	4.2%
Northeast Utilities	\$0.24	\$0.95	\$26.48	\$22.20	\$24.34	3.9%
NorthWestern Corp.	\$0.34	\$1.34	\$26.85	\$23.61	\$25.23	5.3%
NSTAR	\$0.38	\$1.50	\$37.75	\$30.76	\$34.26	4.4%
Portland General Electric	\$0.26	\$1.02	\$21.39	\$18.25	\$19.82	5.1%
UIL Holdings	\$0.43	\$1.73	\$29.00	\$25.27	\$27.14	6.4%
Average						5.3%

Source: Yahoo! Finance.

**COMPARISON COMPANIES
RETENTION GROWTH RATES**

COMPANY	2004	2005	2006	2007	2008	Average	2009	2010	2012-'14	Average
Parcell Proxy Group										
Avista Corp.	1.4%	2.4%	4.9%	0.8%	3.7%	2.6%	4.0%	3.5%	3.0%	3.5%
Hawaiian Electric Industries, Inc.	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.0%	1.5%	3.0%	1.5%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.0%	4.3%
Pinnacle West Capital Corp.	2.3%	1.0%	3.4%	2.5%	0.3%	1.9%	1.0%	2.0%	3.0%	2.0%
Peppo Holdings, Inc.	2.5%	2.4%	1.5%	2.3%	4.2%	2.6%	0.0%	1.0%	2.5%	1.2%
TECO Energy, Inc.	0.0%	3.3%	5.0%	5.1%	0.0%	2.7%	2.0%	3.5%	4.5%	3.3%
Westar Energy, Inc.	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	1.0%	2.0%	2.5%	1.8%
Average						2.4%				2.5%
Pritz Comparable Company Group										
ALLETE, Inc.	4.7%	5.2%	5.0%	5.8%	3.9%	4.9%	0.0%	1.0%	2.0%	1.0%
CH Energy Group, Inc.	1.7%	2.0%	1.2%	1.6%	0.4%	1.4%	0.5%	1.5%	2.5%	1.5%
Empire District Electric Co.	0.0%	0.0%	0.8%	0.0%	0.0%	0.2%	0.0%	0.5%	2.5%	1.0%
Hawaiian Electric Industries	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.0%	1.5%	3.0%	1.5%
MGE Energy, Inc.	2.3%	1.2%	3.7%	4.3%	4.4%	3.2%	3.0%	4.0%	5.5%	4.2%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.0%	4.3%
NorthWestern Corp.	5.8%	4.2%	0.8%	0.7%	2.3%	2.8%				
NSTAR	4.8%	4.6%	4.9%	4.9%	4.9%	4.8%	5.0%	5.0%	6.0%	5.3%
Portland General Electric	7.2%	5.3%	3.5%	6.6%	2.0%	4.9%	2.5%	3.0%	3.5%	3.0%
UIL Holdings	0.0%	0.0%	0.0%	3.1%	1.0%	0.8%	1.0%	1.5%	2.5%	1.7%
Average						2.6%				2.6%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
PER SHARE GROWTH RATES**

COMPANY	5-Year Historic Growth Rates				Est'd '06-'08 to '12-'14 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Parcell Proxy Group								
Avista Corp.	4.0%	5.0%	3.0%	4.0%	6.5%	11.5%	3.5%	7.2%
Hawaiian Electric Industries, Inc.	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.0%	3.0%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	7.0%	4.5%	6.5%
Pinnacle West Capital Corp.	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
Pepco Holdings, Inc.	-2.0%	17.5%	1.5%	5.7%	NMF	NMF	1.0%	1.0%
TECO Energy, Inc.	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Westar Energy, Inc.	21.5%	-0.5%	1.0%	7.3%	4.0%	4.5%	6.0%	4.8%
Average				2.2%				4.0%
Pritz Comparable Company Group								
ALLETE, Inc.					-1.0%	3.0%	3.0%	1.7%
CH Energy Group, Inc.	-1.5%	0.0%	1.5%	0.0%	3.5%	0.0%	2.0%	1.8%
Empire District Electric Co.	3.5%	0.0%	1.5%	1.7%	6.0%	1.0%	1.5%	2.8%
Hawaiian Electric Industries	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.0%	3.0%
MGE Energy, Inc.	6.0%	1.0%	8.0%	5.0%	6.0%	0.5%	7.0%	4.5%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	7.0%	4.5%	6.5%
NorthWestern Corp.	--	--	--					
NSTAR	4.0%	6.0%	5.0%	5.0%	8.0%	5.5%	5.5%	6.3%
Portland General Electric	--	--	--		3.5%	5.5%	2.5%	3.8%
UIL Holdings	--	--	-2.0%	-2.0%	3.0%	0.0%	2.5%	1.8%
Average				1.8%				3.6%

Source: Value Line Investment Survey.

**COMPARISON COMPANIES
DCF COST RATES**

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
Avista Corp.	4.2%	2.6%	3.5%	4.0%	7.2%	5.0%	4.5%	8.7%
Hawaiian Electric Industries, Inc.	6.5%	0.9%	1.5%		3.0%	10.5%	4.0%	10.4%
Northeast Utilities	4.0%	2.6%	4.3%	4.5%	6.5%	9.3%	5.5%	9.5%
Pinnacle West Capital Corp.	6.2%	1.9%	2.0%	2.3%	1.7%	8.0%	3.2%	9.4%
Pepeco Holdings, Inc.	6.9%	2.6%	1.2%	5.7%	1.0%	5.5%	3.2%	10.1%
TECO Energy, Inc.	5.4%	2.7%	3.3%		3.8%	9.8%	4.9%	10.4%
Westar Energy, Inc.	5.9%	3.7%	1.8%	7.3%	4.8%	3.7%	4.3%	10.2%
Mean	5.6%	2.4%	2.5%	4.8%	4.0%	7.4%	4.2%	9.8%
Median	5.9%	2.6%	2.0%	4.5%	3.8%	8.0%	4.3%	10.1%
Composite - Mean		8.0%	8.1%	10.4%	9.6%	13.0%	9.8%	
Composite - Median		8.5%	7.9%	10.4%	9.8%	13.9%	10.2%	
Pritz Comparable Company Group								
ALLETE, Inc.	5.3%	4.9%	1.0%		1.7%	4.0%	2.9%	8.2%
CH Energy Group, Inc.	5.1%	1.4%	1.5%		1.8%	N/A	1.6%	6.7%
Empire District Electric Co.	7.0%	0.2%	1.0%	1.7%	2.8%	6.0%	2.3%	9.3%
Hawaiian Electric Industries	6.5%	0.9%	1.5%		3.0%	10.5%	4.0%	10.4%
MGE Energy, Inc.	4.3%	3.2%	4.2%	5.0%	4.5%	5.0%	4.4%	8.6%
Northeast Utilities	4.0%	2.6%	4.3%	4.5%	6.5%	9.3%	5.5%	9.5%
NorthWestern Corp.	5.4%	2.8%				7.0%	4.9%	10.3%
NSTAR	4.5%	4.8%	5.3%	5.0%	6.3%	5.7%	5.4%	9.9%
Portland General Electric	5.3%	4.9%	3.0%		3.8%	6.8%	4.6%	9.9%
UIL Holdings	6.4%	0.8%	1.7%		1.8%	4.5%	2.2%	8.6%
Mean	5.4%	2.6%	2.6%	4.0%	3.6%	6.5%	3.8%	9.2%
Median	5.3%	2.7%	1.7%	4.8%	3.0%	6.0%	4.2%	9.4%
Composite - Mean		8.0%	8.0%	9.4%	9.0%	11.9%	9.2%	
Composite - Median		8.0%	6.9%	10.0%	8.3%	11.3%	9.5%	

Sources: Prior pages of this schedule.

**STANDARD & POOR'S 500 COMPOSITE
 20-YEAR U.S. TREASURY BOND YIELDS
 RISK PREMIUMS**

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		\$79.07			
1978	\$12.33	\$85.35	15.00%	7.90%	7.10%
1979	\$14.86	\$94.27	16.55%	8.86%	7.69%
1980	\$14.82	\$102.48	15.06%	9.97%	5.09%
1981	\$15.36	\$109.43	14.50%	11.55%	2.95%
1982	\$12.64	\$112.46	11.39%	13.50%	-2.11%
1983	\$14.03	\$116.93	12.23%	10.38%	1.85%
1984	\$16.64	\$122.47	13.90%	11.74%	2.16%
1985	\$14.61	\$125.20	11.80%	11.25%	0.55%
1986	\$14.48	\$126.82	11.49%	8.98%	2.51%
1987	\$17.50	\$134.04	13.42%	7.92%	5.50%
1988	\$23.75	\$141.32	17.25%	8.97%	8.28%
1989	\$22.87	\$147.26	15.85%	8.81%	7.04%
1990	\$21.73	\$153.01	14.47%	8.19%	6.28%
1991	\$16.29	\$158.85	10.45%	8.22%	2.23%
1992	\$19.09	\$149.74	12.37%	7.29%	5.08%
1993	\$21.89	\$180.88	13.24%	7.17%	6.07%
1994	\$30.60	\$193.06	16.37%	6.59%	9.78%
1995	\$33.96	\$215.51	16.62%	7.60%	9.02%
1996	\$38.73	\$237.08	17.11%	6.18%	10.93%
1997	\$39.72	\$249.52	16.33%	6.64%	9.69%
1998	\$37.71	\$266.40	14.62%	5.83%	8.79%
1999	\$48.17	\$290.68	17.29%	5.57%	11.72%
2000	\$50.00	\$325.80	16.22%	6.50%	9.72%
2001	\$24.69	\$338.37	7.43%	5.53%	1.90%
2002	\$27.59	\$321.72	8.36%	5.59%	2.77%
2003	\$48.73	\$367.17	14.15%	4.80%	9.35%
2004	\$58.55	\$414.75	14.98%	5.02%	9.96%
2005	\$69.93	\$453.06	16.12%	4.69%	11.43%
2006	\$81.51	\$504.39	17.03%	4.68%	12.35%
2007	\$66.18	\$529.59	12.50%	4.86%	7.64%
2008	\$14.88	\$451.37	3.30%	4.45%	-1.15%
Average					6.20%

