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BEFORE THE ARIZONA CORPORATION CO.
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AZ CORP COMMISSION
DOCKET CONTROL

MIKE GLEASON, Chairman
WILLIAM A. MUNDELL
JEFF HATCH-MILLER
KRISTIN K. MAYES
GARY PIERCE

IN THE MATTER OF THE APPLICATION OF
UNS ELECTRIC, INC. FOR APPROVAL OF
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.

DOCKET NO. E-04204A-06-0783

STAFF'S NOTICE OF ERRATA FILING

On November 5, 2007, the Arizona Corporation Commission Staff ("Staff") filed its Post-Hearing Brief in the above-captioned matter. A substitute Post-Hearing Brief is attached, which contains the following revisions: (1) on pages 1, 2, 6 and 22, a correction involving the affiliate names of UNSE was made, and, (2) several other pages were revised to correct typographical and other minor wording errors. The only substantive change Staff made was to add the concluding sentence under the Cash Working Capital section which was inadvertently omitted. Staff also corrected the rate base numbers appearing on page 4 of its Brief so they are consistent with the final schedules filed in this case.

Please substitute the attached corrected Post-Hearing Brief containing the changes discussed above for the original Brief sent to parties yesterday.

RESPECTFULLY SUBMITTED this 6th day of November 2007.

Arizona Corporation Commission
DOCKETED

NOV - 6 2007

DOCKETED BY

NR

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28

1 **BEFORE THE ARIZONA CORPORATION COMMISSION**

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STAFF'S POST-HEARING BRIEF

10
11 **I. INTRODUCTION.**

12 Unisource Electric ("UNSE" or "Company") is a public utility that provides electric
13 distribution service to approximately 93,000 customers in Arizona.¹ The Company is requesting a
14 rate increase of \$8.5 Million over test year revenues. This amounts to a 5.5% increase. The
15 Company intends to file another rate case within the next year or two. Staff believes that \$8.5
16 Million being requested by the Company is inflated; and Staff is proposing instead a rate increase of
17 \$3.688 over test year revenues.

18 UNSE was formerly the Arizona electric distribution operations of Citizens Communications
19 Company ("Citizens"), before it was purchased by UniSource Energy in 2003. In addition to
20 purchasing the electric distribution assets of Citizens, UniSource Energy also purchased from
21 Citizens its gas distribution assets.²

22 UNSE and UNS Gas are subsidiaries of UniSource Energy Services ("UES"). The stock of
23 UES is held by UniSource Energy, a holding company, whose principal subsidiary is Tucson Electric
24 Power Company ("TEP"), the second largest investor-owned generation and distribution utility in
25 Arizona.³ In 2006, UNSE accounted for about 12 percent of UniSource Energy's revenues and about
26 6 percent of its total assets.⁴

27 _____
28 ¹ David Parcell Direct Test. (Ex. S-52) p. 12.

² *Id.*

³ David Parcell Direct Test. (Ex. S-52) at p. 12.

⁴ *Id.*

1 Company witness Grant testified that two key issues in the case account for approximately 80
2 percent of the difference between Staff's revenue requirement and the Company's revenue
3 requirement, Construction Work in Progress ("CWIP") and cost of equity.⁵

4 This case, however, stands out for several other reasons as well. First, the Company
5 currently obtains its power through a full requirements contract with Pinnacle West Capital
6 Corporation ("PWCC").⁶ Today, UNSE owns only nominal generation assets in Nogales that are
7 used for must-run and voltage stability purposes.⁷ UNSE must replace the power currently obtained
8 from PWCC when it expires at the end of May, 2008. It hopes to replace that power through a
9 combination of new wholesale power purchases, its own generation assets, or a combination of both.⁸

10 UniSource Energy Development Company ("UED"), an affiliate of UNSE, has purchased
11 assets to construct the Black Mountain Generating Station ("BMGS"), a 90 megawatt gas-fired power
12 plant facility in the Kingman area.⁹ UNSE would like to acquire BMGS and has asked for special
13 treatment of the plant in this case. Staff opposes special treatment or inclusion of the plant in rate
14 base at this time for a variety of reasons discussed in this brief.

15 The Company is also requesting extraordinary treatment of CWIP in this case, by asking that
16 \$10.8 Million of CWIP be included in rate base. Yet, as explained herein, the Company has not
17 offered any compelling reasons for the extraordinary treatment in this case.

18 One of the reasons that the Company is requesting extraordinary treatment of CWIP and the
19 BMGS, is due to customer growth. During the test period, Company witness Ferry testified that
20 customer growth increased in Mohave County by 4.8 percent and in Santa Cruz County by 5.8
21 percent. However, most other utilities filing rate cases before the Commission have also claimed
22 high growth rates to justify special rate base treatment of assets. The Commission has without
23 exception denied those requests because the companies have not met their burden of proof to
24 demonstrate compelling circumstances to justify such exceptional treatment.

25
26 _____
27 ⁵ Tr. at 956.

28 ⁶ Tr. at p. 15.

⁷ *Id.*

⁸ *Id.*

⁹ Tr. at p. 15.

1 UNSE is requesting a cost of equity of 11.8%. Staff, on the other hand, relied upon three
2 well-accepted methodologies in arriving at a range for cost of equity between 9.5% and 10.5%, with a
3 mid-point of 10.0%. The Company's request for 11.8% flies in the face of recent electric utility
4 statistics which show a decline in cost of equity for electric distribution companies over the last 5
5 years; with cost of equity figures much more in line with Staff's proposal in this case.

6 The Company has also proposed many significant revisions to its Purchase Power Fuel
7 Adjustment Clause (PPFAC) in this case. Staff has used the recent changes made to APS' PSA as a
8 helpful guideline in reviewing and recommending changes to the UNSE PPFAC.

9 The Company is proposing some significant changes to its rate design in this case as well.
10 While Staff concurs with the philosophy behind those changes, Staff witness Radigan explains that a
11 phased in approach such as he recommends with respect to certain of the changes including Time-of-
12 Use (TOU) rates and merger of the Mohave and Santa Cruz rate structures would be more
13 appropriate and send more rational pricing signals.

14 Finally, the Company is also requesting approval of additional financing which it plans to use
15 to construct the BMGS. Staff supports the Company's request for financing under certain conditions.

16 Staff presented seven witnesses in this case. Mr. Alexander Igwe was the case lead and
17 testified on the Company's financing application. Mr. Ralph Smith testified as to the Company's
18 revenue requirement and proposed PPFAC. Mr. David C. Parcell testified on cost of capital. Mr.
19 Frank Radigan testified on the Company's proposed rate design. Ms. Julie McNeely-Kirwan testified
20 on the Company's DSM and CARES programs. Mr. Jerry Anderson testified on the DSM rate
21 recovery mechanism and on various rule changes being proposed by UNSE. Finally, Mr. Prem Bahl
22 sponsored the Staff's engineering report and assessment of "used and useful" plant in service.

23 Administrative Law Judge Teena Wolfe conducted hearings on the Company's application on
24 September 10 through 14, 2007 and September 20 and 21, 2007 and October 2, 2007.

25 ...

26 ...

27 ...

28

1 **II. REVENUE REQUIREMENT.**

2 The Company proposes a revenue requirement or base rate increase of \$8.5 Million.¹⁰ Staff
3 believes this is overstated and Staff Witness Ralph Smith recommends instead a base rate increase of
4 \$3.688 Million.¹¹ Mr. Smith is a Senior Regulatory Consultant with Larkin & Associates. Mr.
5 Smith is a CPA, and has a law degree and a Master of Science in Taxation. His firm has sponsored
6 expert witnesses in over 400 regulatory proceedings across the United States.¹²

7 **A. Rate Base.**

8 Staff is proposing an original cost rate base of \$130,740,040.00 and a fair value rate base of
9 \$167,551,067.00.¹³ The Company, on the other hand, is proposing an original cost rate base of
10 \$140,991,324.00 and a fair value rate base of \$177,802,341.00.¹⁴ Staff is proposing four adjustments
11 to the Company's proposed rate base.¹⁵ The primary difference between the Company's proposed
12 rate base and Staff's proposed rate base relates to whether or not to include CWIP in rate base.

13 **1. CWIP.**

14 UNSE proposes to include \$10.8 Million of CWIP in rate base.¹⁶ As Staff witness Smith
15 discusses in his testimony, the Commission's general practice is not to include CWIP in rate base,
16 unless there are extraordinary circumstances such as financial distress.¹⁷ The Company has not
17 demonstrated that it is in financial distress or has experienced extraordinary circumstances that would
18 justify inclusion of CWIP in rate base.¹⁸

19 The primary reason for the Company's proposal to include CWIP appears to be disagreement
20 with the Commission's use of the historical test year.¹⁹ Company witness Kenton Grant testified
21 that inclusion of CWIP in rate base is one of the few available tools to mitigate the effects of
22
23

24 ¹⁰ David Dukes Direct Test. (Ex. UNSE-23) at pp. 4 and 19.

25 ¹¹ Tr. at 1196.

26 ¹² Ralph Smith Direct Test. (Ex. S-56) at p. 1.

27 ¹³ Ralph Smith Surrebuttal Test. (Ex. S-58) at p. 6.

28 ¹⁴ *Id.*

¹⁵ Tr. at p. 1198.

¹⁶ *Id.* at p. 13.

¹⁷ *Id.* at p. 14; See also Tr. at p. 1198.

¹⁸ Tr. at p. 1199.

¹⁹ Ralph Smith Direct Test. (Ex. S-56) at p. 13; See also Kenton Grant Direct Test. (Ex. UNSE-34) at p. 24.

1 regulatory lag.²⁰ He also stated that if the Company's request is denied, the authorized rate of return
2 should be increased.²¹

3 Staff witness Smith explained why inclusion of CWIP is not appropriate except in exceptional
4 circumstances in the following passage from his testimony:

5 CWIP, as the title designates, is not plant that is completed and
6 providing service to ratepayers during the test year. During the test
7 year, it was not used or useful in providing electric service to the
8 Company's customers. The ratemaking process is predicated on an
9 examination of the operations of a utility to insure that the assets upon
10 which ratepayers are required to provide the utility with a rate of return
11 are prudently incurred and are both used and useful in providing
12 services on a current basis. Facilities in the process of being built are
13 not used or useful. The ratemaking process therefore excludes CWIP
14 from rate base until such projects are completed and providing service
15 to ratepayers in the context of a test year that is being used for
16 determining the utility's revenue requirement.²²

17 It is well recognized that inclusion of CWIP in rate base would also result in a mismatch in
18 the ratemaking process.²³ To the extent that CWIP is to serve additional customers, it is considered
19 revenue producing.²⁴ However, the revenues have been annualized to the end of the test year only
20 and not beyond.²⁵ And, if the CWIP is expense reducing, those reductions have not been reflected
21 beyond the test year.²⁶ So it is a mismatch to include CWIP since the post test year impacts have not
22 been quantified and reflected as adjustments to operating income.²⁷

23 The Company also argues that \$8.7 million of the \$10.8 million in CWIP was plant in service
24 as of June 30, 2007. But as Mr. Smith notes, 2007 is a whole year outside of the end of the test year,
25 therefore, it suffers from the same mismatch problem.²⁸

26 The Company does receive a return representing its financing costs called Allowance for
27 Funds Used During Construction ("AFUDC").²⁹ And, when the plant is placed into service, the
28 AFUDC is capitalized and depreciated along with the plant.³⁰

24 ²⁰ Ralph Smith Direct Test. (Ex. S-56 at p. 13; Kenton Grant Direct Test. (Ex. UNSE-34) at p. 24.

25 ²¹ *Id.*

25 ²² Ralph Smith Direct Test. (Ex. S-56) at p. 15.

26 ²³ *Id.*

26 ²⁴ Tr. at pp. 1198-1199

27 ²⁵ Tr. at 1199.

27 ²⁶ *Id.*

27 ²⁷ *Id.*

28 ²⁸ Tr. at p. 1223.

28 ²⁹ Ralph Smith Direct Test. (Ex. S-56) at p. 16.

1 Further, Staff's cost of capital witness, David C. Parcell, disputed the Company's assertion
2 that inclusion of CWIP in rate base is necessary for the Company to attract capital in the future.³¹
3 Mr. Parcell explained that his research indicated that the rating agencies describe the operations of
4 UNSE as low risk.³² Mr. Parcell also explained that UNSE receives its financing based on the credit
5 quality of UniSource Energy or UES. UniSource Energy is publicly traded.³³

6 **2. CWIP Adjustments for Plant in Service.**

7 Staff witness Smith's review of the CWIP account, and Staff's field inspection revealed that
8 there was a project in the CWIP account that was used and useful as of the end of the test year.³⁴ The
9 project was Rhodes Homes (task 8009729), which involved a line extension with a cost of \$442,255,
10 inspected by Staff on June 6, 2007 and in service on May 26, 2006, which was prior to the end of the
11 test year.³⁵ The project involved the installation of 21 kV overhead line to supply service to water
12 pumps for a proposed housing project.³⁶ Customer advances related to this project totaled
13 \$360,117.00 and were already reflected by the Company in its proposed rate base.³⁷ Staff increased
14 rate base by \$442,255.00 in Adjustment B-2 to reflect that this project was in service by the end of
15 the test year.

