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BEFORE THE ARIZONA CORPORATIO

Arizona Corporation Commission
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COMMISSIONERS
BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

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

DOCKET NO. E-04204A-12-0504

STAFF'S NOTICE OF FILING DIRECT TESTIMONY

Staff of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Ralph Smith (Redacted), David Parcell, Michael McGarry, Michael Lewis, Howard Solganick, and Julie McNeely-Kirwan in the above docket. An Unredacted version of Ralph Smith's Direct Testimony has also been provided under seal to the Commissioners, the assigned Administrative Law Judge and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 28th day of June 2013.

Maureen A. Scott, Senior Staff Counsel
Charles H. Hains, Attorney
Bridget A. Humphrey, Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

Original and thirteen (13) copies of the foregoing filed this 28th day of June 2013 with:

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

Copy of the foregoing mailed this
28th day of June 2013 to:

Bradley S. Carroll
Kimberly A. Ruht
UniSource Energy Services
88 East Broadway Boulevard, MS HQE910
Post Office Box 71
Tucson, Arizona 85702

Michael W. Patten
Jason D. Gellman
Roshka, DeWulf & Patten, PLC
One Arizona Center
400 East Van Buren, Suite 800
Phoenix, Arizona 85004
Attorneys for UNS Electric, Inc.

Daniel W. Pozefsky
Residential Utility Consumer Office
1110 West Washington Street, Suite 220
Phoenix, Arizona 85007

Eric J. Lacey, Esq.
Brickfield, Burchette, Ritts & Stone, P.C.
1025 Thomas Jefferson Street, N.W. 8th Floor, West Tower
Washington, D.C. 20007-5201

Robert J. Metli, Esq.
Munger Chadwick, PLC
2398 East Camelback Road, Suite 240
Phoenix, Arizona 85016
Attorney for Nucor Corporation

Kaye Christine

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THOUGHOUT THE STATE OF ARIZONA	)	DOCKET NO. E-04204A-12-0504

DIRECT TESTIMONY

OF

RALPH C. SMITH

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 28, 2013

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-12-0504

My testimony addresses the following issues, and responds to the testimony of UNS Electric, Inc. ("UNSE", "UNS Electric", or "Company") witnesses on these issues:

- The Company's proposed revenue requirement
- The determination of a Fair Value Rate of Return ("FVROR") and its application to Fair Value Rate Base
- Staff's recommended base rate revenue increase
- Adjusted Rate Base
- Adjusted Test Year revenues, expenses, and net operating income
- The Company's proposed changes to its Purchased Power and Fuel Adjustment Clause ("PPFAC")

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

The Company's Proposed Revenue Requirement

The Company's proposed revenue requirement of a base rate increase of $7.523 million, or about 4.6 percent, is significantly overstated. In its filing, UNSE proposed an original cost rate base ("OCRB") and fair value rate base ("FVRB") of approximately $217 million and $286 million, respectively. The Company also requests to set UNSE's FVRB at $286 million based on a 50/50 weighting of OCRB and Reconstruction Cost New Depreciated ("RCND").

UNSE understated operating income. Additionally, the Company is requesting an excessive rate of return. Finally, UNSE has included post-test year plant in rate base that is not in service and has therefore been removed by Staff.

Determination of FVROR and Application to FVRB

The testimony of Staff witness David Parcell addresses Staff's recommended return on equity and weighted cost of capital to be applied to OCRB as well as the determination of the Staff recommended FVROR to be applied to the FVRB in view of the Court of Appeals decision concerning Chaparral Water Company. Attachment RCS-2, Schedule D, shows the derivation of the two FVROR calculations that were considered by Staff, and Staff's recommendation including:

- Staff recommendation: FVRB increment of 0.080 percent which produces results that are equivalent to an ROE of 9.3 percent on OCRB as shown on Schedule D, page 5, and discussed in the testimony of Staff witness Parcell.
- Alternative 1 - With Fair Value Rate Base Increment at Zero Cost
- Alternative 2 - With Fair Value Rate Base Increment at 0.5 percent

My Attachment RCS-2, Schedule A, columns D through F, summarizes the resulting revenue deficiencies that would be produced in the current UNSE rate case from each of those FVROR figures. Schedule A, column D, shows the amount of base rate revenue increase on FVRB of $1.318 million under alternative 1 and in column E, shows the amount of base rate revenue increase on FVRB of $1.888 million under alternative 2.

Staff's Recommended Base Rate Revenue Increase

I recommend that UNSE be authorized a base rate increase of no more than $1.41 million on adjusted FVRB, as shown on Schedule A, column F. That is an average revenue increase of approximately 0.82 percent over adjusted test year revenue of $171.445 million.

Adjusted Rate Base

The following adjustments to UNSE's proposed original cost rate base should be made:

	Summary of Staff Adjustments to Rate Base (Thousands of Dollars)	ACC Jurisdictional OCRB	ACC Jurisdictional RCND
Adj. No.	Description	Increase (Decrease)	Increase (Decrease)
B-1	Post Test Year Plant Not In Service	$ (5,036)	$ (5,036)
B-2	Remove One-Half of Prepaid D&O Insurance	$ (12)	$ (12)
	Total of Staff Adjustments	$ (5,048)	$ (5,048)
	UNSE Proposed Rate Base	$ 216,575	$ 356,077
	Rounding		
	Staff Proposed Rate Base	$ 211,527	$ 351,029

The following table summarizes UNS Electric' requested and Staff's recommend OCRB, RCND rate base and FVRB, and the differences:

Summary of Rate Base (Thousands of Dollars)	Company	Staff	Difference
Original Cost of Rate Base	$ 216,575	$ 211,527	$ (5,048)
RCND Rate Base	$ 356,077	$ 351,029	$ (5,048)
Fair Value Rate Base	$ 286,326	$ 281,278	$ (5,048)

Adjusted Net Operating Income

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

	Summary of Staff Adjustments to Net Operating Income (Thousands of Dollars)	ACC Jurisdictional			
Adj.	Description	Pre-Tax Revenue or Expense Adjustment		Net Operating Income Increase (Decrease)	
C-1	Depreciation and Property Tax Expenses on Post Test Year Plant Not In Service	$	(506)	$	311
C-2	Post Test Year Pay Increase	$	(26)	$	16
C-3	Rate Case Expense	$	(100)	$	61
C-4	Incentive Compensation Expense	$	(100)	$	61
C-5	Injuries and Damages	$	(330)	$	203
C-6	Directors and Officers Insurance Expense	$	(44)	$	27
C-7	Edison Electric Institute Industry Association Dues	$	(13)	$	8
C-8	Allocated Cost of TEP New Headquarters Building to UNSE	$	(284)	$	174
C-9	Interest Synchronization			$	(54)
C-10	Depreciation Rates - Estimated Dismantlement Cost	$	(90)	$	55
C-11	Base Cost of Fuel and Purchased Power				
Total of Staff's Adjustments		**$**	**(1,494)**	**$**	**863**
	Adjusted Net Operating Income per UNSE			$	14,608
	Adjusted Net Operating Income per Staff			$	15,471

PPFAC

Staff recommends that UNSE's proposed revised PPFAC Plan of Administration should not be adopted, but rather UNSE should prepare a different revised PPFAC Plan of Administration that incorporates revised provisions to address the following concerns. Staff has concerns about UNSE's ability to accurately forecast the estimated component of its existing PPFAC rates, which can be subject to variances based on changes in the cost of natural gas. Unlike the situation with its electric utility affiliate, Tucson Electric Power Company ("TEP"), which has substantial coal-fired generation, UNSE's fuel and purchase power costs are subject to a much heavier influence of natural gas price fluctuations. Staff believes that there could be substantial merit in eliminating the forward component of UNSE's PPFAC and re-designing UNSE's PPFAC so it resembles certain aspects of the Purchased Gas Adjustor ("PGA") of the affiliate, UNS Gas, Inc., which is based on adjusting the PGA component of UNSG's rates based on a 12-month rolling average of gas costs. Staff therefore recommends that UNSE present a revised Plan of Administration for its PPFAC that eliminates the forward component and bases PPFAC rate changes on fluctuations in the 12-month rolling average of UNSE's fuel and purchased power costs. The revised Plan of Administration should also incorporate annual and monthly cap provisions to limit the increases experienced by consumers for PPFAC changes in any given monthly period.

Staff recommends that UNSE's rates continue to reflect a base amount of fuel and purchased power, and that PPFAC adjustments continue to be based upon fluctuations of UNSE's fuel and purchased power costs above or below the base cost of fuel. For the reasons described in my testimony, Staff recommends setting the base cost of fuel for UNSE at $0.05706.

Concerning the types of costs that are included in the PPFAC, Staff proposes to continue to reflect the same accounts in UNSE's PPFAC that are currently reflected, but not to expand the types of costs beyond those currently included in UNSE's PPFAC.

I. INTRODUCTION

Q. Please state your name, position and business address.

A. Ralph C. Smith. I am a Senior Regulatory Consultant at Larkin & Associates, PLLC, 15728 Farmington Road, Livonia, Michigan 48154.

Q. Please describe Larkin & Associates.

A. Larkin & Associates is a Certified Public Accounting and Regulatory Consulting firm. The firm performs independent regulatory consulting primarily for public service/utility commission staffs and consumer interest groups (public counsels, public advocates, consumer counsels, attorneys general, etc.). Larkin & Associates has extensive experience in the utility regulatory field as expert witnesses in over 400 regulatory proceedings including numerous telephone, water and sewer, gas, and electric matters.

Q. Mr. Smith, please summarize your educational background.

A. I received a Bachelor of Science degree in Business Administration (Accounting Major) with distinction from the University of Michigan - Dearborn, in April 1979. I passed all parts of the Certified Public Accountant ("C.P.A.") examination in my first sitting in 1979, received my CPA license in 1981, and received a certified financial planning certificate in 1983. I also have a Master of Science in Taxation from Walsh College, 1981, and a law degree (J.D.) cum laude from Wayne State University, 1986. In addition, I have attended a variety of continuing education courses in conjunction with maintaining my accountancy license. I am a licensed C.P.A. and attorney in the State of Michigan. I am also a Certified Financial Planner™ professional and a Certified Rate of Return Analyst ("CRRA"). Since 1981, I have been a member of the Michigan Association of Certified Public Accountants. I am also a member of the Michigan Bar Association and the Society of Utility and Regulatory Financial Analysts ("SURFA"). I have also been a member of the American Bar Association ("ABA"), and the ABA sections on Public Utility Law and Taxation.

Q. Please summarize your professional experience.

A. Subsequent to graduation from the University of Michigan, and after a short period of installing a computerized accounting system for a Southfield, Michigan realty management firm, I accepted a position as an auditor with the predecessor CPA firm to Larkin & Associates in July, 1979. Before becoming involved in utility regulation where the majority of my time for the past 33 years has been spent, I performed audit, accounting, and tax work for a wide variety of businesses that were clients of the firm.

During my service in the regulatory section of our firm, I have been involved in rate cases and other regulatory matters concerning electric, gas, telephone, water, and sewer utility companies. My present work consists primarily of analyzing rate case and regulatory filings of public utility companies before various regulatory commissions, and, where appropriate, preparing testimony and schedules relating to the issues for presentation before these regulatory agencies.

I have performed work in the field of utility regulation on behalf of industry, state attorneys general, consumer groups, municipalities, and public service commission staffs concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Indiana, Illinois, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington D.C., West Virginia and Canada as well as the Federal Energy Regulatory Commission and various state and federal courts of law.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment RCS-1 provides details concerning my experience and qualifications.

Q. On whose behalf are you appearing?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC" or "Commission") Utilities Division Staff ("Staff").

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I have previously testified before the Commission on a number of occasions. I testified before the Commission in the most recent Arizona Public Service Company ("APS") rate case, Docket No. E-01345A-11-0224. I also testified in Docket No. E-01345A-06-0009, involving an emergency rate increase request by APS, and APS's Docket Nos. E-01345A-05-0816, E-01345A-05-0826 and E-01345A-05-0827, concerning proceedings involving APS base rates and other matters. I testified before the Commission in the Arizona-American Water Company in Docket Nos. W-01303A-09-0343 and SW-01303A-09-0343. I also testified before the Commission in the last UNS Gas, Inc. ("UNSG") rate case, Docket Nos. G-04204A-06-0463, G-04204A-06-0013 and G-04204A-05-0831, and in the last UNS Electric, Inc. rate case Docket No. E-04204A-06-0783, as well as Southwest Gas Corporation ("SWG") rate cases, G-01551A-07-0504 and G-01551A-10-0458.

Q. What is the purpose of the testimony you are presenting?

A. The purpose of my testimony is to address the rate base, adjusted net operating income and revenue requirement proposed by UNS Electric, Inc. ("UNSE" or "Company"). I also address changes requested by the Company for its Purchased Power and Fuel Adjustment Clause ("PPFAC").

Q. Have you prepared any exhibits to be filed with your testimony?

A. Yes. Attachments RCS-2 through RCS-5 contain the results of my analysis and copies of selected documents that are referenced in my testimony, respectively.

II. REVENUE REQUIREMENT

Q. What issues are addressed in your testimony?

A. My testimony addresses the Company's proposed revenue requirement and selected other issues.

Q. What revenue increase has been requested by UNSE?

A. UNSE is requesting an increase in base rate revenues of $7.5 million, or approximately 4.6 percent, based on UNSE's adjusted retail electric revenues at current rates of $162.190 million. The revenue amount is from Company Schedule C-1 in UNSE's filing and is also shown on Staff Schedule C in Attachment RCS-2.

Q. What revenue increase does Staff recommend?

A. Staff recommends a revenue increase of no more than $1.41 million on adjusted fair value rate base. As shown on Schedule A, my calculations show a jurisdictional revenue deficiency of approximately $1.318 million on original cost rate base ("OCRB"), of $1.318 million on fair value rate of return ("FVROR") alternative 1, and $1.888 million under FVROR alternative 2. The recommended revenue increase of $1.41 million is equivalent to a 9.3% return on equity on OCRB as shown on Schedule D, page 5, and discussed in the testimony of Staff witness Parcell.

A. Test Year

Q. What test year is being used in this case?

A. UNSE's filing is based on the historic test year ended June 30, 2012. Staff's calculations use the same historic test year.

Q. Could you please discuss the test year concept?

A. Yes. In Arizona, a historic test year approach is used. Various adjustments are made to the historic test year amounts to ensure that there is a matching of investment, revenues and expenses. Rate base items, such as plant in service and accumulated depreciation, are based on the actual level as of the end of the historic test year. Several rate base items that tend to fluctuate from month to month, such as materials and supplies and prepayments, are based on a test year average level. Since end of test year net plant in service is used, revenues are annualized based on end of test year customer levels. Additionally, certain expenses, such as depreciation and payroll costs, are annualized based on end of test year levels. This is to ensure that the going-forward revenue and expense levels are matched with the investment (net plant-in-service) used to serve those customers.

As time goes forward, changes in the Company's cost structure will occur. For example, rate base will increase as new plant is added to serve new customers, revenue will increase as customers are added, expenses will fluctuate, etc. It is very important to be consistent with a test period approach to ensure that there is a consistent matching between investment, revenues and costs. Any adjustments that reach beyond the end of the historic test year must be very carefully considered before being adopted.

B. Summary of Company Proposed and Staff Adjusted Revenue Requirement

Q. What did your review of UNSE's filing indicate?

A. As shown on Attachment RCS-2, Schedule A, column C, based on the weighted cost of capital recommended by Staff witness David Parcell for application to OCRB, and the adjustments to UNSE's rate base and net operating income recommended by myself, I have calculated a jurisdictional base rate revenue requirement deficiency on OCRB of approximately $1.318 million. As also shown on Schedule A, page 1, columns D and E, I have calculated a base rate increase of approximately $1.318 million using a FVROR of 5.79 percent and approximately $1.888 million using a FVROR of 5.91 percent. UNSE should receive a base rate increase of no more than $1.41 million in this case based on a FVROR of 5.81 percent. This represents an overall increase of approximately 0.82 percent and an OCRB equivalent ROE of approximately 9.3 percent.[1]

C. Organization of Staff Accounting Schedules

Q. How are Staff's accounting schedules organized?

A. Staff's accounting schedules are presented in Attachment RCS-2. They are organized into summary schedules and adjustment schedules. The summary schedules consist of Schedules A, A-1, B, B.1, C, C.1 and D. Attachment RCS-2 also contains rate base adjustment Schedules B-1 and B-2 and net operating income adjustment Schedules C-1 through C-11.

Q. What is shown on Schedule A of Attachment RCS-2?

A. Attachment RCS-2 presents the Staff Accounting Schedules and revenue requirement determination. Schedule A presents the overall financial summary, giving effect to all the adjustments I am recommending in my testimony. This schedule presents the change in

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[1] See, e.g., Exhibit RCS-2, Schedule D, page 5.

the Company's gross revenue requirement needed for the Company to have the opportunity to earn Staff's recommended rate of return on Staff's proposed Original Cost and Fair Value rate bases. The rate base and operating income amounts are taken from Schedules B and C, respectively. The overall rate of return on original cost rate base of 7.70 percent, as presented in the prefiled testimony of Staff witness Parcell, is provided on Schedule D for convenience, as are the derivation of Staff's recommended fair value rate of return.

Columns A and B of Schedule A replicate UNSE's proposed calculations of the revenue deficiency. Columns C, D, E and F of Schedule A present Staff's determination of the base rate revenue deficiency on OCRB and FVRB. Column C reflects Mr. Parcell's recommended overall weighted cost of capital for OCRB. Columns D, E and F use Staff's proposed fair value rate of return, which is explained in my testimony and in the testimony of Staff witness Parcell.

The operating income deficiency shown on line 5 of Schedule A is obtained by subtracting the operating income available on line 4 (operating income as adjusted) from the required operating income on line 3. Line 7 represents the gross base rate revenue requirement deficiency, which is obtained by multiplying the income deficiency by the gross revenue conversion factor ("GRCF"). The derivation of the GRCF is shown on Schedule A-1.

Q. What rates of return has Staff applied to the FVRB increment?

A. Similar to information presented by Staff to the Commission in a remand proceeding, Docket No. W-02113A-04-0616, concerning Chaparral City Water Company, and in some other recent rate cases, I have presented on Schedule D and Staff's recommended FVROR and two alternative ways of determining a FVROR for UNSE, including:

- Staff's recommendation, With Fair Value Rate Base Increment at 0.080 percent (equivalent ROE on OCRB of 9.3 percent), FVROR of 5.81 percent.
- Alternative 1 - With Fair Value Rate Base Increment at Zero Cost, FVROR of 5.79 percent
- Alternative 2 - With Fair Value Rate Base Increment at 0.5 percent, FVROR of 5.91 percent

The details for each FVROR calculation are shown on Schedule D, and are addressed in the testimony of Staff witness Parcell. I believe that this information and Staff's recommended FVROR in the current UNSE rate case that was made after considering these alternatives appropriately fulfills the requirement of the Arizona Constitution that the Commission must base rates on a utility's fair value.

Q. What is shown on Schedule A-1?

A. Schedule A-1 shows the derivation of the GRCF. The GRCF is used to convert the net operating income deficiency into a revenue deficiency amount.

Q. How does the GRCF recommended by Staff compare with the GRCF contained in UNSE's filing?

A. As shown on Schedule A-1, Staff recommends a GRCF of 1.6333, which is the same GRCF proposed by the Company.

Q. What is shown on Schedule B?

A. Schedule B presents UNSE's proposed adjusted test year Original Cost and Fair Value rate base and Staff's proposed adjusted test year Original Cost and Fair Value rate base. The beginning rate base amounts presented on Schedule B are taken from the Company's filing for the test year, specifically UNSE Schedule B-1. Staff's recommended adjustments to rate base are summarized on Schedule B.1. I have prepared a Schedule B.1

for adjustments to UNSE's proposed original cost rate base. Because some of the Staff adjustments differ between OCRB and Reconstruction Cost New Depreciated ("RCND") rate base, I have prepared a separate Schedule B.1 each for OCRB and RCND amounts.

Schedules B-1 through B-2 provide further support and calculations for the rate base adjustments Staff is recommending.

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the fair value rate base was determined by weighting Original Cost and Replacement Cost New Less Depreciated ("RCND") rate base information. For purposes of this presentation, I have used the Company's OCRB and RCND information as the starting point for Staff's derivation of the fair value rate base.

Q. What is shown on Schedule C?

A. The starting point on Schedule C is UNSE's adjusted test year net operating income, as provided on Company Schedule C-1. Staff's recommended adjustments to UNSE's adjusted test year revenues and expenses are summarized on Schedule C.1. Each of the adjustments is discussed in my testimony.

Schedules C-1 through C-11 provide further support and calculations for the net operating income adjustments Staff is recommending.

Q. What is shown on Schedule D?

A. Schedule D summarizes the capital structure and cost of capital that was proposed by UNSE and the capital structure and cost of capital that is recommended by Staff witness Parcell. As noted above, Schedule D also presents two alternative calculations of a

FVROR that were considered by Staff in developing Staff's recommended FVROR for use with the Staff's adjusted fair value rate base.

D. Return on Fair Value Rate Base

Q. How was the fair value basis of rate base determined?

A. As shown on Attachment RCS-2, Schedule B, the FVRB was determined by averaging OCRB and RCND. For purposes of this presentation, the Company's RCND information was used as the starting point for Staff's derivation of the FVRB. Adjustments were made to the RCND rate base as shown on Attachment RCS-2, Schedule B.

Q. How did UNSE determine the rate of return to apply to FVRB in its filing?

A. In UNSE's filing, as shown on Schedule A-1, the Company applied its proposed FVROR to its adjusted FVRB. On that Schedule in the Fair Value column, UNSE calculates an increase in gross revenue requirements of approximately $5.688 million. UNSE added to that $1.834 million for an additional base rate revenue increase for the adjusted FVRB, for a total requested base rate revenue increase of $7.523 million.

Q. Describe how the required operating income amount has been calculated as it relates to the calculation of the FVROR.

A. Prior to a 2007 Arizona Court of Appeals decision,[2] the Commission had traditionally determined operating income by multiplying the Weighted Average Cost of Capital ("WACC") by the OCRB. The resulting product was then divided by the FVRB to determine a FVROR. The Arizona Court of Appeals found that the Commission did not comply with Article 15, Section 14 of the Arizona Constitution when it set rates based on original cost instead of fair value. However, the Court noted: "If the Commission

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[2] *Chaparral City Water* Co v *Ariz Corp. Comm'n*, 1 CA-CC 05-0002 (Ariz. App. Feb. 13,2007)

determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." The Commission, in Decision No. 70441 adopted a FVROR based on the WACC modified to reflect a 2.00 percent reduction to the cost of equity, but not to the cost of debt. In Decision No. 71308, the Commission calculated the FVROR by subtracting an inflation factor from both the debt and equity components of the WACC. In other cases, the Commission has reviewed the evidence presented by the parties and used its judgment to derive the FVROR.

Q. How has Staff calculated the FVROR and addressed the ruling in the Court of Appeals decision for purposes of the current UNSE rate case?

A. In addition to its recommendation, Staff is presenting two alternatives for the FVROR range as shown on Schedule D. The results of each of those alternatives for the FVROR are shown on Schedule A in columns D and E, and Staff's recommendation is presented in column F. Schedule D of Attachment RCS-2 shows the derivation of the fair value rate of return for application to the FVRB. On Schedule A of Attachment RCS-2, Staff's adjustment to the weighted cost of capital as described by Mr. Parcell in his Direct Testimony was applied. Based on Parcell's recommendation concerning the FVROR, Staff recommends a revenue requirement increase of not more than the $1.41 million shown on Schedule A in column F. This equates to an increase of 0.82 percent over adjusted base rate revenues for UNSE at current rates, and is equivalent to an ROE of 9.3 percent on OCRB, as shown on Schedule D, page 5, and discussed in the testimony of Staff witness Parcell.

III. ADJUSTMENTS TO RATE BASE

Q. Have you prepared a schedule that summarizes Staff's proposed adjustments to rate base?

A. Yes. As noted above, the adjusted rate base is shown on Schedule B and the adjustments to UNSE's proposed rate base are shown on Schedule B.1. A comparison of the Company's proposed rate base and Staff's recommended rate base on an Original Cost and Fair Value basis is presented below:

Summary of Rate Base (Thousands of Dollars)	Company	Staff	Difference
Original Cost of Rate Base	$ 216,575	$ 211,527	$ (5,048)
RCND Rate Base	$ 356,077	$ 351,029	$ (5,048)
Fair Value Rate Base	$ 286,326	$ 281,278	$ (5,048)

Q. Please discuss Staff's adjustments to UNSE's proposed rate base.

A. Staff has made two adjustments to UNSE's proposed rate base. These have been designated as Staff Adjustments B-1 and B-2. Each adjustment is discussed below.

B-1 Post Test Year Plant Not In Service

Q. Please explain the adjustment shown on Schedule B-1.

A. Staff has removed the portion of the Company's request for post test year plant for plant that Staff has determined is not in service. The Company proposed to include in rate base $5.755 million of post test year plant for a renewable plant project, aka the Rio Rico Project. UNSE estimated an in-service date for the project of May 2013; however, an analysis described in the direct testimony of Staff witness Mike Lewis, based on his on-site inspection and review of documents indicates that this project is not currently in service and is not close to being in service. Because it is not in service, it is being removed. The adjustment shown on Schedule B-1 removes this from Plant and also removes UNSE's related adjustments to Accumulated Depreciation and Accumulated Deferred Income Taxes ("ADIT").

Q. Is there a related adjustment to operating expenses?

A. Yes. Exhibit RCS-2, Schedule C-1, presents a related adjustment to remove Depreciation Expense and pro forma Property Tax Expense on the Company-proposed post test year plant addition which is not in service.

B-2 Remove One-Half of Prepaid Directors and Officers ("D&O") Insurance

Q. Please explain Staff Adjustment B-2.

A. This adjustment reduces jurisdictional rate base by $12,000 to remove one-half of the prepaid D&O insurance that UNSE had included in rate base. As discussed in more detail in conjunction with Staff adjustment C-6, Staff has recommended that the cost of D&O insurance be shared equally between shareholders and ratepayers. The adjustment to prepaid insurance expense on Schedule B-2, although small in amount, is being made to be consistent with the adjustment to D&O Insurance Expense shown on Schedule C-6.

IV. ADJUSTMENTS TO OPERATING INCOME

Q. Please describe how you have summarized Staff's proposed adjustments to operating income.

A. Schedule C summarizes Staff's recommended net operating income. Schedule C.1 presents Staff's recommended adjustments to Arizona test year revenues and expenses. The impact on state and federal income taxes associated with each of the recommended adjustments to operating income is also reflected on Schedule C.1. UNSE's proposed adjusted test year net operating income is $14.608 million, whereas Staff's recommended adjusted net operating income is $15.471 million. The recommended adjustments to operating income are discussed below in the same order as they appear on Schedule C.1.

C-1 Depreciation and Property Tax Expense on Post Test Year Plant Not In Service

Q. Please explain the adjustment for Depreciation and Property Tax Expense on Post Test Year Plant Not In Service.

A. This adjustment removes pro forma Depreciation and Property Tax Expense on Post Test Year Plant that is not in service. As shown on Exhibit RCS-1, Schedule C-1, page 1, the Company's request for Depreciation Expense is reduced by $494,000. As shown on Exhibit RCS-1, Schedule C-1, page 2, the Company's request for Property Tax Expense is reduced by $12,288.

C-2 Post Test Year Pay Increases

Q. What has UNSE proposed for post-test year pay increases?

A. Company witness Dukes states at page 15 of his Direct Testimony that UNSE's Payroll expense adjustment is not fully consistent with the one approved in its last rate case. Rather, UNSE used a simplified approach that he claims was approved in the most recent TEP[3] and UNSG[4] rate cases. The Company in its payroll adjustment used two rounds of pay increases at an average increase rate of 2.65%. UNSE used a 2.5% increase for classified employees and 3.0% for unclassified employees, and arrived at its proposed average increase of 2.65%. As shown on the Company's filing Income - Payroll Expense.pdf, UNSE(0504)003915, this 2.65% increase rate was derived from weighted rates of 2.5% for Classified Wages and 3.0% for Unclassified Wages respectively. The Company applied this average increase of 2.65% to derive its proposed increases for two additional post-test year periods of payroll expense.

[3] Approved in the June 11, 2013 Open Meeting. A final Order has not yet been issued in this matter.
[4] Decision No. 73142 dated May 1, 2012.