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

**COMPARISON COMPANIES
CAPM COST RATES**

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
Avista Corp.	4.27%	0.70	5.23%	7.9%
Hawaiian Electric Industries, Inc.	4.27%	0.70	5.23%	7.9%
Northeast Utilities	4.27%	0.70	5.23%	7.9%
Pinnacle West Capital Corp.	4.27%	0.75	5.23%	8.2%
Pepco Holdings, Inc.	4.27%	0.80	5.23%	8.5%
TECO Energy, Inc.	4.27%	0.85	5.23%	8.7%
Westar Energy, Inc.	4.27%	0.75	5.23%	8.2%
Mean				8.2%
Median				8.2%
Pritz Comparable Company Group				
ALLETE, Inc.	4.27%	0.70	5.23%	7.9%
CH Energy Group, Inc.	4.27%	0.65	5.23%	7.7%
Empire District Electric Co.	4.27%	0.75	5.23%	8.2%
Hawaiian Electric Industries	4.27%	0.70	5.23%	7.9%
MGE Energy, Inc.	4.27%	0.65	5.23%	7.7%
Northeast Utilities	4.27%	0.70	5.23%	7.9%
NorthWestern Corp.	4.27%	0.70	5.23%	7.9%
NSTAR	4.27%	0.65	5.23%	7.7%
Portland General Electric	4.27%	0.70	5.23%	7.9%
UIL Holdings	4.27%	0.70	5.23%	7.9%
Mean				7.9%
Median				7.9%

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Oct, 2009	4.16%
Nov, 2009	4.24%
Dec, 2009	4.40%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2012-14	
																			Average	Average	
Parcell Proxy Group																					
Avisia Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	8.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	7.6%	8.1%	10.4%	6.3%	8.5%
Hawaiian Electric Industries, Inc.	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	7.5%	11.0%	9.2%	9.5%
Northeast Utilities	12.6%	9.4%	12.8%	11.8%	0.1%	-5.2%	-2.3%	-7.3%	-1.3%	8.6%	7.1%	5.1%	5.4%	5.4%	4.5%	8.6%	9.8%	9.6%	3.8%	7.1%	9.0%
Phinikeda West Capital Corp.	10.7%	10.8%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.5%	6.7%	9.2%	8.5%	5.1%	6.8%	11.5%	7.8%	8.0%
Peppo Holdings, Inc.	10.6%	12.0%	10.5%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	6.5%	11.0%	8.1%	7.5%
TECO Energy, Inc.	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.0%	17.4%	11.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.1%	11.0%	15.6%	10.5%	12.0%
Westar Energy, Inc.	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	8.2%	6.7%	8.6%	7.5%
Average	11.9%	11.8%	11.5%	11.8%	10.1%	7.9%	9.0%	6.9%	9.1%	9.8%	8.5%	7.2%	7.5%	8.5%	9.2%	8.7%	7.9%	8.2%	10.0%	8.2%	8.6%
Median	11.0%	12.0%	10.8%	11.1%	10.6%	10.9%	11.3%	11.1%	8.8%	11.9%	8.6%	7.6%	8.2%	8.1%	9.2%	8.5%	7.6%	8.1%	11.1%	8.2%	8.0%
Pritz Comparable Company Group																					
ALLETE, Inc.	11.0%	11.1%	10.7%	10.7%	11.3%	10.9%	10.4%	10.2%	10.5%	10.4%	7.0%	9.1%	8.7%	12.0%	13.2%	13.4%	11.4%	7.6%	11.5%	11.5%	9.0%
CH Energy Group, Inc.	10.3%	9.4%	10.6%	9.4%	9.4%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	7.9%	8.2%	6.7%	6.6%	9.5%	7.9%	8.5%
Empire District Electric Co.	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.2%	6.9%	7.4%	9.6%	8.6%	7.8%	8.5%
Hawaiian Electric Industries	13.1%	13.3%	13.1%	12.5%	7.1%	12.5%	12.2%	13.0%	14.2%	13.1%	13.2%	12.5%	11.4%	9.4%	11.9%	7.7%	7.0%	7.5%	11.0%	9.2%	10.5%
MGE Energy, Inc.	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.5%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	9.6%	12.1%	11.7%	12.0%
Northeast Utilities	11.4%	11.9%	12.2%	10.2%	12.6%	12.6%	12.5%	11.4%	12.3%	13.4%	14.0%	13.9%	13.4%	13.1%	13.2%	13.5%	13.6%	13.7%	12.7%	13.6%	15.0%
NorthWestern Corp.	12.9%	12.0%	11.3%	13.4%	13.9%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	5.9%	11.5%	6.9%	6.4%	12.7%	7.6%	8.5%
Portland General Electric	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.1%	10.1%	9.9%	9.7%	8.4%	10.5%
Ull Holdings	11.4%	11.0%	11.5%	11.4%	9.4%	8.7%	9.4%	8.4%	9.8%	10.6%	10.0%	9.8%	8.7%	8.8%	9.4%	10.2%	9.4%	9.1%	10.0%	9.4%	10.4%
Average	11.2%	10.8%	11.2%	11.4%	10.3%	10.9%	11.5%	11.1%	10.5%	12.1%	8.9%	9.1%	8.7%	9.2%	9.2%	10.1%	9.8%	9.6%	11.1%	9.3%	9.0%
Median	11.2%	10.8%	11.2%	11.4%	10.3%	10.9%	11.5%	11.1%	10.5%	12.1%	8.9%	9.1%	8.7%	9.2%	9.2%	10.1%	9.8%	9.6%	11.1%	9.3%	9.0%

Source: Calculations made from data contained in Value Line Investment Survey.

**COMPARISON COMPANIES
MARKET TO BOOK RATIOS**

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	1992-2001 Average	2002-2009 Average
Parcell Proxy Group																				
Avista Corp.	151%	163%	133%	123%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	127%	110%	88%	163%	108%
Hawaiian Electric Industries,	171%	154%	141%	149%	147%	147%	154%	132%	128%	145%	95%	151%	179%	181%	192%	166%	166%	114%	147%	163%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	109%	131%	163%	128%	112%	118%	118%
Pinnacle West Capital Corp.	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	86%	136%	117%
Pecco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	150%	113%
TECO Energy, Inc.	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	188%	171%	116%	235%	167%
Westar Energy, Inc.	144%	152%	130%	129%	126%	131%	128%	89%	74%	76%	67%	109%	132%	142%	139%	140%	107%	87%	118%	115%
Average	163%	168%	141%	146%	150%	149%	160%	144%	166%	138%	109%	111%	134%	149%	151%	150%	128%	97%	152%	129%
Median	154%	154%	133%	129%	145%	151%	161%	143%	139%	129%	110%	109%	130%	130%	135%	141%	115%	88%	144%	120%
Pritz Comparable Company Group																				
ALLETE, Inc.	123%	193%	107%	112%	114%	135%	155%	133%	125%	141%	152%	147%	322%	212%	219%	195%	166%	113%	203%	203%
CH Energy Group, Inc.	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	149%	145%	154%	145%	132%	133%	135%	145%
Empire District Electric Co.	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	144%	149%	149%	150%	122%	99%	150%	135%
Hawaiian Electric Industries	189%	196%	189%	183%	203%	189%	197%	177%	172%	197%	214%	223%	207%	192%	191%	166%	166%	114%	147%	163%
MGE Energy, Inc.	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	163%	128%	151%	190%	191%
Northeast Utilities	138%	154%	130%	130%	125%	146%	181%	166%	161%	161%	170%	175%	189%	202%	214%	222%	201%	187%	170%	195%
NorthWestern Corp.	115%	125%	112%	140%	198%	111%	151%	144%	141%	139%	126%	113%	133%	135%	153%	140%	101%	80%	139%	119%
Portland General Electric	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	189%	168%	126%	139%	145%
UJL Holdings	150%	156%	135%	138%	142%	133%	157%	149%	149%	153%	159%	148%	179%	167%	175%	172%	148%	124%	154%	157%
Average	150%	156%	135%	138%	142%	133%	157%	149%	149%	153%	159%	148%	179%	167%	175%	172%	148%	124%	154%	157%
Median	146%	154%	129%	135%	134%	138%	155%	144%	141%	145%	152%	147%	164%	165%	174%	166%	156%	114%	142%	155%

Source: Calculations made from data contained in Value Line Investment Survey.

**STANDARD & POOR'S 500 COMPOSITE
 RETURNS AND MARKET-TO-BOOK RATIOS
 1992 - 2008**

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.3%	224%
Averages:		
1992-2001	14.7%	341%
2002-2008	12.4%	275%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.9	0.75	B+	B
Pritz Comparable Company Group	2.1	0.69	A-	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

**UNS ELECTRIC INC
 RATING AGENCY RATIOS**

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	54.24%	7.05%	3.82%	3.82%	
Common Equity	45.76%	10.00%	4.58%	7.63%	
Total	100.00%		8.40%	11.45%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **2.99**
 11.45% / 3.82%

Standard & Poor's Utility Benchmark Ratios:
 Business Profile of "4"