16 Staff's field review also raised an issue concerning whether UNSE had received a customer
17 advance for another construction project, Tubac Golf Resort. Staff confirmed that UNSE had
18 received and accounted for a Customer Advance for this project and therefore withdrew its
19 Adjustment B-3.

20 **3. Cash Working Capital.**

21 Cash working capital is the cash necessary for the Company's day-to-day operations.³⁸ If the
22 Company must pay its expenses in aggregate before it receives cash from operations to do so,
23

24
25 ³⁰ *Id.*

³¹ David Parcell Direct Test. (Ex. S-52) at p. 14.

³² *Id.*

³³ *Id.*

³⁴ Ralph Smith Direct Test. (Ex. S-56) at p. 18.

³⁵ *Id.* at pps. 18-19.

³⁶ *Id.* at 19.

³⁷ Ralph Smith Direct Test. (Ex. S-56) at p. 19.

³⁸ *Id.* at p. 21.

1 investors have to provide the cash working capital.³⁹ A positive cash working capital requirement
2 exists in this case.⁴⁰

3 On the other hand, if revenues from operations are received before payment of expenses are
4 necessary, on average, then ratepayers supply the cash working capital the Company needs and a
5 negative cash working capital allowance is used to reduce rate base.⁴¹

6 In this case the Company did a lead/lag study to calculate its cash working capital
7 requirements.⁴²

8 Staff witness Smith testified that his review of the Company's lead/lag study indicated that
9 UNSE has a negative cash working capital requirement.⁴³ This means that "[o]n average, revenues
10 from ratepayers are received prior to the time when the utility pays the associated expenditures."⁴⁴

11 As shown on Schedule B-4, UNSE's filed cash working request should be increased by
12 approximately \$197,000.00.⁴⁵

13 **4. Accumulated Deferred Income Taxes.**

14 This adjustment by Mr. Smith decreases rate base by \$161,555.00.⁴⁶ It reflects the impact
15 from the following: 1) removal of the ADIT related to the Supplemental Executive Retirement Plan
16 ("SERP"), and 2) removal of the ADIT relating to stock-based compensation⁴⁷

17 The adjustments to ADIT are necessary for consistency with Staff's adjustments to remove
18 the expense for SERP and for stock-based compensation.

19 **B. Operating Income and Expense Adjustments.**

20 **1. CWIP Depreciation and Property Taxes.**

21 The Company's proposal to treat CWIP at the end of the test year as if it were plant in service
22 resulted in the Company increasing depreciation and property tax expenses.⁴⁸ Due to Staff's
23

24 ³⁹ *Id.*

25 ⁴⁰ *Id.*

26 ⁴¹ *Id.* at 21.

27 ⁴² *Id.*

28 ⁴³ *Id.*

⁴⁴ *Id.* at 21.

⁴⁵ *Id.* at 22.

⁴⁶ Ralph Smith Direct Test. (S-56) at p. 22.

⁴⁷ *Id.*

⁴⁸ Ralph Smith Direct Test. (S-56) at p. 18.

1 adjustment removing CWIP from rate base, the Staff has also removed UNSE's related adjustments
2 for depreciation and property tax expenses.⁴⁹ Staff's adjustment reduces the Company's proposed
3 expenses for depreciation by \$449,816.00 and property taxes by \$239,696.00, for a total reduction of
4 \$689,512.00.⁵⁰

5 **2. Depreciation and Property Taxes for Adjustments to CWIP for**
6 **Plant in Service.**

7 This Staff adjustment increases depreciation expense by \$18,265.00 and property tax expense
8 by \$8,317.00.⁵¹ The adjustment increases test year expenses for depreciation and property taxes
9 related to the Rhodes Homes project (task 8009729) which the Company included in CWIP but
10 which Staff found to be used and useful prior to the end of the test year.⁵² The plant was found to be
11 in service on May 26, 2006.⁵³

12 **3. CARES Discount.**

13 Staff witness Julie McNeely-Kirwan is recommending that the existing discount rate structure
14 for CARES be retained. Therefore, Staff made an adjustment to increase the Company's revenue by
15 \$52,937.00 which reversed the Company's new proposal to calculate the CARES discount in the
16 future.⁵⁴

17 **4. Fleet Fuel Expense.**

18 Staff reduced UNSE's proposed increase in Fleet Fuel expense by \$70,391.00.⁵⁵ Staff's
19 adjustment allows for an increase to fuel expense of \$3,270.00.⁵⁶ This is based on a cost of gasoline
20 of \$2.69 and is based upon UNSE's actual fuel costs.⁵⁷

21 In Staff's final accounting schedules, on Schedule C-4, revised 9/17/2007, the Staff
22 adjustment to fleet fuel expense was revised to an adjustment of \$41,909.00. This revision utilized
23

24 _____
25 ⁴⁹ *Id.*

26 ⁵⁰ *Id.* at pp. 23-24.

27 ⁵¹ *Id.* at p. 24.

28 ⁵² *Id.*

⁵³ *Id.* at p 24.

⁵⁴ *Id.*

⁵⁵ Ralph Smith Direct Test. (Ex. S-56) at p. 25.

⁵⁶ *Id.* at p. 24.

⁵⁷ *Id.* at pp. 24-25.

1 the pro forma fleet fuel expense of \$605,498.00 per UNSE witness Dukes' rejoinder testimony at
2 page 2.

3
4 **5. Postage Expense.**

5 Staff increased the Company's proposed normalized postage expense of \$341,321.00 by
6 \$17,503.00.⁵⁸ This adjustment reflects an increase to annualized postage expense to reflect the May
7 14, 2007 increase in the cost of a first class letter from 39 cents to 41 cents.⁵⁹

8 **6. Injuries and Damages Expense.**

9 Staff made a normalizing adjustment to the Company's Injuries and Damages expense to
10 reflect a three-year average through December, 2006.⁶⁰ Staff witness Smith testified that "[t]he tests
11 year Injuries and Damages expense (Account 925) is so high in comparison with the other years
12 because a number of the types of expenses which are recorded in this account appear to be
13 abnormally high in the test year, and would thus require separate adjustment, if the balance in this
14 account were not normalized..."⁶¹

15 Finally, Directors' and Officers' Liability ("D&O) expense, another Account 925 expense,
16 has increased dramatically since 2004.⁶² In 2004, D&O expense was \$22,032.00 and in 2006 it was
17 \$130,330.00.⁶³ Witness Smith testified that the "substantially increased cost of such D&O insurance
18 is a concern because the direct monetary benefits of D&O Insurance is not enjoyed by ratepayers."⁶⁴
19 Mr. Smith further testified that "[b]ecause shareholders benefit materially from this insurance, it may
20 be appropriate to allocate the cost of D&O Insurance equally between shareholders and ratepayers."⁶⁵

21 Overall, because of these concerns, Staff reduced test year expense for Account 925 by
22 \$159,063.00.⁶⁶ As noted in Staff's final accounting schedules, Staff modified its adjustment to agree
23 with the revised normalized amount stated in UNSE witness Dukes' rejoinder testimony at page 4.

24
25 ⁵⁸ Ralph Smith Direct Test. (Ex. S-56) at p. 25.

26 ⁵⁹ *Id.*

27 ⁶⁰ *Id.*

28 ⁶¹ Ralph Smith Direct Test. (S-56) at p. 26.

⁶² *Id.* at p. 27.

⁶³ *Id.*

⁶⁴ *Id.*

⁶⁵ *Id.* at p.27.

⁶⁶ *Id.* at p.26.

1 (See Staff final accounting schedules, Revised Schedule C-6, revised 9/17/2007). As a result of this,
2 Staff's revised adjustment reduced UNSE's test year expense by \$98,161.00.

3 **7. Incentive Compensation.**

4 Staff adjusted the Company's expenses associated with various incentive compensation plans,
5 including the Performance Enhancement Plan ("PEP"). Staff adjusted the amount of the expense
6 related to the various incentive compensation programs of UNSE by 50%.⁶⁷ Incentive compensation
7 programs benefit both shareholders and ratepayers. The removal of 50% of the expense related to
8 such programs provides an equal sharing of the cost of such programs between shareholders and
9 ratepayers, since the programs benefit both groups.⁶⁸

10 The recommendations made by Staff in this case are the same as its recommendations in the
11 recent UNS Gas case. UNSE participates in the same incentive compensation arrangement, the PEP,
12 as its affiliate UNS Gas.⁶⁹ The Company's non-union employees participate in the UniSource Energy
13 Corporation's PEP.⁷⁰ UniSource Energy Services ("UES") is a subsidiary of UniSource Energy
14 Corporation and the parent company of UNSE.⁷¹ The PEP determines eligibility for certain bonus
15 levels by measuring performance in three areas: (1) financial performance; (2) operational cost
16 containment; and (3) core business and customer service goals.⁷² The financial performance and
17 operational cost containment components each make up 30 percent of the bonus structure, while the
18 core business and customer service goals account for the remaining 40 percent.⁷³ The first two of
19 these areas are of primary benefit to shareholders.

20 Staff also removed 100% of the expense associated with the Supplemental Executive
21 Retirement Plan (SERP).⁷⁴ This plan provides supplemental retirement benefits for select executives
22
23
24

25 ⁶⁷ Ralph Smith Direct Test (Ex. S-56) at p. 27.

26 ⁶⁸ *Id.*

26 ⁶⁹ Ralph Smith Direct Test. (Ex. S-56) at p. 28.

27 ⁷⁰ *Id.* at p. 28.

27 ⁷¹ *Id.*

27 ⁷² Ralph Smith Direct Test. (Ex. S-56) at p. 28.

28 ⁷³ *Id.*

28 ⁷⁴ *Id.*

1 of UNSE.⁷⁵ SERPs typically provide for retirement benefits in excess of the limits placed by IRS
2 regulations on pension plan calculations for salaries in excess of specified amounts.⁷⁶

3 Staff's adjustments are consistent with the Commission's recent decision in the last Southwest
4 Gas rate case. In the Southwest Gas case, the Commission adopted Staff's recommendation for an
5 equal sharing of incentive compensation plan costs and RUCO's recommendation to remove SERP
6 expense in its entirety. In the following passage from that Order, the Commission addressed the
7 removal of SERP expense:

8 Although we rejected RUCO's arguments on this issue in the
9 Company's last rate proceeding, we believe that the record in this case
10 supports a finding that the provision of additional compensation to
11 Southwest Gas' highest paid employees to remedy a perceived
12 deficiency in retirement benefits relative to the company's other
13 employees is not a reasonable expense that should be recovered in
14 rates. Without the SERP, the Company's officers still enjoy the same
15 retirement benefits available to any other Southwest Gas employee and
16 the attempt to make these executives 'whole' in the sense of allowing a
17 greater percentage of retirement benefits does not meet the test of
18 reasonableness. If the Company wishes to provide additional
19 retirement benefits above the level permitted by IRS regulations
20 applicable to all other employees it may do so at the expense of its
21 shareholders. However, it is not reasonable to place this additional
22 burden on ratepayers.⁷⁷

23 The Company has not presented any rationale or support for the Commission to treat its
24 incentive compensation plans differently for ratemaking purposes than the Commission's treatment
25 of similar plans in the last Southwest Gas rate case. Further, there was considerable evidence
26 presented regarding the Company's base salaries to support Staff's disallowance.⁷⁸ As noted in
27 Staff's final accounting schedules, the amount of Staff's adjustment was modified in response to
28 UNSE witness Dukes' rejoinder testimony at page 7. Staff's final adjustment (on Schedule C-7,
revised 9/17/2007) of Staff's final accounting schedules reduced expense by \$104,357 for incentive
compensation (\$79,871 for PEP and \$24,486 for other incentive compensation), and by \$4,160 for
related payroll taxes.

29 . . .

30 _____
31 ⁷⁵ Ralph Smith Direct Test (Ex. S-56) at p. 27.

32 ⁷⁶ *Id.*

33 ⁷⁷ Decision No. 68487 at 19.

34 ⁷⁸ See Confidential Exhibit S-1.

1 **8. Rate Case Expense.**

2 UNSE is requesting \$600,000.00 for rate case expense, normalized over a three year period,
3 for an annual allowance of \$200,000.00 per year.⁷⁹ This is the same amount and treatment that its
4 sister company UNS Gas requested in its recent rate case.

5 Staff believes this amount is inflated and instead proposes a rate case expense allowance of
6 \$88,333.00 per year, based on a total of \$265,000 normalized over three years.⁸⁰ The amount
7 requested by UNSE for rate case expense is 3.8 times as high as the amount of rate case expense
8 allowed by the Commission in the Southwest Gas rate case. Yet, the issues were not significantly
9 different or more difficult than the Southwest Gas case.

10 While the current case may be the first rate case for this utility operating under its current
11 ownership, it is not the first rate case for this utility. This electric utility had periodic, recurring rate
12 cases under its prior ownership by Citizens Utilities. The transfer of ownership should not be an
13 excuse for charging ratepayers for what appear to be excessive amounts of rate case cost.