Q. Please explain Staff's adjustment.

A. As shown on Schedule C-2, Staff's adjustment has applied a lower weighted average pay increase based on more current information for actual pay increases that was provided in UNSE's responses to discovery. The Company's responses to data requests STF 7.01 and STF 7.02 indicate that the pay increases have been 2.0 and 2.5 percent for union and non-union employee groups, respectively. The Company's response to STF 7.01 indicates that the percentages of 2.5% for Classified Wages and 3.0% for Unclassified Wages were projected based on market data and internal Company discussions, as they had not yet occurred when the rate case was filed. The increases assumed by UNSE were higher than the increases that have actually occurred; thus, UNSE's proposed payroll adjustment is overstated and should be reduced. Staff's adjustment therefore applies a lower weighted average pay increase, based on the information provided by UNSE in response to discovery. Staff's adjustment C-2 decreases UNSE's requested post test year payroll increases by adjusting the rate of pay increases of 2.65% per year that was used by the Company down to the actual levels of pay increases that were identified in response to discovery. The reduction to UNSE's requested payroll expense is $24,304 on an ACC jurisdictional basis, as shown on Schedule C-2, line 3. Payroll tax expense related to this is reduced by $2,017, as shown on Schedule C-2, line 5.

C-3 Rate Case Expense

Q. What amount of rate case expense is the Company requesting recovery for in this case?

A. UNS Electric is requesting recovery of $500,000 for current rate case expenses over 2.5 years for an annual allowance of $200,000 per year.

Q. Do you agree with the Company's proposed amount of rate case expense for this case?

A. No. The total amount of rate case expense is excessive and would represent an unreasonable burden on ratepayers. Additionally, the amount included in rates for an allowance for rate case expense should be understood to be a normalized amount, not an amortization.

Q. What total amount of rate case expense was allowed in the last UNSE rate case?

A. The allowance for rate case expense was based on a total amount of $300,000 for rate case expenses in its prior rate case, Docket No. G-04204A-09-0206, normalized over a period of three years, for an annual allowance of $100,000 per year.

Q. How does the current UNSE rate case compare with the last UNSE rate case?

A. It appears to be similar if not simpler.

Q. What do you recommend for the allowance for rate case expense for UNSE in this proceeding?

A. I recommend an annual allowance of $100,000, based on normalizing a total amount of $300,000 over a three-year period. Schedule C-3 reduces the Company's proposed annual allowance for current rate case costs by $100,000.

C-4 Incentive Compensation Expense

Q. Please explain Staff Adjustment C-4.

A. This adjustment provides for the allocation of 50 percent of the test year expense for the incentive compensation to shareholders. Test year expense for incentive compensation expense proposed by UNSE is reduced by $98,600. Related payroll tax expense is decreased by $1,692.

Q. Please explain why a 50 percent allocation to shareholders is appropriate for an incentive compensation program.

A. In general, incentive compensation programs can provide benefits to both shareholders and ratepayers. The removal of 50 percent of the incentive compensation expense, in essence, provides an equal sharing of such cost, and therefore provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Both shareholders and ratepayers stand to benefit from the achievement of performance goals; however, there is no assurance that the award levels included in the Company's proposed expense for the test year will be repeated in future years.

Q. Please briefly discuss the key provisions of the incentive compensation program.

A. The Company's response to Uniform Data Request ("UDR") 1.34 states UNSE's non-union employees participate in UNSE's short-term incentive program ("PEP"), which is tied to annual compensation. The structure of the PEP determines eligibility for certain bonus levels by measuring UNSE's performance in four categories: (1) Investors; (2) Customers; (3) Community/Environmental; and (4) Employees. Levels of achievement in each category are assigned percentage-based "scores." Those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15% to 147.5% maximum of the targeted payout level. Over the period of 2009-2012, the Investor category has encompassed a range of 35%-40% of the bonus structure, the Customer category has ranged from 30-35%, and the Community/Environmental and Employees categories respectively account for 15% each.

As explained in the Company's response to UDR 1.34:

> The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% - 14% for regular unclassified employees, and 20-25% for senior management level employees. Bonus percentages, as a percent of base

> salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year.

Q. Does UNSE recognize that its proposed treatment of incentive compensation expense in the current case represents a conscious deviation from principles and policies established in prior Commission Orders?

A. Yes. The response to data request UDR 1.62 stated[5]:

> b. In Commission Decision No. 71914 (September 30, 2010), based on the Direct Testimony of Commission Staff witness, Dr. Thomas H. Fish, 50 percent of the incentive compensation expense was removed. To cite Dr. Fish's testimony, "Since both Company stock holders and rate payers benefit from PEP incentive compensation I recommend that the Company share the incentive compensation expenses with the owners of the Company for PEP-related incentive compensation."
>
> UNS Electric is requesting full recovery of the normal and recurring level of incentive compensation expense for unclassified employees and 50% of incentive compensation for officer and senior management level employees.

Q. What reasoning does UNSE give for its request to recover 100% of its incentive compensation expense despite prior Commission Orders?

A. In his Direct Testimony at page 26, Company witness Dukes cited Arizona Public Service Company rate case Decision No. 69663:

> "Arizona Public Service Company ("APS") - Decision No. 69663: allowed recovery of 100% of APS' Cash-Based Incentive Compensation program."

Q. What criteria has the Commission found important in deciding issues concerning utility incentive compensation in recent cases?

A. The criteria the Commission has found important in deciding this issue in recent cases are described in various orders, which have addressed the treatment of utility incentive

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[5] See Attachment RCS-3.

compensation expense for ratemaking purposes. In Decision No. 68487 (February 23, 2006), the Commission adopted Staff's recommendation for an equal sharing of costs associated with the SWG Management Incentive Plan ("MIP") expense. For example, in reaching its conclusion regarding SWG's MIP, the Commission stated in part on page 18 of Decision No. 68487 that:

> We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendations to be a reasonable resolution.

Q. Do UNSE's shareholders and customers both benefit from the achievement of incentive compensation program?

A. Yes. Shareholders benefit from the achievement of financial goals. Additionally, shareholders benefit from the achievement of expense reduction and expense containment goals between rate cases. Shareholders and ratepayers can both benefit from the achievement of customer service goals.

Q. Have the facts changed materially since the last UNSE rate case that a different result concerning the sharing of incentive compensation expense should occur?

A. No, I don't believe so. The rationale for the 50 percent allocation to shareholders of this expense in this case appears to be consistent with the Commission's findings concerning SWG's MIP in Decision No. 68487, and findings about UNSG's incentive compensation expense in Decision No. 70011. In Decision No. 70011 dated November 27, 2007, (Docket No. G-04204-06-0463 et al) the Commission stated in part on page 27:

> We believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program.

Q. Did UNSG appeal Decision No. 70011?

A. No.

Q. Was an equal sharing of incentive compensation expense ordered in other recent Commission decisions in rate cases involving Arizona utilities?

A. Yes. In Decision No. 70360 (May 27, 2008), in the UNS Electric, Inc. rate case, Docket No. E-04204A-06-0783, the Commission stated at page 21:

> Consistent with our finding in the UNS Electric rate case (Decision No. 70011, at 26-27), we believe that Staff's recommendation provides a reasonable balancing of the interests between ratepayers and shareholders by requiring each group to bear half the cost of the incentive program...Given that the arguments raised in the UNS Electric case are virtually identical to those presented in this case, we see no reason to deviate from that recent decision.

Finally, in Decision No. 70665 (December 24, 2008), SWG rate case Docket No. G-01551A-07-0504, the Commission stated at page 16:

> In the last Southwest Gas rate case, as well as several subsequent cases,[3] we disallowed 50 percent of management incentive compensation on the basis that such programs provide approximately equal benefits to shareholders and ratepayers because the performance goals relate to financial performance and cost containment goals as well as customer service elements. (Decision No. 68487 at 18.) In that Decision, we stated:
>
>> In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.
>
> (Id.) We believe the same rationale exists in this case to adopt the position advocated by Staff and RUCO to disallow 50 percent of the Company's proposed MIP costs.[4]

[3]See UNS Electric, Inc., Decision No. 70011 (November 27, 2007) at 27; Arizona Public Service Co., Decision No. 69663 (June 28, 2007) at 27; and UNS Electric, Inc., Decision No. 70360 (May 27, 2008) at 21.

[4]On the same basis, we will also disallow 100 percent of the Southwest Gas stock incentive plan ("SIP"). The costs related to similar incentive plans were recently rejected for APS and UNS Electric. (See Ex. S-12 at 32-34.) As was noted in the APS case, stock performance incentive goals have the potential to negatively affect customer service, and ratepayers should not be required to pay executive compensation that is based on the performance of the Company's stock price. (Decision No. 69663 at 36.)

Q. Should the 50/50 ratepayer/shareholder sharing that the Commission applied to utility incentive compensation in UNSE's last rate case be modified to a 100 percent ratepayer responsibility for the non-executive portion of cost based on the analysis requested by UNSE?

A. No. The 50/50 sharing of UNSE's incentive compensation program cost ordered by the Commission in Decision No. 70011 should continue to apply in the current UNSE rate case.

Q. Please summarize your recommendation concerning UNSE's incentive compensation expense.

A. I recommend continuing the 50% allocation for UNSE's incentive compensation expense to shareholders ordered by the Commission in Decision No. 71914. This results in a reduction to test year expense of $100,291, as shown on Schedule C-4.

C-5 Injuries and Damages

Q. What did UNSE reflect for Injuries and Damages Expense?

A. As shown on Schedule C-5, the Company proposes to use a 3-year average ending June 30, 2012 as the basis for its requested amount. The Company requests an increase of $313,480 to the amount of its recorded test year expense. This increase is based on UNSE's proposed use of a 3-year average for the period ending June 30, 2012. The Company's requested increase is primarily caused by a $1 million expense recorded for the insurance deductible amount that was paid, pertaining to a truck accident on October 20, 2009. An expense of this size is unusual and nonrecurring. The Company has not demonstrated that it is normal for a $1 million expense to occur, or for it to occur approximately every three years.

Q. Are there additional concerns about the UNSE request for the $1 million amount recorded in 2009?

A. Yes. This Company request for a large expense amount recorded over three years ago raises retroactive ratemaking concerns. The Company had not demonstrated that it requested or received any authority to defer for future recovery this unusually large expense that it recorded in 2009. Thus, additional concerns about retroactive ratemaking argue in favor of removing that 2009 expense, and not providing for prospective recovery of this past expense.

Q. How does the $1 million 2009 amount compare with amounts recorded by the Company in 2010, 2011 and 2012?

A. The comparable amounts recorded by the Company in calendar years 2010 and 2011 were zero and in 2012 was $10,000.

Q. What does Staff recommend for Injuries and Damages Expense?

A. As shown on Schedule C-5, Staff's proposed adjustment is based on a more current three-year average (for calendar years 2010, 2011 and 2012) that does not include the unusual $1 million expense amount that was recorded by UNSE in 2009. Staff's adjustment reduces the UNSE request by $330,270 on an ACC jurisdictional basis.

C-6 D&O Liability Insurance

Q. Please explain Staff Adjustment C-6.

A. This adjustment removes one-half of the D&O Liability Insurance expense and reduces test year O&M expense by $44,106. The removal of one-half of this expense reflects an equal (i.e., 50/50) sharing of the cost for this insurance between shareholders and ratepayers.

Q. Why should the cost of the D&O Liability Insurance expense be shared between shareholders and ratepayers?

A. This type of insurance coverage usually comes into play when a shareholder sues the officers and directors of a public company, such as UNSE's parent UniSource Energy. Thus, it helps protect the officers and directors from the costs of a shareholder lawsuit. Shareholders benefit from payouts under the policy that would reduce the cost not recoverable from ratepayers. On the other hand, ratepayers benefit from this because having such insurance improves the ability of the publicly traded parent corporation to attract and retain qualified directors and officers and enables the directors and officers to make decisions without fear of personal liability. Consequently, it is reasonable for shareholders to bear some of the cost for the D&O liability insurance.

Q. Was this adjustment made in UNSE's last rate case?

A. To my knowledge, it was not.

Q. Did Staff recommend a similar adjustment in the most recent SWG Arizona rate case?

A. Yes, and a similar adjustment was also made in SWG's Nevada rate case, Nevada PSC Docket No. 09-04003, and adopted by the Nevada Commission in an order dated October 29, 2009. Southwest's D&O Liability Insurance expense is a "system allocable" expense, meaning that it is incurred at Southwest's corporate headquarters and the cost is allocated to the divisions. Thus, a portion of the same SWG D&O Liability Insurance expense that was recently disallowed in Nevada was being allocated to Arizona, and was adjusted for 50/50 sharing by Staff in the SWG most recent Arizona rate case, Docket No. G-01151A-10-0458.[6]

Similarly, UNSE's D&O Insurance Expense represents a cost that is allocated to UNSE from affiliates.

Q. Have other regulatory commissions besides Nevada made a similar adjustment for sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. The Nevada Commission order in the last SWG rate case, at page 47, paragraph 157, cites two states (Arkansas and California) that have required a sharing of D&O Liability Insurance expense between ratepayers and shareholders on a 50-50 basis.[7] We are aware of at least two other commissions (Connecticut and Florida) that have made adjustments for a ratepayer and shareholder sharing of D&O Liability Insurance expense. Connecticut has also required shareholders to share a portion of the cost of D&O Liability Insurance expense, with the shareholder portion varying from 50% to 75% in different cases.

Q. Have you included an attachment with excerpts from the orders of which you are aware which have made such findings concerning sharing of D&O Liability Insurance Expense between shareholders and ratepayers?

A. Yes. Attachment RCS-5 contains excerpts from such orders.

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[6] Southwest Gas' most recent Arizona rate case resulted in a settlement being reached by most of the parties to that case, which incorporated this Staff adjustment. The Commission's Final Order incorporated that adjustment.

[7] To date, we have not located the Arkansas and California commission orders which required that sharing.

Q. Please summarize the adjustment to expense for D&O Liability Insurance sharing between shareholders and ratepayers.

A. As shown on Schedule C-6, UNSE's proposed test year expense for D&O Insurance of $88,213 should be reduced by $44,106 to reflect an allocation of 50 percent of this expense to shareholders.

Q. Is there a related adjustment to rate base?

A. Yes. A related adjustment to rate base is shown on Schedule B-2 to remove 50% of the prepaid amount for D&O Liability Insurance.

C-7 Edison Electric Institute and Industry Association ("EEI") Dues

Q. Please explain Staff's proposed adjustment for EEI Dues.

A. This adjustment is shown on Schedule C-7 and reduces test year expense by $12,980 to reflect the removal of 49.93% (27.93% above the Company's 22%) of Regular Dues and to remove dues for the Utility Air Regulatory Group ("UARG").

Q. How does Staff's proposed adjustment for EEI dues compare with UNSE's proposed treatment of such dues?

A. As noted above, I recommend the removal of 49.93% of EEI Regular Dues and the removal of UARG dues, while UNSE's filing reflected the removal of 22% of the EEI Regular Dues and zero percent of UARG.

Q. What information did UNSE provide concerning the specific benefits of EEI activities to the Company and Arizona ratepayers?

A. In its response to UDR 1.54, the Company did provide information that the EEI provides some benefit to the utilities that comprise its membership; however, this does not negate the fact that a significant portion of EEI expenditures are related to programs which should be disallowed for ratemaking purposes. I have included in Attachment RCS-2 a listing and description of the EEI's functions as listed in the March 2005 Annual Audit report to the National Association of Regulatory Utility Commissioners ("NARUC"), and have identified the percentage of EEI activities related to each function.

Q Does the information provided by UNSE show that its requested portion of EEI dues-funded activities is beneficial to the Company and/or to its Arizona ratepayers?

A. No. UNSE has demonstrated that there is some benefit of EEI membership to the Company and to Arizona ratepayers from some of the EEI's functions. However, the Company has failed to demonstrate that ratepayers should fund activities conducted through an industry organization that would be subject to disallowance if conducted directly by the utility. The Company has failed to demonstrate that disallowances of EEI Regular Dues of 22% and 0% of UARG are adequate. As I will discuss below, other states have used a significantly higher disallowance percentage for utility EEI dues than UNSE is proposing here.

Q. To your knowledge what percentage disallowance for utility EEI dues has been used in other recent utility rate cases?

A. In the last UNSE rate case, as described on pages 24 and 25 of Decision No. 71914, the Commission disallowed 49.93% of EEI dues. I recommended a 49.93% disallowance based on a NARUC sponsored Audit report of the Expenditures of the EEI. At pages 24 and 25 of Decision No. 71914, the Commission stated:

> Staff recommended disallowing 49.93 percent, ... In Decision No. 70360 we adopted Staff's position and disallowed 49.93 percent of EEI dues because EEI's "core dues related to legislative advocacy, regulatory advocacy, advertising, marketing, and public relations total 49.93 percent of the total dues."
>
> The Company failed to provide a sufficient reason why ratepayers should pay for advocacy, advertising, marketing, and public relations that are not required for the provision of electric service and do not otherwise benefit

> ratepayers. According, we will adopt Staff's recommendation of disallowing 49.93 percent of EEI dues.

Q. How did you determine the percent disallowance for EEI dues?

A. This was based upon a review of information in the most recent NARUC-sponsored Audit Reports of the Expenditures of the Edison Electric Institute, as well as the Commission's Decision No. 71914 to UNSE's last rate case.

Q. What is the purpose of the NARUC-sponsored audits of EEI expenditures?

A. The purpose of the NARUC-sponsored audits of EEI expenditures is to provide regulatory commissions with information that is useful in helping them decide which, if any, of the costs of the association should be approved for inclusion in utility rates. As stated in the June 2001 memo to the Chairs and Chief Accountants of the State Regulatory Commissions included with the NARUC-sponsored audit of 1999 EEI expenditures: "Often, state commissioners review the costs of the association charged or allocated to the utilities in their jurisdiction in accordance with the policies of their commission for treatment of costs directly incurred by the state's utilities for similar activities." The NARUC-sponsored audit categorizes the EEI expenditures and, as stated in the aforementioned memo, "these expense categories may be viewed by some State commissions as potential vehicles for charging ratepayers with such costs as lobbying, advocacy or promotional activities which may not be to their benefit."

Q. What is UARG?

A. UARG is a voluntary, ad hoc, not-for-profit association of electric generating companies and organizations and national trade associations. UARG's purpose is to participate collectively on behalf of its members in Environmental Protection Agency's ("EPA") rulemakings and other proceedings under the Clean Air Act ("CAA") that affect the interests of electric generators and in litigation arising from those proceedings. The electric utilities and other electric generating companies that are members of UARG own and operate power plants and other facilities that generate electricity for residential, commercial, industrial, institutional, and governmental customers.

Q. Why are you recommending that UNSE's expense for UARG dues be removed?

A. UARG represents the interests of electric generators and in litigation in EPA rulemaking proceedings. Other than stating that UARG's organizational documents prohibit it from engaging in lobbying, UNSE has failed to provide any UARG budgets or other information to substantiate an allocation of the UARG costs among allowable and disallowable functions. Based on the lack of any budgets for UARG activities and lack of supporting documentation from which to ascertain an allocation of UARG dues, the entire amount is being removed.

Q. What amount of EEI membership dues expense and UARG dues have you proposed be removed from test year expense?

A. As shown on Schedule C-7, I have removed 49.93% or $4,993 of the $10,000 of EEI core dues, which removes $2,793 more than the $2,200 that UNS removed for EEI core membership dues. The jurisdictional cost of service is reduced by $2,704. Additionally, the removal of the $10,613 of UARG dues reduces the jurisdictional cost of service by $10,276. The total adjustment for industry association dues reduces UNSE's requested expense by $12,980.

C-8 Allocated Cost of TEP's New Headquarters Building to UNSE

Q. Please explain adjustment C-8.

A. As shown on Schedule C-8, this adjustment reduces the Company's requested expense for the costs allocated to UNSE for the affiliated company, TEP's new headquarters building in downtown Tucson, Arizona.

Q. How does TEP charge the affiliates, such as UNSE, for the cost related to TEP's new headquarters building?

A. TEP charges the costs of the new headquarters building to its affiliates, UNSE, UNSG, and others based on TEP labor hours worked for such affiliates. TEP's calculation of the hourly charge-out rate, however, does not appear to reflect reductions for unused portions of the building, or for costs that should be excluded and not charged to ratepayers.

Q. Was the new TEP headquarters building being fully used to provide utility service when Staff toured it during the recent TEP rate case?

A. No. Staff's tour of the new TEP headquarters building for the TEP rate case revealed that the new building included substantial amounts of office space that are not currently being used, that the new building includes retail space that has a cost, that such retail space is not currently being used, that the building includes a cost of approximately $16 million for garage/parking, and that TEP had not adequately substantiated that its allocation of new building costs is fair and reasonable. It appears that similar concerns persist in terms of the charges for the new building by TEP to UNSE as reflected in UNSE's requested cost of service.

Q. What adjustments has Staff made for the cost of the new headquarters building?

A. Staff's proposed adjustment for new headquarters building cost is shown on Attachment RCS-2, Schedule C-8. Staff recommends that all of the cost of the building related to retail space be borne by shareholders. The cost of the 12,000 square feet of retail space, which is all currently unused, is $2.136 million.

Staff also recommends that the cost related to unused office space be borne by shareholders. As shown on Schedule C-8, there is approximately 8,540 square feet of vacant office and cubicle space. At $263 per square foot, the estimated cost of vacant office space is approximately $2.246 million.

Staff also recommends that half of the cost of the underground garage/parking area not be charged to ratepayers. It is questionable that ratepayers should pay for parking by TEP and affiliate employees in downtown Tucson. In its response to STF 22.6(l) in the most recent TEP rate case, as a reason for why none of the headquarters parking needs to be made available to serve the 12,000 square feet of retail space, for example, TEP cited the Downtown Tucson Partnership web site for stating that:

> With over 15,000 spaces, parking Downtown is quick and easy. Metered street parking is less expensive than in almost any other city (free on evenings and weekends). Private and public parking lots and garages are also a great deal. You walk farther in a mall parking lot than you do parking anywhere Downtown. With parking Downtown, you're never far from where you need to be. ...

With so much relatively inexpensive parking available in Downtown Tucson that could presumably be used by the TEP employees who are working in the new headquarters building, attempting to charge the full cost of the new headquarters building parking areas to ratepayers could be considered to be unreasonable. Additionally, Staff is aware that other major Arizona energy utilities, such as APS, charge their employees for parking. Charging employees for parking in the garage parking at the new UniSource Energy headquarters building in Downtown Tucson would thus be a potential non-ratepayer source of revenue to TEP to cover its costs of having built that parking facility into the new headquarters building. TEP employees working at the headquarters who are parking in the headquarters building parking garage rather than in the over 15,000 spaces of relatively inexpensive private and public parking available in Downtown Tucson should be asked to contribute to the cost of such parking. If employee charges for the parking are insufficient for TEP to recoup its costs of the parking garage, then the shareholders on whose behalf the TEP and UniSource boards approved the building should be responsible for the cost. Given these factors, Staff believes it would be unreasonable to charge UNSE ratepayers for the full cost of the new headquarters building parking garage. TEP's response to STF 26.07 in the most recent TEP rate case identified the cost of the parking structure as $10.5 million.[8] Accordingly, Staff has excluded $5.25 million, or half of the $10.5 million cost for the headquarters parking structure, in deriving the amount for the new headquarters building that is included in the calculation of TEP building costs allocated to UNSE.

Q. Has Staff also reflected a reduction in TEP headquarters building costs charged to UNSE for a reduced financing cost rate?

A. Yes. UNSE's proposed amount for allocated costs for the new TEP headquarters building is based on a calculation that applies a TEP overall cost of capital, including a return on equity, and an income tax "gross-up" on the TEP equity return. In the most recent TEP rate case, a financing cost rate for the new TEP headquarters building that was based on TEP's cost of long-term debt was utilized to determine the amount of costs to be borne by ratepayers. Staff's adjustment for TEP headquarters building costs allocated to UNSE similarly reflects the use of a financing cost based on TEP's long-term cost of debt. Because interest on such debt is tax-deductible, this also eliminates the income tax "gross-up" on the TEP equity return that was included in the Company's calculations.

Q. Has Staff made proportional adjustments to reduce insurance, depreciation and property taxes related to the TEP office buildings, for purposes of computing the charges to UNSE?

A. Yes. As shown on Schedule C-8, page 2, Staff has also made adjustments to proportionately reduce insurance, depreciation and property taxes related to the TEP office

[8] If an allocation of land costs were included, the cost would be approximately $16.0 million.

building, as shown on Schedule C-8, page 2. The adjusted rate per hour for the TEP office building related charges is $10.18, as shown on Schedule C-8, page 2.

Q. Please summarize the adjustment for TEP headquarters building costs.

A. As shown on Exhibit RCS-2, Schedule C-8, the adjusted allowed hourly rate for the TEP office buildings is $10.18 per hour. This compares with the $13.07 per hour cost rate used by UNSE. The Staff adjustment multiplies the hourly rate by the same number of hours used in UNSE's calculation. As shown on Schedule C-8, page 1, Staff's adjustment reduces UNSE's expense on a Total Company basis by $293,258, and by $283,933 on an ACC jurisdictional basis.

C-9 Interest Synchronization

Q. What is interest synchronization?

A. Interest synchronization refers to the widely accepted process used in utility ratemaking which involves coordinating the amount of interest deduction that is used to compute income tax expense for ratemaking purposes with the other elements of the ratemaking formula. The interest synchronization process typically involves multiplying the weighted cost of debt (from the recommended cost of capital) by the adjusted rate base in order to derive a "synchronized" amount of interest expense. The synchronized interest is then treated as the amount of interest deduction in computing the income tax expense.

Q. Please explain your interest synchronization adjustment.

A. The interest synchronization adjustment applies the weighted cost of debt to the calculation of test year income tax expense. After adjustments, my proposed rate base differs from that of the Company. This results in an adjustment to the amount of synchronized interest included in the tax calculation. The calculation of the interest synchronization adjustment is shown on Schedule C-9. This adjustment decreases income tax expense by the amount shown on Schedule C-9 and increases the Company's achieved operating income by a similar amount.

C-10 Depreciation Rates – Dismantlement Cost

Q. What has UNSE requested for revisions to depreciation rates for Dismantlement Cost?

A. UNSE has requested increased depreciation expense of $716,750 on a total Company basis and $705,996 on an ACC jurisdictional basis. Approximately $480,931 of the total Company increase relates to depreciation on distribution plant additions, and $71,020 for increased depreciation on general plant. The Company's workpapers attribute an additional amount of $127,916 relateing to the Company's request for dismantlement costs for Valencia and BMGS. However, a review of the details of the Company's proposed adjustments indicate that additional depreciation expense related to dismantlement for the Valencia and Black Mountain generating stations that has been included in UNSE's jurisdictional base rate revenue requirement totals to $90,125, per the calculations made by UNSE in its depreciation adjustment related to dismantlement costs that are reproduced on Schedule C-10.

Q. Has dismantlement cost been included in the development of UNSE's depreciation rates previously?

A. No, it has not.

Q. Has UNSE filed a complete depreciation rate study in the current case?

A. No, it has not.

Q. How is UNSE proposing to change its depreciation rates in the current case?

A. The Company is proposing to change its depreciation rates to only include costs for estimated dismantlement on its two generating units. This represents an unbalanced approach to establishing new depreciation rates since this only reflects one isolated element, and one that would increase depreciation expense, where, in a comprehensive updating, other changes affecting depreciation rates could contribute to reductions.

Q. What is the basis for the Company's requested dismantlement costs?

A. As noted above, UNSE has included for the first time a request for dismantlement costs. UNSE has made a pro forma adjustment to increase depreciation expense $90,125 for estimated dismantlement for BMGS and Valencia of $1.771 million and $1.133 million, respectively. UNSE's requested dismantlement costs appear to be based on a "greenfield" level of dismantlement that restores the generating plant sites to their original condition. The dismantlement cost study, assumed that the units would be completely dismantled and the plant sites restored to its original condition after the plants are no longer used to generate electricity. This assumption results in very high costs. If instead the retired units are only partially dismantled and/or if the sites are reused for subsequent production facilities, the actual dismantlement costs will be much less. From what we have seen so far, there is no legal requirement to dismantle either the BMGS or Valencia generating plant sites to their original condition. Moreover, there is no need to spend any money for dismantlement activities at either site currently or in the near future. Thus, there is no compelling need to charge UNSE ratepayers for estimated future dismantlement costs in this UNSE rate case. Also, as mentioned above, those plant sites may be ideal locations for future plants. If the existing plants are eventually closed, a new generating facility may be constructed on the same sites, which could result in a substantially lower amount of dismantlement costs ultimately being incurred.

Q. Does Staff agree with UNSE's proposal in this rate case to only update depreciation rates for estimated dismantlement costs on generating units?

A. No. As noted above, this is unbalanced. Staff also has concerns about the levels of dismantlement costs, used by UNSE. There is no need to spend any money for dismantlement costs for either generating plant site during the time when base rates established in the current UNSE rate case are anticipated to be in effect. Consequently, Staff recommends that UNSE's requested dismantlement costs be removed in the current UNSE rate case. Dismantlement costs for the Valencia plant and the BMGS can be considered in a future UNSE rate case where the utility presents a comprehensive depreciation rate study, rather than the piecemeal updating approach proposed by the Company in the current case.

Q. Please explain the adjustment for the Depreciation Expense for Dismantlement Costs.

A. Staff recommends that UNSE's request for dismantlement costs be rejected in the current case. As shown on Schedule C-10, UNSE's requested Depreciation Expense is reduced by $90,125 to totally remove the Company's requested dismantlement costs in the current case for the reasons described above.