	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%

**LONG-TERM PROJECTIONS OF
 GROSS DOMESTIC PRODUCT GROWTH**

Social Security Administration

Year	Real GDP	GDP Index	Nominal GDP	Year	Real GDP	GDP Index	Nominal GDP
2008	2.3%	2.0%	4.3%	2049	2.2%	2.4%	4.6%
2009	2.8%	2.1%	4.9%	2050	2.1%	2.4%	4.5%
2010	2.7%	2.4%	5.1%	2051	2.1%	2.4%	4.5%
2011	2.5%	2.4%	4.9%	2052	2.1%	2.4%	4.5%
2012	2.5%	2.4%	4.9%	2053	2.1%	2.4%	4.5%
2013	2.5%	2.4%	4.9%	2054	2.1%	2.4%	4.5%
2014	2.4%	2.4%	4.8%	2055	2.1%	2.4%	4.5%
2015	2.3%	2.4%	4.7%	2056	2.1%	2.4%	4.5%
2016	2.3%	2.4%	4.7%	2057	2.1%	2.4%	4.5%
2017	2.3%	2.4%	4.7%	2058	2.1%	2.4%	4.5%
2018	2.3%	2.4%	4.7%	2059	2.1%	2.4%	4.5%
2019	2.3%	2.4%	4.7%	2060	2.1%	2.4%	4.5%
2020	2.2%	2.4%	4.6%	2061	2.1%	2.4%	4.5%
2021	2.2%	2.4%	4.6%	2062	2.1%	2.4%	4.5%
2022	2.2%	2.4%	4.6%	2063	2.1%	2.4%	4.5%
2023	2.2%	2.4%	4.6%	2064	2.1%	2.4%	4.5%
2024	2.2%	2.4%	4.6%	2065	2.1%	2.4%	4.5%
2025	2.1%	2.4%	4.5%	2066	2.1%	2.4%	4.5%
2026	2.1%	2.4%	4.5%	2067	2.1%	2.4%	4.5%
2027	2.1%	2.4%	4.5%	2068	2.1%	2.4%	4.5%
2028	2.1%	2.4%	4.5%	2069	2.1%	2.4%	4.5%
2029	2.1%	2.4%	4.5%	2070	2.1%	2.4%	4.5%
2030	2.1%	2.4%	4.5%	2071	2.1%	2.4%	4.5%
2031	2.1%	2.4%	4.5%	2072	2.1%	2.4%	4.5%
2032	2.1%	2.4%	4.5%	2073	2.1%	2.4%	4.5%
2033	2.1%	2.4%	4.5%	2074	2.1%	2.4%	4.5%
2034	2.1%	2.4%	4.5%	2075	2.1%	2.4%	4.5%
2035	2.2%	2.4%	4.6%	2076	2.1%	2.4%	4.5%
2036	2.2%	2.4%	4.6%	2077	2.1%	2.4%	4.5%
2037	2.2%	2.4%	4.6%	2078	2.1%	2.4%	4.5%
2038	2.2%	2.4%	4.6%	2079	2.1%	2.4%	4.5%
2039	2.2%	2.4%	4.6%	2080	2.1%	2.4%	4.5%
2040	2.2%	2.4%	4.6%	2081	2.1%	2.4%	4.5%
2041	2.2%	2.4%	4.6%	2082	2.1%	2.4%	4.5%
2042	2.2%	2.4%	4.6%				
2043	2.2%	2.4%	4.6%				
2044	2.2%	2.4%	4.6%				
2045	2.2%	2.4%	4.6%				
2046	2.2%	2.4%	4.6%				
2047	2.2%	2.4%	4.6%	Average			4.6%
2048	2.2%	2.4%	4.6%				

Source: 2007 OASDI Trustees Report.

**LONG-TERM PROJECTIONS OF
GROSS DOMESTIC PRODUCT GROWTH**

Energy Information Administration

Annual Growth (2005-2030):

Real GDP	2.4%
GDP Chain-type Price Index	2.0%
Nominal GDP Growth	4.4%

Source: Energy Information Administration, Annual Energy Outlook 2008 with Projections to 2030.

RECALCULATION OF FAIR VALUE RATE OF RETURN

Calculation of FVROR as used on pages 54 and 57 of Parcell testimony

	Dollars	Percent	Cost	Wgt Cost
Long-term Debt	\$99,300,000 1/	36.45%	7.05%	2.57%
Common Equity	\$83,800,000 1/	30.76%	10.00%	3.08%
FVRB Increment	\$89,333,154 2/	32.79%	1.50%	0.49% 3/
				4/
	\$272,433,154			6.14%

1/ Dollars of long-term debt and common equity, as used in UNS Electric filing to develop Company's cost of capital.

2/ Differential between FVRB and OCRB, as developed by Staff witness Fish.

3/ This corrects for the mistake on page 57, where 0.34% was incorrectly shown.

4/ This corrects for the mistake on page 57, where 5.99% was incorrectly shown.

This analysis, as developed on page 54, combines the dollars of long-term debt and common equity, with the dollars of the FVRB Increment.

Recalculation of FVROR to reflect matching of OCRB with values of long-term debt and common equity.

FVRB	\$257,949,478			
OCRB	\$168,616,324			
FVRB Increment	\$89,333,154			
		Percent 5/		
Long-term Debt	54.24% \$91,457,494	35.46%	7.05%	2.50%
Common Equity	45.76% \$77,158,830	29.91%	10.00%	2.99%
FVRB Increment	\$89,333,154	34.63%	1.50%	0.52%
Fair Value Rate Base	\$257,949,478	100.00%		6.01%

5/ Percentages of long-term debt and common equity as shown on Schedule 1.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES

Chairman

GARY PIERCE

Commissioner

PAUL NEWMAN

Commissioner

SANDRA D. KENNEDY

Commissioner

BOB STUMP

Commissioner

IN THE MATTER OF THE APPLICATION OF)
UNS ELECTRIC, INC. FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF UNS ELECTRIC, INC.)
DEVOTED TO ITS OPERATIONS)
THROUGHOUT THE STATE OF ARIZONA.)

DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
E-04204A-09-0206

The surrebuttal testimony of W. Michael Lewis of W. M. Lewis and Associates, Inc. ("WML&A") presents certain observations and responses to the rebuttal testimony of Mr. McKenna filed on behalf of UNS Electric ("UNSE"). Specifically, Mr. Lewis's rebuttal testimony addresses UNSE's water supply and treatment facilities at the Black Mountain Generating Station ("BMGS"), the thermal scanning of the BMGS substation, and the contents of an annual report to the Arizona Corporation Commission ("Commission") regarding UNSE's distribution network indices.

With regard to the water supply and treatment facilities at BMGS, Mr. McKenna's rebuttal testimony described a nearly complete raw water supply project. This is a project we were not aware of at the time of the filing of direct testimony that addresses our concerns regarding sufficient water supply at the BMGS. On another matter, Mr. Lewis' direct testimony recommended annual thermal scanning of the BMGS substation. In Mr. McKenna's rebuttal testimony, he does not commit to the annual scanning of the BMGS substation. We continue to recommend that UNSE employ thermal scanning at the BMGS substation on an annual basis, but that this should not be contingent on a Commission order. In our view, such an order from the Commission is unnecessary and would be micro-managing UNSE's operations and maintenance programs.

Lastly, Mr. McKenna's rebuttal testimony does not object to the filing by UNSE with the Commission of an annual report regarding distribution network indices, but does object to the identification of the worst performing circuits. We believe that these circuits should be identified in an annual report since the indice values represent average performance in a service area, which can be misleading. This can be the case since some customers may be experiencing more outages (in frequency and/or duration) associated with the more poorly performing circuits.

1 **Q. Please state your name and business address.**

2 A. My name is William Michael Lewis. My business address is 934 Valley Street,
3 Wheelersburg, Ohio 45694.

4
5 **Q. Have you previously pre-filed testimony in this proceeding?**

6 A. Yes.

7
8 **Q. What is the nature of your Surrebuttal Testimony?**

9 A. My Surrebuttal Testimony is in response to various references to my Direct Testimony
10 presented in the Rebuttal Testimony of Mr. McKenna filed on behalf of UNS Electric, Inc.
11 (“UNSE”).

12
13 **Q. Please cite these references and your responses.**

14 A. At page 6 of his rebuttal, Mr. McKenna responded to my recommendation that UNSE
15 address limitations on water availability as required for operations at the Black Mountain
16 Generating Station (“BMGS”). Mr. McKenna presented a diagram of the station water
17 supply and treatment facilities and explained that a project to increase raw water supply is
18 apparently close to completion. This project evidently will increase the water supply by
19 some 125 gallons per minute (“gpm”).

20
21 **Q. Does that address your concerns as to water limitations?**

22 A. It does. I was not aware of this project when I prepared my Direct Testimony. I would
23 note that this project does add a redundant source for about 53 percent of the raw water
24 requirements which does address my concerns as to raw water supply. There are other
25 considerations as to the requirements for treated (demineralized) water production and

1 storage, however, the added raw water supply does address the stated concerns in my
2 Direct Testimony.

3

4 **Q. Please continue.**

5 A. Mr. McKenna responded to my recommendation that thermal scanning be employed at the
6 BMGS substation on an annual basis. Mr. McKenna noted that UNSE selectively uses
7 this scanning on an annual basis in some service areas, and will do so at the BMGS
8 substation if ordered to do so by the Commission. I assume Mr. McKenna's statement
9 indicates that UNSE will undertake annual scanning of the BMGS substation if ordered by
10 the Commission.

11

12 **Q. What is your response?**

13 A. I do not understand the implied reluctance to employ thermal scanning at the BMGS
14 substation. Thermal scanning is effective in locating, e.g., loose connections. UNSE
15 apparently agrees as noted by Mr. McKenna's description of using scanning after
16 maintenance at other substations. BMGS, as with peaking operations in general, subjects
17 its associated station works to full thermal stress on a regular, if not daily, basis which can
18 lead to poor connections and other bus problems. Given that UNSE evidently has the
19 necessary equipment in-house or on-call and experience in the use of the results of thermal
20 scans, it doesn't seem reasonable that such would not be employed at the BMGS
21 substation or that it would require an order to do so.

22

23 **Q. What was another of Mr. McKenna's references to your testimony?**

24 A. At page 19, starting at line 20, Mr. McKenna stated that my testimony was "only partially
25 accurate."

1 **Q. How do you respond to that?**

2 A. I can only state that my testimony as to UNSE's past practice of data collection was based
3 upon my understanding of statements made during a meeting with the Tucson Electric
4 Power personnel who were preparing the indices in response to our initial data requests
5 regarding quality of service indices.

6
7 **Q. Does Mr. McKenna's clarification affect your subsequent testimony?**

8 A. No.

9
10 **Q. Mr. McKenna does not agree with your recommendation that UNSE provides a**
11 **listing of the worst performing circuits in an annual report of the distribution**
12 **indices. How do you respond and why do you feel that such reporting is necessary?**

13 A. The distribution indices represent an average performance in the affected service area or
14 areas. If, in fact, some customers are experiencing much worse outages, either in
15 frequency or duration, then otherwise acceptable values of indices are, or can be,
16 misleading. A listing of the more poorly performing circuits can indicate to what extent
17 that is the case, and what measures could be taken to mitigate the problems.

18
19 **Q. How do you respond to Mr. McKenna's concerns as to the effect of such a**
20 **submission?**

21 A. I believe that Staff is aware of the problems inherent in addressing specific reliability
22 problems as discussed by Mr. McKenna and will not have any unreasonable expectations
23 as to the timing and nature of corrective actions. I do agree that this listing of specific
24 circuits will result in an incentive to UNSE to address them in a timely manner.