14 Moreover, the current UNSE rate case is similar to and presents many of the same issues,
15 disallowance of incentive compensation, revisions to the commodity cost recovery mechanism
16 (“PGA” or “PPFAC”) addressed by the Commission in the Southwest Gas case, Docket No. G-
17 01551A-04-0876. Staff believes that the Southwest Gas case and the recent UNS Gas rate case
18 provide a reasonable benchmark for what a reasonable allowance for rate case cost should be in the
19 current UNSE rate case.

20 **9. Edison Electric Institute Dues.**

21 Staff witness Ralph Smith reduced test year expense by \$8, 470.00 which reflects 49.93
22 percent of EEI core dues and 100 percent of EEI UARG dues.⁸¹ Mr. Smith reduced the expense
23 levels recorded by the Company because EEI core dues related to the following activities should be
24 excluded and were not:

- 25 • Legislative Advocacy
26 • Regulatory Advocacy

27 ⁷⁹ Ralph Smith Direct Test. (Ex. S-56) p. 33.

28 ⁸⁰ *Id.* at p. 34.

⁸¹ Ralph Smith Direct Test. (S-56) p. 34.

- Advertising
- Marketing
- Public Relations⁸²

The NARUC categorization of EEI dues expenses utilized by Mr. Smith is intended to help state commissions by weeding out potential costs that may not be undertaken for the benefit of ratepayers.⁸³ For instance, the Arkansas Public Service Commission in Docket No. 06-101-U, an Entergy Arkansas, Inc., rate case (Order No. 10 dated 6/15/07) utilized the NARUC categorizations to disallow 49.93 percent of EEI core dues.

Further, Mr. Smith recommends disallowance of \$5,477.00 of UARG dues from the cost of service.⁸⁴ UARG is the EEI Utility Air Regulatory Group which is also referred to as a separately funded activity for the environment. This group advocates the electric utility industry's views before legislative, regulatory and judicial bodies which positions may not be consistent with ratepayer interests.⁸⁵ Accordingly, they should be disallowed.

10. Other Membership Dues.

Mr. Smith also disallowed \$6,482.00 in other discretionary membership and industry association dues which were not related to the safe and reliable provision of electric utility service.⁸⁶ This includes \$1,750.00 for the Arizona-Mexico Commission which the Company concedes was included in error.⁸⁷

Mr. Smith also recommended that in future rate filings, the Company should include a cost-benefit analysis which reflects all of the benefits it believes it received over the prior period from any trade organization for which it seeks recovery of dues.⁸⁸

...

...

⁸² *Id.* at p. 35.

⁸³ Ralph Smith Direct Test. (S-56) p. 35.

⁸⁴ *Id.* at p. 36.

⁸⁵ *Id.* at p. 36.

⁸⁶ *Id.* at 37.

⁸⁷ *Id.*

⁸⁸ Ralph Smith Direct Test. (Ex. S-56) at p. 38.

1 **11. Interest Synchronization.**

2 This adjustment increases income tax expense by \$177,093.00 as shown on Staff
3 revised Schedule C-14 and decreases the Company's operating income by a similar amount.⁸⁹

4 **12. Depreciation Rates.**

5 Staff witness Smith agrees with the depreciation rate study conducted by Dr. White for the
6 Company with one correction for transportation equipment.⁹⁰ The Company's data response to Staff
7 3.39 stated as follows:

8 Foster Associates inadvertently failed to include a 10 percent net
9 salvage rate for UNS Electric transportation equipment. The impact of
10 this oversight would e a further reduction in 2006 annualized accruals
11 of \$143,297.00. It is the opinion of Foster Associates that the
12 magnitude of the additional depreciation reduction does not warrant a
13 refilling of the depreciation study.⁹¹

14 Staff witness Smith made an adjustment that reduced the Company's proposed annualized
15 depreciation expense by \$64,872.00 and also adjusted the utility plant acquisition adjustment account
16 by \$1767.00, for an overall net reduction to operating expense of 63,105.00.⁹² UNS Electric agreed
17 that this correction was necessary.

18 Mr. Smith also recommends that each of the new depreciation rates proposed by UNS Electric
19 should be clearly broken out between (1) a service life rate and (2) a net salvage rate.⁹³ This will
20 allow depreciation expense related to the inclusion estimated future cost of removal in depreciation to
21 be tracked and accounted for by plant account.⁹⁴

22 **13. Emergency Bill Assistance Expense.**

23 Staff increased test year expense to \$20,000.00 to provide for the increase requested by the
24 Company for emergency bill assistance.⁹⁵ UNSE included this amount in its request for increased
25 funding for its low-income weatherization program.⁹⁶

25 ⁸⁹ *Id.*

26 ⁹⁰ Ralph Smith Direct Test. (Ex. S-56) at p. 39.

27 ⁹¹ *Id.*

28 ⁹² *Id.* at p. 39.

⁹³ *Id.* at p. 68.

⁹⁴ *Id.*

⁹⁵ Ralph Smith Direct Test. (Ex. S 56) at p. 41.

⁹⁶ *Id.*

1 The Company had requested that the low-income weatherization program be included in the
2 Demand Side management ("DSM") programs.⁹⁷ However, as discussed in the testimony of Staff
3 witness McNeely-Kirwan, bill assistance should not be a part of the Company's DSM program.
4 Further this particular expense should not be included in the separate DSM surcharge rate.⁹⁸

5
6 **14. Mark-up Above Cost for Charges from Affiliate, Southwest Energy Services.**

7 Southwest Energy Services ("SES") is an affiliated company of UNSE and supplies additional
8 work force assistance to UNSE and its other affiliates.⁹⁹ In response to Staff data requests, it was
9 revealed that SES began performing meter reads for UNSE beginning in February, 2005.¹⁰⁰ In the
10 Company's data response, the Company stated that when SES provides supplemental work force
11 services to UNSE, TEP and other affiliates, SES charges a 10% mark-up on the base wages of the
12 workers.¹⁰¹ In addition, SES charges the cost of the employer's taxes, workers' compensation and
13 benefits.¹⁰² Test year expense should be reduced by \$10,906 to remove the affiliated mark-up above
14 cost.

15 **15. Other Uncontested Adjustments.**

16 Staff's final accounting schedules (and Mr. Smith's surrebuttal testimony) addressed three
17 adjustments which Staff believes are uncontested by UNSE. These adjustments are reflected in
18 Staff's final accounting schedules in Adjustments C-18 (bad debt expense), C-19 (removes double
19 count from outside services Demand Side Management, and C-20 (corrects year-end accrual
20 expense for an out-of-period expense).

21 **B. Cost of Capital.**

22 Staff witness David C. Parcell, President and Senior Economist of Technical Associates,
23 Richmond, Virginia, presented Staff's position on cost of capital.¹⁰³ Mr. Parcell holds a B.A. and
24 M.A. degree in economics from Virginia Polytechnic Institute and State University and a M.B.A.

25 _____
26 ⁹⁷ *Id.*

⁹⁸ *Id.* at 41.

⁹⁹ Ralph Smith Direct Test. (Ex. S-56) at p. 42.

¹⁰⁰ *Id.*

¹⁰¹ *Id.*

¹⁰² *Id.* at p. 42.

¹⁰³ David Parcell Direct Test. (Ex. S-52) at p. 1.

1 from Virginia Commonwealth University. He has provided cost of capital testimony in public utility
2 ratemaking proceedings dating back to 1972. He has filed testimony and or testified in
3 approximately 400 utility proceedings before 40 regulatory agencies in the United States and Canada.
4

5 **1. Capital Structure.**

6 UNSE has used its capital structure as of June 30, 2007 for purposes of this proceeding.¹⁰⁴
7 Staff witness Parcell proposed use of the actual test period capital structure of UNSE as of June 30,
8 2006.¹⁰⁵

9 Mr. Parcell explained in his Direct Testimony that determining an appropriate capital
10 structure is important because one needs to ensure that the capital structure is “appropriate relative to
11 its level of business risk and relative to other utilities.”¹⁰⁶ The common equity ratio receives the most
12 attention for the following three reasons: 1) it commands the highest cost rate; 2) it generates
13 associated income tax liabilities; and, 3) it causes the most controversy since its cost cannot be
14 precisely determined.¹⁰⁷

15 UNSE is a subsidiary of UES, which is a subsidiary of UniSource Energy.¹⁰⁸ UNSE was
16 created when Unisource purchased the electric distribution assets of Citizens Communications.¹⁰⁹
17 Thus UNSE’s capital structure did not exist until 2003.¹¹⁰ Since 2003, UNSE’s common equity ratio
18 has been steadily increasing. In 2003, the common equity ratio of the company (including short-term
19 debt) was 37.6%. By contrast, in 2006, the Company’s common equity ratio was 45.0% (including
20 short-term debt).¹¹¹ UniSource Energy’s common equity ratio has also increased over this same
21 period from 28.8% in 2002 (including short-term debt) to 34.9 % in 2006 (including short-term
22 debt).¹¹²

23
24
25 ¹⁰⁴ *Id.* at p.2.

¹⁰⁵ *Id.*

¹⁰⁶ *Id.* at p. 15.

¹⁰⁷ David Parcell Direct Test. (Ex. S-52) at p. 15.

¹⁰⁸ *Id.* at 16.

¹⁰⁹ *Id.*

¹¹⁰ *Id.*

¹¹¹ David C. Parcell Direct Test. (Ex. S-52) at 16.

¹¹² *Id.*

1 Mr. Parcell also studied the common equity ratios of the two groups of electric utilities
2 reported by AUS Utility Reports: electric and combination gas and electric companies. The common
3 equity ratios of those two groups which were 38% and 36% respectively (inclusive of short-term
4 debt) in 2002 had increased to 45% and 44% respectively (inclusive of short-term debt) in 2006.¹¹³

5 The Company's June 30, 2007, capital structure contains a 48.85% common equity ratio.¹¹⁴
6 Mr. Parcell's proposed capital structure based upon the end of the test year is 48.83%.¹¹⁵ Thus, the
7 capital structures proposed by the Company and Mr. Parcell are only marginally different. In fact the
8 difference in the capital structure between them amounts to only three (3) basis points of the total cost
9 of capital.¹¹⁶

10 2. Cost of Capital.

11 With respect to cost of capital, the primary difference between Staff and the Company is
12 basically cost of equity.¹¹⁷ Mr. Parcell has computed an overall cost of capital for UNSE of 8.74 to
13 9.23 percent, with a midpoint of 8.99%.¹¹⁸ The Company proposed an overall cost of capital of
14 9.89%.¹¹⁹

15 a. Cost of Debt.

16 Mr. Parcell used a cost of long-term debt of 8.16%; and a cost of short-term debt of 6.36%.¹²⁰
17 These were the rates as of June 30, 2006.¹²¹ The Company is proposing a cost of long-term debt of
18 8.22%.¹²²

19 Mr. Parcell testified that the cost of debt is determined primarily by interest payments, issue
20 prices and related expenses.¹²³

21
22
23
24 ¹¹³ *Id.* at 17.

25 ¹¹⁴ *Id.*

26 ¹¹⁵ *Id.* ; DCP-1, Schedule 13.

27 ¹¹⁶ Tr. at- 1125.

28 ¹¹⁷ Tr. at 1126.

¹¹⁸ *Id.*

¹¹⁹ Tr. at 957.

¹²⁰ David Parcell Direct Test. (Ex. S-52) at p. 18.

¹²¹ *Id.*

¹²² Tr. at p. 974.

¹²³ David Parcell Direct Test. (Ex. S-52) at p. 18.

1 **b. Cost of Equity.**

2 The major difference between the Company's overall cost of capital and Staff's overall cost
3 of capital has to do with the computation of the Company's cost of equity.¹²⁴

4 UNSE is requesting an 11.8 percent cost of equity. Staff witness Parcell is proposing a cost of equity
5 for the Company within a range of 9.5% to 10.5%¹²⁵

6 Mr. Parcell used three different methodologies to estimate the Company's cost of equity.¹²⁶
7 Since UNSE is not publicly traded, it is not possible to apply cost of equity models directly to it.¹²⁷

8 While its parent UniSource Energy is publicly traded, the results of a direct analysis applied to this
9 Company would be of limited value because of its diversified nature.¹²⁸ Consequently, Mr. Parcell
10 used a group of comparison or proxy companies to determine UNSE's cost of equity.¹²⁹

11 The three primary methods for determining cost of equity are the Discounted Flow Model
12 ("DCF"), the Comparable Earnings Method ("CE") and the Capital Asset Pricing Model ("CAPM").

13 The DCF Model is based upon the "dividend discount model" and determines the value or
14 price of a security by calculating the discounted present value of all future cash flows.¹³⁰ Results
15 under the DCF Model were calculated by Mr. Parcell assuming that dividends are expected to grow at
16 a constant rate.¹³¹ The DCF Equation recognizes that the return expected by investors is comprised
17 of dividend yield (current income) and expected growth in dividends (future income).¹³²

18 In determining return, Mr. Parcell combined the current dividend yield for each group of
19 proxy utility stocks with several indicators of expected dividend growth.¹³³ The dividend growth rate
20 component of the model is usually the most controversial piece of the equation.¹³⁴ Mr. Parcell
21 considered the following five indicators of growth in his DCF analysis:

22
23
24 ¹²⁴ Tr. at p. 1126.