C-11 Base Cost of Fuel and Purchased Power

Q. Please explain the adjustment for the Base Cost of Fuel and Purchased Power.

A. UNSE proposes to remove all fuel and purchased power costs from its base rates and to instead have all of these costs included in its PPFAC. Staff recommends that a representative level of fuel and purchased power costs continue to be included in UNSE's base rates, and that UNSE's PPFAC address only changes (increases and decreases) above the base fuel amount. Schedule C-11 shows Staff's recommendation for a base cost of fuel and purchased power of $0.05706 per kWh. This rate reflects the effective per kWh cost of PPFAC includable costs that are being recovered in rates by UNSE as of September 2013 when the second-half of the current PPFAC adjustment becomes effective. Staff has reviewed various forecasts made by UNSE of PPFAC-includable costs and levels of over- and under-recoveries. Staff recommends a base cost of fuel in the current UNSE rate case of $0.05706 per kWh. This essentially sets the going-forward base cost of fuel at the current per-kWh level of recovery for PPFAC-includable costs. Additional details concerning this rate are shown on Schedule C-11, page 3. Using this rate will help coordinate the base cost of fuel with the establishment of a new PPFAC rate in 2014 and will help avoid a large build-up of unrecovered fuel costs that could occur if a lower base cost of fuel, such as the $0.05174 calculated and proposed by UNSE were to be used. This adjustment results in increases to fuel and purchased power cost of $9.255 million and a corresponding increase to fuel related revenue.

Q. Is there an equivalent adjustment for fuel-related revenue to correspond with the establishment of a new base cost of fuel?

A. In both UNSE's and Staff's calculation of the adjustment for the base cost of fuel, there is an equivalent adjustment to fuel-related revenue to reflect the fact that UNSE's recovery of PPFAC-includable fuel and purchased power costs occurs on a dollar-for-dollar basis, with no margin being earned by the Company on the PPFAC-includable cost recovery.

Q. Were other levels for the base cost of fuel evaluated by Staff?

A. Yes. As shown on Schedule C-11, pages 2, 4 and 5, Staff evaluated the $0.05174 per kWh included in UNSE's application (which was based on forecast information available at the time UNSE prepared its application, and which is shown on Schedule C-11, page 2), a revised UNSE forecast of $0.050908 (shown on page 4) that was provided in response to Staff discovery, and an actual average 12-month cost for the period May 2012 through April 2013 of $0.05039 (that is shown on Schedule C-11, page 5).

Q. Why is Staff's recommendation preferable to any of these other levels?

A. The problem with using any of these other estimates for establishing the base cost of fuel is that projections of cost recovery of PPFAC-includable fuel costs through base rates and the PPFAC, indicate that UNSE's under-recovered fuel balance would build up to a substantial level, as much as $17 million by June 1, 2014 if a base cost of fuel of approximately $0.05 were to be used. Staff recommends that such a situation be avoided by adjusting the base cost of fuel in the current UNSE rate case to the level of PPFAC-includable cost recovery that will be in effect as of September 2013, i.e., by using the $0.05706 per kWh reflected in Staff's recommendation, and coordinating UNSE's change in base rates and PPFAC rates in the manner described below.

Q. Do you address UNSE's other requested changes to its PPFAC in a subsequent section of your testimony?

A. Yes. I address UNSE's other requested changes to its PPFAC in the following section of my testimony.

V. PURCHASED POWER AND FUEL ADJUSTMENT CLAUSE (PPFAC)

Q. What changes has UNSE proposed to its current PPFAC?

A. In his Direct Testimony, UNSE witness Jones stated:

> I propose two changes to the Purchase Power and Fuel Adjustment Clause ("PPFAC"). The Company is proposing to move all fuel and purchase power costs from base rates and to recover them entirely through the PPFAC. UNS Electric is also proposing multiple PPFAC components that are differentiated on the basis of on-peak and off-peak and some shift in fuel costs to moderate fuel-related bill impacts. I also sponsor a revised Plan of Administration ("POA") for the PPFAC to reflect the Company's proposed changes. While this proposal creates multiple PPFAC components, it will not add to the PPFAC rates any single customer will pay.

Q. Does Staff agree with the UNSE proposed changes to its PPFAC or its revised POA?

A. No.

Q. What is Staff's recommendation concerning whether UNSE's proposed revised PPFAC POA should be adopted?

A. Staff recommends that UNSE's proposed revised PPFAC POA should not be adopted, but rather UNSE should prepare a different revised PPFAC POA that incorporates revised provisions to address some additional concerns that Staff has, which are explained below.

Q. What concerns does Staff have regarding UNSE's existing PPFAC?

A. Staff has concerns about UNSE's ability to accurately forecast the estimated component of its existing PPFAC rates and concerns about UNSE accumulating large under- or over-recovered PPFAC balances. While UNSE's initial PPFAC was intended to resemble the PPFAC of its affiliated electric utility, TEP, Staff has concerns that UNSE's mix of generation and purchased power is heavily influenced by fluctuations in natural gas prices and is therefore significantly different from TEP's generation, which is heavily from coal-fired plants.

Q. Is UNSE's mix of generation and purchased power similar to that of its affiliate, TEP?

A. No. Unlike the situation with its electric utility affiliate, TEP, which has substantial coal-fired generation, UNSE's fuel and purchase power costs appear to be subject to a much heavier influence of natural gas price fluctuations. Concerns about the increases being produced on UNSE customer bills from the operation of the current PPFAC have also recently come to light in Docket No. E-04204A-06-0783 (Decision No. 73886) when the Company's proposed change would have produced a large increase in residential customer bills. As noted by Staff and the Commission in that docket, based on average usage of

887 kWh per month, the recently proposed UNSE PPFAC rate would result in an increase of $9.25 per month for a residential customer. As a consequence, UNSE's recent PPFAC change is being phased in, which in turn is contributing toward UNSE experiencing a build-up of unrecovered fuel and purchased power costs.

Q. Could UNSE's existing PPFAC potentially be improved by eliminating the forward component and replacing it with another form of tracking fluctuations in fuel and purchased power cost, such as the use of a 12-month rolling average?

A. Yes. Staff believes that there may be substantial merit in eliminating the forward component of UNSE's PPFAC and re-designing UNSE's PPFAC so it resembles certain aspects of the Purchased Gas Adjustor of the affiliate, UNSG, which is based on adjusting the PGA component of UNSG's rates on a monthly basis, based on a 12-month rolling average of gas costs, and subject to certain constraints to prevent large changes from month-to-month. Staff therefore recommends that UNSE develop and present a revised POA for its PPFAC that eliminates the forward component and bases prospective PPFAC rate changes on fluctuations in the 12-month rolling average of UNSE's fuel and purchased power costs. The revised POA should also incorporate annual and monthly cap provisions to limit the increases experienced by consumers for PPFAC changes in any given monthly period.

One possible going-forward alternative that Staff believes merits consideration and which Staff recommends be addressed in additional detail by UNSE would help mitigate UNSE having a potentially large increase in the under recovery, and would include maintaining UNSE's average retail fuel rate that is in effect December 2013 of 5.706 cents (current average base fuel less the PPFAC credit in effect beginning in September 2013). This could potentially be accomplished by establishing new base fuel rates in this filing based upon an average base cost of fuel equivalent to 5.706 cents as recommended by Staff and having no PPFAC charge or credit until June 2014 (UNSE's current PPFAC is updated every June 1). Then beginning June 1, 2014, the UNSE's PPFAC would convert to a 12-month rolling average with changes limited to +/- 0.8% per month. The forecast component of UNSE's PPFAC would thus be eliminated effective with the new PPFAC rates that become effective on June 1, 2014. Staff would therefore encourage UNSE to develop a revised PPFAC POA and estimated bill impacts based on this scenario.

Q. What is Staff's position about the request by UNSE for expansion of the types of costs which are included in the PPFAC?

A. Staff proposes to continue to reflect the same accounts in UNSE's PPFAC that are currently reflected, but not to expand the types of costs beyond those currently included in UNSE's PPFAC.

Q. Does Staff agree with UNSE's proposal to remove all fuel and purchased power costs from base rates?

A. No. Staff recommends that UNSE continue to reflect a base amount of fuel and purchased power, and that PPFAC adjustments continue to be based upon fluctuations of UNSE's fuel and purchased power costs above or below the base cost of fuel. Staff's proposal for establishing UNSE's new base cost of fuel at $0.05706 per kWh has been explained above. This new base cost of fuel should also be coordinated with implementation of a revised PPFAC for UNSE, as also described above.

Q. Does Staff agree with UNSE's proposal to include credit costs and broker fees associated with power supply and procurement in UNSE's PPFAC at this time?

A. No. These are not costs that are recorded by UNSE in the four includable expense accounts that are currently reflected in UNSE's PPFAC. As noted above, Staff is <u>not</u> proposing to expand the categories of costs recovered in UNSE's PPFAC at this time.

Q. Does Staff agree with UNSE's proposal to recover future greenhouse gas costs through the PPFAC at this time?

A. No. This request by UNSE is premature as greenhouse gas emission costs are not currently a cost that is incurred by UNSE, and the exact form of future regulation of greenhouse gas emissions at the federal level and in Arizona is not known. If UNSE begins to incur significant amounts of costs related to greenhouse gas emissions, Staff would encourage UNSE to petition the Commission at that time for an appropriate regulatory treatment. Staff does not believe it would be good regulatory policy to expand UNSE's PPFAC at this time for potential future costs that could have significant ratemaking impacts.

Q. Please summarize the recommendations concerning the PPFAC.

A. As described above, Staff recommends that UNSE develop and present a revised Plan of Administration for its PPFAC that eliminates the forward component and bases prospective PPFAC rate changes on fluctuations in the 12-month rolling average of UNSE's fuel and purchased power costs, and which reflects an implementation date that is coordinated with the inclusion of a new base cost of fuel of $0.05706 per kWh in UNSE's base rates. The revised Plan of Administration should also incorporate annual and monthly cap provisions to limit the increases experienced by consumers for PPFAC changes in any given monthly period, and should include only the accounts and types of costs that are included in UNSE's current PPFAC.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Attachment RCS-1
QUALIFICATIONS OF RALPH C. SMITH

Accomplishments

Mr. Smith's professional credentials include being a Certified Financial Planner™ professional, a Certified Rate of Return Analyst, a licensed Certified Public Accountant and attorney. He functions as project manager on consulting projects involving utility regulation, regulatory policy and ratemaking and utility management. His involvement in public utility regulation has included project management and in-depth analyses of numerous issues involving telephone, electric, gas, and water and sewer utilities.

Mr. Smith has performed work in the field of utility regulation on behalf of industry, public service commission staffs, state attorney generals, municipalities, and consumer groups concerning regulatory matters before regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Louisiana, Maine, Maryland, Michigan, Minnesota, Mississippi, Missouri, New Jersey, New Mexico, New York, Nevada, North Carolina, North Dakota, Ohio, Pennsylvania, South Carolina, South Dakota, Texas, Utah, Vermont, Virginia, Washington, Washington DC, West Virginia, Canada, Federal Energy Regulatory Commission and various state and federal courts of law. He has presented expert testimony in regulatory hearings on behalf of utility commission staffs and intervenors on several occasions.

Project manager in Larkin & Associates' review, on behalf of the Georgia Commission Staff, of the budget and planning activities of Georgia Power Company; supervised 13 professionals; coordinated over 200 interviews with Company budget center managers and executives; organized and edited voluminous audit report; presented testimony before the Commission. Functional areas covered included fossil plant O&M, headquarters and district operations, internal audit, legal, affiliated transactions, and responsibility reporting. All of our findings and recommendations were accepted by the Commission.

Key team member in the firm's management audit of the Anchorage Water and Wastewater Utility on behalf of the Alaska Commission Staff, which assessed the effectiveness of the Utility's operations in several areas; responsible for in-depth investigation and report writing in areas involving information systems, finance and accounting, affiliated relationships and transactions, and use of outside contractors. Testified before the Alaska Commission concerning certain areas of the audit report. AWWU concurred with each of Mr. Smith's 40 plus recommendations for improvement.

Co-consultant in the analysis of the issues surrounding gas transportation performed for the law firm of Cravath, Swaine & Moore in conjunction with the case of Reynolds Metals Co. vs. the Columbia Gas System, Inc.; drafted in-depth report concerning the regulatory treatment at both state and federal levels of issues such as flexible pricing and mandatory gas transportation.

Lead consultant and expert witness in the analysis of the rate increase request of the City of Austin - Electric Utility on behalf of the residential consumers. Among the numerous ratemaking issues addressed were the economies of the Utility's employment of outside services; provided both written and oral testimony outlining recommendations and their bases. Most of Mr. Smith's recommendations were adopted by the City Council and Utility in a settlement.

Key team member performing an analysis of the rate stabilization plan submitted by the Southern Bell Telephone & Telegraph Company to the Florida PSC; performed comprehensive analysis of the Company's projections and budgets which were used as the basis for establishing rates.

Lead consultant in analyzing Southwestern Bell Telephone separations in Missouri; sponsored the complex technical analysis and calculations upon which the firm's testimony in that case was based. He has also assisted in analyzing changes in depreciation methodology for setting telephone rates.

Lead consultant in the review of gas cost recovery reconciliation applications of Michigan Gas Utilities Company, Michigan Consolidated Gas Company, and Consumers Power Company. Drafted recommendations regarding the appropriate rate of interest to be applied to any over or under collections and the proper procedures and allocation methodology to be used to distribute any refunds to customer classes.

Lead consultant in the review of Consumers Power Company's gas cost recovery refund plan. Addressed appropriate interest rate and compounding procedures and proper allocation methodology.

Project manager in the review of the request by Central Maine Power Company for an increase in rates. The major area addressed was the propriety of the Company's ratemaking attrition adjustment in relation to its corporate budgets and projections.

Project manager in an engagement designed to address the impacts of the Tax Reform Act of 1986 on gas distribution utility operations of the Northern States Power Company. Analyzed the reduction in the corporate tax rate, uncollectibles reserve, ACRS, unbilled revenues, customer advances, CIAC, and timing of TRA-related impacts associated with the Company's tax liability.

Project manager and expert witness in the determination of the impacts of the Tax Reform Act of 1986 on the operations of Connecticut Natural Gas Company on behalf of the Connecticut Department of Public Utility Control - Prosecutorial Division, Connecticut Attorney General, and Connecticut Department of Consumer Counsel.

Lead Consultant for The Minnesota Department of Public Service ("DPS") to review the Minnesota Incentive Plan ("Incentive Plan") proposal presented by Northwestern Bell Telephone Company ("NWB") doing business as U S West Communications ("USWC"). Objective was to express an opinion as to whether current rates addressed by the plan were appropriate from a Minnesota intrastate revenue requirements and accounting perspective, and to assist in developing recommended modifications to NWB's proposed Plan.

Performed a variety of analytical and review tasks related to our work effort on this project. Obtained and reviewed data and performed other procedures as necessary (1) to obtain an understanding of the Company's Incentive Plan filing package as it relates to rate base, operating income, revenue requirements, and plan operation, and (2) to formulate an opinion concerning the reasonableness of current rates and of amounts included within the Company's Incentive Plan filing. These procedures included requesting and reviewing extensive discovery, visiting the Company's offices to review data, issuing follow-up information requests in many instances, telephone and on-site discussions with Company representatives, and frequent discussions with counsel and DPS Staff assigned to the project.

Lead Consultant in the regulatory analysis of Jersey Central Power & Light Company for the Department of the Public Advocate, Division of Rate Counsel. Tasks performed included on-site review and audit of Company, identification and analysis of specific issues, preparation of data requests, testimony, and cross examination questions. Testified in Hearings.

Assisted the NARUC Committee on Management Analysis with drafting the Consultant Standards for Management Audits.

Presented training seminars covering public utility accounting, tax reform, ratemaking, affiliated transaction auditing, rate case management, and regulatory policy in Maine, Georgia, Kentucky, and Pennsylvania. Seminars were presented to commission staffs and consumer interest groups.

Previous Positions

With Larkin, Chapski and Co., the predecessor firm to Larkin & Associates, was involved primarily in utility regulatory consulting, and also in tax planning and tax research for businesses and individuals, tax return preparation and review, and independent audit, review and preparation of financial statements.

Installed computerized accounting system for a realty management firm.

Education

Bachelor of Science in Administration in Accounting, with distinction, University of Michigan, Dearborn, 1979.

Master of Science in Taxation, Walsh College, Michigan, 1981. Master's thesis dealt with investment tax credit and property tax on various assets.

Juris Doctor, cum laude, Wayne State University Law School, Detroit, Michigan, 1986. Recipient of American Jurisprudence Award for academic excellence.

Continuing education required to maintain CPA license and CFP® certificate.

Passed all parts of CPA examination in first sitting, 1979. Received CPA certificate in 1981 and Certified Financial Planning certificate in 1983. Admitted to Michigan and Federal bars in 1986.

Michigan Bar Association.

American Bar Association, sections on public utility law and taxation.

Partial list of utility cases participated in:

79-228-EL-FAC	Cincinnati Gas & Electric Company (Ohio PUC)
79-231-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
79-535-EL-AIR	East Ohio Gas Company (Ohio PUC)
80-235-EL-FAC	Ohio Edison Company (Ohio PUC)
80-240-EL-FAC	Cleveland Electric Illuminating Company (Ohio PUC)
U-1933*	Tucson Electric Power Company (Arizona Corp. Commission)
U-6794	Michigan Consolidated Gas Co. --16 Refunds (Michigan PSC)
81-0035TP	Southern Bell Telephone Company (Florida PSC)
81-0095TP	General Telephone Company of Florida (Florida PSC)
81-308-EL-EFC	Dayton Power & Light Co.- Fuel Adjustment Clause (Ohio PUC)
810136-EU	Gulf Power Company (Florida PSC)
GR-81-342	Northern States Power Co. -- E-002/Minnesota (Minnesota PUC)
Tr-81-208	Southwestern Bell Telephone Company (Missouri PSC))
U-6949	Detroit Edison Company (Michigan PSC)
8400	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
18328	Alabama Gas Corporation (Alabama PSC)
18416	Alabama Power Company (Alabama PSC)
820100-EU	Florida Power Corporation (Florida PSC)
8624	Kentucky Utilities (Kentucky PSC)
8648	East Kentucky Power Cooperative, Inc. (Kentucky PSC)
U-7236	Detroit Edison - Burlington Northern Refund (Michigan PSC)
U6633-R	Detroit Edison - MRCS Program (Michigan PSC)
U-6797-R	Consumers Power Company -MRCS Program (Michigan PSC)
U-5510-R	Consumers Power Company - Energy conservation Finance Program (Michigan PSC)
82-240E	South Carolina Electric & Gas Company (South Carolina PSC)
7350	Generic Working Capital Hearing (Michigan PSC)
RH-1-83	Westcoast Transmission Co., (National Energy Board of Canada)
820294-TP	Southern Bell Telephone & Telegraph Co. (Florida PSC)
82-165-EL-EFC (Subfile A)	Toledo Edison Company(Ohio PUC)
82-168-EL-EFC	Cleveland Electric Illuminating Company (Ohio PUC)
830012-EU	Tampa Electric Company (Florida PSC)
U-7065	The Detroit Edison Company - Fermi II (Michigan PSC)
8738	Columbia Gas of Kentucky, Inc. (Kentucky PSC)
ER-83-206	Arkansas Power & Light Company (Missouri PSC)
U-4758	The Detroit Edison Company – Refunds (Michigan PSC)
8836	Kentucky American Water Company (Kentucky PSC)
8839	Western Kentucky Gas Company (Kentucky PSC)
83-07-15	Connecticut Light & Power Co. (Connecticut DPU)
81-0485-WS	Palm Coast Utility Corporation (Florida PSC)
U-7650	Consumers Power Co. (Michigan PSC)
83-662	Continental Telephone Company of California, (Nevada PSC)
U-6488-R	Detroit Edison Co., FAC & PIPAC Reconciliation (Michigan PSC)
U-15684	Louisiana Power & Light Company (Louisiana PSC)
7395 & U-7397	Campaign Ballot Proposals (Michigan PSC)
820013-WS	Seacoast Utilities (Florida PSC)
U-7660	Detroit Edison Company (Michigan PSC)
83-1039	CP National Corporation (Nevada PSC)
U-7802	Michigan Gas Utilities Company (Michigan PSC)
83-1226	Sierra Pacific Power Company (Nevada PSC)
830465-EI	Florida Power & Light Company (Florida PSC)
U-7777	Michigan Consolidated Gas Company (Michigan PSC)
U-7779	Consumers Power Company (Michigan PSC)

U-7480-R	Michigan Consolidated Gas Company (Michigan PSC)
U-7488-R	Consumers Power Company – Gas (Michigan PSC)
U-7484-R	Michigan Gas Utilities Company (Michigan PSC)
U-7550-R	Detroit Edison Company (Michigan PSC)
U-7477-R**	Indiana & Michigan Electric Company (Michigan PSC)
18978	Continental Telephone Co. of the South Alabama (Alabama PSC)
R-842583	Duquesne Light Company (Pennsylvania PUC)
R-842740	Pennsylvania Power Company (Pennsylvania PUC)
850050-EI	Tampa Electric Company (Florida PSC)
16091	Louisiana Power & Light Company (Louisiana PSC)
19297	Continental Telephone Co. of the South Alabama (Alabama PSC)
76-18788AA &76-18793AA	Detroit Edison - Refund - Appeal of U-4807 (Ingham County, Michigan Circuit Court)
85-53476AA & 85-534785AA	Detroit Edison Refund - Appeal of U-4758 (Ingham County, Michigan Circuit Court)
U-8091/U-8239	Consumers Power Company - Gas Refunds (Michigan PSC)
TR-85-179**	United Telephone Company of Missouri (Missouri PSC)
85-212	Central Maine Power Company (Maine PSC)
ER-85646001 & ER-85647001	New England Power Company (FERC)
850782-EI & 850783-EI	Florida Power & Light Company (Florida PSC)
R-860378	Duquesne Light Company (Pennsylvania PUC)
R-850267	Pennsylvania Power Company (Pennsylvania PUC)
851007-WU & 840419-SU	Florida Cities Water Company (Florida PSC)
G-002/GR-86-160	Northern States Power Company (Minnesota PSC)
7195 (Interim)	Gulf States Utilities Company (Texas PUC)
87-01-03	Connecticut Natural Gas Company (Connecticut PUC))
87-01-02	Southern New England Telephone Company (Connecticut Department of Public Utility Control)
3673-	Georgia Power Company (Georgia PSC)
29484	Long Island Lighting Co. (New York Dept. of Public Service)
U-8924	Consumers Power Company – Gas (Michigan PSC)
Docket No. 1	Austin Electric Utility (City of Austin, Texas)
Docket E-2, Sub 527	Carolina Power & Light Company (North Carolina PUC)
870853	Pennsylvania Gas and Water Company (Pennsylvania PUC)
880069**	Southern Bell Telephone Company (Florida PSC)
U-1954-88-102	Citizens Utilities Rural Company, Inc. & Citizens Utilities
T E-1032-88-102	Company, Kingman Telephone Division (Arizona CC)
89-0033	Illinois Bell Telephone Company (Illinois CC)
U-89-2688-T	Puget Sound Power & Light Company (Washington UTC))
R-891364	Philadelphia Electric Company (Pennsylvania PUC)
F.C. 889	Potomac Electric Power Company (District of Columbia PSC)
Case No. 88/546*	Niagara Mohawk Power Corporation, et al Plaintiffs, v. Gulf+Western, Inc. et al, defendants (Supreme Court County of Onondaga, State of New York)
87-11628*	Duquesne Light Company, et al, plaintiffs, against Gulf+ Western, Inc. et al, defendants (Court of the Common Pleas of Allegheny County, Pennsylvania Civil Division)
890319-EI	Florida Power & Light Company (Florida PSC)
891345-EI	Gulf Power Company (Florida PSC)
ER 8811 0912J	Jersey Central Power & Light Company (BPU)
6531	Hawaiian Electric Company (Hawaii PUCs)

R0901595	Equitable Gas Company (Pennsylvania Consumer Counsel)
90-10	Artesian Water Company (Delaware PSC)
89-12-05	Southern New England Telephone Company (Connecticut PUC)
900329-WS	Southern States Utilities, Inc. (Florida PSC)
90-12-018	Southern California Edison Company (California PUC)
90-E-1185	Long Island Lighting Company (New York DPS)
R-911966	Pennsylvania Gas & Water Company (Pennsylvania PUC)
I.90-07-037, Phase II	(Investigation of OPEBs) Department of the Navy and all Other Federal Executive Agencies (California PUC)
U-1551-90-322	Southwest Gas Corporation (Arizona CC)
U-1656-91-134	Sun City Water Company (Arizona RUCO)
U-2013-91-133	Havasu Water Company (Arizona RUCO)
91-174***	Central Maine Power Company (Department of the Navy and all Other Federal Executive Agencies)
U-1551-89-102 & U-1551-89-103	Southwest Gas Corporation - Rebuttal and PGA Audit (Arizona Corporation Commission)
Docket No. 6998	Hawaiian Electric Company (Hawaii PUC)
TC-91-040A and TC-91-040B	Intrastate Access Charge Methodology, Pool and Rates Local Exchange Carriers Association and South Dakota Independent Telephone Coalition
9911030-WS & 911-67-WS	General Development Utilities - Port Malabar and West Coast Divisions (Florida PSC)
922180	The Peoples Natural Gas Company (Pennsylvania PUC)
7233 and 7243	Hawaiian Nonpension Postretirement Benefits (Hawaiian PUC)
R-00922314 & M-920313C006	Metropolitan Edison Company (Pennsylvania PUC)
R00922428	Pennsylvania American Water Company (Pennsylvania PUC)
E-1032-92-083 & U-1656-92-183	Citizens Utilities Company, Agua Fria Water Division (Arizona Corporation Commission)
92-09-19	Southern New England Telephone Company (Connecticut PUC)
E-1032-92-073	Citizens Utilities Company (Electric Division), (Arizona CC)
UE-92-1262	Puget Sound Power and Light Company (Washington UTC))
92-345	Central Maine Power Company (Maine PUC)
R-932667	Pennsylvania Gas & Water Company (Pennsylvania PUC)
U-93-60**	Matanuska Telephone Association, Inc. (Alaska PUC)
U-93-50**	Anchorage Telephone Utility (Alaska PUC)
U-93-64	PTI Communications (Alaska PUC)
7700	Hawaiian Electric Company, Inc. (Hawaii PUC)
E-1032-93-111 & U-1032-93-193	Citizens Utilities Company - Gas Division (Arizona Corporation Commission)
R-00932670	Pennsylvania American Water Company (Pennsylvania PUC)
U-1514-93-169/ E-1032-93-169	Sale of Assets CC&N from Contel of the West, Inc. to Citizens Utilities Company (Arizona Corporation Commission)
7766	Hawaiian Electric Company, Inc. (Hawaii PUC)
93-2006- GA-AIR*	The East Ohio Gas Company (Ohio PUC)
94-E-0334	Consolidated Edison Company (New York DPS)
94-0270	Inter-State Water Company (Illinois Commerce Commission)
94-0097	Citizens Utilities Company, Kauai Electric Division (Hawaii PUC)
PU-314-94-688	Application for Transfer of Local Exchanges (North Dakota PSC)
94-12-005-Phase I	Pacific Gas & Electric Company (California PUC)
R-953297	UGI Utilities, Inc. - Gas Division (Pennsylvania PUC)
95-03-01	Southern New England Telephone Company (Connecticut PUC)
95-0342	Consumer Illinois Water, Kankakee Water District (Illinois CC)
94-996-EL-AIR	Ohio Power Company (Ohio PUC)
95-1000-E	South Carolina Electric & Gas Company (South Carolina PSC)