25

1 **Q. Are there other comments in Mr. McKenna's Rebuttal Testimony that you feel**
2 **should be addressed?**

3 A. Yes. Mr. McKenna stated at page 13 of his Rebuttal Testimony that my conclusion that
4 the Call Center operates in an effective manner "further justifies" the costs for the Call
5 Center as proposed by UNSE in Mr. Duke's Direct Testimony. I do not agree with that
6 statement as the costs of the Call Center were not considered in my review of the
7 operation and procedures of the Call Center. My only consideration was the Call Center's
8 handling of the notification and restoration of service outages.

9
10 **Q. Does this conclude your Surrebuttal Testimony?**

11 A. Yes.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF)
UNS ELECTRIC, INC. FOR THE)
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THROUGHOUT THE STATE OF ARIZONA.)
_____)

DOCKET NO. E-04204A-09-0206

RATE DESIGN
SURREBUTTAL
TESTIMONY
OF
WILLIAM C. STEWART
ON BEHALF OF
UTILITIES DIVISION
ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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SCHEDULES

**Schedules Accompanying
The Surrebuttal Testimony of William C. Stewart**

Schedule	Description
WCS H-1S	Summary of Revenues by Customer Classification
WCS H-2S	Comparison of Revenues by Rate Schedule
WCS H-3S	Comparison of Present and Proposed Rates
WCS H-4S	Present and Proposed Rates

**EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206**

The purpose of my Surrebuttal Testimony is to respond to certain issues raised by Company witness Erdwurm in his Rebuttal Testimony. The issues I address include the Customer Assistance Residential Energy Support ("CARES") program for low-income customers, CARES Purchased Power and Fuel Adjustment Clause ("PPFAC"), and rate changes.

Staff recommends that possible changes in qualifications for CARES and other low income programs be discussed by interested parties. Staff also recommends that its recommendation for PPFAC treatment for CARES customers be adopted by the Commission.

Staff also provides revised proposed rate schedules. Although there are minor changes in the H Schedules as a result of the information provided in the Company's Rebuttal Testimony, the Company and Staff proposed percentage increases are not changed. The Company is proposing the following percentage increases to adjusted test year revenues:

Customer Class	Percentage change
Total	8.48%
Residential	9.21%
Residential CARES	-9.41%
Small General Service	9.21%
Large General Service	9.21%
Large Power Service	9.21%
Interruptible Power Service	9.21%
Lighting	9.21%

Staff proposes the following percentage increases to adjusted test year revenues:

Customer Class	Percentage Change
Total	4.76%
Residential	5.17%
Residential CARES	-5.23%
Small General Service	5.17%
Large General Service	5.17%
Large Power Service	5.17%
Interruptible Power Service	5.17%
Lighting	5.17%

1 **INTRODUCTION**

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

3 A. My name is *William C. Stewart*. I am employed by Ariadair Economics Group as a utility
4 analyst. My business address is 1020 Fredericksburg Road, Excelsior Springs, Missouri
5 64024.

6
7 **Q. What is the purpose of your Surrebuttal Testimony?**

8 A. The purpose of my Surrebuttal Testimony is to respond to certain issues raised by
9 Company witness Erdwurm in his Rebuttal Testimony. The issues I address include the
10 Customer Assistance Residential Energy Support ("CARES") program for low-income
11 customers, CARES Purchased Power and Fuel Adjustment Clause ("PPFAC"), and rate
12 changes.

13
14 **Q. Did you revised your Schedules as a result of your analysis and review?**

15 A. Yes. In my Direct Testimony, I prepared Schedules WCS H-1 through WCS H-4 based
16 on a gross revenue requirement increase of \$7,517,565 as provided by Dr. Fish. Dr. Fish
17 has modified the gross revenue requirement increase to \$7,579,110 in his Surrebuttal
18 Testimony. Therefore, I have recalculated these Schedules based on the modified gross
19 revenue requirement and present them as Schedule WCS H-1S, WCS H-2S, WCS H-3S,
20 and WCS H-4S attached.

21
22 **CARES PROGRAM**

23 **Q. Does Mr. Erdwurm recommend increasing CARES eligibility from 150 percent to**
24 **200 percent of poverty level?**

25 A. In his Direct Testimony at page 3, Mr. Erdwurm recommends "...to expand low-income
26 assistance programs to households with incomes of up to 200 percent of poverty."

1 However, in his Rebuttal Testimony at page 12, Mr. Erdwurm states “expansion of the
2 program (CARES) could be costly and UNS Electric, Inc. (“UNS Electric”, “UNSE” or
3 “Company”) stands by its position that its support of expanded low income programs is
4 contingent on program costs being fully recovered from other retail customers on a timely
5 basis.” Mr. Erdwurm seems to be backing away from his earlier recommendation.

6
7 **Q. What is Staff’s position with respect to expanding qualification for the CARES
8 program?**

9 A. Staff is not opposed to expanding qualification for the CARES program. However, Staff
10 believes that before significant expansion of the program is proposed, the structure of any
11 such expansion should be determined on the basis of consultation between the Company,
12 Staff, Residential Utility Consumer Office, and any other interested parties.

13
14 **CARES PPFAC**

15 **Q. Does Mr. Erdwurm support your recommendation with respect to CARES
16 customers’ PPFAC charges?**

17 A. No. Staff recommends that the PPFAC rate for CARES customers be frozen at zero
18 except if a reduction in fuel and purchased power costs results in a negative PPFAC rate.
19 Mr. Erdwurm argues at page 12 of his Rebuttal Testimony that it is unfair for CARES
20 customers to enjoy a reduction in the PPFAC if they do not incur increases in the PPFAC
21 rate.

22
23 **Q. Do you agree with Mr. Erdwurm’s argument with respect to this issue?**

24 A. No. The purpose of the CARES program is to provide an opportunity for those UNSE
25 customers who are facing more difficult economic circumstances than their more fortunate
26 neighbors to obtain electric service. Mr. Erdwurm’s objection ignores this fact.

1 **RATE CHANGES**

2 **Q. Is it clear from proposed rates that the Company is actually requesting an increase in**
3 **rates?**

4 A. The possibility exists for some confusion as to the actual impact of the Company's request
5 for a rate increase. The H Schedules provided by the Company showing its current and
6 proposed rates shows a rate decrease as a result of the Company's rate request as does
7 Staff's H Schedules in the Direct Testimony and in this Surrebuttal Testimony.

8
9 **Q. What is the cause of the apparent reduction in rates associated with the application**
10 **for rate relief?**

11 A. The cause of the apparent reduction is the treatment of the PPFAC. It is common for
12 electric utilities to reset their PPFAC to zero when they request rate relief and that was
13 done in this case.

14
15 **Q. How did resetting the PPFAC to zero affect the Company's rate structure?**

16 A. The Company's original PPFAC rate went into effect June 1, 2008 at +1.4746 cents/kWh.
17 Some of the highest recorded oil and natural gas costs occurred around this time.
18 Subsequently, energy prices declined significantly. UNS Electric submitted its Annual
19 Update to its December 31, 2008 PPFAC Report on April 1, 2009. This report indicated
20 that the PPFAC would be reset to -1.0564 cents/kWh on June 1, 2009, for a reduction of
21 2.5310 cents/kWh. As part of its rate case filing, the Company proposed resetting its
22 PPFAC to zero. This, in turn, required that the average cents per kWh of base rates be
23 reduced by -1.0564 cents/kWh. This reduction in base rates offset the resetting of PPFAC
24 to zero but might give the appearance that the application for a rate increase results in
25 lower rates.
26

1 **Q. Would resetting the PPFAC rate to -1.0564 cents/kWh clear up the possible**
2 **confusion?**

3 **A. No. Resetting the PPFAC rate to -1.0564 would require increasing the average kWh base**
4 **rate by that amount so that the aggregate impact would be the same.**

5
6 **Q. Does that conclude your Surrebuttal Testimony?**

7 **A. Yes.**

UNS Electric, Inc.
Summary of Revenues by Customer Classifications-Stewart Surrebuttal Testimony
Adjusted Present Rates And Proposed Rates
Test Year Ended December 31, 2008

Line No.	Class of Service	Test Year Present Net Revenue	Adjusted Present Net Revenue	Proposed Net Revenue	Staff Proposed Net Increase	Proposed Percent Increase to Test Year Revenues (a)	Proposed Percent Increase to Adjusted Test Year Revenues (a)	Line No.
1	Residential Service	\$85,575,371	\$74,148,720	\$77,983,215	\$3,834,494	4.48%	5.17%	1
2	Residential Cares	6,547,952	6,355,558	6,023,183	(\$332,375)	-5.08%	-5.23%	2
3	Small General Service	11,642,400	10,569,832	11,116,435	\$546,604	4.69%	5.17%	3
4	Large General Service	55,358,044	48,286,092	50,783,138	\$2,497,046	4.51%	5.17%	4
5	Large Power Service	19,626,605	16,938,518	17,814,468	\$875,950	4.46%	5.17%	5
6	Interruptible Service	2,271,247	2,481,084	2,609,390	\$128,306	5.65%	5.17%	6
7	Lighting DD	617,297	562,438	591,524	\$29,086	4.71%	5.17%	7
8	Subtotal	181,638,915	159,342,242	166,921,353	7,579,110	4.17%	4.76%	8
9	Other Operating Revenue	\$1,645,619	\$1,645,619	1,645,619	\$0	0.00%	0.00%	9
10	Total	\$183,284,534	\$160,987,861	\$168,566,971	\$7,579,110	4.14%	4.71%	10

Supporting Schedules (a) H-2 (P2) Recap Schedules A-1 Recap Schedules A-1

Line No.	Class of Service	Rate Schedule Present	Proposed	Actual			Test Year End Sales Adjustments	Adjusted			Line No.
				kWh Sales	Average Number of Customers	Average kWh per Customer		kWh Sales	Average Number of Customers	Average Sales per Customer	
1	Residential Service	RES-01	RES-01	757,895,043	71,505	10,599	(17,627,814)	740,267,229	70,602	10,485	1
2	Residential Cares	CARES	CARES	63,995,155	6,869	9,317	5,725,945	69,721,100	7,522	9,269	2
3	Small General Service	SGS-10	SGS-10	92,855,781	7,711	12,042	570,617	93,426,398	7,778	12,012	3
4	Large General Service	LGS	LGS	496,893,145	2,069	241,167	(19,755,862)	479,137,283	2,000	239,589	4
5	Large General Service TOU	LGS-TOU	LGS-TOU	3,045,144	11	287,730	(45,296)	2,999,848	10	299,985	5
6	Large Power Service <69KV	LPS	LPS	60,317,878	9	6,520,852	3,946,904	64,264,781	11	5,842,253	6
7	Large Power Service >69KV	LPS	LPS	158,685,112	8	19,835,639	0	158,685,112	8	19,835,639	7
8	Interruptible Power Service	IPS	IPS	24,484,630	25	989,278	7,021,780	31,506,409	34	926,659	8
9	Lighting	LTG	LTG	3,145,228	1,781	1,766	0	3,145,228	1,781	1,766	9
10	Total Electric Retail Service			<u>1,653,317,115</u>	<u>89,986</u>	<u>18,484</u>	<u>(20,163,726)</u>	<u>1,643,153,389</u>	<u>89,746</u>	<u>18,309</u>	10