25 ¹²⁵ Tr. at p. 1126.

26 ¹²⁶ David Parcell Direct Test. (Ex. S-52) at p. 18.

27 ¹²⁷ *Id.*

28 ¹²⁸ *Id.*

¹²⁹ David Parcell Direct Test. (Ex. S-52) at pp. 18-19.

¹³⁰ David Parcell Direct Test. (Ex. S-52) at p. 19.

¹³¹ *Id.* at pp. 19-20.

¹³² *Id.* at p. 20.

¹³³ *Id.*

¹³⁴ *Id.* at p. 21.

- 1 1. 2002-2006 (5-year average) earnings retention, or fundamental growth (per Value
2 Line);
- 3 2. 5-year average of historic growth in earnings per share (EPS), dividends per share
4 (DPS), and book value per share (BVPS)(per Value Line);
- 5 3. 2007, 2008 and 2010-2012 projections of EPS, D PS, and BVPS (per Value Line);
- 6 4. 2004-2006 to 2010-2012 projections of EPS, DPS, and BVPS (per Value Line);
- 7 and,
- 8 5. 5-year projections of EPS growth as reported in First Call (per Yahoo Finance).¹³⁵

9 The DCF results in Schedule 7 of Mr. Parcell's Direct Testimony indicate average DCF cost
10 rates of approximately 8.5%. Mr. Parcell's analysis yielded a range of 9.5% to 10.5% percent for the
11 proxy group.¹³⁶ The Company's DCF analysis (9.7% to 10.5%) does not vary significantly from
12 Staff's DCF analysis (9.5% to 10.5%).

13 Mr. Parcell then used the CAPM model which is a version of the risk premium method.¹³⁷
14 The CAPM describes the relationship between a security's investment risk and its market rate of
15 return.¹³⁸ Mr. Parcell used the same group of proxy companies when calculating the cost of equity
16 using CAPM.¹³⁹

17 The first variable in the equation is the risk-free rate.¹⁴⁰ The risk-free rate is generally
18 recognized by use of U.S. Treasury securities. Mr. Parcell used the three month average yield
19 (March-May 2007) for 20-year U.S. Treasury bonds which produced an average yield of 4.91
20 percent.¹⁴¹ The next variable in the CAPM equation is beta, which is a measure of the relative
21 volatility or risk of a stock in relation to the overall market.¹⁴² To calculate the risk premium (the
22 investor expected premium of common stock over the risk-free rate) Mr. Parcell used the S&P 500
23

24
25 ¹³⁵ *Id.* at p. 21.

26 ¹³⁶ *Id.* at 23.

27 ¹³⁷ David Parcell Direct Test. (Ex. S-52) at p. 23.

28 ¹³⁸ *Id.*

¹³⁹ *Id.* at p. 24.

¹⁴⁰ *Id.*

¹⁴¹ *Id.*

¹⁴² David Parcell Direct Test. (Ex. S-52) at p. 24.

1 and 20 year U.S. Treasury Bonds.¹⁴³ This yielded a risk premium of about 5.9%.¹⁴⁴ The CAPM
2 calculations indicated a cost of about 10% to 10.5% for the two groups of comparable utilities.¹⁴⁵

3 The Company CAPM results are much different than Staff's, because the Company relied
4 only upon 1926-2005 arithmetic average differences between large company stocks (S&P 500) and
5 long-term Treasury bonds.¹⁴⁶ As Mr. Parcell testified it is preferable to have multiple sources of risk
6 premium measures.¹⁴⁷ Further, Company witness Grant's 7.1 risk premium used only arithmetic
7 returns and ignores geometric (compound) returns in deriving the risk premium, which is again
8 inappropriate.¹⁴⁸ Investors have access to both types of returns and use both when they make their
9 investment decisions.¹⁴⁹ Mr. Parcell also points out that Value Line, one of the reports relied by
10 UNSE, show historic returns on a geometric rate basis, not on an arithmetic rate basis.¹⁵⁰

11 Finally, with respect to his CAPM analyses, Mr. Grant focuses on the top end of the range in
12 developing his recommendation with respect to cost of equity. He chose 11.8%, the top end of his
13 CAPM range, which represents the result for a single company.¹⁵¹ Had he instead focused on the
14 mid-points of his DCF and CAPM analyses, his recommendation would have been within a range
15 (10.1% to 10.8%) very similar to Mr. Parcell's (9.5% to 10.5%).¹⁵²

16 The CE method is based upon the "corresponding risk" standard of the United States Supreme
17 Court's decisions in the *Bluefield*¹⁵³ and *Hope*¹⁵⁴ cases. The CE method is "designed to measure the
18 returns expected to be earned on the original cost book value of similar risk enterprises."¹⁵⁵ Mr.
19 Parcell's CE analysis is based upon market data (through the use of market-to-book ratios) and thus is
20 a market test.¹⁵⁶ He considered the equity returns of the proxy groups of utilities for the period 1992-

22 ¹⁴³ *Id.* at p. 25.

23 ¹⁴⁴ *Id.* at p. 25.

24 ¹⁴⁵ *Id.* at p. 26.

25 ¹⁴⁶ David C. Parcell Direct Test. (Ex. S-52) at p. 32.

26 ¹⁴⁷ *Id.*

27 ¹⁴⁸ *Id.*

28 ¹⁴⁹ David C. Parcell Direct Test. (Ex. S-52) at p. 32.

¹⁵⁰ *Id.* at p 33.

¹⁵¹ David C. Parcell Direct Test. (S-52) at p. 35.

¹⁵² *Id.*

¹⁵³ *Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia*, 262 U.S. 679 (1923).

¹⁵⁴ *Federal Power Comm'n v. Hope Natural Gas Co.*, 230 U.S. 591 (1942).

¹⁵⁵ David Parcell Direct Test. (Ex. S-52) at p. 26.

¹⁵⁶ *Id.* at p. 27.

1 2006, or the last 15 years.¹⁵⁷ Mr. Parcell explained that he used this period because the CE analysis
2 requires the use of a long period of time to determine trends in earnings over at least a full business
3 cycle.¹⁵⁸ Mr. Parcell discussed his results in the following passage from his Direct Testimony:

4 These results indicate that historic returns of 9.0-10.6 percent have
5 been adequate to produce market-to-book ratios of 148-154 percent for
6 the groups of proxy utilities. Furthermore, projected returns on equity
7 for 2007, 2008, and 2010-2012 are within a range of 9.5 percent to 10.7
8 percent for the utility groups. These relate to 2006 market-to-book
9 ratios of 151 percent or higher.¹⁵⁹

10 Overall, Mr. Parcell testified that his CE analysis indicated a cost of equity for the proxy
11 utilities of no more than 10%.¹⁶⁰ He stated that recent returns of 9.0%-10.6% have resulted in
12 market-to-book ratios of 148 and greater.¹⁶¹ Prospective returns of 9.5% to 10.7% have resulted in
13 market-to-book ratios of over 151%. Thus, an earned return of 10% should result in a market-to-
14 book ratio of at least 100%.¹⁶²

15 A summary of Mr. Parcell's results under the three methods is:

16 Discounted Cash Flow	9.5-10.5% (10.0% mid-point)
17 Capital Asset Pricing Model	10.0-10.5% (10.25% mid-point)
18 Comparable Earnings	10%

19 Thus, his cost of equity for UNSE is a range from 9.5% to 10.5% with a mid-point of
20 10.0%.¹⁶³ This results in an overall total cost of capital of a range from 8.74% to 9.23% with a mid-
21 point of 8.99 percent.¹⁶⁴

22 UNSE witness Grant made a 60 basis point adjustment for UNSE. Thus he compounded his
23 overstated cost of equity for UNSE by adding sixty basis points to his 9.7% to 11.8% range to reflect
24 UNSE's operations which he states are decidedly riskier than the proxy group.¹⁶⁵ The adjustment
25 was made because he has erroneously assumed that UNSE is a non-investment grade company.¹⁶⁶

26 ¹⁵⁷ *Id.*
27 ¹⁵⁸ *Id.*
28 ¹⁵⁹ David Parcell Direct Test. (Ex. S-52) at p. 28.
29 ¹⁶⁰ *Id.* at p. 29.
30 ¹⁶¹ *Id.* at p. 29.
31 ¹⁶² *Id.*
32 ¹⁶³ David Parcell Direct Test. (Ex. S-52) at p. 30.
33 ¹⁶⁴ *Id.*
34 ¹⁶⁵ *Id.* at p. 35.
35 ¹⁶⁶ *Id.*

1 He also cited size as one reason for adjustment but this is not a legitimate reason since UNSE
2 does not raise its own equity capital and its debt is guaranteed by UES.¹⁶⁷ It is not the size of UNSE
3 that investors evaluate, rather it the size of the publicly-traded entity, UniSource Energy.¹⁶⁸

4 Staff's proposed cost of equity is also much more consistent with trends in authorized returns
5 on equity for electric utilities as reported by Regulatory Research Associates in recent years:

7	2000	11.43%
8	2001	11.09%
9	2002	11.16%
10	2003	10.99%
	2004	10.75%
	2005	10.54%
	2006	10.36% ¹⁶⁹

11
12 **c. Chaparral City Water Company Decision.**

13 UNSE proposed in Schedule A-1, that the total cost of capital for the Company be applied to
14 the "fair value" of the Company's rate base. This is apparently in response to the recent Arizona
15 Court of Appeals decision in *Chaparral City Water Company*.¹⁷⁰

16 UNSE's proposal to simply apply the same cost of capital analysis as is applied to original
17 cost rate base is inappropriate and would result in overstatement of the Company's current cost of
18 capital. The Court in *Chaparral City* recognized this when it stated: If the Commission determines
19 that the cost of capital analysis is not the appropriate methodology to determine the rate of return to
20 be applied to the FVRB, the Commission has the discretion to determine the appropriate
21 methodology."¹⁷¹

22 The Commission currently has a proceeding open to address the Chaparral City Water
23 Company decision. That proceeding is still underway.

24 The Company argues that "Staff has proposed a methodology that is mathematically
25 equivalent to the 'backing in' method that was expressly rejected in a recent Arizona Court of

26 _____
27 ¹⁶⁷ *Id.*

¹⁶⁸ *Id.*

¹⁶⁹ David C. Parcell Direct Test. (Ex. S-52) at p. 34.

¹⁷⁰ *Chaparral City Water Company v. Arizona Corporation Commission*, 1CH-CC-05-0002 (2007).

¹⁷¹ *Id.*

1 Appeals ruling involving Chaparral City Water Company (“Chaparral decision”). Staff’s
2 methodology should be rejected and replaced with a methodology that actually gives credence to
3 FVRB in setting rates.”¹⁷²

4 The Company’s argument that Staff through its methodology is backing into a rate of return is
5 meritless. As Mr. Smith pointed out, the cost of capital applicable to the amount of FVRB that is in
6 excess of the Original Cost Rate Base is zero, since that rate base is not reported on the utility’s
7 financial statements and therefore has not been financed by any source of capital (debt or equity) that
8 is reported on the utility’s financial statements.¹⁷³ Moreover, the application of Staff’s adjusted
9 weighted cost of capital to the FVRB results in revenue increase of \$3.668 million. Thus, in this
10 case, the application produces a slightly higher revenue requirement than does the application of the
11 unadjusted rate of return to Original Cost Rate Base.¹⁷⁴

12 Further, Mr. Smith pointed out at the hearing that Unisource responded to Staff data requests
13 that information concerning reconstruction cost new, reconstruction cost new depreciated, Handy-
14 Whitman Index information, Marshall Index information, Bureau of Labor Statistics information was
15 given little or no weight by UniSource in deciding how much to pay for the electric utility. The
16 arms-length transaction that occurred demonstrates that the RCND was not a good estimate of the fair
17 value of this utility as of the date of the acquisition.¹⁷⁵ Mr. Smith further testified:

18
19 The price paid in an arms-length transaction would represent the fair
20 value of the utility as of the date of the acquisition. The price paid was
21 substantially below the original cost depreciated book value. Because
22 the acquisition occurred fairly recently in August of 2003, this suggests
23 that using RCN and RCND information to establish the fair value of the
24 utility rate base in the current rate case could potentially result in a
25 substantial overstatement of the fair value rate basing of the
26 Commission’s traditional methods for determining fair value rate
27 base.¹⁷⁶

24 ...
25 ...

26 _____
27 ¹⁷² Kentton C. Grant Rebuttal Test. (Ex. UNSE-35) at p. 3.
28 ¹⁷³ Ralph C. Smith Surrebuttal Test. (Ex. S-58) at p. 5.
¹⁷⁴ *Id.* at pps. 5-6.
¹⁷⁵ Tr. at pp. 1197-1198.
¹⁷⁶ Tr. at p. 1198.