Non-Docketed Staff Investigation	Citizens Utility Company - Arizona Telephone Operations (Arizona Corporation Commission)
E-1032-95-473	Citizens Utility Co. - Northern Arizona Gas Division (Arizona CC)
E-1032-95-433	Citizens Utility Co. - Arizona Electric Division (Arizona CC)
	Collaborative Ratemaking Process Columbia Gas of Pennsylvania (Pennsylvania PUC)
GR-96-285	Missouri Gas Energy (Missouri PSC)
94-10-45	Southern New England Telephone Company (Connecticut PUC)
A.96-08-001 et al.	California Utilities' Applications to Identify Sunk Costs of Non-Nuclear Generation Assets, & Transition Costs for Electric Utility Restructuring, & Consolidated Proceedings (California PUC)
96-324	Bell Atlantic - Delaware, Inc. (Delaware PSC)
96-08-070, et al.	Pacific Gas & Electric Co., Southern California Edison Co. and San Diego Gas & Electric Company (California PUC)
97-05-12	Connecticut Light & Power (Connecticut PUC)
R-00973953	Application of PECO Energy Company for Approval of its Restructuring Plan Under Section 2806 of the Public Utility Code (Pennsylvania PUC)
97-65	Application of Delmarva Power &Light Co. for Application of a Cost Accounting Manual and a Code of Conduct (Delaware PSC)
16705	Entergy Gulf States, Inc. (Cities Steering Committee)
E-1072-97-067	Southwestern Telephone Co. (Arizona Corporation Commission)
Non-Docketed Staff Investigation	Delaware - Estimate Impact of Universal Services Issues (Delaware PSC)
PU-314-97-12	US West Communications, Inc. Cost Studies (North Dakota PSC)
97-0351	Consumer Illinois Water Company (Illinois CC)
97-8001	Investigation of Issues to be Considered as a Result of Restructuring of Electric Industry (Nevada PSC)
U-0000-94-165	Generic Docket to Consider Competition in the Provision of Retail Electric Service (Arizona Corporation Commission)
98-05-006-Phase I	San Diego Gas & Electric Co., Section 386 costs (California PUC)
9355-U	Georgia Power Company Rate Case (Georgia PUC)
97-12-020 - Phase I	Pacific Gas & Electric Company (California PUC)
U-98-56, U-98-60, U-98-65, U-98-67	Investigation of 1998 Intrastate Access charge filings (Alaska PUC)
(U-99-66, U-99-65, U-99-56, U-99-52)	Investigation of 1999 Intrastate Access Charge filing (Alaska PUC)
Phase II of 97-SCCC-149-GIT	Southwestern Bell Telephone Company Cost Studies (Kansas CC)
PU-314-97-465	US West Universal Service Cost Model (North Dakota PSC)
Non-docketed Assistance	Bell Atlantic - Delaware, Inc., Review of New Telecomm. and Tariff Filings (Delaware PSC)
Contract Dispute	City of Zeeland, MI - Water Contract with the City of Holland, MI (Before an arbitration panel)
Non-docketed Project	City of Danville, IL - Valuation of Water System (Danville, IL)
Non-docketed Project	Village of University Park, IL - Valuation of Water and Sewer System (Village of University Park, Illinois)

E-1032-95-417	Citizens Utility Co., Maricopa Water/Wastewater Companies et al. (Arizona Corporation Commission)
T-1051B-99-0497	Proposed Merger of the Parent Corporation of Qwest Communications Corporation, LCI International Telecom Corp., and US West Communications, Inc. (Arizona CC)
T-01051B-99-0105	US West Communications, Inc. Rate Case (Arizona CC)
A00-07-043	Pacific Gas & Electric - 2001 Attrition (California PUC)
T-01051B-99-0499	US West/Quest Broadband Asset Transfer (Arizona CC)
99-419/420	US West, Inc. Toll and Access Rebalancing (North Dakota PSC)
PU314-99-119	US West, Inc. Residential Rate Increase and Cost Study Review (North Dakota PSC
98-0252	Ameritech - Illinois, Review of Alternative Regulation Plan (Illinois CUB)
00-108	Delmarva Billing System Investigation (Delaware PSC)
U-00-28	Matanuska Telephone Association (Alaska PUC)
Non-Docketed	Management Audit and Market Power Mitigation Analysis of the Merged Gas System Operation of Pacific Enterprises and Enova Corporation (California PUC)
00-11-038	Southern California Edison (California PUC)
00-11-056	Pacific Gas & Electric (California PUC)
00-10-028	The Utility Reform Network for Modification of Resolution E-3527 (California PUC)
98-479	Delmarva Power & Light Application for Approval of its Electric and Fuel Adjustments Costs (Delaware PSC)
99-457	Delaware Electric Cooperative Restructuring Filing (Delaware PSC)
99-582	Delmarva Power & Light dba Conectiv Power Delivery Analysis of Code of Conduct and Cost Accounting Manual (Delaware PSC)
99-03-04	United Illuminating Company Recovery of Stranded Costs (Connecticut OCC)
99-03-36	Connecticut Light & Power (Connecticut OCC)
Civil Action No. 98-1117	West Penn Power Company vs. PA PUC (Pennsylvania PSC)
Case No. 12604	Upper Peninsula Power Company (Michigan AG)
Case No. 12613	Wisconsin Public Service Commission (Michigan AG)
41651	Northern Indiana Public Service Co Overearnings investigation (Indiana UCC)
13605-U	Savannah Electric & Power Company – FCR (Georgia PSC)
14000-U	Georgia Power Company Rate Case/M&S Review (Georgia PSC)
13196-U	Savannah Electric & Power Company Natural Gas Procurement and Risk Management/Hedging Proposal, Docket No. 13196-U (Georgia PSC)
Non-Docketed	Georgia Power Company & Savannah Electric & Power FPR Company Fuel Procurement Audit (Georgia PSC)
Non-Docketed	Transition Costs of Nevada Vertically Integrated Utilities (US Department of Navy)
Application No. 99-01-016, Phase I	Post-Transition Ratemaking Mechanisms for the Electric Industry Restructuring (US Department of Navy)
99-02-05	Connecticut Light & Power (Connecticut OCC)
01-05-19-RE03	Yankee Gas Service Application for a Rate Increase, Phase I-2002-IERM (Connecticut OCC)
G-01551A-00-0309	Southwest Gas Corporation, Application to amend its rate Schedules (Arizona CC)
00-07-043	Pacific Gas & Electric Company Attrition & Application for a rate increase (California PUC)

97-12-020 Phase II	Pacific Gas & Electric Company Rate Case (California PUC)
01-10-10	United Illuminating Company (Connecticut OCC)
13711-U	Georgia Power FCR (Georgia PSC)
02-001	Verizon Delaware § 271(Delaware DPA)
02-BLVT-377-AUD	Blue Valley Telephone Company Audit/General Rate Investigation (Kansas CC)
02-S&TT-390-AUD	S&T Telephone Cooperative Audit/General Rate Investigation (Kansas CC)
01-SFLT-879-AUD	Sunflower Telephone Company Inc., Audit/General Rate Investigation (Kansas CC)
01-BSTT-878-AUD	Bluestem Telephone Company, Inc. Audit/General Rate Investigation (Kansas CC)
P404, 407, 520, 413 426, 427, 430, 421/ CI-00-712	Sherburne County Rural Telephone Company, dba as Connections, Etc. (Minnesota DOC)
U-01-85	ACS of Alaska, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-34	ACS of Anchorage, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-83	ACS of Fairbanks, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
U-01-87	ACS of the Northland, dba as Alaska Communications Systems (ACS), Rate Case (Alaska Regulatory Commission PAS)
96-324, Phase II	Verizon Delaware, Inc. UNE Rate Filing (Delaware PSC)
03-WHST-503-AUD	Wheat State Telephone Company (Kansas CC)
04-GNBT-130-AUD	Golden Belt Telephone Association (Kansas CC)
Docket 6914	Shoreham Telephone Company, Inc. (Vermont BPU)
Docket No. E-01345A-06-009	Arizona Public Service Company (Arizona Corporation Commission)
Case No. 05-1278-E-PC-PW-42T	Appalachian Power Company and Wheeling Power Company both d/b/a American Electric Power (West Virginia PSC)
Docket No. 04-0113	Hawaiian Electric Company (Hawaii PUC)
Case No. U-14347	Consumers Energy Company (Michigan PSC)
Case No. 05-725-EL-UNC	Cincinnati Gas & Electric Company (PUC of Ohio)
Docket No. 21229-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 19142-U	Georgia Power Company (Georgia PSC)
Docket No. 03-07-01RE01	Connecticut Light & Power Company (CT DPUC)
Docket No. 19042-U	Savannah Electric & Power Company (Georgia PSC)
Docket No. 2004-178-E	South Carolina Electric & Gas Company (South Carolina PSC)
Docket No. 03-07-02	Connecticut Light & Power Company (CT DPUC)
Docket No. EX02060363, Phases I&II	Rockland Electric Company (NJ BPU)
Docket No. U-00-88	ENSTAR Natural Gas Company and Alaska Pipeline Company (Regulatory Commission of Alaska)
Phase 1-2002 IERM, Docket No. U-02-075	Interior Telephone Company, Inc. (Regulatory Commission of Alaska)
Docket No. 05-SCNT-1048-AUD	South Central Telephone Company (Kansas CC)
Docket No. 05-TRCT-607-KSF	Tri-County Telephone Company (Kansas CC)
Docket No. 05-KOKT-060-AUD	Kan Okla Telephone Company (Kansas CC)
Docket No. 2002-747	Northland Telephone Company of Maine (Maine PUC)
Docket No. 2003-34	Sidney Telephone Company (Maine PUC)

Docket No. 2003-35	Maine Telephone Company (Maine PUC)
Docket No. 2003-36	China Telephone Company (Maine PUC)
Docket No. 2003-37	Standish Telephone Company (Maine PUC)
Docket Nos. U-04-022, U-04-023	Anchorage Water and Wastewater Utility (Regulatory Commission of Alaska)
Case 05-116-U/06-055-U	Entergy Arkansas, Inc. EFC (Arkansas Public Service Commission)
Case 04-137-U	Southwest Power Pool RTO (Arkansas Public Service Commission)
Case No. 7109/7160	Vermont Gas Systems (Department of Public Service)
Case No. ER-2006-0315	Empire District Electric Company (Missouri PSC)
Case No. ER-2006-0314	Kansas City Power & Light Company (Missouri PSC)
Docket No. U-05-043,44	Golden Heart Utilities/College Park Utilities (Regulatory Commission of Alaska)
A-122250F5000	Equitable Resources, Inc. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
E-01345A-05-0816	Arizona Public Service Company (Arizona CC)
Docket No. 05-304	Delmarva Power & Light Company (Delaware PSC)
05-806-EL-UNC	Cincinnati Gas & Electric Company (Ohio PUC)
U-06-45	Anchorage Water Utility (Regulatory Commission of Alaska)
03-93-EL-ATA, 06-1068-EL-UNC	Duke Energy Ohio (Ohio PUC)
PUE-2006-00065	Appalachian Power Company (Virginia Corporation Commission)
G-04204A-06-0463 et. al	UNS Gas, Inc. (Arizona CC)
Docket No. 2006-0386	Hawaiian Electric Company, Inc (Hawaii PUC)
E-01933A-07-0402	Tucson Electric Power Company (Arizona CC)
G-01551A-07-0504	Southwest Gas Corporation (Arizona CC)
Docket No.UE-072300	Puget Sound Energy, Inc. (Washington UTC)
PUE-2008-00009	Virginia-American Water Company (Virginia SCC)
PUE-2008-00046	Appalachian Power Company (Virginia SCC)
E-01345A-08-0172	Arizona Public Service Company (Arizona CC)
A-2008-2063737	Babcock & Brown Infrastructure Fund North America, LP. and The Peoples Natural Gas Company, d/b/a Dominion Peoples (Pennsylvania PUC)
08-1783-G-42T	Hope Gas, Inc., dba Dominion Hope (West Virginia PSC)
08-1761-G-PC	Hope Gas, Inc., dba Dominion Hope, Dominion Resources, Inc., and Peoples Hope Gas Companies (West Virginia PSC)
Docket No. 2008-0085	Hawaiian Electric Company, Inc. (Hawaii PUC)
Docket No. 2008-0266	Young Brothers, Limited (Hawaii PUC)
G-04024A-08-0571	UNS Gas, Inc. (Arizona CC)
Docket No. 09-29	Tidewater Utilities, Inc. (Delaware PSC)
Docket No. UE-090704	Puget Sound Energy, Inc. (Washington UTC)
09-0878-G-42T	Mountaineer Gas Company (West Virginia PSC)
2009-UA-0014	Mississippi Power Company (Mississippi PSC)
Docket No. 09-0319	Illinois-American Water Company (Illinois CC)
Docket No. 09-414	Delmarva Power & Light Company (Delaware PSC)
R-2009-2132019	Aqua Pennsylvania, Inc. (Pennsylvania PUC)
Docket Nos. U-09-069, U-09-070	ENSTAR Natural Gas Company (Regulatory Commission of Alaska)
Docket Nos. U-04-023, U-04-024	Anchorage Water and Wastewater Utility - Remand (Regulatory Commission of Alaska)
W-01303A-09-0343 & SW-01303A-09-0343	Arizona-American Water Company (Arizona CC)
09-872-EL-FAC & 09-873-EL-FAC	Financial Audits of the FAC of the Columbus Southern Power Company and the Ohio Power Company - Audit I (Ohio PUC)
2010-00036	Kentucky-American Water Company (Kentucky PSC)
E-04100A-09-0496	Southwest Transmission Cooperative, Inc. (Arizona CC)
E-01773A-09-0496	Arizona Electric Power Cooperative, Inc. (Arizona CC)

R-2010-2166208, R-2010-2166210, R-2010-2166212, & R-2010-2166214	Pennsylvania-American Water Company (Pennsylvania PUC)
PSC Docket No. 09-0602	Central Illinois Light Company D/B/A AmerenCILCO; Central Illinois Public Service Company D/B/A AmerenCIPS; Illinois Power Company D/B/A AmerenIP (Illinois CC)
10-0713-E-PC	Allegheny Power and FirstEnergy Corp. (West Virginia PSC)
Docket No. 31958	Georgia Power Company (Georgia PSC)
Docket No. 10-0467	Commonwealth Edison Company (Illinois CC)
PSC Docket No. 10-237	Delmarva Power & Light Company (Delaware PSC)
U-10-51	Cook Inlet Natural Gas Storage Alaska, LLC (Regulatory Commission of Alaska)
10-0699-E-42T	Appalachian Power Company and Wheeling Power Company (West Virginia PSC)
10-0920-W-42T	West Virginia-American Water Company (West Virginia PSC)
A.10-07-007	California-American Water Company (California PUC)
A-2010-2210326	TWP Acquisition (Pennsylvania PUC)
08-1012-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 1 (Ohio PUC)
10-268-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit II (Ohio PUC)
Docket No. 2010-0080	Hawaiian Electric Company, Inc. (Hawaii PUC)
G-01551A-10-0458	Southwest Gas Corporation (Arizona CC)
10-KCPE-415-RTS	Kansas City Power & Light Company – Remand (Kansas CC)
PUE-2011-00037	Virginia Appalachian Power Company (Commonwealth of Virginia SCC)
R-2011-2232243	Pennsylvania-American Water (Pennsylvania PUC)
U-11-100	Power Purchase Agreement between Chugach Association, Inc. and Fire Island Wind, LLC (Regulatory Commission of Alaska)
A.10-12-005	San Diego Gas & Electric Company (California PUC)
PSC Docket No. 11-207	Artesian Water Company, Inc. (Delaware PSC)
Cause No. 44022	Indiana-American Water Company, Inc. (Indiana Utility Regulatory Commission)
PSC Docket No. 10-247	Management Audit of Tidewater Utilities, Inc. Affiliate Transactions (Delaware Public Service Commission)
G-04204A-11-0158	UNS Gas, Inc. (Arizona Corporation Commission)
E-01345A-11-0224	Arizona Public Service Company (Arizona CC)
UE-111048 & UE-11049	Puget Sound Energy, Inc. (Washington Utilities and Transportation Commission)
Docket No. 11-0721	Commonwealth Edison Company (Illinois CC)
11AL-947E	Public Service Company of Colorado (Colorado PSC)
U-11-77 & U-11-78	Golden Heart Utilities, Inc. and College Utilities Corporation (The Regulatory Commission of Alaska)
Docket No. 11-0767	Illinois-American Water Company (Illinois CC)
PSC Docket No. 11-397	Tidewater Utilities, Inc. (Delaware PSC)
Cause No. 44075	Indiana Michigan Power Company (Indiana Utility Regulatory Commission)
Docket No. 12-0001	Ameren Illinois Company (Illinois CC)
11-5730-EL-FAC	Financial, Management, and Performance Audit of the FAC for Dayton Power and Light – Audit 2 (Ohio PUC)
PSC Docket No. 11-528	Delmarva Power & Light Company (Delaware PSC)
11-281-EL FAC et al.	Financial Audit of the FAC of the Columbus Southern Power Company and the Ohio Power Company – Audit III (Ohio PUC)
Cause No. 43114-IGCC-4S1	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 12-0293	Ameren Illinois Company (Illinois CC)
Docket No. 12-0321	Commonwealth Edison Company (Illinois CC)
12-02019 & 12-04005	Southwest Gas Corporation (Public Utilities Commission of Nevada)
Docket No. 2012-218-E	South Carolina Electric & Gas (South Carolina PSC)
Docket No. E-72, Sub 479	Dominion North Carolina Power (North Carolina Utilities Commission)

12-0511 & 12-0512	North Shore Gas Company and The Peoples Gas Light and Coke Company (Illinois CC)
E-01933A-12-0291	Tucson Electric Power Company (Arizona CC)
Case No. 9311	Potomac Electric Power Company (Maryland PSC)
Cause No. 43114-IGCC-10	Duke Energy Indiana, Inc. (Indiana Utility Regulatory Commission)
Docket No. 36498	Georgia Power Company (Georgia PSC)
Case No. 9316	Columbia Gas of Maryland, Inc. (Maryland PSC)

UNS Electric, Inc
Docket No. E-04204A-12-0504
Attachment RCS-2
Staff Accounting Schedules
Accompanying the Direct Testimony of Ralph C. Smith

UNS Electric, Inc
Computation of Increase in Gross Revenue Requirement
ACC Jurisdictional
Test Year Ended June 30, 2012
(Thousands of Dollars)

Docket No. E-04204A-12-0504
Schedule A
Page 1 of 1

Line No.	Description	Reference	UNSE Proposed Original Cost (A)	UNSE Proposed Fair Value (B)	Staff Calculated Original Cost (C)	Staff Calculated Fair Value Option 1 (D)	Staff Calculated Fair Value Option 2 (E)	Staff Recommended Fair Value (F)
1	Adjusted Rate Base	Sch. B (ACC)	$ 216,575	$ 286,326	$ 211,527	$ 281,278	$ 281,278	$ 281,278
2	Rate of Return	Sch. D	8.35%	6.71%	7.70%	5.79%	5.91%	5.81%
3	Operating Income Required for Rate of Return		$ 18,091	$ 19,214	$ 16,278	$ 16,278	$ 16,627	$ 16,334
4	Net Operating Income Available	Sch. C (ACC)	$ 14,608	$ 14,608	$ 15,471	$ 15,471	$ 15,471	$ 15,471
5	Operating Income Excess/Deficiency		$ 3,483	$ 4,606	$ 807	$ 807	$ 1,156	$ 863
6	Gross Revenue Conversion Factor	Sch. A-1	1.6333	1.6333	1.6333	1.6333	1.6333	1.6333
7	Base Rate Revenue Deficiency		$ 5,688	$ 7,523	$ 1,318	$ 1,318	$ 1,888	$ 1,410
8	Base Rate Revenue Deficiency for Adjusted FVRB	[a]	$ 1,834					
9	Total Base Rate Revenue Deficiency		$ 7,523	$ 7,523	$ 1,318	$ 1,318	$ 1,888	$ 1,410
10	Equivalent OCRB ROE	Sch. D	11.49%	11.49%	9.25%	9.25%	9.56%	9.30%
			Sch,D, p.2, L19	Sch,D, p.2, L19	Sch,D, p.1,L7	Sch,D, p.3, L19	Sch,D, p.4, L19	Sch,D, p.5, L19
	Revenue Increase and Estimated Percentage Rate Increase (Decrease)							
11	Electric Retail Revenues - Current Rates	Sch. C (ACC)	$ 162,190	$ 162,190	$ 171,445	$ 171,445	$ 171,445	$ 171,445
12	With Proposed Base Rate Increase	L9 + L11	$ 169,713	$ 169,713	$ 172,763	$ 172,763	$ 173,333	$ 172,855
13	Percent Retail Revenue Increase		4.6%	4.6%	0.77%	0.77%	1.10%	0.82%

Notes and Source
Cols. A & B taken from UNSE filing, Schedule A-1
[a]:

14	Adjusted OCRB Rate Base		$ 216,575	Col.A, L.1
15	Adjusted FVRB		$ 286,326	Col.B, L.1
16	Difference from OCRB		$ 69,751	
17	Return on FV Increment		1.61%	2012 UNSE Rev Req Model.xls, Cover, numbered Line 32
18	Operating Income Required on FVRB Increment		$ 1,123	
19	Gross Revenue Conversion Factor	Sch. A-1	1.6333	Also see, 2012 UNSE Rev Req Model.xls, Cover, numbered Line 21
20	Base Revenue Deficiency for Adjusted FVRB	Col.A, L.8	$ 1,834	
21	Revenue Deficiency on OCRB	Col.A, L.7	$ 5,688	
22	Revenue Deficiency Claimed by UNSE	Col.A, L.9	$ 7,523	Also see, 2012 UNSE Rev Req Model.xls, Cover, numbered Line 22

UNS Electric, Inc
Computation of Gross Revenue Conversion Factor

Docket No. E-04204A-12-0504
Schedule A-1
Page 1 of 1

Test Year Ended June 30, 2012

Line No.	Description	Company Proposed	Staff Proposed
		(A)	(B)
1	Gross Revenue	100.00%	100.00%
2	Less: Uncollectible Revenue	0.31961%	0.31961%
3	Taxable Income as a Percent	99.68%	99.68%
4	Less: Federal and State Income Taxes	38.45%	38.45%
5	Change in Net Operating Income	61.23%	61.23%
6	Gross Revenue Conversion Factor	1.6333	1.6333

Notes and Source

Col.A:	UNSE Filing, Schedule C-3		
7	Combined State and Federal Income Tax Rate	38.577%	38.577%

Components of Revenue Requirement Increase or (Decrease)

		Amount ('000)	Percent
8	Net Income	$ 863	61.2267%
9	Federal and State Income Taxes	$ 542	38.4537%
10	Uncollectibles	$ 5	0.3196%
11	Total Revenue Increase	$ 1,410	100.0000%
12	From Schedule A, Column F	$ 1,410	

UNS Electric, Inc
Original Cost and RCND Adjusted Rate Base
ACC Jurisdiction

Docket No. E-04204A-12-0504
Schedule B
Page 1 of 1

Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	Original Cost: As Adjusted by UNSE (A)	Original Cost: Staff Adjustments (B)	Original Cost: As Adjusted by Staff (C)	RCND: As Adjusted by UNSE (D)	RCND: Staff Adjustments (E)	RCND: As Adjusted by Staff (F)
1	Gross Utility Plant in Service	$ 535,855	$ (5,755)	$ 530,100	$ 947,024	$ (5,755)	$ 941,269
2	Less: Accumulated Depreciation	$ (234,964)	$ 564	$ (234,400)	$ (442,733)	$ 564	$ (442,169)
3	Net Utility Plant in Service	$ 300,891	$ (5,191)	$ 295,700	$ 504,291	$ (5,191)	$ 499,100
4	Citizens Acquisition Discount	$ (80,856)	$ -	$ (80,856)	$ (149,521)	$ -	$ (149,521)
5	Less: Accum. Amort.-Citizens Acq. Discount	$ 28,773	$ -	$ 28,773	$ 54,324	$ -	$ 54,324
6	Net Citizens Acquisition Discount	$ (52,083)	$ -	$ (52,083)	$ (95,197)	$ -	$ (95,197)
7	Total Net Utility Plant	$ 248,808	$ (5,191)	$ 243,617	$ 409,094	$ (5,191)	$ 403,903
8	Customer Advances for Construction	$ (7,616)	$ -	$ (7,616)	$ (9,038)	$ -	$ (9,038)
							$ -
9	Customer Deposits	$ (6,224)	$ -	$ (6,224)	$ (6,224)	$ -	$ (6,224)
10	Other (ITC)	$ (2,855)	$ -	$ (2,855)	$ (2,855)	$ -	$ (2,855)
11	Accumulated Deferred Income Taxes	$ (22,010)	$ 155	$ (21,855)	$ (41,372)	$ 155	$ (41,217)
12	Total Deductions	$ (38,705)	$ 155	$ (38,550)	$ (59,489)	$ 155	$ (59,334)
13	Allowance for Working Capital	$ 6,472	$ (12)	$ 6,460	$ 6,472	$ (12)	$ 6,460
							$ -
14	Regulatory Assets	$ -	$ -	$ -	$ -	$ -	$ -
15	Regulatory Liabilities	$ -	$ -	$ -	$ -	$ -	$ -
16	Total Rate Base	$ 216,575	$ (5,048)	$ 211,527	$ 356,077	$ (5,048)	$ 351,029

Notes and Source
Cols. A and D: UNSE filing, Schedule B-1

Line No.	Fair Value Calculation (Per Company)	Amount	
17	Original Cost	$ 216,575	
18	RCND	$ 356,077	
19	Total	$ 572,652	
20	Average (Fair Value)	$ 286,326	See Sch. A

Line No.	Fair Value Calculation (Per Staff)	Amount	
21	Original Cost	$ 211,527	
22	RCND	$ 351,029	
23	Total	$ 562,556	
24	Average (Fair Value)	$ 281,278	See Sch. A

UNS Electric, Inc
Summary of Rate Base Adjustments
ACC Jurisdiction

Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	Staff Adjustments	Post Test Year Plant Not In Service B-1	Remove One-Half of Prepaid D&O Insurance B-2	B-3	B-4
1	Gross Utility Plant in Service	$ (5,755)	$ (5,755)			
2	Less: Accumulated Depreciation	$ 564	$ 564			
3	Net Utility Plant in Service	$ (5,191)	$ (5,191)	$ -	$ -	$ -
4	Citizens Acquisition Discount	$ -				
5	Less: Accum.Amort.-Citizens Acq. Discount	$ -				
6	Net Citizens Acquisition Discount	$ -	$ -	$ -	$ -	$ -
7	Total Net Utility Plant	$ (5,191)	$ (5,191)	$ -	$ -	$ -
8	Customer Advances for Construction	$ -				
9	Customer Deposits	$ -				
10	Other (ITC)	$ -				
11	Accumulated Deferred Income Taxes	$ 155	$ 155			
12	Total Deductions	$ 155	$ 155	$ -	$ -	$ -
13	Allowance for Working Capital	$ (12)		$ (12)		
14	Regulatory Assets	$ -				
15	Regulatory Liabilities	$ -				
16	Total Rate Base	$ (5,048)	$ (5,036)	$ (12)	$ -	$ -

UNS Electric, Inc
Adjusted Net Operating Income
ACC Jurisdictional

Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	As Adjusted by UNSE (A)	Staff Adjustments (B)	As Adjusted by Staff (C)
	Operating Revenues			
1	Electric Retail Revenues	$ 162,190	$ 9,255	$ 171,445
2	Sales for Resale	$ -	$ -	$ -
3	Other Operating Revenues	$ 1,791	$ -	$ 1,791
4	Total Operating Revenues	$ 163,981	$ 9,255	$ 173,236
	Operating Expenses			
5	Fuel, Purchased Power and Transmission	$ 100,337	$ 9,255	$ 109,592
6	Other O&M Expenses	$ 20,717	$ (896)	$ 19,821
7	Depreciation & Amortization	$ 18,534	$ (584)	$ 17,950
8	Taxes Other Than Income Taxes	$ 4,407	$ (14)	$ 4,393
9	Income Taxes	$ 5,378	$ 631	$ 6,009
10	Total Operating Expenses	$ 149,373	$ 8,392	$ 157,765
11	Net Operating Income	$ 14,608	$ 863	$ 15,471

Notes and Source
Col. A: UNSE Schedule C-1
Col. B: Staff Schedule C.1

UNS Electric, Inc
Summary of Net Operating Income Adjustments
ACC Jurisdiction

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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	Staff Adjustments	Depreciation and Property Tax Expenses on Post Test Year Plant Not In Service	Post Test Year Pay Increase	Rate Case Expense	Incentive Compensation Expense
			C-1	C-2	C-3	C-4
	Operating Revenues					
1	Electric Retail Revenues	$ 9,255			$ -	
2	Sales for Resale	$ -				
3	Other Operating Revenues	$ -	$ -			
4	Total Operating Revenues	$ 9,255	$ -	$ -	$ -	$ -
	Operating Expenses					
5	Fuel, Purchased Power and Transmission	$ 9,255				
6	Other O&M Expenses	$ (896)		$ (24)	$ (100)	$ (100)
7	Depreciation & Amortization	$ (584)	$ (494)			
8	Taxes Other Than Income Taxes	$ (14)	$ (12)	$ (2)		
9	PRE-TAX OPERATING EXPENSES	$ 7,761	$ (506)	$ (26)	$ (100)	$ (100)
10	PRE-TAX OPERATING INCOME	$ 1,494	$ 506	$ 26	$ 100	$ 100
11	Income Taxes	$ 631	$ 195	$ 10	$ 39	$ 39
12	TOTAL OPERATING EXPENSES	$ 8,392	$ (311)	$ (16)	$ (61)	$ (61)
13	OPERATING INCOME	$ 863	$ 311	$ 16	$ 61	$ 61