Line No.	Class of Service	Company Adjusted Net Revenue	Proposed TY Delivery Charge Revenue	Proposed Increase Delivery \$	%	Proposed TY Base Power Supply Revenue	Proposed TY Total Revenue Requirement	Line No.
1	Residential Service	\$74,148,720	\$18,648,666	\$3,901,405	20.92%	\$55,380,872	\$77,930,943	1
1	Residential Cares	\$6,355,558	\$1,066,561	-202,697	-19.00%	4,996,214	\$5,860,079	1
2	Small General Service	\$10,569,832	3,776,052	550,223	14.57%	6,787,334	11,113,609	2
3	Large General Service	\$47,992,353	17,307,444	2,406,067	13.90%	30,820,985	50,534,495	3
4	Large General Service TOU	\$293,739	101,622	14,306	13.88%	192,968	308,696	4
5	Large Power Service <69KV	\$5,736,652	2,507,990	257,206	10.26%	3,283,095	6,048,291	5
6	Large Power Service >69KV	\$11,201,866	3,229,525	512,728	15.88%	8,106,746	11,848,999	6
7	Interruptible Power Service	\$2,481,084	827,912	114,933	13.88%	1,676,982	2,619,837	7
8	Lighting	\$562,438	511,110	25,147	4.92%	58,344	594,602	8
9	Total Electric Service	<u>\$159,342,242</u>	<u>\$47,976,882</u>	<u>\$7,579,118</u>	<u>15.80%</u>	<u>\$111,303,550</u>	<u>\$166,859,551</u>	9

(1) Adjustments include Customer Annualization, Weather Normalization, Cares Discount and PPFAC Adjustment

	Present Rate	Proposed Rate	Increase	
			\$	%
Residential Service				
Customer Charge	\$7.50	\$6.00	\$0.50	6.67%
Energy Charge 1st 400 kWhs	\$0.011255	\$0.016204	\$0.004949	43.97%
Energy Charge, all additional kWhs	\$0.021269	\$0.026218	\$0.004949	23.27%
Base Power Supply Charge, all kWhs	\$0.077993	\$0.076207	-\$0.001786	-2.29%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%
Residential Service CARES				
Customer Charge	\$7.50	\$3.50	-\$4.00	-53.33%
Energy Charge 1st 400 kWhs	\$0.011255	\$0.011255	\$0.000000	0.00%
Energy Charge, all additional kWhs	\$0.021269	\$0.021269	\$0.000000	0.00%
Base Power Supply Charge, all kWhs	\$0.077993	\$0.074438	-\$0.003555	-4.56%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%
Residential Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak	\$0.092183	\$0.160533	\$0.068350	74.15%
Summer Shoulder	\$0.081803	\$0.076207	-\$0.005596	-6.84%
Summer off-peak	\$0.077183	\$0.055553	-\$0.021630	-28.02%
Winter on-peak	\$0.080873	\$0.160533	\$0.079660	98.50%
Winter off-peak	\$0.065873	\$0.043269	-\$0.022584	-34.28%
Small General Service				
Customer Charge	\$12.00	\$12.50	\$0.50	4.17%
Energy Charge 1st 400 kWhs	\$0.022449	\$0.028058	\$0.005609	24.99%
Energy Charge, all additional kWhs	\$0.032463	\$0.038072	\$0.005609	17.28%
Base Power Supply Charge, all kWhs	\$0.075738	\$0.074004	-\$0.001734	-2.29%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%
Small General Service Time of Use Rates, all kWhs				
(These rates would include all Delivery charges above and replace The Base Power Supply charge)				
Summer on-peak	\$0.090348	\$0.138114	\$0.047766	52.87%
Summer Shoulder	\$0.079658	\$0.074004	-\$0.005654	-7.10%
Summer off-peak	\$0.075348	\$0.048114	-\$0.027234	-36.14%
Winter on-peak	\$0.079448	\$0.138114	\$0.058666	73.84%
Winter off-peak	\$0.064448	\$0.039894	-\$0.024554	-38.10%

Large General Service

Customer Charge	\$15.50	\$16.00	\$0.50	3.23%
Demand Charge, per kW	\$10.71	\$13.35	\$2.64	24.68%
Energy Charge (kWhs)	\$0.003254	\$0.003815	\$0.000561	17.25%
Base Power Supply Charge, all kWhs	\$0.067062	\$0.065786	-\$0.001276	-1.90%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%

Large General Service TOU

Customer Charge	\$20.40	\$20.90	\$0.50	2.45%
Demand Charge, per kW	\$10.71	\$13.35	\$2.64	24.68%
Energy Charge (kWhs)	\$0.003254	\$0.003815	\$0.000561	17.25%
Base Power Supply Charge, all kWhs	\$0.067062	\$0.065526	-\$0.001536	-2.29%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%

Large General Service Time of Use Rates, all kWhs

(These rates would include all Delivery charges above and replace The Base Power Supply charge)

Summer on-peak	\$0.082832	\$0.122421	\$0.039589	47.79%
Summer Shoulder	\$0.071452	\$0.065526	-\$0.005926	-8.29%
Summer off-peak	\$0.067832	\$0.047421	-\$0.020411	-30.09%
Winter on-peak	\$0.071072	\$0.122421	\$0.051349	72.25%
Winter off-peak	\$0.056072	\$0.033703	-\$0.022369	-39.89%

Large Power Service (<69KV)

Customer Charge	\$365.00	\$372.00	\$7.00	1.92%
Demand Charge, per kW	\$17.90	\$21.22	\$3.33	18.59%
Energy Charge (kWhs)	\$0.000000	(\$0.000000)	\$0.000000	0.00%
Base Power Supply Charge, all kWhs	\$0.053260	\$0.052040	-\$0.001220	-2.29%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%

Large Power Service (>69KV)

Customer Charge	\$400.00	\$407.00	\$7.00	1.75%
Demand Charge, per kW	\$11.61	\$14.93	\$3.32	0.00%
Energy Charge (kWhs)	\$0.000000	(\$0.000000)	\$0.000000	0.00%
Base Power Supply Charge, all kWhs	\$0.053260	\$0.052040	-\$0.001220	-2.29%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	100.00%

Large Power Service Time of Use Rates, all kWhs

(These rates would include all Delivery charges above and replace The Base Power Supply charge)

Summer on-peak	\$0.070170	\$0.100000	\$0.029830	42.51%
Summer Shoulder	\$0.058180	\$0.052040	-\$0.006140	-10.55%
Summer off-peak	\$0.055170	\$0.040000	-\$0.015170	-27.50%
Winter on-peak	\$0.058170	\$0.100000	\$0.041830	71.91%
Winter off-peak	\$0.043170	\$0.027986	-\$0.015184	-35.17%

Interruptible Power Service

Customer Charge	\$15.50	\$16.00	\$0.50	3.23%
Demand Charge, per kW	\$3.40	\$4.66	\$1.26	37.17%
Energy Charge (kWhs)	\$0.014800	\$0.016091	\$0.001291	8.72%
Base Power Supply Charge, all kWhs	\$0.055491	\$0.054220	-\$0.001271	-2.29%
PPFAC	\$0.014746	\$0.000000	-\$0.014746	-100.00%

Interruptible Power Service Time of Use Rates, all kWhs

(These rates would include all Delivery charges above and replace The Base Power Supply charge)

Summer on-peak	\$0.071861	\$0.102904	\$0.031043	43.20%
Summer Shoulder	\$0.059691	\$0.054220	-\$0.005471	-9.17%
Summer off-peak	\$0.056861	\$0.042904	-\$0.013957	-24.55%
Winter on-peak	\$0.059411	\$0.102904	\$0.043493	73.21%
Winter off-peak	\$0.044411	\$0.027772	-\$0.016639	-37.47%

Lighting Dusk to Dawn

New 30' Wood Pole (Class 6) - Overhead	\$4.12	\$4.35	\$0.23	5.61%
New 30' Metal or Fiberglass - Overhead	\$8.26	\$8.72	\$0.46	5.61%
Existing Wood Pole - Underground	\$2.06	\$2.18	\$0.12	5.62%
New 30' Wood Pole (Class 6) - Underground	\$6.20	\$6.54	\$0.35	5.62%
New 30' Metal or Fiberglass - Underground	\$10.32	\$10.90	\$0.58	5.62%
Wattage, per Watt	\$0.046577	\$0.048736	\$0.002159	4.63%
Lighting Base Power Supply Charge, per Watt	\$0.007818	\$0.007639	-\$0.000179	-2.29%

Residential Service		<u>Present</u>	<u>Proposed</u>		
Customer Charge		\$7.50	\$8.00		
Energy Charge 1st 400 kWh		\$0.011255	\$0.016204		
Energy Charge, all additional kWhs		\$0.021269	\$0.026218		
Base Power Supply Charge, all kWhs		\$0.077993	\$0.076207		
PPFAC		\$0.014746	\$0.000000		
Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase \$	Proposed Increase %	
0	\$7.50	\$8.00	\$0.50	6.67%	
50	\$12.70	\$12.62	(\$0.08)	-0.62%	
100	\$17.90	\$17.24	(\$0.41)	-2.29%	
200	\$28.30	\$26.48	(\$1.82)	-6.42%	
400	\$49.10	\$44.96	(\$4.13)	-8.42%	
600	\$71.90	\$65.45	(\$6.45)	-8.97%	
800	\$94.70	\$85.93	(\$8.77)	-9.26%	
1,000	\$117.50	\$106.42	(\$11.08)	-9.43%	
2,000	\$231.51	\$208.84	(\$22.67)	-9.79%	
2,500	\$288.51	\$260.06	(\$28.46)	-9.86%	
5,000	\$573.53	\$516.12	(\$57.41)	-10.01%	
10,000	\$1,143.57	\$1,028.24	(\$115.33)	-10.09%	