1
2 **d. Financing Application.**

3 This case also included a request by the Company for authority to issue up to \$40 Million in
4 new debt securities consisting of either long-term and/or short- to intermediate-term debt and
5 allowing the Company to refinance any short-or intermediate-term debt into long-term debt when the
6 Company believes favorable market conditions exist.¹⁷⁷ The Company is seeking authority to obtain
7 \$80 Million in total (including the \$40 Million in new debt securities) of new financing authority in
8 order to finance the \$60 to \$65 Million purchase price for BMGS. The Company intends to receive
9 the additional \$40 Million through an infusion of additional equity from UniSource Energy
10 Corporation (“UniSource”) and seeks Commission authority of this infusion to maintain a balanced
11 capital structure.¹⁷⁸ UNSE is also seeking Commission authority to enter into indentures or security
12 agreements which grant liens on some or all of its properties to provide security with the financing
13 transactions.¹⁷⁹

14 The Staff witness addressing the Company’s financing application was Mr. Alexander Igwe.
15 Mr. Igwe has a B.S. degree in Accounting from the University of Benin, Nigeria and a Master of
16 Information Systems Management degree from Keller Graduate School of Management of Devry
17 University. He is a C.P.A. and a member of the American Institute of Certified Public Accountants.
18 Mr. Igwe recommended:

- 19 “1) that the Commission approve UNS request to incur up to \$40 million in new
20 debt financing and to receive up to \$40 million in new equity infusion, for the sole
21 purpose of acquiring BMGS;
- 22 2) that the Commission authorize UNS to issue up to \$40 million in debt financing
23 as recommended in (1) above, in long-term debt, and in short-term to intermediate-
24 term debt;
- 25 3) that the Commission authorize UNS to refinance any short-term and
26 intermediate-term debt, issued under this docket, to long-term debt, without further
27 Commission authorization;
- 28 4) that the Commission authorize UNS to issue guarantees and grant liens on some
or all of its assets, including BMGS, and any other properties acquired subsequent to
this transaction, to secure its obligation under the proposed debt issuance and to secure
other obligations at the time such liens are granted;

177 Application (Ex. UNSE-1) p. 5 and p. 8.

178 *Id.* at p. 9

179 *Id.* at p 7.

1 5) that the Commission authorize UNS to engage in any transactions and to execute
2 or cause to be executed any documents so as to effectuate the authorizations requested
3 with this application.

4 6) that UNS file a report with Docket Control demonstrating that it had a DSC and a
5 TIER equal to or greater than 1.0, at the time of new debt issuance, within 60 days
6 from the close of each transaction under this docket.

7 7) that UNS file a report with Docket Control, within 60 days from the close of each
8 financing package, describing the transaction and demonstrating that the terms are
9 consistent with those generally available to comparable entities.”¹⁸⁰

10 UNSE accepted all of Mr. Igwe’s recommendations.¹⁸¹ As to the impact upon Mr. Parcell’s
11 capital structure recommendation in this case, Mr. Igwe testified that grant of the Company’s
12 financing application would have no material impact.¹⁸² He also testified that the exact impact of
13 UNS’ proposed financing on its capital structure cannot be determined at this time because of its need
14 for flexibility in determining the appropriate mix of debt and equity at the time the various
15 transactions occur.¹⁸³

16 In addition, because of the Company’s request for flexibility, factors such as the exact debt
17 amount, composition of proposed debt, interest rates and durations are vague at this time, Staff could
18 not calculate the traditional financial indicators such as the DSC ratio and TIER. Instead Staff
19 witness Igwe recommended that UNSE be required to demonstrate that it meets a minimum DSC and
20 a TIER, equal to or greater than 1.0, at the time of each debt issuance.¹⁸⁴

21 **III. BLACK MOUNTAIN GENERATING STATION (BMGS).**

22 In his pre-filed testimony, UNSE Vice President Michael DeConcini discussed UNSE’s
23 power requirements. UNSE has a current base demand of 200-250 MW, with a peak demand of 450
24 MW. Presently, UNSE obtains 100% of its power through a full requirements Power Supply
25 Agreement (“PSA”) with Pinnacle West Capital Corporation (“PWCC”).¹⁸⁵ The contract with

26 ¹⁸⁰ Alexander Igwe Direct Test. (Ex. S-54) at p. 7.

27 ¹⁸¹ Tr. at 1251.

28 ¹⁸² Alexander Igwe Direct Test. (Ex. S-54) p. 4.

¹⁸³ *Id.*

¹⁸⁴ *Id.* at p. 6.

¹⁸⁵ Michael DeConcini Direct Test. (Ex. UNSE-14) p. 1.

1 PWCC expires at the end of May, 2008.¹⁸⁶ As Kevin Larson, Vice President of UniSource Energy
2 Services testified, “[W]e essentially are going to lose all of our resources on the 1st of June 2008.”¹⁸⁷
3 Currently, UNSE is negotiating with alternative vendors to replace the power no longer being
4 provided under the PSA with PWCC.

5
6 One component of UNSE’s strategy to remedy its situation is the Black Mountain Generating
7 Station (“BMGS”). BMGS is a proposed 90 Mw peaking facility slated for construction in Mohave
8 County, near Kingman, Arizona. If and when it is placed in service, the facility would provide
9 approximately 20 to 25% of UNSE’s peak demand.¹⁸⁸ The site for the project has been selected and
10 two turbines have been purchased, but actual construction has not yet begun.

11
12 Currently, “all of the development and the buildout is being done by UniSource Energy
13 Development Company” (“UED”).¹⁸⁹ “UED has purchased the turbines and then has entered into a
14 turnkey contract.”¹⁹⁰ 1) The cost of the turbines themselves was approximately \$17 million,¹⁹¹ and
15 the total projected cost of the BMGS is currently projected to be at least \$60 to \$65 million.¹⁹² To
16 date, all costs have been incurred by UED. To date, UNSE has contributed nothing to the cost of
17 BMGS.¹⁹³ Because construction has not yet begun, no UNSE customers are yet receiving any benefit
18 from the proposed plant.

19
20 The expenses related to the BMGS have been carried as Construction Work In Progress
21 (“CWIP”). UNSE has proposed to have the BMGS put into rate base at this time. However, to allow
22 UNSE to begin earning a return on the BMGS at this time would be inappropriate for many reasons.

23 . . .

24
25 ¹⁸⁶ *Id.*

26 ¹⁸⁷ Tr. at 175.

27 ¹⁸⁸ Tr. at 198.

28 ¹⁸⁹ Tr. at p. 163.

¹⁹⁰ *Id.*

¹⁹¹ Tr. at p. 164.

¹⁹² Tr. at p. 89.

¹⁹³ Tr. at p. 89.

1 **A. The BMGS is Not Owned by UNSE.**

2 In order for an asset to be placed into rate base, the asset must be owned by the utility
3 requesting rate recognition. BMGS does not currently belong to UNSE. It is the property of UED.
4 When commissioner Mayes asked UNSE witness Pignatelli why UNSE was unable to secure
5 financing for the project, Pignatelli responded “It is owned by another company.” He went on to add
6 that for financing purposes “[T]hese companies are stand-alone and should be treated as stand-
7 alone.”¹⁹⁴ This same statement is just as valid for rate-making purposes. UNSE has no basis for
8 requesting that an asset of UED be placed into the rate base of UNSE. More directly, there is no
9 authority which would allow UNSE to earn a return from its ratepayers on an asset belonging to
10 UED.
11

12 Unless and until BMGS is transferred to UNSE, there is no basis for placing the asset into the
13 UNSE rate base.
14

15 **B. CWIP Should Not be Included in Rate Base.**

16 Even if BMGS were the property of UNSE, the costs associated with the CWIP should not be
17 included in rate base.
18

19 **1. BMGS is Not Yet Used and Useful.**

20 One of the fundamental considerations in deciding whether or not an expense can be placed
21 into rate base is whether or not the item is used and useful. Utilities can not earn a return on an asset
22 that is not being used to serve current customers. Even if the Commission were to overlook the fact
23 that BMGS belongs to UED, or if the Commission were to consider BMGS an asset of UNSE, the
24 fact remains that BMGS is currently nothing more than an idea.
25

26 As of the date of hearing, construction had not yet begun. UNSE witness Larson was
27 questioned about the date BMGS could be placed into service.
28

¹⁹⁴ Tr. at p. 85.

1 Q: Now you want to get this asset into rate base and start earning a
2 return on it right away, but it's not actually going to be operational at
the close of this proceeding; correct?

3 A: We expect it to be operational ... May 1.¹⁹⁵

4 And as Larson had previously testified:

5 Q: So the earliest that it will be used and useful will be in May of 2008
6 or when the completion report is done; correct?

7 A: Yes.¹⁹⁶

8 Until the asset is placed into service of UNSE customers, UNSE is not entitled to earn a return
9 on the asset.

10 **2. Final Cost of BMGS is not Known and Measurable.**

11 Before a utility can expect to earn a return on an asset, that asset must have a known value.
12 The total cost of the BMGS project, however, can not be measured with any certainty. The company
13 has provided testimony that the project will cost \$60 to \$65 million, but the only amount that is in
14 any way certain is the cost of the turnkey contract, at \$46 million. The remaining costs are mere
15 estimates of such expenses as:

16 The additional costs of permitting, making site improvements,
17 obtaining water supply, connecting to a nearby gas pipeline, making
18 substation improvements, providing project supervision and paying
19 interest on borrowed funds during construction...¹⁹⁷

20 And as Mr. Larson admits, "Because these additional costs are not known with certainty, the
21 Company's proposed adjustment to rate base reflects the minimum cost estimate of \$60 million."¹⁹⁸

22 UNSE readily admits that it can only estimate an additional \$14 to \$19 million for the
23 "additional costs" associated with BMGS, and these \$14 to \$19 million dollars only reflect the
24 *minimum* costs that UNSE expects.
25

26
27 ¹⁹⁵ Tr. at p. 206.

¹⁹⁶ Tr. at p. 177.

28 ¹⁹⁷ Kevin Larson Direct Test. (Ex. UNSE-8) p. 4.

¹⁹⁸ *Id.*

1 The only figure that UNSE can provide with any certainty is the \$46 million associated
2 directly with the construction costs. Beyond those, there are expenses estimated within a \$5 million
3 window, at a minimum. This is hardly a figure that can be said to be "known and measurable" for
4 ratemaking treatment. The Commission should wait until UNSE actually owns the BMGS and
5 knows not only the final construction cost but how much UNSE actually paid for the laundry list of
6 provisional expenses.
7

8 As a final consideration, if these contingent costs do end up making the BMGS more
9 expensive than currently planned, UNSE may never acquire the asset at all, and even if it does so, the
10 Commission may disallow much of the expenses when it considers the prudence of the transaction.
11 All of these considerations indicate that placing BMGS into rate base now would be premature.
12

13 **3. BMGS is not Being Built by UNSE.**

14 As already stated, BMGS is currently being developed and built by UED. The turnkey
15 contract for construction was negotiated and executed by UED officials. Upon completion, the
16 BMGS project will be owned by UED. According to UNSE, there is a plan in place by which the
17 parent company of UNSE and UED will transfer ownership of the BMGS to UNSE upon completion,
18 but even so, there exists much uncertainty.

19 As UNSE witness Larson testified:

20 Q: [I]s there a contract, a formal written agreement between these two
21 companies for the transfer of the facility?

22 A: I don't believe there is at this time, no.¹⁹⁹

23 Larson testified that upon completion of the BMGS, the facility would be transferred to
24 UNSE "at cost."²⁰⁰ But in the absence of a written agreement, there are still questions to be
25 answered about the transaction. For example, UNSE may have the option to buy the plant at cost, but
26
27

28 ¹⁹⁹ Tr. at p. 193.

²⁰⁰ Tr. at pp. 192-193; See also, Kevin Larson Rebuttal Test. (Ex. UNSE-9) at 12.

1 is UNSE *required* to buy? If there have been cost overruns, is UNSE required to pay the final price,
2 including the overruns, or will they be passed on to UED or the ultimate parent company? If UNSE
3 buys the BMGS despite cost overruns, how much will UNSE be willing to pay and how much will
4 UNSE seek to put into rate base?

5
6 Absent a written agreement, there is no way to answer these questions. Without answers to
7 these questions, placing the BMGS project into rate base is extremely premature.

8 **4. Project is Still in the Planning Stage.**

9 As of the date of hearing, UED has purchased two turbines and selected a site for the BMGS
10 project. No actual construction had yet begun. As shown previously, the only cost figures known
11 with certainty are those directly associated with the construction contract itself. A list of ancillary
12 expenses was also provided by UNSE which cited additional expenditures which could total as much
13 as \$19 million more. Because the project is still in such an early stage, there is simply no way to
14 know with any reasonable certainty just how much the final bill for BMGS will be. Until that figure
15 is known, UNSE can not be certain it will even purchase the BMGS. And until that purchase is
16 actually consummated and the final cost figure to UNSE is known, UNSE can not expect the
17 Commission to allow UNSE to earn a return on the project.
18

19 **5. UNSE May Never Own BMGS.**

20
21 At hearing, UNSE witness Kevin Larson testified that there existed the possibility that UNSE
22 may *never* own BMGS, depending largely on how the Commission chose to treat the facility for
23 ratemaking purposes.

24 Q: I asked you if you were telling me that the company would have
25 trouble remaining financially viable if this asset were not included in
rate base in this rate proceeding.