Notes and Source

Combined Effective Tax Rate* 38.577%

* Per UNSE filing, Schedule C-3

UNS Electric, Inc
Summary of Net Operating Income Adjustments
ACC Jurisdiction

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Test Year Ended June 30, 2012
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Line No.	Description	Injuries and Damages	Directors and Officers Insurance Expense	Edison Electric Institute Industry Association Dues	Allocated Cost of TEP New Headquarters Building to UNSE	Interest Synchronization	Depreciation Rates - Estimated Dismantlement Cost
		C-5	C-6	C-7	C-8	C-9	C-10
	Operating Revenues						
1	Electric Retail Revenues						
2	Sales for Resale						
3	Other Operating Revenues						
4	Total Operating Revenues	$ -	$ -	$ -	$ -	$ -	$ -
	Operating Expenses						
5	Fuel, Purchased Power and Transmission						
6	Other O&M Expenses	$ (330)	$ (44)	$ (13)	$ (284)		
7	Depreciation & Amortization						$ (90)
8	Taxes Other Than Income Taxes						
9	PRE-TAX OPERATING EXPENSES	$ (330)	$ (44)	$ (13)	$ (284)	$ -	$ (90)
10	PRE-TAX OPERATING INCOME	$ 330	$ 44	$ 13	$ 284	$ -	$ 90
11	Income Taxes	$ 127	$ 17	$ 5	$ 110	$ 54	$ 35
12	TOTAL OPERATING EXPENSES	$ (203)	$ (27)	$ (8)	$ (174)	$ 54	$ (55)
13	OPERATING INCOME	$ 203	$ 27	$ 8	$ 174	$ (54)	$ 55

Notes and Source

Combined Effective Tax Rate* 38.577%

* Per UNSE filing, Schedule C-3

UNS Electric, Inc
Summary of Net Operating Income Adjustments
ACC Jurisdiction

Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	Base Cost of Fuel and Purchased Power C-11	C-12	C-13	C-14
	Operating Revenues				
1	Electric Retail Revenues	$ 9,255			
2	Sales for Resale				
3	Other Operating Revenues				
4	Total Operating Revenues	$ 9,255	$ -	$ -	$ -
	Operating Expenses				
5	Fuel, Purchased Power and Transmission	$ 9,255			
6	Other O&M Expenses				
7	Depreciation & Amortization				
8	Taxes Other Than Income Taxes				
9	PRE-TAX OPERATING EXPENSES	$ 9,255	$ -	$ -	$ -
10	PRE-TAX OPERATING INCOME	$ -	$ -	$ -	$ -
11	Income Taxes	$ -	$ -	$ -	$ -
12	TOTAL OPERATING EXPENSES	$ 9,255	$ -	$ -	$ -
13	OPERATING INCOME	$ -	$ -	$ -	$ -

Notes and Source
Combined Effective Tax Rate* 38.577%
* Per UNSE filing, Schedule C-3

UNS Electric, Inc
Capital Structure & Cost Rates

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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Capital Source	Capitalization Amount (A)	Capitalization Percent (B)	Cost Rate (C)	Weighted Avg. Cost of Capital (D)
	I. UNSE - Proposed				
1	Short-Term Debt				
2	Long-Term Debt	129,135	47.40%	5.97%	2.83%
3	Common Stock Equity	143,287	52.60%	10.50%	5.52%
4	Total Capital	$ 272,422	100.00%		8.35%
	II. ACC Staff - Proposed for OCRB [b]	**Supporting OCRB**			
5	Short-Term Debt				0.00%
6	Long-Term Debt	$ 100,264	47.40%	5.97%	2.83%
7	Common Stock Equity	$ 111,263	52.60%	9.25% [b]	4.87%
8	Total Capital	$ 211,527	100.00%		7.70%
9	Difference				-0.6575%
10	Weighted Cost of Debt				2.83%
	III. ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 1				
11	Short-Term Debt	$ -	0.00%	0.00%	0.00%
12	Long-Term Debt	$ 100,264	35.65%	5.97%	2.13%
13	Common Stock Equity	$ 111,263	39.56%	9.25% [b]	3.66%
14	Capital financing OCRB	$ 211,527			
15	Appreciation above OCRB not recognized on utility's books	$ 69,751	24.80%	0% [a]	0.00%
16	Total capital supporting FVRB	$ 281,278	100.00%		5.79%
	IV. ACC Staff - Proposed Cost of Capital for Fair Value Rate Base - Option 2				
17	Short-Term Debt	$ -	0.00%	0.00%	0.00%
18	Long-Term Debt	$ 100,264	35.65%	5.97%	2.13%
19	Common Stock Equity	$ 111,263	39.56%	9.25% [b]	3.66%
20	Capital financing OCRB	$ 211,527			
21	Appreciation above OCRB not recognized on utility's books	$ 69,751	24.80%	0.50% [c]	0.12%
22	Total capital supporting FVRB	$ 281,278	100.00%		5.91%

Notes and Source

Lines 1-4 taken from UNS Electric Inc. filing, Schedule D-1

Lines 12-16, Col.A:

23	Fair Value Rate Base	$ 281,278	Schedule A
24	Original Cost Rate Base	$ 211,527	Schedule A
25	Difference	$ 69,751	

Difference is appreciation of Fair Value over Original Cost that is not recognized on the utility's books.

[a] The appreciation of Fair Value over Original Cost has not been recognized on the utility's books. Such off-book appreciation has not been financed by debt or equity capital recorded on the utility's books. The appreciation over Original Cost book value is therefore recognized for cost of capital purposes at zero cost.

[b] Per Staff witness David Parcell

[c] Per Staff witness David Parcell

UNS Electric, Inc
Equivalent Original Cost Rate Base Return on Equity - Proposed by UNSE

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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Capital Source	Reference	Amount (A)	Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. UNSE - Proposed Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Sch. B	$ 216,575			
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 356,077			
3	Fair Value Rate Base (FVRB)	Sch. B	$ 286,326			
4	FVRB/OCRB Multiple	L.3 / L.1	1.32206			
	II. UNSE - Proposed Capital Structure for OCRB					WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ -	0.00%	0.00%	0.00%
6	Long-Term Debt		$ 102,657	47.40%	5.97%	2.83%
7	Common Stock Equity		$ 113,918	52.60%	10.50%	5.52%
8	Total Capital Supporting OCRB		$ 216,575	100.00%		8.35%
	III. UNSE - Proposed Fair Value Rate of Return					FVROR
9	Short-Term Debt	Col.A, L5	$ -	0.00%	0.00%	0.00%
10	Long-Term Debt	Col.A, L6	$ 102,657	35.85%	5.97%	2.14%
11	Common Stock Equity	Col.A, L7	$ 113,918	39.79%	10.50%	4.18%
12	FVRB Increment Above Original Cost	L3 - L1	$ 69,751	24.36%	1.61%	0.39%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 286,326	100.00%		6.71%
	IV. Net Income and Net Equivalent OCRB Proposed ROE					
14	Net Operating Income (FVROR x FVRB)		$ 19,214 =	$ 286,326 x	6.71%	
	Interest Expense (Debt x Debt Cost):					
15	Short Term Debt		$ - =	$ - x	0.00%	
16	Long Term Debt		$ (6,129) =	$ 102,657 x	5.97%	
17	Net Income		$ 13,085			
18	Common Equity Supporting OCRB	Line 7	$ 113,918			
19	Equivalent ROE on OCRB Proposed by UNSE	L17 /L18	11.49%			

UNS Electric, Inc
Equivalent Original Cost Rate Base Return on Equity - Staff FVROR Option 1

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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Capital Source	Reference	Amount (A)	Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. Staff Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Sch. B	$ 211,527			
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 351,029			
3	Fair Value Rate Base (FVRB)	Sch. B	$ 281,278			
4	FVRB/OCRB Multiple	L.3 / L.1	1.32975			
	II. Staff Proposed Capital Structure for OCRB - Per Staff Witness Parcell					WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ -	0.00%	0.00%	0.00%
6	Long-Term Debt		$ 100,264	47.40%	5.97%	2.83%
7	Common Stock Equity		$ 111,263	52.60%	9.25%	4.87%
8	Total Capital Supporting OCRB		$ 211,527	100.00%		7.70%
	III. Staff Fair Value Rate of Return Option 1					FVROR
9	Short-Term Debt	Col.A, L5	$ -	0.00%	0.00%	0.00%
10	Long-Term Debt	Col.A, L6	$ 100,264	35.65%	5.97%	2.13%
11	Common Stock Equity	Col.A, L7	$ 111,263	39.56%	9.25%	3.66%
12	FVRB Increment Above Original Cost	L3 - L1	$ 69,751	24.80%	0.00%	0.00%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 281,278	100.00%		5.79%
	IV. Net Income and Net Equivalent OCRB Proposed ROE					
14	Net Operating Income (FVROR x FVRB)		$ 16,278 =	$ 281,278 x	5.79%	
	Interest Expense (Debt x Debt Cost):					
15	Short Term Debt		$ - =	$ - x	0.00%	
16	Long Term Debt		$ (5,986) =	$ 100,264 x	5.97%	
17	Net Income		$ 10,292			
18	Common Equity Supporting OCRB	Line 7	$ 111,263			
19	Equivalent ROE on OCRB - Staff FVROR Option 1	L17 /L18	9.25%			

UNS Electric, Inc
Equivalent Original Cost Rate Base Return on Equity - Staff FVROR Option 2

Test Year Ended June 30, 2012
(Thousands of Dollars)

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Line No.	Capital Source	Reference	Amount (A)	Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. Staff Adjusted Fair Value Rate Base					
1	Original Cost Rate Base (OCRB)	Sch. B	$ 211,527			
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 351,029			
3	Fair Value Rate Base (FVRB)	Sch. B	$ 281,278			
4	FVRB/OCRB Multiple	L.3 / L.1	1.32975			
	II. Staff Proposed Capital Structure for OCRB - Per Staff Witness Parcell					WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ -	0.00%	0.00%	0.00%
6	Long-Term Debt		$ 100,264	47.40%	5.97%	2.83%
7	Common Stock Equity		$ 111,263	52.60%	9.25%	4.87%
8	Total Capital Supporting OCRB		$ 211,527	100.00%		7.70%
	III. Staff Fair Value Rate of Return Option 2					FVROR
9	Short-Term Debt	Col.A, L5	$ -	0.00%	0.00%	0.00%
10	Long-Term Debt	Col.A, L6	$ 100,264	35.65%	5.97%	2.13%
11	Common Stock Equity	Col.A, L7	$ 111,263	39.56%	9.25%	3.66%
12	FVRB Increment Above Original Cost	L3 - L1	$ 69,751	24.80%	0.50%	0.12%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 281,278	100.00%		5.91%
	IV. Net Income and Net Equivalent OCRB Proposed ROE					
14	Net Operating Income (FVROR x FVRB)		$ 16,627 =	$ 281,278 x	5.91%	
	Interest Expense (Debt x Debt Cost):					
15	Short Term Debt		$ - =	$ - x	0.00%	
16	Long Term Debt		$ (5,986) =	$ 100,264 x	5.97%	
17	Net Income		$ 10,641			
18	Common Equity Supporting OCRB	Line 7	$ 111,263			
19	Equivalent ROE on OCRB - Staff FVROR Option 2	L17 /L18	9.56%			

UNS Electric, Inc
Equivalent Original Cost Rate Base Return on Equity - Staff FVROR Recommendation

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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Capital Source	Reference	Amount (A)		Percent (B)	Cost Rate (C)	Rate Of Return (D)
	I. Staff Adjusted Fair Value Rate Base						
1	Original Cost Rate Base (OCRB)	Sch. B	$ 211,527				
2	Reconstruction Cost new Depreciated (RCND)	Sch. B	$ 351,029				
3	Fair Value Rate Base (FVRB)	Sch. B	$ 281,278				
4	FVRB/OCRB Multiple	L.3 / L.1	1.32975				
	II. Staff Proposed Capital Structure for OCRB - Per Staff Witness Parcell						WACC
5	Short-Term Debt	L.1 and Sch.D, p.1	$ -		0.00%	0.00%	0.00%
6	Long-Term Debt		$ 100,264		47.40%	5.97%	2.83%
7	Common Stock Equity		$ 111,263		52.60%	9.25%	4.87%
8	Total Capital Supporting OCRB		$ 211,527		100.00%		7.70%
	III. Staff Fair Value Rate of Return Recommendation - Point Between FVROR Options 1 and 2						FVROR
9	Short-Term Debt	Col.A, L5	$ -		0.00%	0.00%	0.00%
10	Long-Term Debt	Col.A, L6	$ 100,264		35.65%	5.97%	2.13%
11	Common Stock Equity	Col.A, L7	$ 111,263		39.56%	9.25%	3.66%
12	FVRB Increment Above Original Cost	L3 - L1	$ 69,751		24.80%	0.080%	0.02%
13	Total Capital Supporting OCRB Plus FVRB Increment		$ 281,278		100.00%		5.81%
	IV. Net Income and Net Equivalent OCRB Proposed ROE						
14	Net Operating Income (FVROR x FVRB)		$ 16,334	=	$ 281,278 x	5.81%	
	Interest Expense (Debt x Debt Cost):						
15	Short Term Debt		$ -	=	$ - x	0.00%	
16	Long Term Debt		$ (5,986)	=	$ 100,264 x	5.97%	
17	Net Income		$ 10,348				
18	Common Equity Supporting OCRB	Line 7	$ 111,263				
19	Equivalent ROE on OCRB - Staff FVROR	L17 /L18	9.30%				

UNS Electric, Inc
Post Test Year Plant Not In Service

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Schedule B-1
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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)
1	Gross Utility Plant in Service	$ 5,755	$ -	$ (5,755)
2	Less: Accumulated Depreciation	$ (564)	$ -	$ 564
3	Net Utility Plant in Service	$ 5,191	$ -	$ (5,191)
4	ADIT on Post Test Year Plant - Renewable	$ (155)	$ -	$ 155
5	Total Rate Base	$ 5,036	$ -	$ (5,036)

Notes and Source:
Col. A: Company filing Schedule B-2, page 3 of 3

Line 4: ADIT on Post Test Year Plant - Renewable data from Company Adjustment Rate Base-ADIT:

	Description	Amount	Reference
6	Federal Total Depreciation	978	UNSE(0504)011881
7	Federal Tax Rate	31.64%	UNSE(0504)011887
8	ADIT - Federal	$ 309	
9	Arizona First Year Depreciation	978	UNSE(0504)011881
10	Arizona Tax Rate	6.93%	UNSE(0504)011887
11	ADIT-State	$ 68	
12	Total ADIT	$ 377	L8+L11
13	Total Booked Depreciation	$ 564	UNSE(0504)011882
14	Booked ADIT-State	$ 39	L13*L10
15	Booked ADIT-Federal	$ 178	L13*L7
16	Total Booked ADIT	$ 218	L14+L15
17	ADIT Adjustment	$ (160)	L12-L16
18	ACC Jurisdictional Factor	97.00%	UNSE Excel File 2012_UNSE_Rev_Req_Model
19	ACC ADIT Adjustment	$ (155)	

UNS Electric, Inc
Remove One-Half of Prepaid D&O Insurance

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Schedule B-2
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Test Year Ended June 30, 2012

Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)=(A)*0.5	Staff Adjustment (C)
1	Prepaid Directors and Officers' Insurance	$ 23,354	$ 11,677	$ (11,677)

Notes and Source:
Col. A: STF 7.05 Prepaid Balance:

	Month	Amount
2	Jun-11	$ -
3	Jul-11	$ 29,050
4	Aug-11	$ 69,511
5	Sep-11	$ 58,250
6	Oct-11	$ 46,989
7	Nov-11	$ 35,727
8	Dec-11	$ 24,466
9	Jan-12	$ 13,204
10	Feb-12	$ 10,563
11	Mar-12	$ 7,923
12	Apr-12	$ 5,282
13	May-12	$ 2,641
14	Jun-12	$ 0
15	Total	$ 303,605
16	13 Month Average	$ 23,354

UNS Electric, Inc
Depreciation and Property Tax Expenses on Post Test Year Plant Not In Service

Test Year Ended June 30, 2012

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Schedule C-1
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Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)
1	Total Company Depreciation Expense on Post Test Year Plant - Renewable	$ 544,149	$ -	$ (544,149)
2	ACC Allocator (L6 Below)	90.77%	$ -	90.77%
3	ACC Depreciation Expense on Post Test Year Plant - Renewable	$ 493,941	$ -	$ (493,941)

Notes and Source:
Col. A, line 1: Company Pro Forma Adjustment Income-Post Test Year Depreciation, UNSE(0504)003942

4	Post Test Year Plant Depreciation Expense Total Company	$ 1,191,035
5	Post Test Year Plant Depreciation Expense ACC Jurisdictional	$ 1,081,139
6	ACC Allocator (L5/L4)	90.77%

Col.A, lines 4 and 5: Company Pro Forma Adjustment Income-Post Test Year Depreciation UNSE (0504)003940

UNS Electric, Inc
Depreciation and Property Tax Expenses on Post Test Year Plant Not In Service

Test Year Ended June 30, 2012

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Schedule C-1
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Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)
1	Renewables Cost less ADOR Depreciation	$ 5,122,144	$ 5,122,144	$ -
2	Plus: Post Test Yr & Delayed Plant Additions	$ 5,755,000	$ -	$ (5,755,000)
3	Adjusted Renewables Cost less ADOR Depreciation	$ 10,877,144	$ 5,122,144	$ (5,755,000)
4	Statutory Full Cash Value Adjustment	20.00%	20.00%	
5	Full Cash Value	$ 2,175,429	$ 1,024,429	$ (1,151,000)
6	Assessment Ratio	19.50%	19.50%	
7	Taxable Value	$ 424,209	$ 199,764	$ (224,445)
8	Average Tax Rate	10.0087%	10.0087%	
9	Property Tax - Total Company	$ 42,458	$ 19,994	$ (22,464)
10	ACC Allocator			54.70%
11	ACC Jurisdictional Property Tax Expense Adjustment			$ (12,288)

Notes and Source:

Col. A, line 1: Company Pro Forma Adjustment Income-Post Test Year Depreciation, UNSE(0504)003946

12	Post Test Year Plant Property Tax Expense Total Company	$ 351,000	UNSE Schedule C-2, page 3
13	Post Test Year Plant Property Tax Expense ACC Jurisdictional	$ 192,000	UNSE Schedule C-2, page 7
14	ACC Allocator (L13/L12)	54.70%	

UNS Electric, Inc
Post Test Year Pay Increase

Test Year Ended June 30, 2012

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Line No.	Description	Total Company Amount Per Company (A)	Total Company Amount Per Staff (B)	Total Company Staff Adjustment (C)=(B)-(A)	Payroll Expense ACC Juris. Factor (D)	Staff Adjustment ACC Juris. (E)=(C)*(D)
	I. Payroll Expense Adjustment					
1	Test Year Recorded Payroll Expense	$ 3,739,206	$ 3,739,206.00	$ -		
2	Payroll Expense Adjustment	$ 218,722	$ 193,723	$ (24,999)	0.97222	$ (24,304)
3	Total Requested Payroll Expense	$ 3,957,928	$ 3,932,929	$ (24,999)	0.97222	$ (24,304)
	II. Payroll Tax Expense Adjustment					
4	Effective tax rate					8.30%
5	Payroll tax Expense Adjustment(L3*L4)					$ (2,017)

Notes and Source:
Col.A: Company Filing Income - Payroll Expense.pdf, UNSE(0504)003907
Col. B, line 2: Company Filing Income - Payroll Expense.pdf, UNSE(0504)003908:

	Description	Per Company (F)	Per Staff (G)
6	Total O&M Wages	$ 4,072,850	$ 4,072,850
7	Average Wage Increase	2.65%	2.35% [a]
8	2013 Wage Increase(L6*L7)	$ 107,931	$ 95,736
9	2013 Wages (L6+L8)	$ 4,180,781	$ 4,168,586
10	2014 Wage Increase(L9*L7)	$ 110,791	$ 97,987
11	2014 Wages(L9+L10)	$ 4,291,571	$ 4,266,573
12	Total Adjustment(L8+L10)	$ 218,721	$ 193,723

Col. D: Payroll Expense ACC Jurisdictional Factor Calculation based on Company Filing, Income - Payroll Expense.pdf, UNSE(0504)003905

	Description	Total Company	ACC Juris.	ACC Factor
13	Payroll Adjustment	$ 218,722	$ 212,645	0.97222

[a]: STF 7.01 and STF 7.02:

	Description	Amount	Increase Rate	Wage Increase
14	Unclassified	$ 2,735,667	2.50%	$ 68,392
15	Classified	$ 1,165,739	2.00%	$ 23,315
16	Total	$ 3,901,406	2.35%	$ 91,706

UNS Electric, Inc
Rate Case Expense

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Schedule C-3
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Test Year Ended June 30, 2012
(Thousands of Dollars)

Line No.	Description	Amount Per Company (A)	Amount Per Staff (B)	Staff Adjustment (C)
1	Estimated Total Rate Case Expense for Current Case	$ 500	$ 300	
2	Amortization Years	2.5	$ 3	
3	Rate Case Expense	$ 200	$ 100	$ (100)

Notes and Source:
Col. A: Company Pro Forma Adjustment Income-Rate Case Expense.pdf, UNSE(0504)003980

UNS Electric, Inc
Incentive Compensation Expense

Test Year Ended June 30, 2012

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Schedule C-4
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Line No.	Description	2012 Recorded Company Total	Total Company Pro Forma Adjustment Per Company	Company Requested Total Company	Staff Recommended Total Company	Staff Adjustments Total Company	ACC Juris. Factor	Staff Adjustments ACC Juris.
		(A)	(B)	(C)=(A)+(B)	(D)	(E)=(D)-(C)	(F)=(J)	(G)=(E)*(F)
	FERC							
1	0583	$ 4,827	$ 8,407	$ 13,234	$ 4,826	$ (8,408)	1.00000	$ (8,408)
2	0592	$ 1,512	$ 2,633	$ 4,145	$ 1,512	$ (2,633)	1.00000	$ (2,633)
3	0593	$ 4,924	$ 8,577	$ 13,501	$ 4,923	$ (8,578)	1.00000	$ (8,578)
4	0901	$ 6,388	$ 11,126	$ 17,514	$ 6,387	$ (11,127)	1.00000	$ (11,127)
5	0908	$ 7,304	$ 12,722	$ 20,026	$ 7,303	$ (12,723)	1.00000	$ (12,723)
6	0920	$ 42,568	$ 58,500	$ 101,068	$ 42,561	$ (58,507)	0.96821	$ (56,647)
7	0920 capitalized	$ (8,981)		$ (8,981)	$ (7,415)	$ 1,566	0.96821	$ 1,516
8	O&M Expense	$ 58,542	$ 101,965	$ 160,507	$ 60,097	$ (100,410)		$ (98,600)
9	0408 FICA Tax	$ -	$ 4,255	$ 4,255	$ 2,508	$ (1,747)	0.96827	$ (1,692)
10	Total	$ 58,542	$ 106,220	$ 164,762	$ 62,605	$ (102,157)		$ (100,291)

Notes and Source:
Cols. A and B: Company Pro Forma Adjustment Income-Incentive Compensation Expense.pdf, UNSE(0504)003782
Col. C: Company Pro Forma Adjustment Income Incentive Compensation Expense.pdf, UNSE(0504)003781:

	FERC	Total Company	ACC	ACC Factor
		(H)	(I)	(J)
11	0583	$ 8,407	$ 8,407	1.00000
12	0592	$ 2,633	$ 2,633	1.00000
13	0593	$ 8,577	$ 8,577	1.00000
14	0901	$ 11,126	$ 11,126	1.00000
15	0908	$ 12,722	$ 12,722	1.00000
16	0920	$ 58,500	$ 56,640	0.96821
17	0408	$ 4,255	$ 4,120	0.96827

Col. D: Staff Recommended Incentive (PEP) Expense - Based on 50/50 Allocation of a Test Year recorded amount

	FERC	Total	Staff Proposed Total Company Before Capitalization	Staff Proposed Total Company Adjust Acct 920 For Capitalization	Staff Proposed Total Company After Capitalization
		(K)	(L)	(M)	(N)
18	0426	$ 67,501			
19	0583	$ 4,827	$ 4,826		$ 4,826
20	0592	$ 1,512	$ 1,512		$ 1,512
21	0593	$ 4,924	$ 4,923		$ 4,923
22	0901	$ 6,388	$ 6,387		$ 6,387
23	0908	$ 7,304	$ 7,303		$ 7,303
24	0920	$ 42,568	$ 42,561	$ (7,415)	$ 35,146
25	O&M Expense	$ 67,523	$ 67,512	$ (7,415)	$ 60,097
26	Total	$ 135,024			

Portion of account 920 capitalized:

		UNSE Recorded	Percent	Staff Adjusted
27	0920 Expense	$ 42,568	82.58%	$ 35,146
28	0920 Capitalized	$ 8,981	17.42%	$ 7,415
29	0920 Before Capitalization	$ 51,549	100.00%	$ 42,561

Col.D: Payroll Taxes Per Staff are in same proportion to UNSE's pro forma adjustment in Col. B.

UNS Electric, Inc
Injuries and Damages

Test Year Ended June 30, 2012

Docket No. E-04204A-12-0504
Schedule C-5
Page 1 of 1

Line No.		Description	Requested by Company	Proposed by Staff	Staff Adjustment Total Company	ACC Factor	Staff Adjustment ACC Juris.
			(A)	(B)	(C)=(B)-(A)	(D)	(E)
	Account No.	**Account Description**					
1	50250	Workers' Compensation	$ 31,927	$ 36,578	$ 4,651	0.9682062	$ 4,503
2	78040	Workers' Compensation	$ (19,994)	$ (35,761)	$ (15,766)	0.9682062	$ (15,265)
3	78100	Injuries and Damages	$ 333,333	$ 3,333	$ (330,000)	0.9682062	$ (319,508)
4	Total		$ 345,266	$ 4,150	$ (341,115)		$ (330,270)

Notes and Source:

Col.A: Company Pro Forma Adjustment Income-Injuries and Damages.pdf, UNSE(0504)003892

			12 Months Ended 6/30/2010	12 Months Ended 6/30/2011	12 Months Ended 6/30/2012	3 Year Average
5	50250	Workers' Compensation	$ 23,433	$ 22,509	$ 49,838	$ 31,927
6	78040	Workers' Compensation	$ 160	$ (31,796)	$ (28,347)	$ (19,994)
7	78100	Injuries and Damages	$ 1,000,000	$ -	$ -	$ 333,333
8	Total		$ 1,023,593	$ (9,287)	$ 21,491	$ 345,266

Col. B: Staff Proposed Average, data from STF 7.06:

			12 Months Ended 12/31/2010	12 Months Ended 12/31/2011	12 Months Ended 12/31/2012	3 Year Average
9	50250	Workers' Compensation	$ 23,159	$ 30,988	$ 55,586	$ 36,578
10	78040	Workers' Compensation	$ (51,060)	$ (23,305)	$ (32,917)	$ (35,761)
11	78100	Injuries and Damages	$ -	$ -	$ 10,000	$ 3,333
12	Total		$ (27,901)	$ 7,683	$ 32,669	$ 4,150

Col. D:
ACC Factor derived from Company Pro Forma Adjustment Income-Injuries and Damages.pdf, UNSE(0504)003891:

	FERC	**Account Description**	Total Company	ACC Juris.	ACC Factor
13	925	Workers' Compensation	$ 323,774	$ 313,480	0.968206

UNS Electric, Inc
Directors and Officers Insurance Expense

Test Year Ended June 30, 2012

Line No.	Description	Total Company Amount 6/30/2012	ACC Factor	ACC Amount 6/30/2012	Staff Adjustment ACC Juris.
		(A)	(B)	(C)=(A)*(B)	(D)=-(C)*0.5
	GL Account				
1	78000	$ 91,110	96.82%	$ 88,213	$ (44,106)

Notes and Source:
Cols. A and B: Company Filing 2012 UNSE Rev Req Model.xls, tab Rev-Exp

UNS Electric, Inc
Edison Electric Institute Industry Association Dues

Test Year Ended June 30, 2012

Line No.	Description	Test Year Amount (A)	Company Adjustment (B)	Company Adjusted Amount (C)	Staff Adjustment to Total Company Amount (D)	ACC Jurisdictional Staff Adjustment (E)	
	Edison Electric Institute Dues						
1	Regular Dues	$ 10,000	$ (2,200)	$ 7,800	$ (2,793)	$ (2,704)	a
2	UARG	$ 10,613	$ -	$ 10,613	$ (10,613)	$ (10,276)	b
3	USWAG	$ 3,360	$ (302)	$ 3,058	$ -	$ -	
4	Total Dues Expense	$ 23,973	$ (2,502)	$ 21,471	$ (13,406)	$ (12,980)	

Notes and Source:

Col. A, lines 1 and 3: Company filing Income-Membership Dues.pdf, UNSE(0504)003894

Col. A, line 2: Company response to UDR 1.54 a.

a: Staff adjustment for Regular Dues based on a disallowance percentage of 49.93% (see page 2)

	Regular Dues	Staff Adjustment	
5	Regular Dues	$ 10,000	
6	Regular Dues disallowance percentage	49.93%	
7	Staff adjustment to Regular Dues	$ 4,993	
8	Company adjustment to Total Company	$ (2,200)	
9	Staff net adjustment to Total Company	$ 2,793	
10	ACC Jurisdictional Allocation Factor	96.82%	[c]
11	Staff Adjustment - ACC Jurisdictional Amount	$ 2,704	

b: **Test Year UARG Provided in UDR 1.54**

12	Total Dues for UARG in Test Year	$ 10,613	
13	Disallowance Percentage	100.00%	[d]
14	Staff Adjustment for UARG Dues	$ 10,613	
15	ACC Jurisdictional Allocation Factor	96.82%	[c]
16	Staff Adjustment - ACC Jurisdictional Amount	$ 10,276	

c: ACC jurisdictional allocation factor taken from UNSE's "2012 Rev Req Model" workpapers

d: see testimony

Edison Electric Institute
Schedule of Expenses by NARUC Category
For Core Dues Activities
For the Year Ended December 31, 2005

NARUC Operating Expense Category	% of Dues	Recommended Disallowance
Legislative Advocacy	20.38%	20.38%
Legislative Policy Research	6.02%	
Regulatory Advocacy	16.49%	16.49%
Regulatory Policy Research	13.99%	
Advertising	1.67%	1.67%
Marketing	3.68%	3.68%
Utility Operations and Engineering	11.31%	
Finance, Legal, Planning and Customer Service	18.75%	
Public Relations	7.71%	7.71%
Total Expenses	100.00%	49.93%

Comments:

* The above percentages represent expenses associated with EEI's core dues activities, based on the operating expense categories established by NARUC. Core expenses are those expenses paid for by shareholder-owned electric utilities' dues.