Residential Service CARES		<u>Present</u>	<u>Proposed</u>	Discounts:	
Customer Charge		\$7.50	\$3.50	0-300 kWh	30.0%
Energy Charge 1st 400 kWh		\$0.011255	\$0.011255	301-600 kWh	20.0%
Energy Charge, all additional kWhs		\$0.021269	\$0.021269	601-1000 kWh	10.0%
Base Power Supply Charge, all kWhs		\$0.077993	\$0.074438	1001+ kWh	\$8.00
PPFAC		\$0.014746	\$0.000000		
Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase \$	Proposed Increase %	
0	\$5.25	\$2.45	(\$2.80)	-53.33%	
50	\$8.89	\$5.45	(\$3.44)	-38.70%	
100	\$12.53	\$8.45	(\$4.08)	-32.57%	
200	\$19.81	\$14.45	(\$5.36)	-27.07%	
400	\$39.28	\$30.22	(\$9.06)	-23.06%	
600	\$57.52	\$45.53	(\$11.98)	-20.84%	
800	\$85.23	\$68.45	(\$16.78)	-19.68%	
1,000	\$105.75	\$85.68	(\$20.07)	-18.98%	
2,000	\$223.51	\$182.91	(\$40.60)	-18.17%	
2,500	\$280.51	\$230.76	(\$49.75)	-17.74%	
5,000	\$565.53	\$470.03	(\$95.51)	-16.89%	
10,000	\$1,135.57	\$948.56	(\$187.01)	-16.47%	

Residential Service Time-of-Use Summer	<u>Present</u>	<u>Proposed</u>	Assume:	
Customer Charge	\$7.50	\$8.00	On Peak Usage:	16.6%
Energy Charge 1st 400 kWh	\$0.011255	\$0.016204	Shoulder-Peak Usage:	15.4%
Energy Charge, all additional kWhs	\$0.021269	\$0.026218	Off-Peak Usage:	67.9%
Base Power Supply Charge				
On-Peak, all kWhs	\$0.092183	\$0.160533		
Shoulder-Peak, all kWhs	\$0.081803	\$0.076207		
Off-Peak, all kWhs	\$0.077183	\$0.055553		
PPFAC	\$0.014746	\$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase \$	Proposed Increase %
0	\$7.50	\$8.00	\$0.50	6.67%
50	\$12.82	\$12.62	(\$0.20)	-1.55%
100	\$18.14	\$17.24	(\$0.90)	-4.95%
200	\$28.78	\$26.48	(\$2.30)	-7.98%
400	\$50.06	\$44.96	(\$5.09)	-10.17%
600	\$73.34	\$65.45	(\$7.89)	-10.76%
800	\$96.62	\$85.94	(\$10.68)	-11.06%
1,000	\$119.90	\$106.42	(\$13.48)	-11.24%
2,000	\$236.31	\$208.85	(\$27.46)	-11.62%
2,500	\$294.51	\$260.06	(\$34.45)	-11.70%
5,000	\$585.53	\$516.12	(\$69.40)	-11.85%
10,000	\$1,167.56	\$1,028.25	(\$139.31)	-11.93%

Residential Service Time-of-Use Winter	<u>Present</u>	<u>Proposed</u>	Assume:	
Customer Charge	\$7.50	\$8.00	On Peak Usage:	28.1%
Energy Charge 1st 400 kWhs	\$0.011255	\$0.016204		
Energy Charge, all additional kWhs	\$0.021269	\$0.026218	Off-Peak Usage:	71.9%
Base Power Supply Charge				
On-Peak, all kWhs	\$0.080873	\$0.160533		
Shoulder-Peak, all kWhs				
Off-Peak, all kWhs	\$0.065873	\$0.043289		
PPFAC	\$0.014746	\$0.000000		

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase \$	Proposed Increase %
0	\$7.50	\$8.00	\$0.50	6.67%
50	\$12.30	\$12.62	\$0.32	2.57%
100	\$17.11	\$17.24	\$0.13	0.77%
200	\$26.72	\$26.48	(\$0.24)	-0.88%
400	\$45.93	\$44.96	(\$0.97)	-2.11%
600	\$67.15	\$65.45	(\$1.71)	-2.54%
800	\$88.37	\$85.93	(\$2.44)	-2.76%
1,000	\$109.59	\$106.42	(\$3.18)	-2.90%
2,000	\$215.69	\$208.84	(\$6.85)	-3.18%
2,500	\$268.74	\$260.05	(\$8.69)	-3.23%
5,000	\$533.99	\$516.10	(\$17.89)	-3.35%
10,000	\$1,064.48	\$1,028.21	(\$36.27)	-3.41%

Small General Service	<u>Present</u>	<u>Proposed</u>
Customer Charge	\$12.00	\$12.50
Energy Charge 1st 400 kWhs	\$0.022449	\$0.028058
Energy Charge, all additional kWhs	\$0.032463	\$0.038072
Base Power Supply Charge, all kWhs	\$0.075738	\$0.074004
PPFAC	\$0.014746	\$0.000000

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase \$	Proposed Increase %
50	\$17.65	\$17.60	(\$0.04)	-0.25%
100	\$23.29	\$22.71	(\$0.59)	-2.52%
250	\$40.23	\$38.02	(\$2.22)	-5.51%
500	\$69.47	\$64.53	(\$4.94)	-7.10%
1,000	\$130.94	\$120.57	(\$10.37)	-7.92%
2,000	\$253.89	\$232.65	(\$21.24)	-8.37%
3,500	\$438.31	\$400.76	(\$37.55)	-8.57%
5,000	\$622.73	\$568.87	(\$53.86)	-8.65%
10,000	\$1,237.46	\$1,129.25	(\$106.21)	-8.74%
30,000	\$3,696.40	\$3,370.77	(\$325.63)	-8.81%
50,000	\$6,155.34	\$5,612.29	(\$543.06)	-8.82%

Large General Service Delivery Charges	<u>Present</u>	<u>Proposed</u>
Customer Charge	\$15.50	\$16.00
Demand Charge, per kW	\$10.71	\$13.35
Energy Charge (kWhs)	\$0.003254	\$0.003815
Base Power Supply Charge, all kWhs	\$0.067062	\$0.065786
PPFAC	\$0.014746	\$0.000000

Assumes
Load Factor = 55.0%

Average Sales per Month	Total Bill Present Rate	Total Bill Proposed Rate	Proposed Increase \$	Proposed Increase %
5,000	\$574.18	\$530.29	(\$43.89)	-7.64%
10,000	\$1,132.87	\$1,044.59	(\$88.28)	-7.79%
25,000	\$2,808.92	\$2,587.47	(\$221.45)	-7.88%
50,000	\$5,602.35	\$5,158.94	(\$443.41)	-7.91%
100,000	\$11,189.20	\$10,301.88	(\$887.32)	-7.93%
200,000	\$22,362.89	\$20,587.76	(\$1,775.13)	-7.94%
300,000	\$33,536.59	\$30,873.64	(\$2,662.95)	-7.94%
400,000	\$44,710.29	\$41,159.52	(\$3,550.76)	-7.94%
500,000	\$55,883.98	\$51,445.41	(\$4,438.58)	-7.94%
600,000	\$67,057.68	\$61,731.29	(\$5,326.40)	-7.94%

	<u>Present</u>	<u>Proposed</u>		
Large General Service TOU				
Customer Charge	\$20.40	\$20.90		
Demand Charge, per kW	\$10.71	\$13.35	Assumes	
Energy Charge (kWhs)	\$0.003254	\$0.003815	Load Factor =	55.0%
Base Power Supply Charge, all kWhs	\$0.067062	\$0.065526		
PPFAC	\$0.014746	\$0.000000		
			Proposed	Proposed
			Increase	Increase
			\$	%
<u>Average Sales per Month</u>	<u>Total Bill</u>	<u>Total Bill</u>		
	<u>Present Rate</u>	<u>Proposed Rate</u>		
5,000	\$572.42	\$525.58	(\$46.83)	-8.18%
10,000	\$1,124.43	\$1,030.26	(\$94.17)	-8.37%
25,000	\$2,780.48	\$2,544.31	(\$236.17)	-8.49%
50,000	\$5,540.56	\$5,067.72	(\$472.85)	-8.53%
100,000	\$11,060.72	\$10,114.53	(\$946.19)	-8.55%
200,000	\$22,101.04	\$20,208.16	(\$1,892.88)	-8.56%
300,000	\$33,141.37	\$30,301.80	(\$2,839.57)	-8.57%
400,000	\$44,181.69	\$40,395.43	(\$3,786.26)	-8.57%
500,000	\$55,222.01	\$50,489.06	(\$4,732.95)	-8.57%
600,000	\$66,262.33	\$60,582.69	(\$5,679.64)	-8.57%

Assumes maximum peak period demand is 5% lower than maximum demand in non-peak period.