26 A: '... I guess depending upon how this proceeding – how Black
27 Mountain is ultimately treated will determine whether or not we
transfer it into UNS Electric.' ²⁰¹

28

²⁰¹ Tr. at pp. 211-212.

1 Q: And so if Black Mountain is not put into the rate base of UNS
2 Electric in this proceeding, that Black Mountain facility will possibly
3 never be transferred to UNS Electric; is that correct?

4 A: There could be a scenario like that, yes.²⁰²

5 Q: So in other words, you're not actually going to transfer the asset to
6 UNS Electric until it looks financially viable for UNS Electric?

7 A: I think it would be a mistake on the part of management to transfer
8 an asset into UNS Electric if it's going to put it in a very difficult
9 financial condition.²⁰³

10 As UNSE testified, there is no formal written agreement to purchase the finalized BMGS
11 project. In the absence of such an agreement, there is no guarantee that UNSE will ever own BMGS.
12 The primary consideration, then, in determining if the transfer of BMGS to UNSE takes place at all is
13 the financial condition that UNSE will be placed in as a result. If the project goes as planned and
14 there are no cost overruns with construction, then UNSE would likely accept the asset upon which it
15 was already making a return.

16 However, should cost overruns occur, and the parties could not agree on equitable terms for
17 the transfer, UNSE is clearly not *obligated* to purchase BMGS in any way. For example, if the
18 project were to end up costing \$80 million, UNSE may find that it could satisfy its power needs more
19 cheaply on the open market, making the BMGS an imprudent investment. Knowing it would not
20 receive rate base reimbursement for an imprudent investment, UNSE may have no choice but to
21 forego the purchase. If BMGS were already placed into rate base, however, UNSE ratepayers would
22 be providing a return to UNSE on an investment UNSE *never even made*.

23 The obvious way to avoid this is to forego putting the BMGS into rate base until the company
24 can meet the minimum requirement for rate treatment and show that it has at least acquired the asset.

25 ...

26 ...

27
28 ²⁰² Tr. at p. 213.

²⁰³ *Id.*

1 **6. Operational and Maintenance Costs are Uncertain.**

2 In the event UNSE does purchase BMGS, the final costs associated with the BMGS are quite
3 uncertain. Until construction is completed and the plant actually becomes operational, UNSE has no
4 way to know how much the plant will cost to operate and to maintain. Operation and Maintenance
5 (“O & M”) fees can be quite significant, depending upon a long list of factors, including the physical
6 size of the plant and the cost of fuel to run the plant. Because none of these figures can be stated with
7 certainty, there is simply no way to determine what the impact upon the company’s revenues will be.
8 It is possible that BMGS will enable UNSE to produce 90 MW of power that is cheaper than that
9 available on the market. But it is also possible that unforeseen circumstances will render the cost
10 only equal to the market cost, in which case the company would have been more prudent to have
11 simply purchased the power instead of acquiring an asset which produces increased overhead for the
12 same power.
13

14
15 Coupled with the other unknown potential costs, the uncertainty regarding the cost to UNSE
16 of O & M expenses makes the final cost of the BMGS even less certain and makes the option to
17 include the facility in rate base much less viable.

18 **C. The Commission has not Made a Determination of Prudence.**

19
20 As a general ratemaking principal, before any utility may earn a return on an investment, the
21 Commission must make a determination that the expense was prudently incurred. But as UNSE
22 acknowledges, their proposal to include BMGS in rate base in the current case would prevent the
23 Commission from doing so.

24 Q: Well, let’s take the potential situation that the Commission were to
25 approve it. The company were to file its report in May 2008, and the
26 Commission were to determine at that time that the project was not
27 prudent. The costs under the company’s proposal would already be in
28 rate base at that time; correct?

1 A: Yes.²⁰⁴

2 In the case of the BMGS, there are many factors which the Commission will need to consider
3 in determining whether or not the investment in BMGS was prudent.

4 First, the cost of the plant itself will dictate the extent of the benefit, if any, to ratepayers of
5 constructing the resource. If the plant is too expensive, then it may be a great many years before the
6 asset begins to show a benefit to ratepayers and the Commission may decide that UNSE was
7 imprudent in its decision. If that were to happen, the Commission would normally simply disallow
8 recovery of the asset in rate base.

9
10 In the instant matter, however, UNSE's suggested course of action takes that discretion from
11 the Commission. If the Commission were to take such action, and BMGS were later found to have
12 been prudent, then there would be no issue. However, in the event that unforeseen circumstances
13 lead the Commission to decide the BMGS was imprudently acquired, the Commission would then
14 have to take action not only to remove the asset from rate base, but to reverse the harm to ratepayers
15 that had already occurred in allowing a return on the investment. At that time, it may prove difficult
16 to determine exactly the extent of reimbursement to which UNSE's ratepayers would be entitled.
17 And even if the assessment were made, it is likely that many ratepayers who had contributed to
18 UNSE's ill-gotten gains would no longer be UNSE customers. There may also be customers who did
19 not contribute to the return but who would be customers at the time the rates were adjusted to
20 compensate. These customers would receive a benefit to which they were not entitled.

21
22
23 UNSE has suggested that BMGS be included in rate base now, while "the prudence of
24 construction costs can be addressed in the company's next rate case."²⁰⁵ UNSE seems to
25 acknowledge that prudence review is essential while avoiding it at all costs.
26
27

28 ²⁰⁴ Tr. p. 169.

²⁰⁵ Kevin Larson Rebuttal Test. (Ex. UNSE-9) p. 9.

1 The only scenario by which there can be certainty as to the prudence of the decision is to
2 subject the asset to a prudence review *before* placing it into rate base. UNSE is correct that a
3 determination of BMGS's prudence should be determined in UNSE's *next* rate case. But in the mean
4 time BMGS should not be placed into rate base in *this* rate case.

5 IV. RATE DESIGN.

6 Frank Radigan presented Staff's testimony on the Company's proposed revenue allocation and
7 rate design.²⁰⁶ Mr. Radigan is a principal with the Hudson River Energy Group which is an energy
8 consulting firm. He has 25 years of experience and has testified as an expert witness in utility rate
9 proceedings on more than 50 occasions before various regulatory bodies.

10 Staff and the Company are in substantial agreement on the following issues:

11 1) customer charges for the residential and small Residential or Small General Service
12 classes;²⁰⁷ The Company has revised its proposed customer charges and now proposes a charge of
13 \$7.70 per month for the Residential Class and \$12.00 per month for the Small General Service Class.
14 Mr. Radigan had proposed that the Residential Class customer charge increase from \$6.50 to \$7.50
15 per month and that the Small General Service Class should be increased from \$10.00 to \$12.00 per
16 month.²⁰⁸

17 2) the level of miscellaneous service fees;²⁰⁹

18 3) the increased threshold at which a customer would be placed on a large general
19 service;²¹⁰

20 4) the rate differentials in the time-of-use periods for the time-of-use classes;²¹¹

21 On the other hand, Staff and the Company are not in agreement on the following issues:

22 1) whether time-of-use rates should be mandatory;²¹²

23
24
25 _____
26 ²⁰⁶ See Frank Radigan Direct and Surrebuttal Test. (Ex. S-61 and Ex. S-62).

²⁰⁷ Tr at p. 1255.

²⁰⁸ Frank Radigan Surrebuttal Test. (Ex. S-62) Exec. Summary.

²⁰⁹ *Id.*

²¹⁰ *Id.*

²¹¹ Tr. at p. 1256.

²¹² Tr. at p. 1255-1256.

- 1 2) full merger of the rates between Mohave and Santa Cruz County over the next two rate
2 cases,²¹³
- 3 3) implementation of inclining block rates over the next two rates cases;²¹⁴
- 4 4) differential in the demand charge for large service customers;²¹⁵
- 5 5) purchased power allocation between service classes.²¹⁶

6 Staff's positions on the issues in dispute are discussed next.

7 **A. Time of Use (TOU) Rates Should Not be Mandatory.**

8 The Company proposes to require TOU rates for all new residential, small general service,
9 and large general service (4000 kW) customers and all new and existing Large Power Service
10 customers.²¹⁷ Staff opposes mandatory TOU rates, but supports their use on a voluntary basis. Staff
11 witness Radigan based his conclusion on the Company's billing data.²¹⁸ He testified that for a meter
12 with a cost of \$200 and a carrying cost of 15%, the incremental annual cost of a new meter would be
13 approximately \$30.00.²¹⁹

14 Using the Summer On-Peak/Off-Peak differentials proposed by the Company, a residential
15 customer would have move over 2,200kWh of energy during the summer months from on-peak to
16 off-peak or 400 kWh per month to break even or benefit.²²⁰ But the billing data shows 30 percent of
17 bills are for less than 400 kWh in total.²²¹ Ninety-two percent of all bills are for usage of less than
18 2,000 kWh per month.²²²

19 Mr. Radigan stated that "[s]ince most bills are for relatively small amounts of energy, it is
20 very doubtful that the customers could move enough energy from the on-peak period to the off-peak
21 period to justify the meter expense.²²³

22
23
24 ²¹³ Tr. at 1256.

25 ²¹⁴ *Id.*

26 ²¹⁵ *Id.*

27 ²¹⁶ Tr. at 1256.

28 ²¹⁷ D. Bentley Erdwurm Direct Test. (Ex. UNSE-17) at pp. 16-17.

²¹⁸ Frank Radigan Direct Test. (Ex. S-61) at p. 9.

²¹⁹ *Id.*

²²⁰ *Id.*

²²¹ Frank Radigan Direct Test. (Ex. S-61), p. 9.

²²² *Id.* at pp. 8-9.

²²³ *Id.*

1 But Staff witness Radigan recognized that some customers would benefit from TOU rates.
2 Those 8% of residential customers with over 2,000 kWh per month account for over 25 percent of all
3 UNSE's sales to the Residential Service Classification.²²⁴ These customers could benefit from TOU
4 rates and thus Mr. Radigan recommended a vigorous customer education program to incent these
5 customers to move to TOU rates.²²⁵

6 The Small General Service Classification is similar to the Residential Customer
7 Classification. Based upon the meter cost discussed above, a customer would have to shift over
8 2,100 kWh during the summer period to pay for the meter, or 340 kWh per month.²²⁶ For the Small
9 General Service Classification, 39% of bills are over 340 kWh per month, and 84% are under 2,000
10 kWh per month.²²⁷ So, there is likely to be little benefit for these customers. But for the 16% of bills
11 above 2,000 kWh per month which account for 49 percent of all usage for this service classification,
12 there is a great potential benefit.²²⁸

13
14 **B. Merger of Mohave and Santa Cruz Rates At This Time.**

15 The Company also proposes to eliminate the separate rate structures for Mohave and Santa
16 Cruz counties in this case.²²⁹ Staff witness Radigan has proposed to accomplish the complete merger
17 of these rates over two rate cases for the following reasons.

18 First, under the separate rate structures now in existence, the absolute dollar differential in the
19 customer's bill is small.²³⁰ Merger of the two separate rate structures at this time, would send the
20 wrong price signal to some customers since it would end up in Santa Cruz customer's experiencing a
21 decrease in rates (a lower per kWh rate) at a time when the Company's costs are rising.²³¹

22 Second, it would seem to make more sense to increase the customer charge applicable to both
23 counties, and then leave Santa Cruz customers at their current levels and recover the remaining rate
24

25 ²²⁴ Frank Radigan Direct Test. (Ex. S-61). P. 9.

26 ²²⁵ *Id.*

27 ²²⁶ *Id.*

28 ²²⁷ *Id.*

²²⁸ Frank Radigan Direct Test. (Ex. S-61) p. 9.

²²⁹ *Id.* at p. 14.

²³⁰ *Id.*

²³¹ Frank Radigan Direct Test. (Ex. S-61) p. 14-15.

1 increase from the energy charge of the Mohave County customers.²³² The remaining Santa Cruz
2 differentials could be eliminated altogether in the Company's next rate case.

3 Mr. Radigan's proposed rate design still significantly reduces the rate differentials between
4 the two counties.²³³ However, both sets of customers would receive a small increase to rates; for
5 customers in Mohave County, the increase would be approximately 2.9% and for customers in Santa
6 Cruz County the rates would increase overall by 1.5%.²³⁴

7
8 **C. Inclining Block Rates.**

9 The Company is also proposing to introduce an inclining block rate structure in this case to
10 encourage conservation.²³⁵ While Mr. Radigan supports the use of inclining block rate structures in
11 general, in this case it is impractical given the relatively small recommended rate increase and
12 increases in the customer charge.²³⁶ This would result in an additional increase in the customer
13 charge, and would have widely divergent impacts on the customer base of the Company.²³⁷ Some
14 customers would receive decreases and others would receive increases leading to unnecessary
15 confusion. Mr. Radigan recommends for this reason that an inclining block rate structure be
16 reevaluated in the Company's next rate case.²³⁸

17 **D. Differential in Demand Charge for Large Service Customers.**

18 The Company proposed to lower the demand charges for large commercial customers taking
19 service at less than 69 kV but it has not offered, nor does it have, any cost data to support its
20 proposal.²³⁹

21 The Company admits that it has no cost study data to support its proposal in this case. Instead
22 it relies upon what was approved the APS case.²⁴⁰ But APS' costs are not relevant or comparable to
23 UNSE's costs. Mr. Radigan testified that UNS transmits power at 115 kV and 69 kV and that:

24
25 ²³² *Id.* at 14.