* The legislative advocacy percent will differ slightly for IRS reporting requirements. For 2005, the lobbying % for IRS reporting is 19.4%.

* Administrative expenses are included in the percentages listed above. Approximately 11% of EEI's core dues expenses are administrative.

UNS Electric, Inc
Allocated Cost of TEP New Headquarters Building to UNSE

Test Year Ended June 30, 2012

Docket No. E-04204A-12-0504
Schedule C-8
Page 1 of 2

Line No.	Description	Per Company (A)	Per Staff (B)	Staff Adjustment Total Company (C)=(B)-(A)	Staff Adjustment ACC Juris. (D)=(C)*96.82% a
	I. Adjust Based on Difference from Test Year Recorded Amount				
1	Proposed Total Amount	$ 774,814	$ 774,814	$ -	$ -
2	Three Year Average	$ 483,297	$ -	$ (483,297)	$ (467,928)
3	Test Year Recorded Amount	$ -	$ 605,374	$ 605,374	$ 586,123
4	Proposed Adjustment	$ 291,517	$ 169,440	$ (122,077)	$ (118,195)
	II. Adjust Allowed Amount for New TEP Headquarters Building				
5	Hours	59,282	59,282		
6	Rate Per Hour	$ 13.07	$ 10.18		
7	Proposed Total Amount	$ 774,816	$ 603,635	$ (171,181)	$ (165,738)
8	**III. Total Adjustment**			$ (293,258)	$ (283,933)
9	Allowed increase over test year recorded amount		$ (1,739)		

Notes and Source:
Col.A: Company filing Income - Building Allocation to Affiliate.pdf, UNSE(0504)003674
Col. B, Lines 1 through 5: Company filing Income - Building Allocation to Affiliate.pdf, UNSE(0504)003674
Col. B, line 6: see page 2 of this schedule
a:ACC jurisdictional allocation factor taken from UNSE's "2012 Rev Req Model" workpapers

UNS Electric, Inc
Building Allocation to Affiliates

Test Year Ended June 30, 2012

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Schedule C-8
Page 2 of 2

Line No.	Description	Per Company (A)	Staff Adjustment to New TEP Headquarters Building (B)	Per Staff (C)=(A)+(B)	Staff Adjustment (D)=(C)-(A)
1	Investment in Land-downtown HQ	$ 8,549,938	$ -	$ 8,549,938	$ -
2	Investment in Office Facilities (OF)	$ 110,941,234	$ (9,632,000) c	$ 101,309,234	$ (9,632,000)
3	Investment in Furniture and Equipment (F&E)	$ 24,687,485	$ -	$ 24,687,485	$ -
4	Less: Accumulated Depreciation Office Facilities	$ (15,482,984)	$ -	$ (15,482,984)	$ -
5	Less: Accumulated Depreciation F&E	$ (5,555,009)	$ -	$ (5,555,009)	$ -
6	Less: Accumulated Deferred Income Taxes OF/ F&E	$ (14,849,526)	$ -	$ (14,849,526)	$ -
7	Net Investment in OF and F&E	$ 108,291,136	$ (9,632,000)	$ 98,659,136	$ (9,632,000)
8	X Rate of Return	8.03%		5.97% a	
9	Required Return on Office Facilities and F&E	$ 8,695,778		$ 5,890,644	$ (2,805,135)
	Add:				
10	O&M Expenses Applicable to OF and F&E	$ 5,453,352		$ 5,453,352	$ -
11	PC/Lan Expenses	$ 6,541,567		$ 6,541,567	$ -
12	Rent on UNS Tower (Net of Direct Sub Charges)	$ -		$ -	$ -
13	Property Taxes Applicable to Office Facilities	$ 966,480	$ (77,906) f	$ 888,574	$ (77,906)
14	Insurance Costs Applicable to Office Facilities	$ 121,850	$ (8,653) e	$ 113,197	$ (8,653)
15	Book Depreciation on Office Facilities	$ 3,288,086	$ (233,511) d	$ 3,054,574	$ (233,511)
16	Income Taxes on Equity Portion of Return	$ 3,091,784		$ - b	$ (3,091,784)
17	Revenue Requirement for Office Facilities and F&E	$ 28,158,897		$ 21,941,907	$ (6,216,990)
18	/ Number of Employees - Excluding SPG	1,036		1,036	
19	Cost Per Employee	$ 27,180		$ 21,179	
20	Annual Labor Hrs. / Employee	2,080		2,080	
21	Facilities Cost Per Hour	$ 13.07		$ 10.18	

Notes and Source:

Col A: Company filing Income-Building Allocation to Affiliate.pdf, UNSE(0504)003678

a: see schedule D, Cost rate of long term debt

b: Staff removed income tax because there is no equity portion allowed in the return, which is based on TEP's cost of debt

c: Staff's adjustments to New TEP's Headquarters Building:

	Description	Amount
22	Retail Space	$ (2,136,000)
23	Vacant Office Space	$ (2,246,000)
24	Half of Parking Structure	$ (5,250,000)
25	Total adjustment	$ (9,632,000)

d Adjustment to Book Depreciation:

26	Investment in Depreciable property per Staff	$ 125,996,718	Lines 2&3, col. C
27	Investment in Depreciable property per UNSE/TEP	$ 135,628,718	Lines 2&3, col. A
28	Ratio of allowed Depreciable property	0.928982592	
29	Book Depreciation on Office Facilities per UNSE/TEP	$ 3,288,086	Line 15
30	Allowed Book Depreciation on Office Facilities per Staff	$ 3,054,574	Line 28 x Line 29
31	Staff adjustment to depreciation	$ (233,511)	Line 30 - Line 29

e Adjustment for Insurance Cost on TEP office buildings

32	Ratio of allowed Depreciable property	0.928982592	Line 28
33	Insurance Costs Applicable to Office Facilities per UNSE	$ 121,850	Line 14
34	Insurance Costs Applicable to Office Facilities per Staff	$ 113,197	Line 32 x Line 33
35	Staff adjustment to insurance	$ (8,653)	Line 34 - Line 35

f Adjustment for Property Taxes on TEP office buildings

36	Allowed investment in land and building per Staff	$ 109,859,171	Lines 1&2, col. C
37	Investment in land and building per Staff	$ 119,491,171	Lines 1&2, col. A
38	Ratio of allowed land and building cost	0.919391534	
39	Property Taxes Applicable to Office Facilities per UNSE/TEP	$ 966,480	Line 13
40	Property Taxes Applicable to Office Facilities per Staff	$ 888,574	Line 38 x Line 39
41	Staff adjustment to property taxes	$ (77,906)	Line 40 - Line 39

UNS Electric, Inc
Interest Synchronization

Test Year Ended June 30, 2012

Line No.	Description	Tax Rate	Per Company Amount (A)	Per Staff Amount (B)	Reference
1	Adjusted Rate Base -ACC		$ 216,575,000	$ 211,527,000	Schedule B
2	Weighted Cost of Debt		2.83%	2.83%	Schedule D
3	Synchronized Interest Deduction		$ 6,129,317	C $ 5,986,453	L1 x L2
4	Increase (Decrease) in Deductible Interest			$ (142,864)	L3, B-A
5	State Income Taxes	4.57%		$ 6,529	Schedule A-1
6	Federal Taxable Income			$ (136,335)	
7	Federal Income Taxes	35.00%		$ 47,717	Schedule A-1
8	Increase (Decrease) to Income Tax Expense			$ 54,246	L5 +L7

UNS Electric, Inc
Depreciation Rates - Estimated Dismantlement Cost

Test Year Ended June 30, 2012

Docket No. E-04204A-12-0504
Schedule C-10
Page 1 of 1

Line No.	Description	Plant Balance as of June 2012 (A)	Plant Cost Recovery Rate Per Existing Depreciation Rates (B)	Company Estimated Dismantlement Cost Recovery Per Study (C)	Generating Plant Depreciation Per Company Including Dismantlement Estimates (D)=(A)*((B)+(C))	Total Generating Plant Depreciation Per Staff (E)=(A)*(B)	Staff Adjustment to Remove Estimated Dismantlement Depreciation (F)=(E)-(D)
	Valencia	[**BEGIN CONFIDENTIAL**]			[**BEGIN CONFIDENTIAL		
	FERC						
1	341	[redacted]	0.0205	0.0011	[redacted]		
2	342		0.0252	0.0015			
3	343		0.0253	0.0017			
4	344		0.0233	0.0012			
5	345		0.0235	0.0015			
6	346		0.0264	0.0014			
7	Total						
	Black Mountain						
8	341	[redacted]	0.0262	0.0008	[redacted]		
9	342		0.0262	0.0008			
10	343		0.0262	0.0008			
11	344		0.0262	0.0008			
12	345		0.0262	0.0008			
13	346		0.0262	0.0008			
14	Total						
		[**END CONFIDENTIAL**]				[**END CONFIDENTIAL**]	
15	Total				$ 2,367,875	$ 2,277,749	$ (90,125)

Notes and Source
Col. A: CONFIDENTIAL information from STF 5.3
Col. B: UDR 1.73 Attachment Depreciation Study
Col.C: Company witness Dukes direct testimony Exhibit DJD-1
Col. E: Staff Allowance uses existing authorized depreciation rates which do not include estimated dismantlement costs

UNS Electric, Inc
Base Cost of Fuel and Purchased Power

Test Year Ended June 30, 2012

Line No.	Description	Per Company (A)	Per Staff (B)	Staff Adjustment (C)
1	Test Year Adjusted Billing Determinants (kWh)	1,740,589,963	1,740,589,963	$ -
2	Proposed Base Cost of Fuel and Purchased Power	$ 0.05174	$ 0.05706	$ 0.00532
3	Base Cost of Fuel and Purchased Power	$ 90,058,125	$ 99,312,842	$ 9,254,717
4	Revenue for Fuel and Purchased Power			$ 9,254,717
5	Net Impact on Pre-Tax Operating Income			$ -

Notes and Source

Col.A: The Company has proposed to remove all fuel and purchased power cost from base rates, Company witness DeConcini Direct Testimony Pages 17 and 18.

Col.B: See page 3 of this Schedule for line 2, base cost of fuel and purchased power

UNS Electric, Inc | Docket No. E-04204A-12-0504
Base Cost of Fuel and Purchased Power-Company Calculated Rate | Schedule C-11

Test Year Ended June 30, 2012

Line No.	Month	UNSE Recorded PPFAC Includable Costs (A)	Actual PPFAC Includable Sales (GWH) (B)	Base Cost of Fuel (Dollars per kWh) (C)
		[**BEGIN CONFIDENTIAL**]		
1	Jun-14	[redacted]		
2	Jul-14			
3	Aug-14			
4	Sep-14			
5	Oct-14			
6	Nov-14			
7	Dec-14			
8	Jan-15			
9	Feb-15			
10	Mar-15			
11	Apr-15			
12	May-15			
13	12 month (6/14-5/15)			
			[**END CONFIDENTIAL**]	
14	Base Cost of Fuel			$ 0.05174

Notes and Source

STF 8.9(a)-Confidential COMPETITIVELY SENSITIVE-CONFIDENTIAL

UNS Electric, Inc
Base Cost of Fuel and Purchased Power-Staff Proposed Rate

Test Year Ended June 30, 2012

Docket No. E-04204A-12-0504
Schedule C-11
Page 3 of 5

Line No.	Description	Base Cost of Fuel (Dollars per kWh) (A)
1	Base Cost of Fuel	$ 0.05706

Notes and Source

Staff recommends setting the base cost of fuel at the current per-kWh level of recovery for PPFAC-includable costs. Using this rate will help coordinate the base cost of fuel with the establishment of a new PPFAC rate in 2014 and will help avoid a large build-up of unrecovered fuel costs that could occur if a lower base cost of fuel, such as the $0.05174 proposed by UNSE were to be used.

The components listed below illustrate how this new base cost of fuel coordinates with fuel and purchased power recovery for UNSE based on PPFAC rates expected to be in place effective September 1, 2013:

2	Current Average Base Cost of Fuel based upon supporting documents for ACC Decision No. 71914, per UNSE	$	0.06107
3	Forward Component Rate - FC effective September 1, 2013, per UNSE	$	(0.01125)
4	True-Up Component Rate - HC per UNSE	$	0.00724
5	Per kWh recovery of PPFAC-includable fuel and purchase power costs	$	0.05706

UNS Electric, Inc Docket No. E-04204A-12-0504
Base Cost of Fuel and Purchased Power-Company Updated Forecast Schedule C-11

Test Year Ended June 30, 2012

Line No.	Month	UNSE Recorded PPFAC Includable Costs	Actual PPFAC Includable Sales (MWH)	Base Cost of Fuel (Dollars per kWh)
		(A)	(B)	(C)
		[**BEGIN CONFIDENTIAL**]		
1	Jun-14	[redacted]		
2	Jul-14			
3	Aug-14			
4	Sep-14			
5	Oct-14			
6	Nov-14			
7	Dec-14			
8	Jan-15			
9	Feb-15			
10	Mar-15			
11	Apr-15			
12	May-15			
13	12 month (6/14-5/15)			
			[**END CONFIDENTIAL**]	
14	Base Cost of Fuel			$ 0.050908

Notes and Source
STF 8.9(b)-Confidential COMPETITIVELY SENSITIVE-CONFIDENTIAL

UNS Electric, Inc
Base Cost of Fuel and Purchased Power-Actual through April 2013

Docket No. E-04204A-12-0504
Schedule C-11
Page 5 of 5

Test Year Ended June 30, 2012

Line No.	Month	UNSE Recorded PPFAC Includable Costs	Actual PPFAC Includable Sales (GWH)	Base Cost of Fuel (Dollars per kWh)
		(A)	(B)	(C)
1	May-12	$ 6,878,015	137,147.13	$ 0.05015
2	Jun-12	$ 8,451,525	164,825.51	$ 0.05128
3	Jul-12	$ 9,172,822	186,657.67	$ 0.04914
4	Aug-12	$ 9,488,917	194,880.10	$ 0.04869
5	Sep-12	$ 8,229,790	167,154.35	$ 0.04923
6	Oct-12	$ 6,641,628	149,683.40	$ 0.04437
7	Nov-12	$ 5,982,188	111,733.73	$ 0.05354
8	Dec-12	$ 6,754,885	115,868.27	$ 0.05830
9	Jan-13	$ 7,120,416	152,868.87	$ 0.04658
10	Feb-13	$ 6,006,413	122,914.02	$ 0.04887
11	Mar-13	$ 6,279,070	116,588.60	$ 0.05386
12	Apr-13	$ 6,495,666	116,262.33	$ 0.05587
13	12 month (May 2012 - April 2013)	$ 87,501,335	1,736,583.98	
14	Base Cost of Fuel			$ 0.05039

Notes and Source

UNSE Fuel and Purchased Power PPFAC Schedule 3 Excel File
Col.A: UNSE PPFAC Schedule 3, line 10, through April 2013
Col.B: UNSE PPFAC Schedule 3, line 2, through April 2013

UNS Electric, Inc.
Docket No. E-04204A-12-0504
Attachment RCS-3
Copies of UNSE's Non-Confidential Responses to Data Requests and Documents Referenced in the Direct Testimony and Schedules of Ralph C. Smith

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
STF 7.01	Payroll percentage increases for 2013 and 2014 were projected based on market data and internal Company discussion because they had yet occurred when the current rate case was filed	No	1	2
STF 7.02	Actual percentage of pay increases broken out by union and non-union groups for 2013	No	3	3 - 5
UDR 1.34 Supplemental	All UNSE non-union employees participate in UNS' short-term incentive program. Provides description of the program, as well as its payout requirements (without confidential attachments)	No	3	6 - 8
UDR 1.62	UNSE's proposed treatment of incentive compensation expense deiviates from principles and policies establised in prior Commission Orders	No	1	9
UDR 1.54	UNSE provided information concerning Edison Electric Institute, including details for test year assessment amounts	No	6	10 - 15
	Supplemental response to data request STF 22.6(I) in Tucson Electric Power Company's Docket No. E-01933A-12-0291 regarding Downown Tucson has abundant relatively inexpensive parking and TEP did not need area in the headquarters parking garage to be available for the 12,000 gsf of retail space	No	5	16 - 20
	Response to data request STF 26.07 in Tuscon Electric Power Company's Docket No. E-01933A-12-0291 regarding the cost of the new UniSource headquarters building broken out by components, including cost for the parking structure	No	2	21 - 22
STF 7.05	13 monthly amounts of UNSE's Prepaid D&O Liability Insurance for June 2011 through June 2012	No	2	23 - 24
STF 7.06 Supplemental	Recorded Injuries and Damages expense recorded for calendar years 2005-2012	No	2	25 - 26
UDR 1.73	UNSE's most recent depreciation study is a 2009 Depreciation Study	No	37	27 - 63
	Total Pages Including this Page		63	

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 10, 2013

STF 7.01

Payroll. Refer to the Company's PDF workpapers Income-Payroll Expense.pdf, UNSE(0504)003915.

a. Identify what groups of employees are within Classified.

b. Identify what groups of employees are within the category Unclassified.

c. In which group are Union Employees?

d. Show and explain in detail how the 2.5% and 3.0% increase for 2013 was derived.

e. As of what dates did the increases of 2.5% and 3% become effective? What amounts were these increases applied to?

f. Provide comparable Classified Total and Unclassified total payroll to that shown on UNSE(0504)003915 for the 12 months ending March 31, 2013.

RESPONSE:

a. Classified employees are those represented by a union.

b. Unclassified employees are those not represented by a union.

c. Union Employees are in the Classified group.

d. The percentages of increases for 2013 and 2014 were projected based on market data and internal Company discussions, as they had not yet occurred when the rate case was filed.

e. Unclassified merit increases took effect March 25, 2013. IBEW Local Union 769 increase took effect January 14, 2013. IBEW Local Union 387 increase took effect March 1, 2013. These increases applied to existing wage rates.

f. The comparable data for the 12 months ending March 31, 2013 are as follows. Please note that this represents only the portion of payroll charged to Operations and Maintenance expense and is comparable to the pro forma adjustment. It does not include payroll expense capitalized, or UNS Electric payroll expense charged to affiliates.

Employee Class	12 Month Ending 3/31/2013
Classified Total	2,735,667
Unclassified Total	1,165,739
	3,901,407

RESPONDENT:

Pricing (Anne Liu) (part f) and Gabrielle Camacho (parts a-e).

WITNESS:

Dallas Dukes

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 10, 2013

STF 7.02

Payroll. Refer to the response to UDR 1.21 and UDR 1.22.

a. Identify the dollar amount of wages to which each of the increases listed in that response was applied.

b. Provide the test year amount of payroll broken out into the same categories as UDR 1.21: (1) Union 387; (2) Union 769 and (3) Non-Union.

c. Identify the actual 2013 pay increase for each group identified in response to part b.

d. Please update UDR 1.22 to show the range of recommended increases and the budget for 2013 and 2014.

RESPONSE:

a. The table below details the dollar amount of base wages to which each of the increase listed in UDRs 1.21 and 1.22 were applied:

	Dollar Amount of Wages		
Year	Union – 387	Union – 769	Non-Union
2009	$1,476,946	$5,955,810	$1,946,710
2010	$1,504,339	$5,934,074	$1,917,424
2011	$1,469,666	$5,641,147	$1,964,135
2012	$1,528,883	$5,833,547	$2,035,408

b. The table below contains the amount of payroll by group identified in UDRs 1.21 and 1.22:

	Test Year Amount of Payroll		
Year	Union – 387	Union – 769	Non-Union
July 1, 2011- June 30, 2012	$2,011,702	$6,584,510	$2,313,067

c. The actual 2013 pay increase for each group identified in response to part b are listed in the table below:

	Wage Increase (%)		
Year	Union – 387	Union – 769	Non-Union
2013	2.5%	2.5%	2.0%

**UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 10, 2013**

d. Union employees do not receive merit increases.

Management is required to keep the overall spending for merit increases for non-union employees within the established budget. Individual merit increases vary based on performance and other factors. Please see the table below for the actual recommended ranges of merit increases and budget for non-union employees for 2013. 2014 figures are projected.

Year	Non-union Merit Increases (%)	
	Range of recommended individual merit increases	Budget
2013	0 - 4.35	2.00
2014	0 - 4.75	3.00

RESPONDENT:

Gabrielle Camacho

WITNESS:

Dallas Dukes

UNS ELECTRIC INC.'S REVISED RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 12, 2013

STF 7.02

Payroll. Refer to the response to UDR 1.21 and UDR 1.22.

a. Identify the dollar amount of wages to which each of the increases listed in that response was applied.

b. Provide the test year amount of payroll broken out into the same categories as UDR 1.21: (1) Union 387; (2) Union 769 and (3) Non-Union.

c. Identify the actual 2013 pay increase for each group identified in response to part b.

d. Please update UDR 1.22 to show the range of recommended increases and the budget for 2013 and 2014.

RESPONSE: June 10, 2013

b. The table below contains the amount of payroll by group identified in UDRs 1.21 and 1.22:

Year	Test Year Amount of Payroll		
	Union – 387	Union – 769	Non-Union
July 1, 2011- June 30, 2012	$2,011,702	$6,584,510	$2,313,067

RESPONDENT:

Gabrielle Camacho

WITNESS:

Dallas Dukes

REVISED RESPONSE: **June 12, 2013**

b. The table below contains the revised amount of payroll by group identified in UDRs 1.21 and 1.22:

Year	Test Year Amount of Payroll		
	Union – 387	Union – 769	Non-Union
July 1, 2011- June 30, 2012	$2,011,342	$6,577,706	$2,302,942

RESPONDENT:

Gabrielle Camacho

WITNESS:

Dallas Dukes

**UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO
UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
April 30, 2013**

UDR 1.34

Incentive Programs. List and describe all retirement and incentive programs available to Company officers and employees. Provide a complete copy of each incentive compensation program and all related materials. Identify the goals and targets in each year 2009-2012, and all evaluations of whether such goals were exceeded.

a. Specifically identify the cost of any SERP or similar programs directly charged or allocated.

b. State the cost by program, of each retirement program directly charged or allocated.

RESPONSE: January 4, 2013

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

Incentives:

All UNS Electric non-union employees participate in UNS's short-term incentive program ("PEP"), which is tied to annual compensation.

The structure determines eligibility for certain bonus levels by measuring UNS's performance as it impacts four stakeholder categories:

- Investors;
- Customers;
- Community/Environment; and
- Employees.

Levels of achievement in each category are assigned percentage-based "scores," and those scores are combined to calculate the final payout level. The amount made available for bonuses through this formula may range from 15 percent to 147.5 percent maximum of the targeted payout level.

Over the period of 2009-2012, the Investor category has encompassed a range of 35-40 percent of the bonus structure, the Customer category has ranged from 30-35 percent, and the Community/Environment and Employees categories respectively account for 15% each.

The scores from each goal are totaled and then multiplied by the targeted bonus of each employee to determine the total available dollars to be paid out. Targeted bonus percentages, as a percent of base salary, range from 3% - 14% for regular unclassified employees, and 20-25% for senior management level employees. Bonus percentages, as a percent of base salary, are used in the calculation of total available dollars, and actual awards may vary at management's discretion based on individual employee contribution. If a payout is achieved, employee PEP bonuses will be distributed near the end of the first quarter the following year. Please see the files listed below for the goals for each year and evaluations of yearly performance.

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-12-0504 April 30, 2013

File Name	Bates Numbers
UDR 1.34 2009-2011 PEP Hist Prcnts-Pos-Confidential.pdf	UNSE\002692-002693
UDR 1.34 2009 PEP Goals-Confidential.pdf	UNSE\002694-002695
UDR 1.34 2010 PEP Goals-Confidential.pdf	UNSE\002696-002697
UDR 1.34 2011 PEP Goals-Confidential.pdf	UNSE\002698-002699
UDR 1.34 2012 PEP Goals-Confidential.pdf	UNSE\002700-002701

Retirement Programs:

UNS Electric employees are eligible to participate in The Pension Plan for Employees of UniSource Energy Services. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.34 UES_Plan_SPD-Confidential.pdf	UNSE\002702-002735

Additionally, UNS Electric employees are eligible to participate in the TEP 401(k) Plan as described below:

401(k) Plan

TEP's 401(k) Plan takes advantage of Section 401(k) of the Internal Revenue Code and permits employees to voluntarily save from 1/2% to 50% of their pay, before any deduction for state or federal income taxes. The Company matches $0.50 on the dollar, up to 6% of pay saved in the 401(k) Plan for UNS Electric employees.

Employees' savings and Company matching contributions are invested in one or any combination of a selection professionally managed investment funds at the direction of the employee. Employees are eligible to join the 401(k) Plan upon their date of employment. Company matching contributions are fully and immediately vested. Please see the file listed below for the summary plan description.

File Name	Bates Numbers
UDR 1.34 401K_SPD-Confidential.pdf	UNSE\002636-002691

a. SERP expense allocated to UNS Electric and charged to FERC 0426 during the test year was $148,643.

b. Retirement program expense (other than SERP) directly charged or allocated to UNS Electric during the test year was as follows:

UES Union and Salaried Pension Plans (FERC 0926)	$366,838
UES 401K Plan (FERC 0926)	94,487
TEP Pension/401K (FERC 0926)	308,573
UNS Gas Pension/401K (FERC 0926)	16,671
Deferred Compensation Plan (FERC 0920)	5,476
Total	$792,045

UNS ELECTRIC, INC.'S SUPPLEMENTAL RESPONSE TO UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-12-0504 April 30, 2013

RESPONDENT:

Georgia Hale, Ann Eckert and Gabrielle Camacho

WITNESS:

Dallas Dukes

SUPPLEMENTAL RESPONSE: **April 30, 2013**

In response to STF 3.05, please see UDR 1.34 2013 PEP Goals-Confidential.pdf, Bates No. UNSE\013785-013786, to update the goals through 2013.

a. In response to STF 3.15a, please see the supplemental response to UDR 1.35 b-c for SERP account and subaccount detail and test-year information.

RESPONDENT:

Gabrielle Camacho, Ann Eckert and Gabrielle Camacho

WITNESS:

Dallas Dukes

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
January 4, 2013**

UDR 1.62

Accounting Adjustments.

a. Please identify any aspects of the Company's accounting adjustments and revenue requirement claim that represent a conscious deviation from the principles and policies established in prior Commission Orders.

b. Identify each area of deviation, and for each deviation explain the Company's perception of the principle established in the prior Commission Orders, and the dollar impact resulting from such deviation.

c. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE:

a. The only revenue requirement claims that knowingly deviate from the Commission's prior decision for UNS Electric is the "Incentive Compensation Adjustment".

b. In Commission Decision No. 71914 (September 30, 2010), based on the Direct Testimony of Commission Staff witness, Dr. Thomas H. Fish, 50 percent of the incentive compensation expense was removed. To cite Dr. Fish's testimony, "Since both Company stock holders and rate payers benefit from PEP incentive compensation I recommend that the Company share the incentive compensation expenses with the owners of the Company for PEP-related incentive compensation."

UNS Electric is requesting full recovery of the normal and recurring level of incentive compensation expense for unclassified employees and 50% of incentive compensation for officer and senior management level employees.

c. Please see supporting pro forma workpapers provided in response to UDR 1.01, specifically the files Income – Incentive Compensation.pdf, Bates Nos. UNSE\003781-003791, and Income – Incentive Compensation.xlsm, for the accounts affected and dollars impacted.