	<u>Present</u>	<u>Proposed</u>		
Large Power Service (<69KV)				
Customer Charge	\$365.00	\$372.00		
Demand Charge, per kW	\$17.90	\$21.22	Assumes	
Energy Charge (kWhs)	\$0.000000	(\$0.000000)	Load Factor =	65.0%
Base Power Supply Charge, all kWhs	\$0.053260	\$0.052040		
PPFAC	\$0.014746	\$0.000000		
			Proposed	Proposed
			Increase	Increase
			\$	%
<u>Average Sales per Month</u>	<u>Total Bill</u>	<u>Total Bill</u>		
	<u>Present Rate</u>	<u>Proposed Rate</u>		
300,000	\$32,081	\$29,401	(\$2,680)	-8.35%
450,000	\$47,939	\$43,916	(\$4,023)	-8.39%
650,000	\$69,083	\$63,268	(\$5,814)	-8.42%
850,000	\$90,226	\$82,621	(\$7,606)	-8.43%
950,000	\$100,798	\$92,297	(\$8,501)	-8.43%
1,500,000	\$158,944	\$145,517	(\$13,427)	-8.45%
1,750,000	\$185,374	\$169,708	(\$15,666)	-8.45%
2,000,000	\$211,804	\$193,899	(\$17,905)	-8.45%
2,500,000	\$264,663	\$242,280	(\$22,383)	-8.46%

	<u>Present</u>	<u>Proposed</u>		
Large Power Service (>69KV) Delivery Charges				
Customer Charge	\$400.00	\$407.00		
Demand Charge, per kW	\$11.61	\$14.93	Assumes	
Energy Charge (kWhs)	\$0.000000	(\$0.000000)	Load Factor =	70.0%
Base Power Supply Charge, all kWhs	\$0.053260	\$0.052040		
PPFAC	\$0.014746	\$0.000000		
	<u>Total Bill</u>	<u>Total Bill</u>	<u>Proposed</u>	<u>Proposed</u>
<u>Average Sales per Month</u>	<u>Present Rate</u>	<u>Proposed Rate</u>	<u>Increase</u>	<u>Increase</u>
			<u>\$</u>	<u>%</u>
300,000	\$27,617.85	\$24,784.33	(\$2,834)	-10.26%
450,000	\$41,226.77	\$36,972.99	(\$4,254)	-10.32%
650,000	\$59,372.00	\$53,224.55	(\$6,147)	-10.35%
850,000	\$77,517.23	\$69,476.10	(\$8,041)	-10.37%
950,000	\$86,589.85	\$77,601.87	(\$8,988)	-10.38%
1,500,000	\$136,489.23	\$122,293.64	(\$14,196)	-10.40%
1,750,000	\$159,170.77	\$142,608.08	(\$16,563)	-10.41%
2,000,000	\$181,852.31	\$162,922.52	(\$18,930)	-10.41%
2,500,000	\$227,215.39	\$203,551.41	(\$23,664)	-10.41%

	<u>Present</u>	<u>Proposed</u>		
Interruptible Power Service Delivery Charges				
Customer Charge	\$15.50	\$16.00		
Demand Charge, per kW	\$3.40	\$4.66	50 Assumes	
Energy Charge (kWhs)	\$0.014800	\$0.016091	Load Factor =	55.0%
Base Power Supply Charge, all kWhs	\$0.055491	\$0.054220		
PPFAC	\$0.014746	\$0.000000		
	<u>Total Bill</u>	<u>Total Bill</u>	<u>Proposed</u>	<u>Proposed</u>
<u>Average Sales per Month</u>	<u>Present Rate</u>	<u>Proposed Rate</u>	<u>Increase</u>	<u>Increase</u>
			<u>\$</u>	<u>%</u>
10,001	\$950.65	\$835.35	(\$115.29)	-12.13%
15,000	\$1,418.08	\$1,244.90	(\$173.18)	-12.21%
20,000	\$1,885.60	\$1,654.54	(\$231.07)	-12.25%
30,000	\$2,820.66	\$2,473.81	(\$346.85)	-12.30%
50,000	\$4,690.76	\$4,112.34	(\$578.42)	-12.33%
75,000	\$7,028.39	\$6,160.51	(\$867.88)	-12.35%
100,000	\$9,366.02	\$8,208.68	(\$1,157.34)	-12.36%
125,000	\$11,703.66	\$10,256.85	(\$1,446.80)	-12.36%
150,000	\$14,041.29	\$12,305.03	(\$1,736.26)	-12.37%

	Present	Proposed	Proposed Increase \$	Proposed Increase %
Lighting Dusk to Dawn Delivery Charges				
Overhead Service				
New 30' Wood Pole (Class 6)	\$4.12	\$4.35	\$0.23	5.61%
New 30' Metal or Fiberglass	\$8.26	\$8.72	\$0.46	5.61%
Underground Service				
Existing Wood Pole	\$2.06	\$2.18	\$0.12	5.62%
New 30' Wood Pole (Class 6)	\$6.20	\$6.54	\$0.35	5.62%
New 30' Metal or Fiberglass	\$10.32	\$10.90	\$0.58	5.62%
Per Watt	\$0.046577	\$0.048736	\$0.0022	4.63%
Lighting Base Power Supply Charge, per Watt	\$0.007818	\$0.00764		
PPFAC	\$0.014746	\$0.000000		
100 Watts - Overhead				
Existing Wood Pole	\$4.67	\$5.64	\$0.97	20.83%
New 30' Wood Pole (Class 6)	\$8.79	\$9.99	\$1.20	13.69%
New 30' Metal or Fiberglass	\$12.92	\$14.36	\$1.44	11.11%
100 Watts - Underground				
Existing Wood Pole	\$6.73	\$7.82	\$1.09	16.17%
New 30' Wood Pole (Class 6)	\$10.86	\$12.18	\$1.32	12.15%
New 30' Metal or Fiberglass	\$14.98	\$16.53	\$1.55	10.35%
200 Watts - Overhead				
Existing Wood Pole	\$9.32	\$11.27	\$1.96	21.04%
New 30' Wood Pole (Class 6)	\$13.44	\$15.63	\$2.19	16.30%
New 30' Metal or Fiberglass	\$17.57	\$20.00	\$2.42	13.79%
200 Watts - Underground				
Existing Wood Pole	\$12.94	\$13.45	\$0.51	3.95%
New 30' Wood Pole (Class 6)	\$17.07	\$17.82	\$0.74	4.36%
New 30' Metal or Fiberglass	\$19.63	\$22.17	\$2.54	12.93%
400 Watts - Overhead				
Existing Wood Pole	\$21.76	\$22.55	\$0.79	3.64%
New 30' Wood Pole (Class 6)	\$25.88	\$26.90	\$1.02	3.95%
New 30' Metal or Fiberglass	\$30.02	\$31.27	\$1.26	4.18%
400 Watts - Underground				
Existing Wood Pole	\$23.82	\$24.73	\$0.91	3.81%
New 30' Wood Pole (Class 6)	\$27.95	\$29.09	\$1.14	4.08%
New 30' Metal or Fiberglass	\$32.08	\$33.45	\$1.37	4.27%

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES

Chairman

GARY PIERCE

Commissioner

PAUL NEWMAN

Commissioner

SANDRA D. KENNEDY

Commissioner

BOB STUMP

Commissioner

IN THE MATTER OF THE APPLICATION OF)
UNS ELECTRIC, INC. FOR THE)
ESTABLISHMENT OF JUST AND)
REASONABLE RATES AND CHARGES)
DESIGNED TO REALIZE A REASONABLE)
RATE OF RETURN ON THE FAIR VALUE OF)
THE PROPERTIES OF UNS ELECTRIC, INC.)
DEVOTED TO ITS OPERATIONS)
THROUGHOUT THE STATE OF ARIZONA.)

DOCKET NO. E-04204A-09-0206

SURREBUTTAL

TESTIMONY

OF

KENNETH C. ROZEN

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JANUARY 15, 2010

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**EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-09-0206**

- In its Direct Testimony, Staff opposed UNS Electric, Inc.'s ("UNSE") proposed revisions to its Rules and Regulations which would 1) implement a Facilities Operation Charge, 2) specify accounting treatment of up-front payment of estimated line extension construction costs in its tariff, and 3) increase service reconnection and reestablishment fees by requiring customers whose service was disconnected to pay the applicable monthly customer charges that would have accrued had the Company continued to furnish electricity to the customer. Staff also recommended that Subsections 9.A.3 and 9.B.1.e. of the line extension tariff be revised to specify that materials costs given in line extension construction cost estimates must be itemized.
- In its Rebuttal Testimony, the Company agrees to withdraw its proposals to implement the Facilities Operation Charge, include accounting treatment of estimated construction cost payments in its tariff, and increase service reconnection and reestablishment charges.
- UNSE identifies several concerns with Staff's recommendation relating to material cost itemization in line extension agreements. Despite the Company's arguments to the contrary, Staff continues to recommend that material cost estimates in line extension agreements be itemized.
- Staff recommends that the Company clarify the intent and effect of new language in the line extension tariff related to conditions for rectifying differences in estimated and actual construction costs.

1 **I. INTRODUCTION**

2 **Q. Please state your name and business address.**

3 A. My name is Kenneth Rozen. My business address is 14218 North 43rd Street, Phoenix,
4 Arizona 85032.

5
6 **Q. By whom are you employed and in what capacity?**

7 A. I am a self-employed consultant currently under contract with the Utilities Division of the
8 Arizona Corporation Commission. My duties include evaluating various utility
9 applications and reviewing utility tariff filings on behalf of the Utilities Division Staff
10 (“Staff”).

11

12 **Q. Have you previously filed testimony in this docket?**

13 A. Yes. I filed Direct Testimony concerning revisions that UNS Electric, Inc. (“UNSE” or
14 “Company”) proposed to make to its Rules and Regulations, as outlined in the Direct
15 Testimony of Thomas A. McKenna.

16

17 **Q. Did you review the Rebuttal Testimony that UNSE witness Mr. McKenna filed in
18 response to your Direct Testimony?**

19 A. Yes. I will begin by summarizing Staff’s and the Company’s positions as set forth in our
20 respective Direct Testimonies. I will then summarize my understanding of Mr.
21 McKenna’s Rebuttal Testimony which was filed in response to my testimony. Finally, I
22 will discuss Staff’s position on Mr. McKenna’s Rebuttal Testimony.

1 **II. SUMMARY OF THE COMPANY'S AND STAFF'S DIRECT TESTIMONY**

2 **Q. Please summarize the Company's proposed revisions to its Rules and Regulations**
3 **that remained for Commission consideration when you filed your Direct Testimony.**

4 A. After the Commission's recent approval of certain previously-ordered revisions to
5 UNSE's line extension tariff¹, a number of other revisions to its Rules and Regulations,
6 which the Company proposed in its Direct Testimony in this case, remain for Commission
7 consideration. They are as follows:

- 8 • Further revisions to the line extension tariff (Section 9), including the addition of
9 the "Facilities Operation Charge" and language specifying in the tariff how up-
10 front payments of estimated line extension construction costs are to be treated for
11 accounting purposes.
- 12 • Revisions that would increase service reconnection and reestablishment fees
13 (Sections 2, 3 and 14) by requiring customers whose service was disconnected to
14 pay the monthly customer charges that would have accrued had the Company
15 continued to furnish electricity to the customer.
- 16 • Revisions adding time frames for rectifying under- and over-billings resulting from
17 meter and meter reading errors (Section 11); and
- 18 • Numerous technical and clarifying revisions throughout the Rules and Regulations.

19
20 **Q. Please summarize Staff's recommendations regarding these proposals and any other**
21 **matters relating to UNSE's Rules and Regulations?**

22 A. Staff has no objections to UNSE's proposed revisions that would add timeframes for
23 rectifying meter and meter reading errors or to the numerous technical and clarifying
24 changes. For reasons explained in my Direct Testimony, however, Staff opposes UNSE's
25 proposals to: 1) implement a Facilities Operation Charge, 2) specify in the line extension

¹ The Commission approved UNSE's line extension tariff, as revised to eliminate the free-footage allowance, in Decision No. 71285 dated October 7, 2009.