²³³ *Id.* at p. 20.

²³⁴ *Id.* at p. 22.

²³⁵ Frank Radigan Direct Test. (Ex. S-61) at p. 13.

²³⁶ *Id.*

²³⁷ *Id.*

²³⁸ Frank Radigan Direct Test. (Ex. S-61) at p. 13.

²³⁹ *Id.*

²⁴⁰ *Id.*

1
2 On the UNS system there is a variety of 69 kV substations transforming
3 power down to a variety of different voltages. Without a study, one
4 cannot determine which of these lower voltages the majority of large
5 commercial customers are taking power from or what the cost
6 differential might be. For example, a large commercial customer could
7 take service from a 13.9 kV line and should pay for not only the
8 transformation of power but for the distribution of power across many
9 miles of distribution lines. Without a study, it is impossible to tell how
10 much equipment on the other side of the step down transformer is being
11 used by the large commercial customers. Rather than guess what the
12 differential should be, a UNS specific cost of service study should be
13 developed and the issue be raised in the next rate proceeding.²⁴¹

8 **E. Purchased Power Allocation**

9 The Company proposes to allocate purchased power using the Average and Peaks Method
10 which is made up of two components: an average demand component and a peak demand
11 component.²⁴²

12 Company witness Erdwurm uses the purchased power costs of TEP to develop a split of costs
13 which he then applies to the PWCC purchased power contract which expires in 2008.²⁴³ But as
14 discussed by Mr. Radigan, this is like to fit a square peg into a round hole. Mr. Radigan explained in
15 the following passage from his surrebuttal testimony:

16
17 The contract with Pinnacle West Corporation is the Company's power
18 supply contract. It has no provision for demand charges or any
19 segregation of charges by time of day, month or season. It is merely an
20 energy charge. However much Mr. Erdwurm tries to reverse engineer
21 this energy charge into demand and energy components, the simple fact
22 remains that the purchased power charge is purely volumetric. The
23 Company has provided no credible evidence to show that the Average
24 and Peaks Method should be used in this case.²⁴⁴

21 **V. PURCHASED POWER FUEL ADJUSTMENT CLAUSE (PPFAC).**

22 In its Application, the Company proposed several major changes to its PPFAC.²⁴⁵
23 UNSE proposed that its PPFAC have an automatic adjustment mechanism on a going forward
24 basis.²⁴⁶ Staff and the Company agree that the revised or new PPFAC for UNSE should become

26 ²⁴¹ Id. at p. 5.

27 ²⁴² Id. at p. 2

28 ²⁴³ Id.

²⁴⁴ Id.

²⁴⁵ Application (Ex. UNSE-1) at p. 3.

²⁴⁶ Id.

1 effective June 1, 2008.²⁴⁷ The Company also proposed that the Commission do the following: 1)
2 clarify the costs that can be included in the PPFAC; 2) use a 12-month rolling average cost of
3 purchase power and fuel; 3) recognize carrying costs on PPFAC bank balances at an interest rate
4 equal to the cost of the Company's short-term borrowing.²⁴⁸

5 UNSE also proposed that the following costs be subject to recovery in its PPFAC:

6 1) all generation fuel used in steam generation including natural gas, fuel oil and coal, and fuel
7 transportation and coal rail expenses; 2) generation fuel used in combustion turbine generation
8 including natural gas and fuel oil; 3) purchased power costs for both energy and demand charges; 4)
9 transmission related expenses; and 5) credit costs for both fuel and purchased power.²⁴⁹

10 UNSE finally proposed that the PPFAC rate automatically adjust on a monthly basis.²⁵⁰

11 The Company's proposed changes to its PPFAC were addressed by Staff witness Ralph
12 Smith. Mr. Smith testified that despite difference between APS and UNSE, the extensive evaluation
13 of APS' PSA and related Staff recommendations in the last APS rate case, can provide helpful
14 guidance for any changes to UNSE's PPFAC in this case.²⁵¹

15 The Current UNSE PPFAC rate was set in Commission Decision No. 66028 dated July 3,
16 2003, which approved the acquisition of Citizen's electric distribution assets. The current PPFAC
17 rate is \$0.01825/kWh and reflects the fixed energy price under the PWCC PSA.²⁵² The PPFAC
18 provides an adjustment mechanism which allows UNSE to pass through purchased power and fuel
19 cost increases and/or savings relative to a base power supply rate through a surcharge or credit.²⁵³

20 The Company's current base power supply rate is \$0.05194/kWh established in Decision No. 59951
21 dated January 3, 1997.

22 Mr. Smith described the functioning of the current PPFAC in the following passage from his
23 direct testimony:

24
25 _____
26 ²⁴⁷ Tr. at 1201.

27 ²⁴⁸ *Id.*

28 ²⁴⁹ Application (Ex. UNSE-1) at p. 3.

²⁵⁰ *Id.*

²⁵¹ Ralph Smith Direct Test. (Ex. S-56) at pp. 70-71.

²⁵² *Id.* at p. 72.

²⁵³ *Id.*

1 The current PPFAC functions in the following manner. The
2 Company's actual fuel and purchased power costs (excluding demand
3 charges) are charged to a PPFAC Bank Balance. The sum of the base
4 power supply rate plus any PPFAC rate are multiplied by energy
5 consumption. The product of that multiplication, indicating the
6 Company's recovery of fuel and purchased power costs, is subtracted
7 from the PPFAC bank balance. When the PPFAC bank balance
8 reaches a predetermined threshold, UNS Electric must make a filing
9 with the Commission to propose a method to recover or return the bank
10 balance. The current PPFAC cannot be changed without Commission
11 approval.²⁵⁴

12 Staff witness Smith presented testimony in this case which agreed that some changes to the
13 Company's PPFAC were warranted. In fact, Mr. Smith presented a copy of a red-lined version of
14 the APS Plan of Administration, revised for use for UNSE, which is presented in Attachment RCS-7
15 to Mr. Smith's surrebuttal testimony

16 Witness Smith took exception to a number of the Company's proposals. First, the Company
17 was and is still including inappropriate costs in its PPFAC most notably expenses for credit
18 support.²⁵⁵ Second, the Company was sponsoring changes to its PPFAC which would make it more
19 self-effectuating and less subject to regulatory approvals and oversight.²⁵⁶ In addition, the Company
20 proposes to include the costs from FERC accounts 501, 547, 555 and 565 in its PPFAC. However,
21 for 2002 through 2006, the Company did not record any fuel expenses to these accounts.²⁵⁷ UNSE
22 has typically recorded its purchased power costs to FERC Account 555.²⁵⁸ Nonetheless, all of these
23 accounts were essentially the same accounts that the APS PSA Plan of Administration covered.²⁵⁹

24 Other changes proposed by Mr. Smith to the Company's proposed PPFAC included: 1)
25 allowance of prudent direct costs of contracts it uses for hedging system fuel and purchased power
26 under its PPFAC, 2) inclusion of purchased energy expenses; however exclusion of capacity costs.²⁶⁰
27 A normalized level of purchased capacity costs are typically recovered in the utility's base rates.²⁶¹
28 Such dissimilar treatment as allowing purchased capacity costs to be recovered in the PPFAC while

25 ²⁵⁴ *Id.* at p. 72.

26 ²⁵⁵ *Id.*

27 ²⁵⁶ Ralph Smith Direct Test. (Ex. S-56) p. 72.

28 ²⁵⁷ *Id.* at p. 74.

²⁵⁸ *Id.*

²⁵⁹ *Id.*

²⁶⁰ Ralph Smith Direct Test. (Ex. S-56) at p. 75.

²⁶¹ *Id.*

1 the Company's own generation or transmission capacity costs are included in base rates is neither
2 appropriate or desirable.²⁶²

3 The Company and Staff have been able to come to agreement on most aspects of the
4 Company's PPFAC. The Company ultimately accepted many of Witness Smith's revisions to its
5 PPFAC. The Company agrees with the revisions presented in Attachment RCS-7 with the exception
6 of one area.²⁶³

7 The Company still wants to include the costs of credit support associated with fuel and
8 purchased power procurement and hedging in its PPFAC.²⁶⁴ Witness Smith testified that this is
9 neither reasonable or appropriate nor is it common industry practice that such costs would be
10 recorded in these FERC accounts and recovered through a PPFAC mechanism.²⁶⁵

11 Finally, due to late-filed information by the Company regarding prospective gas prices, Staff
12 is also recommending a cap on the PPFAC in order to prevent rate shock.

13 **VI. DEMAND SIDE MANAGEMENT PROGRAMS AND EPS/REST ADJUSTOR.**

14 **A. Demand Side Management.**

15 Staff's position on Demand Side Management and the EPS/REST Adjustor was presented by
16 Ms. Julie McNeely-Kirwan and Mr. Jerry Anderson. Ms. McNeely-Kirwan graduated magna cum
17 laude from Arizona State University and holds a Master's Degree from the University of Wisconsin.
18 Mr. Anderson has double majors in Economics and Business Management. He also has an MBA
19 degree from Xavier University in Cincinnati, Ohio.
20

21 Within the context of this rate case, UNSE has proposed to add new programs to its existing
22 portfolio. Staff has proposed many recommendations regarding cost recovery of the programs, but
23 consideration of the programs themselves is being undertaken in a separate docket E-04204A-07-
24

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27 ²⁶² *Id.* at p. 76.

²⁶³ Tr. at p. 1202.

²⁶⁴ *Id.* at p. 78.

²⁶⁵ Ralph C. Smith Direct Test. (S-56) at p. 78.

1 0365. Within the context of this rate case, Staff has made recommendations regarding only the
2 method by which the programs are funded.

3 Currently, UNSE funds four separate Demand-Side Management programs, aimed at
4 decreasing customer demand. These programs are funded from base rates, in the amount of \$175,000
5 annually, as ordered by the Commission in Decision No. 59951, January 3, 1997.

6
7 Because it is not known at this time which of UNSE's proposed programs will ultimately be
8 approved by the Commission, Staff's objective is to provide a funding mechanism that would be
9 responsive to those DSM programs and activities that the Commission may ultimately approve for
10 UNSE outside of this docket.

11 **B. Low Income Weatherization Program.**

12 UNSE currently operates a Low Income Weatherization ("LIW") program, costing \$70,000.
13 In Decision No. 59951, the Commission removed the program from the UNSE DSM portfolio, but
14 continued to finance the program separately from base rates. Staff has recommended that the LIW
15 program be returned to the DSM portfolio. UNSE has concurred in Staff's position.

16
17 Staff made no recommendation regarding the viability of the program itself, and insists that
18 the program be proven cost-effective, just as any other DSM program.

19 **a. Emergency Bill Assistance.**

20 UNSE had included \$20,000 annually in its LIW program for Emergency Bill Assistance
21 ("EBA"). Staff does not consider the EBA program to be DSM, and removed it.

22
23 However, Staff does believe the EBA program should be included as part of UNSE's Warm
24 Spirits program, and that Warm Spirits should continue to be funded through base rates and
25 shareholder contributions. EBA should not be funded through DSM funds.

26 ...

27 ...

28

1 **B. Time Of Use Rates.**

2 UNSE has proposed that Time Of Use (“TOU”) pricing be considered as an option to reduce
3 demand during peak hours. The TOU rates have been evaluated by Staff witness Frank Radigan.
4 Staff believes that TOU pricing plans are not considered part of DSM and that TOU pricing plans not
5 be funded using DSM monies.
6

7 **C. Funding of DSM Programs.**

8 UNSE has proposed to exclude costs from base rates and to implement a single line-item per
9 kWh charge on all customers’ bills in order to collect the necessary funds. In essence, this line-item
10 charge constitutes a “DSM adjustor mechanism”. Staff supports the removal of DSM program costs
11 from base rates and the use of this adjustor mechanism to recover UNSE’s prudently-incurred costs
12 related to DSM. UNSE has concurred.
13

14 **a. Alternative Approaches.**

15 Staff has reviewed several alternatives to the adjustor mechanism, including 1) recovery
16 through base rates with no deferral accounting, 2) recovery through a deferral account, 3) recovery by
17 amortization or capitalization of costs over time, and 4) recovery through a combination method.
18 After weighing these alternatives, Staff concluded that an adjustor mechanism is preferable.

19 **1. Recovery Through Base Rates with Deferral Account.**

20 Staff believes this method would provide timely recovery, but would lack the flexibility to
21 adjust as new programs were added or current programs were expanded. A specific weakness is that
22 when actual incurred costs are less than the base rate amount, ratepayers could be paying for DSM
23 costs not yet expended. UNSE concurs in Staff’s analysis.
24

25 ...

26 ...

27 ...

28

1 **2. Recovery through Deferral Account.**

2 Staff believes that a deferral account does not allow a timely recovery of DSM costs and
3 would not appropriate for that reason. UNSE concurs.