RESPONDENT:

Pricing (Anne Liu)

WITNESS:

Dallas Dukes

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
January 4, 2013**

UDR 1.54

Industry Association Dues. Please list all membership payments made to industry associations (e.g., Edison Electric Institute, etc.) requested for recovery during the test year. Identify the account into which such amounts are charged.

a. State the purpose and objective of each organization listed.

b. Provide descriptive material the Company has concerning each organization's financial statements, annual budget, and activities.

c. Do any of the organizations listed engage in lobbying activities, attempts to influence public opinion, institutional or image-building advertising? If so, list each organization which engages in such activities, and state the Company's best estimate of the portion of the organization's expenses devoted to such activities. Explain and show how such estimates were derived. State if the Company has included the portions of dues related to such activities in the test year.

d. For each of the organizations identified, please describe how the Company perceives such expense to benefit ratepayers.

RESPONSE:

Please see part "a", below, for the membership payments made to industry associations requested for recovery during the test year. The account used was FERC 930.

a. Utility Air Regulatory Group ("UARG"). UARG is a voluntary association of electric utility companies and organizations established to advance the interests of its members at the federal level in air quality regulation matters by: i) participating in administrative and regulatory proceedings; ii) advocacy before administrative and regulatory agencies; and iii) conducting litigation. UARG also provides its members with interpretations and clarifications of federal air regulations.

UNS Electric's total dues for UARG during the test year were $10,612.69. UARG dues are calculated based on total generating nameplate capacity and total gas-fired generation nameplate capacity. No portion of the dues relates to lobbying activities

Edison Electric Institute ("EEI"). EEI is the association of U.S. shareholder-owned electric companies. Organized in 1933, EEI works closely with all of its members, representing their interests and advocating equitable policies in legislative and regulatory arenas. Please see part "c", below, for dues paid.

Utility Solid Waste Activities Group ("USWAG"). Please see the files listed below for USWAG membership and dues information.

File Name	Bates Numbers
UDR 1.54 USWAG Dues Formula1.pdf	UNSE\002895
UDR 1.54 USWAG Member Assessment Form.pdf	UNSE\002896
UDR 1.54 USWAG Member Update Memo.pdf	UNSE\002897

**UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
January 4, 2013**

The USWAG membership costs are charged as follows: 90% to TEP and 10% to UNSE.

b. Through UNS Electric's membership in these organizations, the Company possesses information on the budgets or activities of these organizations, that information could shed light on strategic direction and is considered confidential business information. Information about the associations' finances and activities is available on public websites and member-only websites. Both EEI and USWAG have public websites, but restrict confidential information to their member-only websites. UARG only has a members'-only site, which requires membership and password access.

c. UARG's charter specifically excludes legislative lobbying activities.

EEI and USWAG engage in legislative advocacy activities. The portions of the dues related to such activities were per EEI's letter of March 29, 2012 and have been excluded in the test year, this includes EEI's lobbying efforts to preserve or retain significant funding from Congress for the low-income home-energy assistance program. Please see the file, UDR 1.54 EEI 2012 Lobbying Letter.pdf, Bates No. UNSE\002894, for the referenced EEI letter.

	Total Paid	% for Legislative Advocacy*	Expenses Excluded
EEI	10,000	22%	2,200
USWAG	3,360	9%	302
Total	13,360		2,502
*Per EEI March 29, 2012 Letter – Copy attached.			

d. Compliance with federal air quality regulations can result in the need to install and operate pollution control equipment costing hundreds of millions of dollars. UARG's involvement in new rulemakings and rule updates provides a check against overly burdensome and costly regulations. When federal agencies pass regulations that overstep their authority, UARG has a strong track record for having those regulations rescinded or modified, resulting in reduced operating costs for UARG members.

Similarly, EEI works to ensure favorable regulatory outcomes at the Federal Energy Regulatory Commission, the Department of Energy, the Environmental Protection Agency and other federal agencies through direct dialogue, and formal comments on key policy issues affecting the electric utility industry. In addition to public policy leadership, EEI provides critical industry data, strategic business intelligence, and one-of-a-kind conferences and forums. All of which assist UNS Electric in reducing operating costs, which savings are passed on to its customers.

RESPONDENT:

Pricing (Anne Liu), Chuck Komadina, Erik Bakken and Jeffrey Yockey

WITNESS:

Dallas Dukes

USWAG DUES FORMULA

Capacity (MW)	Shares	Coal (MW)	Shares	Elec Sales (Million MWhr)	Shares	Gas Sales (Million Cubic Feet X 10^3)	Shares
0	0	0	0	0	0	0	0.000
1 - 500	0.125	1 – 500	0.125	0.1 - 10	0.125	0.1 - 50	0.125
501 – 2000	0.250	501 – 2000	0.250	>10 – 20	0.250	>50 – 100	0.250
2001 - 5000	0.375	2001 –4000	0.375	>20 – 40	0.375	>100 – 200	0.375
5001 – 10000	0.500	4001 – 7000	0.500	>40 – 60	0.500	>200	0.500
10001 – 15000	0.625	7001 – 10000	0.625	>60 – 80	0.625		
15001 – 20000	0.750	10001 – 15000	0.750	>80 – 100	0.750		
20001 – 25000	0.875	15001 – 20000	0.875	>100 – 150	0.875		
25001 – 30000	1.000	20001 – 25000	1.000	>150 – 200	1.000		
30001 – 35000	1.125	> 25000	1.125	>200	1.125		
35001 – 40000	1.250						
40001 – 45000	1.375						
45001 – 50000	1.500						
> 50000	1.625						

Membership Share equals the sum of the fractional shares from each category.
Minimum membership share equals .125 shares; minimum dues equals $7,500.

October 2006

USWAG 2012 Assessment Form

NAME: Charles W. Komadina

COMPANY: UniSource Energy Corporation

PHONE NUMBER: 520-918-8316

E-MAIL ADDRESS: ckomadina@tep.com

The 2012 assessment is based on capacity and/or sales figures as of December 31, 2011.

Please fill in the following information:

Total Generating Capacity as of 12/31/11: 2,336 MW

+

Coal Capacity as of 12/31/11: 1,505 MW

+

Electric Sales as of 12/31/11: 11.2 Million MWhr

+

Gas Sales as of 12/31/11: 13,194 Million Cubic Feet

Please return by January 31, 2012 by e-mail, fax, or regular mail to:

Gayle Novak
USWAG Program Services
701 Pennsylvania Ave., N.W.
Washington, D.C. 20004-2696
E-mail: gayle.novak@uswag.org
Fax: 202/508-5150
Phone: 202/508-5654

Utility Solid Waste Activities Group
c/o Edison Electric Institute
701 Pennsylvania Avenue, NW
Washington, DC 20004-2696
202-508-5645
www.uswag.org

USWAG

TO: USWAG Policy Committee

FROM: Gayle Novak

DATE: October 26, 2011

SUBJECT: Annual Updating of USWAG Membership

Attached please find the USWAG Membership Commitment Form and the USWAG Assessment Form.

Dues Assessments

Dues are calculated by adding total capacity, coal capacity, electric sales, and gas sales together; please refer to the USWAG Dues Formula for reference. The 2012 assessment is based on capacity and/or sales figures as of December 31, 2011. Holding companies are requested to return one form reflecting cumulative capacity and/or sales figures from your subsidiaries. Billings for 2012 USWAG dues will be sent out in February. The Policy Committee approved the 2012 budget, and agreed to a per share dues assessment of $33,600. The per share assessment is slightly higher than that originally discussed at the Summer Budget Planning meeting to be able to have a round number for each one-eighth share—$4200—and thereby facilitate accounting.

Reminder of Policy Regarding USWAG Membership

In an effort to mitigate against delays in establishing USWAG membership for the year, the USWAG Policy Committee recommended, starting in 2003, the use of the Membership Commitment Form. The purpose of this form is to allow us to establish USWAG membership as soon as possible while giving you extra time if needed to compile information for the Assessment Form. Establishing USWAG membership for 2012 in a more timely fashion will eliminate the necessity to withhold dissemination of members-only information pending resolution of membership and will also facilitate budget management.

In keeping with this policy, **the Membership Commitment Form must be returned to us no later than close of business, December 16th. If you do not return this form by December 16th, we will assume that you are not renewing membership for 2012 and you will lose access to USWAG information.** [If you paid dues early for 2012, you do not need to return the Membership Commitment Form.]

In addition, **the 2012 Assessment Form must be returned by January 31, 2012** so that dues can be processed.

The Membership Commitment Form and the Assessment Form are being transmitted in Word format to allow members to fill out and return them electronically if they prefer. If you choose to fill out the form(s) electronically, you may delete the lines and simply type the requested information in the appropriate area.

If you have any questions, please contact me at 202/508-5654 or gayle.novak@uswag.org.

Attachments

701 Pennsylvania Avenue, N.W. | Washington, D.C. 20004-2696 | 202.508.5000 | www.eei.org

Power by Association℠

EEI Edison Electric Institute

March 29, 2012

Dear Committee Members:

We have completed the calculation of EEI's actual final expenditures relating to influencing legislation for calendar year 2011. A total of 21.3% of our regular dues was devoted to non-deductible activities in 2011. In addition, 29.1% of the assessment for the SFA for Industry Issues, 6.0% of the assessment for the SFA for Environment, 8.2% of the assessment for the Utility Solid Waste Activities Group ("USWAG"), and 68.2% of the assessment for the Water Advocacy Coalition (WAC) were devoted to non-deductible activities in 2011. These percentages may affect the extent to which your 2011 EEI dues and SFA payments qualify as a deductible business expense.

These actual figures differ from the earlier estimates contained in your 2011 dues invoice and our letter dated June 9, 2011. For your convenience, a chart with original and revised estimates for 2011 and 2012, as well as actual results for 2011, is provided below. The actual percentages for calendar year 2012 will be provided to you by mid-2013.

Summary of 2011 and 2012 Estimated, Revised and Actual Percentages

	Regular Activities	Separately Funded Activities (SFA)			
	Core Dues	Industry Issues	Environment	USWAG	WAC
2011					
Original Estimate on dues invoice	21.0%	35.0%	2.0%	-	-
Revised Estimate – June 2011	26.0%	36.0%	2.0%	6.0%	50%
Actual/Final	**21.3%**	**29.1%**	**6.0%**	**8.2%**	**68.2%**
2012					
Original Estimate on dues invoice	26.0%	36.0%	2.0%	-	-
Revised Estimate – March 2012	22.0%	34.0%	6.0%	9.0%	75.0%

Please do not hesitate to contact me at (202) 508-5540 or jschlenker@eei.org if you have any questions.

Sincerely,

John Schlenker
CFO & Treasurer

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

STF 22.06

UniSource Headquarters Building. Refer to the response to STF 16.08 and to TEP's workpapers for TEP rate base adjustment A and expense adjustments O and P.

a. What is the total cost of the new UniSource headquarters building? Identify all costs by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

b. What amounts for the new UniSource headquarters building has TEP included in jurisdictional rate base (1) before and (2) after TEP's pro forma adjustments? Show by account.

c. What amounts for the new UniSource headquarters building has TEP included in jurisdictional operating expenses (1) before and (2) after TEP's pro forma adjustments? Show by account.

d. Has TEP included any rental income related to the new UniSource headquarters building in jurisdictional revenues? If so, please identify the amounts of such jurisdictional revenue (1) before and (2) after TEP's pro forma adjustments and show the revenue amounts by account.

e. Identify all costs in rate base and operating expenses for the 12,000 gsf of retail space, by account.

f. Refer to the response to STF 16.08(d). Why are there no UniSource personnel in the UniSource headquarters building?

g. Refer to STF 16.08 TEP HQ Stacking Plan 2012-20-24-Confidential. On what floor (or floors) is the 12,000 gsf of retail space?

    1. Show the amount of retail space on each floor and reconcile it to the diagram provided in STF 16.08 TEP HQ Stacking Plan 2012-20-24-Confidential.

h. What is the total cost of the underground parking? Provide by account.

    1. Identify all costs by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

i. How much of the underground parking will be available for retail use?

j. What other parking besides the [BEGIN CONFIDENTIAL] 249,410 gsf of underground parking [END CONFIDENTIAL] is available in the HQ building area for the 12,000 gsf of retail space?

k. Is TEP aware of any ordinances or regulations that provide for a certain number of parking places or that require the availability of parking for buildings with retail space?

    1. If so, please identify those requirements as it would apply to the 12,000 gsf of retail space.

    l. How much parking area needs to be available related to 12,000 gsf of retail space? Explain fully and identify any source documents relied upon.

m. Identify the cost for each floor, for floors 1 through 9, by account.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

1. Identify the cost by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

n. Identify the total cost for floors 1 through 9, by account.

1. Identify the cost by balance sheet account as of 12/31/2011, and by income statement account for each month of 2011 and 2012.

o. Identify in detail how TEP has allocated the cost of non-occupied space in total and for each floor.

p. Please confirm the occupied space per occupant listed in the following table, compiled from TEP's responses to STF 16.08(a) and (d), and identify any corrections or revision needed to make the information totally accurate:

UniSource Headquarters				
Occupied and Unoccupied Space and Space Per Occupant				
[BEGIN CONFIDENTIAL]				
Floor	Space GSF	Occupied Percent	Occupied Space	Unoccupied Space
9	28,750	87%	25,013	3,738
8	28,750	75%	21,563	7,188
7	28,750	86%	24,725	4,025
6	28,750	94%	27,025	1,725
5	28,750	87%	25,013	3,738
4	37,410	95%	35,540	1,871
3	40,660	59%	23,989	16,671
2	31,730	79%	25,067	6,663
1	27,730	100%	27,730	-
Total	281,280		235,663	45,617
	[END CONFIDENTIAL]			
Current occupancy			539	
Space per occupant			437.22	
Source: TEP response to STF 16.08(a) and (d)				

q. Refer to the response to STF 16.08(d). Please confirm that there are no employees in the UniSource headquarters building for any of the following affiliates, and if there are any employees at the headquarters building for any of these, identify the count (1) as of 12/31/2011 and (2) at present/most recent available:

1. UniSource Energy, Inc.
2. UNSE
3. UNSG
4. UED
5. Millennium

r. Show in detail how each of the cost per square foot figures in the response to STF 16.08(e) were derived.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

s. Are the costs per square foot figures in the response to STF 16.08(e) annual costs?

1. If not, for what period do they represent?

t. Can the cost of the unoccupied office space in the UniSource headquarters building be derived by multiplying the $263/sf listed in the response to STF 16.08(e) by the number of unoccupied square feet?

1. If not, explain fully why not.

u. Does TEP have any calculation of the cost of the unoccupied office space in the UniSource headquarters building?

1. If so, please identify and provide those calculations.

RESPONSE: November 19, 2012

a. Please see TEP's response AECC 9.1.

b. Please see TEP's response AECC 9.1.

c. TEP included a net $286,055 of operating expenses in jurisdictional rate base for the new UNS headquarters building less the costs associated with the old UNS headquarters building. Please see the rate case adjustment labeled Income - Building Expense Annualization.pdf and Income - Building Allocation to Affiliates.xlsm for details. (The referenced files are located in TEP's electronic data room in TEP Uniform Data Requests\Attachments\UDR 1.01\Workpapers – Schedules\Pro Forma Adjustments.)

d. TEP did not include any rental income for the new UNS headquarters building in jurisdictional revenue, as there is no rental income.

e. TEP estimated/allocated roughly $2.1 million ($1.6 million ACC Jusrisdiction) to the retail space construction costs in response to STF 16.08 that are included in rate base. TEP does not track operating costs associated with the currently un-leased retail space.

g. All of the retail space is located on the first floor.

1. There is no retail space on Floors 2 – 9. The 12,000 gross square footage ("gsf") of retail is not shown on STF 16.08 TEP HQ Stacking Plan 2012-20-24-Confidential.pdf, which was provided in response to STF 16.08 as a diagram showing the gross square footage and current occupancy of the new TEP headquarters office building.

h. TEP estimated/allocated roughly $16.0 million ($11.8 million ACC Jurisdiction) to the parking construction costs in response to STF 16.08 that are included in rate base.

i. None of the underground parking is available for retail space. 100% of the parking in the building is for TEP employees and secured by a cardkey access system.

j. There is no parking available in the building for the retail space.

k. Yes.

1. The City of Tucson Land Use Code specifically addresses parking requirements for all

new facilities located in the Tucson city limits. Due to the urban setting of the building location and the availability of public parking in the downtown area, no parking for the retail space was required within the building.

l. TEP is not required to provide parking for the 12,000gsf of retail space. The Downtown Tucson Partnership on their website states "**PARKING,** With over 15,000 spaces, parking Downtown is quick and easy. Metered street parking is less expensive than in almost any other city (free on evenings and weekends). Private and public parking lots and garages are also a great deal. You walk farther in a mall parking lot than you do parking anywhere Downtown. With parking Downtown, you're never far from where you need to be. For more information about parking downtown, visit ParkWise or call their office at (520) 791-5071" - http://www.downtowntucson.org/get-around/parking/.

m. TEP does not have construction or operating costs by floor for the UNS headquarters building.

n. TEP does not have construction or operating costs by floor for the UNS headquarters building.

o. TEP does not allocate building costs directly. Building costs are allocated through labor. Building costs are allocated based on total building dollars and not by individual building.

p. The table shown in data request STF 22.06 (p) is not accurate based on the following assumptions. The gsf numbers as listed in response to STF 16.08 (a) includes all common areas, mechanical space, electrical rooms, communication rooms, restrooms, conference space, copy rooms, file rooms, break rooms, elevators, elevator lobbies, dedicated computer room space, an auditorium, area for outside auditors, the main lobby, and service areas. The occupancy numbers were based on a comparison of vacant cubicles and offices to occupied cubicles and offices. All of the common and ancillary areas throughout the entire building are being used by the current building occupants every day.

The entire office building was designed using a standard floorplate methodology which maximizes all space, capitalizing on standardization as a means to operational efficiencies. All space assignment is based on pay grade, strictly enforced, and designed for maximum efficiency. All cubicles are 80sf and in one of two configurations. The offices and conference rooms are common sizes and have a standard layout. We have three office sizes; these three sizes correspond to the same size conference room. Small office/conference rooms are 120sf. Medium office/conference rooms are 180sf. Large office/conference rooms are 345sf and, when configured as an office, includes conference space within the office. In application, if there is no employee with the proper criteria to be housed in an office, the room is fitted with conference room furniture and made available for all employee use.

TUCSON ELECTRIC POWER COMPANY'S SUPPLEMENTAL RESPONSE TO STAFF'S TWENTY SECOND SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE
DOCKET NO. E-01933A-12-0291
December 6, 2012

q. There are no employees in the UNS headquarters building from affiliates UNS, UNS Electric, UNS Gas or UED. There were approximately 8-10 SES (a Millennium subsidiary) employees in the building as of 12/31/2011.

r. The cost per square foot figures were based on total construction costs and gross square footage.

The square foot cost for the parking was calculated based on ½ of the land cost, direct construction cost, and 20% of the sales tax/ plans, permits, and impact fees/ capital cost.

The square foot cost for the retail space was calculated based on ½ of the land cost, direct construction cost for the shell building, and 80% of the sales tax/ plans, permits, and impact fees/ capital cost.

The square foot cost for the office space was calculated based on ½ of the land cost, direct construction cost for the shell building, 80% of the sales tax/plans, permits, and impact fees/capital cost, tenant improvements, and furniture fixtures and equipment ("FF&E").

s. No, the costs per square foot figures in the response to STF 16.08 (e) are based on one-time construction costs. As such, they do not represent a time period.

t. No, the costs per square foot figures in the response to STF 16.08 (e) are based on one-time construction costs. The unoccupied office space represents vacant cubicles and office/conference rooms designed for operational flexibility and does not take into consideration all of the common and ancillary space as listed in STF 22.06 (p). While there are vacant cubicles and offices within the building, all of the common and ancillary areas are being used by the current occupants every day.

u. It does not.

RESPONDENT:

Steve Sims, Scott Rathbun and Pricing (David Lewis)

WITNESS:

Michael DeConcini, Karen Kissinger, Craig A. Jones and Dallas Dukes

SUPPLEMENTAL RESPONSE: December 6, 2012

f. The response to part "f" was mistakenly left out of the original response.

UNS is a holding company and does not have any employees.

RESPONDENT:

Dallas Dukes

WITNESS:

Dallas Dukes

TUCSON ELECTRIC POWER COMPANY'S RESPONSE TO STAFF'S TWENTYSIXTH SET OF DATA REQUESTS REGARDING THE 2012 TEP RATE CASE DOCKET NO. E-01933A-12-0291
December 6, 2012

STF 26.07

Refer to the response to STF 22.06(r), which describes how TEP calculated the cost per square foot of (1) parking; (2) retail space; and (3) office space. Provide TEP's detailed calculations for each: (1) parking; (2) retail space; and (3) office space.

RESPONSE:

Please see STF 26.07.xlsx for the requested information.

RESPONDENT:

Pricing (David Lewis)

WITNESS:

Michael DeConcini

Tucson Electric Power
New Building Expenditures
Cost per Square Foot

New Building Expenditures

Land	8,000,000
Building (Shell)	39,000,000
Overhead	8,750,000
Tenant Improvements	11,366,894
Furniture & Equipment	4,000,000
IT Infrastructure	2,500,000
Data Center	4,200,000
LEED	1,800,000
Parking Structure	10,500,000
	90,116,894

Cost per Square Foot

	Total SF	$/SF
Retail	281,280	177.76
Office	281,280	261.61
Parking	249,410	64.15

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 10, 2013

STF 7.05

Prepaids. Refer to the Company's PDF workpapers Rate Base - Working Capital.pdf, UNSE(0504)004045.

a. Please provide breakouts of the 13 monthly amounts for prepaid insurance, show the amounts related to each type of insurance.

b. Please provide a detailed itemization and an explanation for each item that is included in each of the 13 monthly Other Prepaids, account 14100.

RESPONSE:

a.-b. Please see STF 7.05 Prepaid Expenses.xlsm for the 13 monthly amounts, as requested.

RESPONDENT:

Pricing (Anne Liu) and Martha Garcia

WITNESS:

Dallas Dukes

UNS Electric, Inc.
STF 7.05 Prepaid Balances
For the test year ended June 30, 2012

	2011							2012					
STF 7.05 a. 14010 - Prepaid Insurance	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Property Insurance	14,153.69	7,076.86	(0.00)	140,194.08	127,449.17	114,704.25	101,959.33	89,214.41	76,469.49	63,724.57	50,979.65	38,234.73	25,489.81
Injury and Damage Insurance	71,495.71	181,624.96	165,113.59	148,602.22	132,090.85	115,579.48	99,068.11	82,556.74	66,045.37	49,534.00	33,022.63	16,511.26	180,849.91
D&O Liability	-	29,049.51	69,511.39	58,249.97	46,988.55	35,727.13	24,465.71	13,204.29	10,563.43	7,922.57	5,281.71	2,640.85	0.00
Ending Balance	85,649.40	217,751.33	234,624.98	347,046.27	306,528.57	266,010.86	225,493.15	184,975.44	153,078.29	121,181.14	89,283.99	57,386.84	206,339.72

STF 7.05 b. 14100 - Other Prepaids	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY	JUN
Permit fee for 115KV Overhead Line from Tucson to Nogales	18,652.50	18,238.00	17,823.50	17,409.00	16,994.50	16,580.00	16,165.50	15,751.00	15,336.50	14,922.00	14,507.50	14,093.00	13,678.50
AZ Land Department Lease	53,770.04	53,165.88	52,561.72	51,957.56	51,353.40	50,749.24	50,145.08	49,540.92	48,936.76	48,332.60	47,728.44	47,124.28	46,520.12
Software and Computer Maintenance Fees	25,577.73	23,252.48	20,927.23	18,601.98	16,276.73	13,951.48	11,626.23	9,300.98	59,954.15	55,862.95	51,771.75	47,680.57	95,980.86
Fire and EMS services for Black Mountain	-	-	-	-	-	-	-	25,061.33	12,530.66	-	25,061.33	12,530.66	-
WAPA - Operations and Maintenance of Substations	12,188.82	8,125.88	4,062.95	0.01	-	-	68,010.76	60,454.01	52,897.26	45,340.52	37,783.77	30,227.02	22,670.27
WAPA - Prepayment of Long-term Firm Point to Point Transmission Services	139,700.00	-	139,700.00	-	139,700.00	139,700.00	139,700.00	139,700.00	139,700.00	139,700.00	139,700.00	139,700.00	139,700.00
WAPA - Prepayment of Long-term Firm Point to Point Transmission Services	108,470.88	108,470.88	108,470.88	-	-	108,470.88	-	108,470.88	108,470.88	108,470.88	108,470.88	108,470.88	108,470.88
APS Call Option Premium to buy power at a certain point and price	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00	162,500.00
Prepaid Postage	87,732.49	94,676.59	96,543.31	101,465.85	72,942.66	78,592.51	86,257.87	92,382.74	64,411.33	56,132.01	48,866.73	39,873.45	32,802.11
Ending Balance	608,592.46	468,429.71	602,589.59	351,934.40	459,767.29	570,544.11	534,405.44	663,161.86	664,737.54	631,260.96	636,390.40	602,199.86	622,322.74

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-12-0504 June 12, 2013

STF 7.06

Injuries and Damages. Refer to the Company Adjustment Income - Injuries and Damages.pdf, UNSE(0504)003892.

a. Please provide comparable expense amounts for the 12 month periods ending 6/30/2002; 6/30/2003; 6/30/2004; 6/30/2005; 6/30/2006; 6/30/2007; 6/30/2008; and 6/30/2009 for each account 50250; 78040; and 78100.

b. Please provide for each account 50250, 78040 and 78100, the calendar year recorded expense for years 2012 through 2012.

c. Did the Company make any request to defer the $1 million recorded in account 78100 (FERC Account 925) related to the 10/20/2009 truck accident?

1. If not, explain fully why not.
2. If so, identify and provide the documentation for the deferral request.

d. How much of the $1 million was recorded in 2009?

e. Was there any determination of fault in the 10/20/2009 truck accident?

1. If so, explain fully and provide the related documents.

f. Has the Company attempted to recoup any portion of the $1 million from any party?

1. If not, explain fully why not.
2. If so, please explain the efforts and the results to-date.

g. Does the Company have any balance sheet account relating to an Injuries and Damages reserve or liability?

1. If so, please provide the monthly amounts for 1/1/2009 through 3/31/2013.

ORIGINAL RESPONSE: June 10, 2013

a.-d. UNS Electric is in the process of gathering this information and will provide it as soon as possible.

e. No. This was a compromised settlement with no admission of fault.

f. There were no third parties identified as potential contributors to the accident.

g. UNS Electric is in the process of gathering this information and will provide it as soon as possible.

RESPONDENT:

Pricing (Anne Liu) and Legal (Janice Spencer)

WITNESS:

Dallas Dukes

UNS ELECTRIC INC.'S SUPPLEMENTAL RESPONSE TO STAFF'S SEVENTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-12-0504 June 12, 2013

SUPPLEMENTAL RESPONSE: June 12, 2013

a. Data for the 12 month periods ended prior to 6/30/2007 is not readily available.

				12 Months Ended		
Account	**Account Description**	**FERC**	**FERC Description**	**6/30/2007**	**6/30/2008**	**6/30/2009**
50250	Workers' Compensation	0925	Injuries & Damages	20,588	21,385	23,565
78040	Workers' Compensation	0925	Injuries & Damages	(46,740)	34,646	275,003
78100	Injuries & Damages	0925	Injuries & Damages	17,889	188,174	36,364
				(8,263)	244,205	334,932

b. Data prior to calendar year 2005 is not readily available.

Acct	**Acct Name**	**DEC-05**	**DEC-06**	**DEC-07**	**DEC-08**	**DEC-09**	**DEC-10**	**DEC-11**	**DEC-12**
50250	Workers' Compensation	11,444	12,803	19,885	23,885	22,882	23,159	30,988	55,586
78040	Workers' Compensation	31,580	81,037	(3,951)	211,836	124,887	(51,060)	(23,305)	(32,917)
78100	Injuries & Damages	-	10,064	174,182	13,992	1,036,364	-	-	10,000
		43,024	103,904	190,116	249,713	1,184,132	(27,901)	7,683	32,670

c. No, the Company did not make a request to defer the $1 million recorded in account 78100.

1. The Company is self-insured up to $1 million dollars for an individual incident. This historically has led to moderate recurring levels of Injuries and Damages expense, by avoiding higher annual premium expenses. However, this does provide for the possibility (within the normal course of business) that a catastrophic incident(s) will occur and expenses will be higher in some years. Since the Company has historically recovered injuries and damages expense through a normalization process – the Company believed any such incurred normal expenses would be considered and treated consistently in future rate cases. With actual expenses incurred historically being evaluated and an appropriate normalized recurring expense level being determined; as has been done in prior rate filings.

d. The entire $1 million was recorded in 2009.

e. No. This was a compromised settlement with no admission of fault.

f. No. There were no third parties identified as potential contributors to the accident.

g. No. The Company does not have any balance sheet account reserves related to Injuries and Damages.