1 tariff the accounting treatment for the proceeds from up-front payments of estimated
2 construction costs, and, 3) increase service reconnection and reestablishment fees by
3 requiring customers whose service was disconnected to pay the applicable monthly
4 customer charges that would have accrued had the Company continued to furnish
5 electricity to the customer. Apart from UNSE's proposed revisions, Staff is further
6 recommending that Subsections 9.A.3 and 9.B.1.e. of the line extension tariff be revised to
7 specify that materials costs given in line extension construction cost estimates must be
8 itemized.

9
10 **III. UNSE'S REBUTTAL TESTIMONY**

11 **Q. Please summarize Mr. McKenna's Rebuttal Testimony.**

12 A. Mr. McKenna's Rebuttal Testimony indicates that UNSE: 1) withdraws its request to
13 implement a Facilities Operation Charge, 2) agrees to remove proposed language in its
14 line extension tariff that would specify accounting treatment for up-front payments
15 received by the Company for estimated line extension construction costs and 3) agrees to
16 delete the proposed revisions that would have allowed the Company to collect, in addition
17 to the service reestablishment and reconnection fees. However, Mr. McKenna has a
18 number of concerns about Staff's recommendation that Subsection 9.B.1.e of the line
19 extension tariff be revised to specify that material costs listed in construction cost
20 estimates included in line extension agreements should be itemized. Finally, Mr.
21 McKenna's Rebuttal Testimony includes a number of additional requests for technical and
22 typographical revisions to various sections of UNSE's Rules and Regulations.

1 **Q. On December 11, 2009, UNSE filed Exhibit TAM-5, which UNSE states reflects**
2 **UNSE's proposed changes to its current Commission-approved Rules and**
3 **Regulations as revised by Mr. McKenna's Rebuttal Testimony. Have you reviewed**
4 **Exhibit TAM-5?**

5 A. Yes.

6
7 **Q. Is Exhibit TAM-5 consistent with Mr. McKenna's Rebuttal Testimony?**

8 A. Yes.

9
10 **Q. Does Staff have any concerns with any of the additional technical and typographical**
11 **revisions that Mr. McKenna proposes in his Rebuttal Testimony?**

12 A. No.

13
14 **Q. What are UNSE's concerns with Staff's recommendation to itemize material costs in**
15 **the construction cost estimates that are contained in line extension agreements?**

16 A. Mr. McKenna states that the Company:

- 17 1. Does not believe that itemizing material costs will enhance Applicants' understanding
18 of cost estimates in part because most customers are unfamiliar with power line
19 engineering and construction materials (He does not identify other factors which may
20 contribute to UNSE's belief that material cost itemization would not help Applicant's
21 understand line extension construction cost estimates.);
- 22 2. Cannot sacrifice safe and reliable construction and operation in deference to the
23 Applicant's interest in minimizing extension costs, even if materials were itemized;
24 and;

1 3. Believes that the line extension description and sketch already required by
2 Commission rule² and the parallel provision in UNSE's Rules and Regulations are
3 sufficient for the Applicant to understand what the Company requires and why.
4

5 **IV. STAFF'S SURREBUTTAL TESTIMONY**

6 **Q. Please respond to UNSE's concerns regarding Staff's recommendation to itemize**
7 **materials costs in the construction cost estimates contained in line extension**
8 **agreements.**

9 A. The line extension description and sketch may provide sufficient basis for an Applicant to
10 understand what is being required and why, but neither a sketch nor a description that does
11 not identify the costs of the various construction items comprising the facility provides the
12 Applicant with an adequate basis for understanding line extension costs. Regardless of the
13 extent to which any one Applicant chooses to consider it, Staff believes UNSE should
14 provide all Applicants with a sound basis for understanding extension costs, including
15 itemized materials costs, both as estimated in the Agreement and in the context of any
16 adjustments necessitated by the results of the Company's comparison between the
17 estimated and actual costs³.

18
19 Staff agrees that the Company must not sacrifice reliability and safety in deference to an
20 Applicant's interest in minimizing costs. It is difficult to understand, however, how
21 requiring the Company to itemize costs would compromise reliability and safety. Further,
22 the Company's concern on this issue seems to presume that Applicants' proclivity to
23 dispute the Company's cost estimates would increase if estimated materials costs were
24 itemized. This presumption remains unsubstantiated. Finally, Staff disagrees with
25 UNSE's view that itemizing estimated materials costs would not enhance Applicant's

² A.A.C. R14-2-207.B.1.d

³ For rectifying estimated and actual costs, see proposed Exhibit TAM-5, relined version, page 31, Subsection 9.D.1.

1 understanding of cost estimates because most customers are unfamiliar with power line
2 construction materials.

3
4 For example, the table at the top of UNSE's response to Data Request STF 17.2⁴ lists
5 twelve "Construction Units." Among these, Staff suspects that many if not most
6 customers would know that "Transformer" is a piece of equipment needed to reduce
7 voltage, "Primary Conductor" refers to wires used to transmit electricity, and "Guys" are
8 wires or cables used to support or brace structures, such as poles, which are used to
9 suspend conductor overhead. Although many if not most customers would be unfamiliar
10 with "Tangent," "Angle," and "Dead End," many might correctly surmise that these terms
11 distinguish different kinds of towers and poles, based on their position in and the
12 configuration of the line extension. Regardless of any one Applicant's familiarity with the
13 Construction Units listed in the table, however, Staff fails to see how providing the
14 Applicant with the "Unit Cost" and "# Req'd." for each could *not* enhance the Applicant's
15 understanding of the estimated Total Material cost, and by extension, the Line Extension
16 Cost Estimate, of which Total Material Cost is a significant component.

17
18 **Q Mr. McKenna notes that the line extension agreement requirements in UNSE's rules**
19 **and regulations are directly from A.A.C. R14-2-207. Would the application of that**
20 **rule in any way limit the Commission's ability to require a company to expand**
21 **information in line extension agreements beyond what is required by R14-2-207.B.1?**

22 A. No. Both A.A.C. R14-2-207.B.1 and Subsection 9.B.1 state "Each line extension
23 agreement [must/shall], *at a minimum*, include the following information:"(emphasis
24 added) Staff is of the opinion that this language allows the Commission to expand the
25 requirements when it finds that such expansion is warranted.

⁴ Exhibit KCR-2 to Rozen Direct Testimony

1 **Q. After considering Mr. McKenna's Rebuttal Testimony, does Staff have any reason to**
2 **change its recommendation that the Company revise Subsection 9.B.1.e to require**
3 **that material costs be itemized in construction cost estimates that are included in line**
4 **extension agreements.**

5 A. No.

6
7 **Q. Are there any other matters relating to UNSE's Rules and Regulations that you**
8 **would like to address?**

9 A. Yes, there are two such matters, both relating to Section 9, the line extension tariff.

10
11 **Q. What is the first of these?**

12 A. In the revised line extension tariff that UNSE filed in Docket E-04204A-06-0783, as
13 ordered in Commission Decision No. 71285, Subsection 9.D.1.b, which applies to
14 overhead extensions to Large Light and Power Customers, contains the following
15 provision:

16
17 "Upon completion of construction the Company will compare actual cost
18 to the estimated cost and any difference will be either billed or refunded to
19 the Customer."

20
21 UNSE's proposed revision to its line extension tariff shown in TAM-2 and TAM-5 retains
22 this same language, but moves it to the very beginning of Subsection 9.D ("Conditions
23 Governing Extensions of Electric Distribution and Service Lines") and adds new language
24 as follows:

25

1 “- except if the difference is less than \$500. If the difference is less than
2 \$500, the amount may be billed or refunded according to the specific
3 extension agreement with the customer.”
4

5 **Q. Does Staff have any concerns with these changes?**

6 A. Staff supports moving the language that provides for rectifying differences between
7 estimated and actual costs to the beginning of Subsection 9.D because it has the effect of
8 applying the rectification provision to all of the subsections comprising Subsection 9.D.
9 However, Staff is concerned that the intent and effect of the new language is unclear.
10

11 **Q. What is Staff's recommendation regarding the new language?**

12 A. Staff recommends that the Company clarify the intent and effect of the new language in its
13 Rejoinder Testimony. Staff will respond to the clarification at the hearing.
14

15 **Q. What is the second matter regarding the line extension tariff that you would like to**
16 **address?**

17 A. The revised line extension tariff that UNSE filed in Docket E-04204A-06-0783, as well as
18 the revisions proposed in TAM-5, eliminate the free footage allowance as the Commission
19 ordered in Decision No. 70360. However, A.A.C. R14-2-207.C continues to require that
20 each line extension shall include a maximum footage or equipment allowance to be
21 provided by the utility at no charge. Therefore, UNSE's current and proposed line
22 extension tariffs conflict with provisions of R14-2-207, including Subsection A.1, which
23 states “each utility shall file, in Docket Control, for Commission approval, a line extension
24 tariff which incorporates the provisions of this rule.”

1 **Q. Does Staff have a recommendation regarding a resolution to this conflict?**

2 A. Yes. Neither the Decision (No. 70360) in which the Commission ordered the elimination
3 of the free footage allowance, nor the Decision (No. 71285) in which the Commission
4 approved the responsive revision to UNSE's line extension tariff, granted UNSE a waiver
5 to A.A.C. R14-2-207.C. Therefore, Staff recommends that the Commission consider
6 granting such a waiver in this proceeding.

7

8 **V. SUMMARY OF STAFF RECOMMENDATIONS**

9 **Q. Please summarize Staff's recommendations.**

10 A. Staff's recommendations are as follows:

11 1. Staff maintains its recommendation that Subsection 9.B.1.e of UNSE's line
12 extension tariff be revised to require that the materials costs given in construction
13 cost estimates contained in line extension agreements be itemized.

14

15 2. Staff recommends that, in its Rejoinder Testimony, the Company clarify the intent
16 and effect of the new language regarding rectifying differences between estimated
17 and actual line extension construction costs.

18

19 3. Staff recommends that the Commission consider granting UNSE a waiver to
20 A.A.C. R14-2-207.C in this proceeding.

21

22 **Q. Does this conclude your Surrebuttal Testimony?**

23 A. Yes, it does.