4 **3. Amortization or Capitalization.**

5 While this program has the advantage of lessening the impact of recovery over time, it is not
6 appropriate where programs are small or just beginning. UNSE concurs with Staff's analysis.

7 **4. Combination Method.**

8 While this method has been used with other utilities in the past, it is inappropriate in a case
9 such as this in which there are uncertain levels and timelines for the DSM activities. The program
10 could actually be confusing and less than transparent to customers. UNSE does not dispute Staff's
11 analysis.
12

13 **D. DSM Cost Recovery.**

14 Staff recommends that UNSE be allowed to recover all prudently-incurred DSM expenses in
15 conjunction with Commission-approved DSM programs and activities. These costs should include
16 rebate processing, customer training and technical assistance, customer education, program planning
17 and administration, program implementation, program marketing and communications, measurement
18 and evaluation activities, and properly allocated portions of baseline study expenses if and when such
19 studies are approved by the Commission.
20

21 Actual incurred costs should be itemized in the Company's semi-annual DSM reports, and
22 should be reviewed by Staff. Staff recommends DSM related expenses be recorded in the DSM
23 adjustor account by DSM program and other major categories of expense. Within each DSM
24 program or major sub-account, the further disaggregation by type of expense would separately record
25 rebates and incentives, marketing, direct program implementation, and administrative costs. UNSE
26 has not objected.
27
28

1 Staff recommends that UNSE's DSM adjustor rate be reset annually on June 1 of each year
2 beginning June 1, 2009, and that the per kWh rate be based upon currently projected DSM costs for
3 that year, adjusted by the previous year's over- or under- collection, divided by projected retail sales
4 for that same year. Staff further recommends that UNSE submit to Docket Control its prudently-
5 incurred DSM expenses from the previous calendar year in connection with Commission-approved
6 DSM programs and activities, and that UNSE submit its actual DSM cost recovery collected in the
7 previous year, annually by April 1 of each year.
8

9 The disaggregated costs placed in each DSM Adjustor sub-account for the previous year
10 should be summed to a total DSM cost and compared with documented DSM cost recovery that same
11 year to determine over- or under-collection adjustment needed to modify projected DSM costs for the
12 current year adjustor rate calculation. Staff further recommends that UNSE submit, with its previous
13 year DSM costs and DSM recovery, a proposed calculation of the new DSM adjustor rate for the
14 current year. Staff also recommends that UNSE's proposed new DSM Adjustor rate shall become
15 effective on June 1 if no action is taken by the Commission to modify or reject it.
16

17 Staff is recommending that the adjustor rate not be reset until June 1, 2009 because that date
18 would be the first adjustor rate based upon actual operation of the DSM programs proposed in
19 UNSE's Portfolio Plan.
20

21 Staff proposes that the initial adjustor rate be based upon 25 percent of currently estimated
22 Portfolio Plan first year program costs for all programs except the LIW program, for which 100
23 percent of the estimated 2008 program costs should be included. These costs should be divided by
24 adjusted Test Year kWh retail sales as reported on Schedule H-2, page 1, line 9.

25 UNSE has concurred with Staff proposal as suggested above.
26
27
28

1 **E. EPS/REST Adjustor.**

2 UNSE is required to meet the Environmental Portfolio Standard (“EPS”) set forth in A.A.C.
3 R14-2-1618. Staff witness Jerry Anderson described the EPS requirements in the following passage
4 from his Direct Testimony:

5 The EPS required load-serving entities to derive a portion of the retail
6 energy they sell from solar resources or environmental friendly
7 renewable electricity technologies. The portfolio percentage increases
8 annually. It was 1.00 percent in 2005 and became 1.05 percent in 2006
9 with at least 60 percent from solar resources. The requirement is 1.1
10 percent for 2007.²⁶⁶

11 The Commission adopted the Renewable Energy Standard and Tariff (“REST”) rules on
12 November 14, 2006 in Decision No. 69127. The REST rules are intended to replace the current EPS
13 rules.²⁶⁷

14 UNSE currently recovers its renewable costs in an EPS surcharge. The Environmentally
15 Friendly Portfolio Surcharge (“EFPS”) tariff contains the following surcharges: \$0.000875 per kWh
16 with monthly caps per service of \$0.35 for residential customers; \$13.00 for non-residential
17 customers; and \$39.00 for non-residential customers with demands of 3,000 kW or more.²⁶⁸

18 Decision No. 63360 had approved the EFPS on an interim basis on February 8, 2001, pending
19 true-up in a rate case in which fair value findings would be made by the Commission.²⁶⁹ Staff
20 witness Anderson recommendation was that the EFPS surcharge become an adjustor mechanism.
21 The initial rate would be the same as the current EFPS tariff including caps, with an allowance for
22 future funding changes.²⁷⁰ The change to an adjustor mechanism would accommodate the REST
23 rules requirement that a utility have an adjustor mechanism in place under which the utility can
24 request to reset those rates at certain times.²⁷¹

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26 _____
26 ²⁶⁶ Jerry D. Anderson Direct Test. (Ex. S-63) at p. 17.

27 ²⁶⁷ *Id.* at p. 18.

28 ²⁶⁸ *Id.*

²⁶⁹ See Decision 63360, Citizens Communications Company (EFPS Surcharge) February 8, 2001.

²⁷⁰ Jerry D. Anderson Direct Test. (Ex. S-63) at p. 19.

²⁷¹ *Id.*

1 Witness Anderson testified that the adjustor would work through an application filed by the
2 Company to change the renewables adjustor rate and caps. Staff would review each application and
3 make recommendations to the Commission for approval.²⁷²

4 **VII. RULE CHANGES.**

5 UNSE proposed numerous changes to its rules and regulations. The Company's reasons for
6 doing so were addressed in the testimony of UNSE witness Ferry. The Company's existing rules
7 and regulations were "inherited" from Citizens Electric when it sold its assets to UniSource Energy.
8 The Company stated that many of the changes it is proposing are intended to make UNSE's rules and
9 regulations more consistent with those of TEP.²⁷³ Staff supports or has no objection to the majority
10 of changes.²⁷⁴

11 Staff is concerned with the changes UNSE is proposing to make to its line extension tariff and
12 its bill estimation procedures.²⁷⁵

13 **A. Line Extension Charges.**

14 With respect to its line extension tariff, the Company is proposing to increase the total free
15 overhead extension distance from 400 feet to 500 feet, including the service drop.²⁷⁶ The goal
16 appears to be to make the free allowance the same as TEP offers under its current tariff.²⁷⁷

17 In response to Staff data requests, UNSE indicated that during the test year, it closed
18 approximately 4, 980 work orders in both of its service territories.²⁷⁸ The Company also responded
19 that each work order would have to be individually examined in order to determine the forgone
20 revenue associated with the free allowance.²⁷⁹

21 At the same time the Company is proposing to increase the free footage allowance for new
22 customers, it cites to increased growth in both service areas.²⁸⁰ Staff believes that in this
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24 _____
25 ²⁷² *Id.* at pp. 19-20.

26 ²⁷³ Bing E. Young Direct Test. (Ex. S-64) at p. 2.

27 ²⁷⁴ *Id.* at p. 2.

28 ²⁷⁵ *Id.*

²⁷⁶ *Id.*

²⁷⁷ Bing E. Young Direct Test. (Ex. S-64), p. 2.

²⁷⁸ *Id.*

²⁷⁹ *Id.*

²⁸⁰ Bing E. Young Direct Test. (Ex. S-64) pp. 4-5

1 circumstance, and as a result proposed, that the Company eliminate the free footage allowance for
2 new customers, rather than expand it.²⁸¹ Staff witness Young testified in support of Staff's proposal
3 in the following passage from his direct testimony:

4 Under these circumstances, there will be great financial pressure placed
5 on UNS Electric to meet its increasing demand, which also will likely
6 translate to significant upward pressure on the rates it must charge.
7 Staff believes that UNS should use the means it has to offset its costs
8 attributable to this growth. Staff believes that such a policy to
eliminate the free footage allowance would significantly improve UNS
Electric's ability to recover its distribution costs associated with this
growth.²⁸²

9 The Commission took similar action in eliminating the free footage allowance in the recent
10 Arizona Public Service Company rate case.²⁸³

11 Finally, ALJ Wolfe asked the parties to address whether elimination of the free line extension
12 allowance comported with the requirements of the Arizona Administrative Code. A.A.C. R14-2-
13 207(C) states in part as follows:

- 14 1. A maximum footage or equipment allowance to be provided by the utility at no
15 charge. The maximum footage or equipment allowance may be differentiated by
customer class.
- 16 2. An economic feasibility analysis for those extensions which exceed the
17 maximum footage or equipment allowance. Such economic feasibility analysis
18 shall consider the incremental revenues and costs associated with the line
19 extension. In those instances where the requested line extension does not meet
20 the economic feasibility criteria established by the utility, the utility may require
the customer to provide funds to the utility, which will make the line extension
economically feasible. The methodology employed by the utility in determining
economic feasibility shall be applied uniformly and consistently to each
applicant requiring a line extension.

21 Staff does not believe that these provisions of the Arizona Administrative Code mandate that
22 a company provide a free footage allowance. Rather, the rules mandate that the Company's policies
23 on free footage allowances be specifically set forth in its line extension tariff, even if that footage
24 allowance is zero, as Staff is recommending in this case. In regard to (C)(2) of the rules, if the free
25 footage is zero, then all extensions would be economically feasible from the utility's perspective. In
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²⁸¹ *Id.* at p. 5.

²⁸² *Id.*

²⁸³ See, APS Rate Case (Docket No. E-01345A-05-0816), Decision No. 69663, dated 6/28/07.

1 any event, even if these rules are interpreted to require a free footage allowance, the Commission can
2 always waive that requirement of the rules as it has done in at least one other recent case.

3 At the request of Commissioner Mayes to examine the efficacy of hook-up fees in this case,
4 the Company proposed at the hearing to introduce a \$250 hook-up fee in this case.²⁸⁴ The
5 Commission has also opened a generic docket (Docket No. E-00000K-07-0052) to examine the
6 efficacy of hook-up fees for new electric and natural gas customers in the future. Staff witness
7 Young testified that Staff is aware of at least two electric utilities in Arizona that utilize hook-up fees:
8 Dixie Escalante Rural Electric Association and Wellton-Mohawk Irrigation and Drainage District.²⁸⁵
9 Staff continues to believe that the issue of hook-up fees for electric utilities should be addressed in
10 the generic docket.

11 **B. Bill Estimation Methodologies.**

12 Currently, the Company's tariff does not describe its bill estimation methodologies.²⁸⁶ Staff
13 believes that the Company should be required to submit a separate tariff setting forth its estimation
14 methodologies for Commission approval within 30 days of a decision in this docket.²⁸⁷ Staff witness
15 Young addressed the specific parameters that the Company's tariff should include at pages 8-9 of his
16 direct testimony.²⁸⁸

17 **C. Bill Due Dates.**

18 One of the changes proposed by UNSE to its tariff was to move up the due date on bills by 5
19 days. This would mean a significant change to customer bills. Currently customer bills are due 15
20 days after issuance. The Company's proposed change would mean that customer bills would
21 henceforth be due 10 days after issuance. Staff opposes UNSE's proposal in this regard.

22 UNSE modeled its proposed billing terms to match the UNS Gas billing terms.²⁸⁹ The
23 Commission's rules, however, differ for electric and gas companies on this point. For electric
24

25
26 ²⁸⁴ Tr. at pp. 960-961.

²⁸⁵ Bing E. Young Direct Test. (Ex. S-64) p. 7.

27 ²⁸⁶ *Id.*

²⁸⁷ *Id.* at p. 8.

28 ²⁸⁸ *Id.* at pp. 8-9.

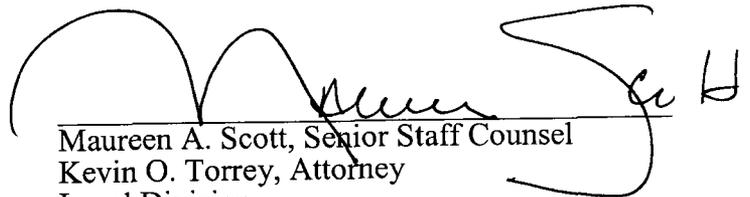
²⁸⁹ Thomas Ferry Direct Test. (Ex. UNSE-20) at p. 24.

1 companies, the rules provide: "All bills for utility services are due and payable no later than 15 days
2 from the date of the bill."²⁹⁰ UNSE should comply with Commission rules on this point.

3
4 **VIII. CONCLUSION.**

5 The Commission should approve increased revenues for the Company in the amount of
6 \$3.688 Million. The Commission should deny UNSE's requests for extraordinary treatment of CWIP
7 and the BMGS in this case. The Company has not met its burden of proof in this case to justify the
8 special treatment it is requesting. The Commission should approve the changes to the Company's
9 PPFAC proposed by Staff. The Staff's changes are modeled after the new Plan of Administration
10 adopted in the APS rate case, with appropriate adjustments where necessary to recognize the unique
11 circumstances of the Company.

12 RESPECTFULLY SUBMITTED this 6th day of November 2007.

13
14 

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²⁹⁰ See R14-2-210(C)(1).

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