RESPONDENT:

Pricing (Anne Liu) (a-d and g) and Legal (Janice Spencer) (e and f)

WITNESS:

Dallas Dukes

Arizona Corporation Commission ("Commission")
Federal Energy Regulatory Commission ("FERC")
Open Access Transmission Tariff ("OATT")
Tucson Electric Power Company ("TEP" or the "Company")
UNS Energy Corporation fka UniSource Energy Corporation ("UNS")
UniSource Energy Services ("UES")
UniSource Energy Development Company ("UED")
UNS Electric, Inc. ("UNS Electric")
UNS Gas, Inc. ("UNS Gas")

UNS ELECTRIC, INC.'S RESPONSE TO
UNIFORM DATA REQUESTS - 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
January 4, 2013

PLANT IN SERVICE:

UDR 1.73

Depreciation Study. Please provide a complete copy (both in electronic and paper) of UNS Electric's last complete depreciation study.

RESPONSE:

Please see UDR 1.73 2009 Depreciation Study.pdf, Bates Nos. UNSE\002924-002959, for the most recent UNS Electric depreciation study, which was prepared by Foster & Associates as of December 31, 2008.

RESPONDENT:

Carl Dabelstein

WITNESS:

Dallas Dukes

CONTENTS

March 2009

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EXECUTIVE SUMMARY

INTRODUCTION

This report presents the findings and recommendations developed by Foster Associates in a 2009 Technical Update of depreciation rates for UNS Electric, Inc. (UNS Electric), an operating subsidiary of UniSource Energy Services, Inc. Parameters (*i.e.*, projection curves, projection lives and future net salvage rates) used in the update were developed in the Company's 2006 Depreciation Rate Review based on December 31, 2005 plant and reserve balances. Rates developed in the 2006 Review were approved by the Arizona Corporation Commission (ACC) in Docket No. E–04204A–06–0783 (Decision No. 70360, dated May 27, 2008).[1] Age distributions of surviving plant on December 31, 2008 were used in the 2009 update to derive composite service life statistics and theoretical depreciation reserves.

The purpose of a technical update is to adjust depreciation rates for changes in the variables associated with a remaining life accrual rate. The variables for an account include the age distribution of surviving plant, the recorded depreciation reserve and the average net salvage rate used in the calculation of a theoretical reserve. A technical update retains the parameters developed and/or approved in the most recent full depreciation study and adjusts depreciation rates for subsequent changes in plant, reserves and realized net salvage activity.

At the request of UNS Electric, two updates were prepared. The first update excludes Black Mountain Generation Station. The station is a simple cycle 90 megawatt combustion turbine generation plant constructed by UniSource Energy Development Company. The plant, located in Kingman, Arizona, commenced commercial operation May 30, 2008. The second update includes Black Mountain using an estimated year of final retirement provided by Tucson Electric Power engineers.

The principal findings from this review are summarized in the attached statements. Statement A provides a comparative summary of current and proposed annual depreciation rates for each rate category. Investment and net salvage components are displayed as directed by the ACC in Decision No. 70360. Statement B provides a comparison of current and proposed annualized depreciation accruals. Statement C provides a comparison of recorded, computed and redistributed depreciation reserves for each rate category. Statement D provides a summary of the components used to obtain a weighted-average net salvage rate for each plant ac-

[1] With the exception of transportation equipment and amortizable categories, projection lives and projection curves recommended in the 2006 Review were derived from the parameters estimated by Citizens in the 1991 study. Parameters for transportation equipment (not included in the Citizens study) were adopted from a UNS Gas study conducted by Foster Associates in 2006. Projection lives approved for Citizens were adopted as amortization periods for the proposed amortization categories.

count. Statement E provides a comparative summary of current and proposed parameters and statistics including projection life, projection curve, average service life, average remaining life, and average and future net salvage rates.

SCOPE OF STUDY

The principal activities undertaken in the course of conducting the 2009 Technical Update included:

- Collection of plant and net salvage data;
- Reconciliation of data to the official records of the Company;
- Computation of average net salvage rates; and
- Development of adjusted accrual rates for each rate category.

PROPOSED DEPRECIATION RATES

Table 1 provides a summary of the changes in annual rates and accruals resulting from the 2009 Technical Update excluding the Black Mountain Generation Station. Rates proposed for each primary account (with the exception of amortization accounts) have been developed including an allowance for net salvage.

	Accrual Rate			2009 Annualized Accrual		
Function	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	5.25%	5.11%	-0.14%	$403,155	$392,316	($10,839)
Other Production	2.44%	2.43%	-0.01%	642,594	642,285	(309)
Transmission	3.52%	3.36%	-0.16%	1,959,277	1,866,367	(92,910)
Distribution	4.17%	3.97%	-0.20%	13,845,594	13,174,058	(671,536)
General Plant	8.73%	8.01%	-0.72%	1,980,388	1,817,624	(162,764)
Total Utility	4.24%	4.03%	-0.21%	$18,831,008	$17,892,650	($938,358)

Table 1. Current and Proposed Rates and Accruals Excluding Black Mountain

Adjustments developed in the technical update produce a composite depreciation rate of 4.03 percent. Depreciation expense is currently accrued at an equivalent rate of 4.24 percent. The change in the composite depreciation rate is a reduction of 0.21 percentage points.

A continued application of rates derived from currently approved parameters would produce annual depreciation expense of $18,831,008 compared with an annual expense of $17,892,650 using the rates developed in the update. The expense reduction of $938,358 is generally attributable to a change in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

Table 2 provides a summary of the changes in annual rates and accruals resulting from the 2009 Update including the Black Mountain Generation Station.

Function	Accrual Rate			2009 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible Plant	5.25%	5.11%	-0.14%	$403,155	$392,316	($10,839)
Other Production	2.55%	2.56%	0.01%	2,257,314	2,268,100	10,786
Transmission	3.52%	3.36%	-0.16%	1,959,278	1,866,366	(92,912)
Distribution	4.17%	3.97%	-0.20%	13,845,595	13,174,058	(671,537)
General Plant	8.73%	8.01%	-0.72%	1,980,388	1,817,622	(162,766)
Total Utility	4.04%	3.85%	-0.19%	$20,445,730	$19,518,462	($927,268)

Table 2. Current and Proposed Rates and Accruals Including Black Mountain

Adjustments developed in the update produce a composite depreciation rate of 3.85 percent. Depreciation expense is currently accrued at an equivalent rate of 4.04 percent. The change in the composite depreciation rate is a reduction of 0.19 percentage points.

A continued application of rates derived from current parameters would produce annual depreciation expense of $20,445,730 compared with an annual expense of $19,518,462 using the rates developed in the update. The expense reduction of $927,268 is generally attributable to a change in the mix of plant investments among primary accounts and changes in the age distributions of surviving plant.

STUDY PROCEDURE

INTRODUCTION

Unlike a full depreciation study in which projection curves, projection lives and future net salvage rates are estimated from a statistical analysis of recorded retirements and net salvage realized in the past, a technical update generally retains the parameters currently used by the utility and adjusts depreciation rates for known and measurable changes in the age distributions of surviving plant, depreciation reserves, and average net salvage rates due to the passage of time. A technical update is intended to align depreciation rates with the accounting year the rates will become effective.

SCOPE

The steps involved in preparing a technical update can be grouped into five principal activities:

- Data collection;
- Calculation of service life statistics;
- Computation of average net salvage rates;
- Rebalancing of depreciation reserves; and
- Development of accrual rates.

The scope of the 2009 update for UNS Electric included a consideration of each of these tasks as described below.

DATA COLLECTION

Plant accounting and depreciation reserve transactions recorded over the period 2006–2008 and age distributions of surviving plant at December 31, 2008 were provided to Foster Associates in an electronic format and appended to the database used in conducting the 2006 Review. Depreciation rates currently used by UNS Electric were developed using a broad–group procedure. The realized life of surviving vintages derived from the dollar–years of service provided by each vintage is not relevant to an update of broad–group depreciation rates. Therefore, plant transactions recorded in prior activity years were only used to derive age distribution at December 31, 2008. The accuracy and completeness of the assembled database was verified by comparisons to FERC Form 1 for activity years 2006–2008. Prior activity years were reconciled in the 2006 Review. Derived age distributions were reconciled to the continuing property records at December 31, 2008.

CALCULATION OF SERVICE LIFE STATISTICS

The composite remaining life and average service life of a plant category used in the calculation of depreciation rates are derived from a tabular arrangement of the age distribution of surviving plant and related statistics. The format of such a table is called a *generation arrangement.*

The age distribution of surviving plant is a column of numbers showing the dollar amount of investment remaining in service at the beginning of a study year from each of the vintages installed in prior years. The sum of an age distribution is the total plant in service for a plant category. The source of data used to construct an age distribution is a company's Continuing Property Record (CPR) system.

Statistics for each vintage (*i.e.*, average service life and remaining life) contained in a generation arrangement are derived from a mathematical function called a *survivor curve*. The survivor curve most descriptive of the forces of retirement acting upon a plant category is identified from a statistical analysis of past retirement experience, coupled with a consideration of how these forces are likely to change in the future. The collection of past retirements used in the statistical analysis can be viewed as a random sample from an unknown parent population. The objective of a life analysis is to estimate the parameters (*i.e.*, mean service life and dispersion characteristics) of the parent population. The mean service life of the population which best describes the timing of past and future retirements is called a *projection life* and the survivor curve selected to describe the forces of retirement acting upon the population is called a *projection curve*. A technical update generally retains the service life parameters estimated in a full depreciation study. Statistics for each vintage, however, are updated to reflect known and measurable changes in the age distributions of surviving plant.

COMPUTATION OF AVERAGE NET SALVAGE RATES

Estimates of net salvage rates applicable to future retirements are derived in a full depreciation study from an analysis of gross salvage and removal expense realized in the past and a consideration of future expectations that may dictate a departure from historical indications. Future net salvage rates adopted from such an analysis are retained as fixed parameters in a technical update.

The average net salvage rate for an account or plant function is derived from a direct dollar weighting of a) historical retirements with historical (or realized) net salvage rates and b) future retirements (*i.e.*, surviving plant) with the estimated future net salvage rate. Average net salvage rates will change, therefore, as additional years of retirement and net salvage activity become available and as subsequent plant additions alter the weighting of future net salvage estimates.

The computation of salvage rates is shown in Statement D.

Rebalancing of Depreciation Reserves

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important measure of the status of the company's depreciation practices and procedures. If a company has not previously conducted statistical life studies or considered retirement dispersion in setting depreciation rates, it is likely that some accounts will be over–depreciated and other accounts will be under–depreciated relative to a calculated or theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are changed in the course of depreciation reviews. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute recorded reserves among the various primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

A rebalancing of recorded reserves is consistent with the objectives of a technical update and is considered appropriate for UNS Electric. The rebalancing of reserves undertaken in the 2009 update will help to stabilize depreciation rates and preserve consistency between measured reserve imbalances and the parameters used in the formulation of updated remaining–life accrual rates.

A redistribution of the recorded reserve was achieved for UNS Electric by multiplying the calculated reserve for each primary account within a function (or plant location) by the ratio of the function (or location) total recorded reserve to the function (or location) total calculated reserve. The sum of the redistributed reserves within a function (or location) is, therefore, equal to the function (or location) total recorded depreciation reserve before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for UNS Electric at December 31, 2008. The recorded reserve excluding Black Mountain was $193,348,358 or 43.5 percent of the depreciable plant investment. The corresponding computed reserve is $184,859,206 or 41.6 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $8,489,152 will be amortized over the composite weighted–average remaining life of each rate category.

The recorded reserve including Black Mountain was $194,357,557 or 38.4 percent of the depreciable plant investment. The corresponding computed reserve is $185,594,056 or 36.7 percent of the depreciable plant investment. A proportionate amount of the measured reserve excess of $8,763,501 will be amortized over the composite weighted–average remaining life of each rate category.

DEVELOPMENT OF ACCRUAL RATES

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Depreciation rates currently approved for UNS Electric were developed using a system composed of the straight–line method, broad–group procedure, remaining–life technique. Depreciation rates proposed in the update were developed using the currently approved system.

STATEMENTS

INTRODUCTION

This section provides a comparative summary of depreciation rates, annualized depreciation accruals, recorded and computed depreciation reserves, and current and proposed service life and net salvage parameters for UNS Electric. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and proposed annual depreciation rates for calendar year 2009 using the straight-line method, broad group procedure, remaining-life technique.
- Statement B provides a comparison of the current and proposed annualized depreciation accruals for calendar year 2009 derived from the rates developed in Statement A.
- Statement C provides a comparison of recorded and computed reserves for each rate category and sets forth the computations used to redistribute recorded reserves among primary plant accounts.
- Statement D provides a summary of the components used to obtain a weighted average net salvage rate for each rate category.
- Statement E provides a comparative summary of current parameters including projection life, projection curve and future net salvage rates. The statement also contains current and proposed statistics including average service life, average remaining life, and average net salvage rates.

Current depreciation accruals shown on Statement B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. Similarly, proposed depreciation accruals shown on Statement B are the product of the plant investment and the proposed depreciation rates shown on Statement A. Both current and proposed remaining life accrual rates are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio} - \text{Future Net Salvage Rate}}{\text{Remaining Life}}.$$

Statements A through E

UNS ELECTRIC, INC. (Excluding Black Mountain)

Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Current Rates (at 12/31/2008) Investment	Current Rates (at 12/31/2008) Net Salvage	Current Rates (at 12/31/2008) Total	Proposed Rates (at 12/31/2008) Investment	Proposed Rates (at 12/31/2008) Net Salvage	Proposed Rates (at 12/31/2008) Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
Depreciable						
303.WP Misc. Intangible - WAPA Switchboard	3.13%		3.13%	2.82%		2.82%
Total Depreciable	3.13%		3.13%	2.82%		2.82%
Amortizable						
302.00 Franchises and Consents	← 25 Year Amortization →					
303.00 Miscellaneous Intangible Plant	← 15 Year Amortization →			← 15 Year Amortization →		
303.WC Misc. Intangible - WAPA Fiber Optic	← 23 Year Amortization →			← 23 Year Amortization →		
303.PC Misc.Intangible Plant - PC Software	← 5 Year Amortization →			← 5 Year Amortization →		
Total Amortizable	7.00%		7.00%	7.00%		7.00%
Total Intangible Plant	5.25%		5.25%	5.11%		5.11%
OTHER PRODUCTION PLANT						
341.00 Structures and Improvements	2.07%		2.07%	2.05%		2.05%
342.00 Fuel Holders, Producers and Accessories	2.51%		2.51%	2.52%		2.52%
343.00 Prime Movers	2.53%		2.53%	2.53%		2.53%
344.00 Generators	2.33%		2.33%	2.33%		2.33%
345.00 Accessory Electric Equipment	2.35%		2.35%	2.35%		2.35%
346.00 Miscellaneous Power Plant Equipment	2.64%		2.64%	2.64%		2.64%
Total Other Production Plant	2.44%		2.44%	2.43%		2.43%
TRANSMISSION PLANT						
350.RW Rights of Way	2.02%		2.02%	1.91%		1.91%
352.00 Structures and Improvements	3.13%		3.13%	2.93%		2.93%
353.00 Station Equipment	3.15%		3.15%	3.02%		3.02%
354.00 Towers and Fixtures	5.03%		5.03%	4.89%		4.89%
355.00 Poles and Fixtures	4.08%	0.40%	4.48%	3.86%	0.38%	4.24%
356.00 Overhead Conductors and Devices	2.66%		2.66%	2.55%		2.55%
358.00 Underground Conductors and Devices	4.36%		4.36%	1.99%	0.10%	2.09%
359.00 Roads and Trails	2.02%		2.02%	1.93%		1.93%
Total Transmission Plant	3.38%	0.15%	3.52%	3.22%	0.14%	3.36%
DISTRIBUTION PLANT						
360.RW Rights of Way	2.03%		2.03%	1.95%		1.95%
361.00 Structures and Improvements	2.96%		2.96%	2.90%		2.90%
362.00 Station Equipment	4.09%		4.09%	3.84%		3.84%
364.00 Poles, Towers and Fixtures	3.76%	0.38%	4.14%	3.54%	0.34%	3.88%
365.00 Overhead Conductors and Devices	3.76%	0.37%	4.13%	3.57%	0.35%	3.92%
366.00 Underground Conduit	3.61%	0.18%	3.79%	3.49%	0.17%	3.66%
367.00 Underground Conductors and Devices	4.40%		4.40%	4.25%	0.02%	4.27%
368.00 Line Transformers	4.41%	0.22%	4.63%	4.21%	0.24%	4.45%
369.OH Services - Overhead	3.77%		3.77%	3.54%		3.54%
369.UG Services - Underground	3.75%		3.75%	3.61%		3.61%
370.00 Meters	2.96%	0.15%	3.11%	2.90%	0.11%	3.01%
373.00 Street Lighting and Signal Systems	4.04%		4.04%	3.87%		3.87%
Total Distribution Plant	3.95%	0.22%	4.17%	3.76%	0.21%	3.97%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.65%		2.65%	2.60%		2.60%
392.C1 Transportation Equipment - Class 1	12.75%		12.75%	12.35%	-0.46%	11.89%
392.C2 Transportation Equipment - Class 2	16.99%		16.99%	16.33%	-1.24%	15.09%
392.C3 Transportation Equipment - Class 3	20.21%		20.21%	19.32%	-0.94%	18.38%
392.C4 Transportation Equipment - Class 4	13.47%		13.47%	11.88%	-0.32%	11.56%
392.C5 Transportation Equipment - Class 5	12.55%		12.55%	12.33%	-1.23%	11.10%
396.00 Power Operated Equipment	6.92%		6.92%	6.53%		6.53%
Total Depreciable	11.04%		11.04%	10.56%	-0.68%	9.87%

UNS ELECTRIC, INC. (Excluding Black Mountain)

Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Current Rates (at 12/31/2008) Investment	Net Salvage	Total	Proposed Rates (at 12/31/2008) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Amortizable						
391.10 Office Furniture and Equipment	← 21 Year Amortization →			← 21 Year Amortization →		
391.20 Computer Equipment - PCs	← 5 Year Amortization →			← 5 Year Amortization →		
393.00 Stores Equipment	← 33 Year Amortization →			← 33 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 29 Year Amortization →			← 29 Year Amortization →		
395.00 Laboratory Equipment	← 40 Year Amortization →			← 40 Year Amortization →		
397.CE Communication Equipment	← 23 Year Amortization →			← 23 Year Amortization →		
398.00 Miscellaneous Equipment	← 18 Year Amortization →			← 18 Year Amortization →		
Total Amortizable	5.04%		5.04%	5.04%		5.04%
Total General Plant	8.73%		8.73%	8.43%	-0.42%	8.01%
TOTAL UTILITY	4.06%	0.18%	4.24%	3.88%	0.15%	4.03%

Statement B

UNS ELECTRIC, INC. (Excluding Black Mountain)

Comparison of Current and Proposed Accruals
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/08 Investment	Current 2009 Annualized Accrual Investment	Current Net Salvage	Current Total	Proposed 2009 Annualized Accrual Investment	Proposed Net Salvage	Proposed Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
INTANGIBLE PLANT								
Depreciable								
303.WP Misc. Intangible - WAPA Switchboard	$3,466,688	$108,507		$108,507	$97,761		$97,761	($10,746)
Total Depreciable	$3,466,688	$108,507		$108,507	$97,761		$97,761	($10,746)
Amortizable								
302.00 Franchises and Consents								
303.00 Miscellaneous Intangible Plant	2,124,607	141,711		141,711	141,499		141,499	(212)
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	73,298		73,298	73,298		73,298	
303.PC Misc.Intangible Plant - PC Software	398,194	79,639		79,639	79,758		79,758	119
Total Amortizable	$4,207,801	$294,648		$294,648	$294,555		$294,555	($93)
Total Intangible Plant	$7,674,489	$403,155		$403,155	$392,316		$392,316	($10,839)
OTHER PRODUCTION PLANT								
341.00 Structures and Improvements	$1,969,407	$40,767		$40,767	$40,373		$40,373	($394)
342.00 Fuel Holders, Producers and Accessories	847,308	21,267		21,267	21,352		21,352	85
343.00 Prime Movers	13,419,272	339,508		339,508	339,508		339,508	
344.00 Generators	6,304,468	146,894		146,894	146,894		146,894	
345.00 Accessory Electric Equipment	2,513,408	59,065		59,065	59,065		59,065	
346.00 Miscellaneous Power Plant Equipment	1,329,274	35,093		35,093	35,093		35,093	
Total Other Production Plant	$26,383,137	$642,594		$642,594	$642,285		$642,285	($309)
TRANSMISSION PLANT								
350.RW Rights of Way	$346,016	$6,990		$6,990	$6,609		$6,609	($381)
352.00 Structures and Improvements	427,830	13,391		13,391	12,535		12,535	(856)
353.00 Station Equipment	18,912,564	595,746		595,746	571,159		571,159	(24,587)
354.00 Towers and Fixtures	521,825	26,248		26,248	25,517		25,517	(731)
355.00 Poles and Fixtures	20,666,171	843,180	82,665	925,845	797,714	78,531	876,245	(49,600)
356.00 Overhead Conductors and Devices	14,516,855	386,148		386,148	370,180		370,180	(15,968)
358.00 Underground Conductors and Devices	27,437	1,196		1,196	546	27	573	(623)
359.00 Roads and Trails	183,860	3,714		3,714	3,548		3,548	(166)
Total Transmission Plant	$55,602,558	$1,876,613	$82,665	$1,959,278	$1,787,808	$78,558	$1,866,366	($92,912)
DISTRIBUTION PLANT								
360.RW Rights of Way	$133,365	$2,707		$2,707	$2,601		$2,601	($106)
361.00 Structures and Improvements	5,690,805	168,448		168,448	165,033		165,033	(3,415)
362.00 Station Equipment	39,478,232	1,614,660		1,614,660	1,515,964		1,515,964	(98,696)
364.00 Poles, Towers and Fixtures	85,011,451	3,196,431	323,044	3,519,475	3,009,405	289,039	3,298,444	(221,031)

UNS ELECTRIC, INC. (Excluding Black Mountain)

Statement B

Comparison of Current and Proposed Accruals
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/08 Investment	Current 2009 Annualized Accrual: Investment	Current 2009 Annualized Accrual: Net Salvage	Current 2009 Annualized Accrual: Total	Proposed 2009 Annualized Accrual: Investment	Proposed 2009 Annualized Accrual: Net Salvage	Proposed 2009 Annualized Accrual: Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
365.00 Overhead Conductors and Devices	58,978,060	2,217,575	218,219	2,435,794	2,105,517	206,423	2,311,940	(123,854)
366.00 Underground Conduit	16,265,133	587,171	29,277	616,448	567,653	27,651	595,304	(21,144)
367.00 Underground Conductors and Devices	37,799,476	1,663,177		1,663,177	1,606,478	7,560	1,614,038	(49,139)
368.00 Line Transformers	61,999,842	2,734,193	136,400	2,870,593	2,610,193	148,800	2,758,993	(111,600)
369.OH Services - Overhead	8,523,830	321,348		321,348	301,744		301,744	(19,604)
369.UG Services - Underground	4,877,076	182,890		182,890	176,062		176,062	(6,828)
370.00 Meters	9,135,761	270,419	13,704	284,123	264,937	10,049	274,986	(9,137)
373.00 Street Lighting and Signal Systems	4,107,216	165,932		165,932	158,949		158,949	(6,983)
Total Distribution Plant	$332,000,247	$13,124,951	$720,644	$13,845,595	$12,484,536	$689,522	$13,174,058	($671,537)
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$2,611,428	$69,203		$69,203	$67,897		$67,897	($1,306)
392.C1 Transportation Equipment - Class 1	147,553	18,813		18,813	18,223	(679)	17,544	(1,269)
392.C2 Transportation Equipment - Class 2	1,260,656	214,185		214,185	205,865	(15,632)	190,233	(23,952)
392.C3 Transportation Equipment - Class 3	1,056,586	213,536		213,536	204,132	(9,932)	194,200	(19,336)
392.C4 Transportation Equipment - Class 4	1,834,288	247,079		247,079	217,913	(5,870)	212,043	(35,036)
392.C5 Transportation Equipment - Class 5	5,144,272	645,606		645,606	634,289	(63,275)	571,014	(74,592)
396.00 Power Operated Equipment	1,879,460	130,059		130,059	122,729		122,729	(7,330)
Total Depreciable	$13,934,243	$1,538,481		$1,538,481	$1,471,048	($95,388)	$1,375,660	($162,821)
Amortizable								
391.10 Office Furniture and Equipment	$1,574,954	$74,968		$74,968	$74,968		$74,968	
391.20 Computer Equipment - PCs	670,109	134,022		134,022	134,089		134,089	67
393.00 Stores Equipment	118,860	3,601		3,601	3,601		3,601	
394.00 Tools, Shop and Garage Equipment	2,666,594	91,997		91,997	91,997		91,997	
395.00 Laboratory Equipment	1,430,916	35,773		35,773	35,773		35,773	
397.CE Communication Equipment	2,175,606	94,639		94,639	94,639		94,639	
398.00 Miscellaneous Equipment	124,227	6,907		6,907	6,895		6,895	(12)
Total Amortizable	$8,761,266	$441,907		$441,907	$441,962		$441,962	$55
Total General Plant	$22,695,509	$1,980,388		$1,980,388	$1,913,010	($95,388)	$1,817,622	($162,766)
TOTAL UTILITY	$444,355,940	$18,027,701	$803,309	$18,831,010	$17,219,955	$672,692	$17,892,647	($938,363)

Statement C

UNS ELECTRIC, INC. (Excluding Black Mountain)

Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	$3,466,688	$502,351	14.49%	$431,169	12.44%	$722,638	20.85%
Total Depreciable	$3,466,688	$502,351	14.49%	$431,169	12.44%	$722,638	20.85%
Amortizable							
302.00 Franchises and Consents		($113)					
303.00 Miscellaneous Intangible Plant	2,124,607	965,818	45.46%	1,302,255	61.29%	1,302,255	61.29%
303.WO Misc. Intangible - WAPA Fiber Optic	1,685,000	394,086	23.39%	402,935	23.91%	402,935	23.91%
303.PC Misc.Intangible Plant - PC Software	398,194	766,040	192.38%	200,354	50.32%	200,354	50.32%
Total Amortizable	$4,207,801	$2,125,831	50.52%	$1,905,544	45.29%	$1,905,544	45.29%
Total Intangible Plant	$7,674,489	$2,628,182	34.25%	$2,336,713	30.45%	$2,628,182	34.25%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	$1,969,407	$322,478	16.37%	$349,268	17.73%	$339,030	17.21%
342.00 Fuel Holders, Producers and Accessories	847,308	173,591	20.49%	177,087	20.90%	171,896	20.29%
343.00 Prime Movers	13,419,272	3,848,955	28.68%	3,867,602	28.82%	3,754,230	27.98%
344.00 Generators	6,304,468	536,070	8.50%	694,958	11.02%	674,586	10.70%
345.00 Accessory Electric Equipment	2,513,408	682,563	27.16%	651,148	25.91%	632,061	25.15%
346.00 Miscellaneous Power Plant Equipment	1,329,274	132,763	9.99%	128,380	9.66%	124,617	9.37%
Total Other Production Plant	$26,383,137	$5,696,420	21.59%	$5,868,443	22.24%	$5,696,420	21.59%
TRANSMISSION PLANT							
350.RW Rights of Way	$346,016	$130,587	37.74%	$148,095	42.80%	$157,153	45.42%
352.00 Structures and Improvements	427,830	157,831	36.89%	145,721	34.06%	154,634	36.14%
353.00 Station Equipment	18,912,564	7,219,008	38.17%	6,784,882	35.88%	7,199,854	38.07%
354.00 Towers and Fixtures	521,825	171,132	32.79%	141,415	27.10%	150,064	28.76%
355.00 Poles and Fixtures	20,666,171	9,143,150	44.24%	8,415,066	40.72%	8,929,742	43.21%
356.00 Overhead Conductors and Devices	14,516,855	5,141,109	35.41%	5,057,978	34.84%	5,367,330	36.97%
358.00 Underground Conductors and Devices	27,437	2,509	9.14%	1,440	5.25%	1,529	5.57%
359.00 Roads and Trails	183,860	64,515	35.09%	65,528	35.64%	69,535	37.82%
Total Transmission Plant	$55,602,558	$22,029,840	39.62%	$20,760,126	37.34%	$22,029,840	39.62%
DISTRIBUTION PLANT							
360.RW Rights of Way	$133,365	$39,430	29.57%	$45,264	33.94%	$47,397	35.54%
361.00 Structures and Improvements	5,690,805	1,317,861	23.16%	1,324,972	23.28%	1,387,406	24.38%

UNS ELECTRIC, INC. (Excluding Black Mountain)
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Statement C

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
362.00 Station Equipment	39,478,232	19,358,765	49.04%	18,049,448	45.72%	18,899,960	47.87%
364.00 Poles, Towers and Fixtures	85,011,451	46,789,344	55.04%	45,847,620	53.93%	48,008,017	56.47%
365.00 Overhead Conductors and Devices	58,978,060	29,819,099	50.56%	28,578,409	48.46%	29,925,059	50.74%
366.00 Underground Conduit	16,265,133	6,047,350	37.18%	5,696,863	35.03%	5,965,306	36.68%
367.00 Underground Conductors and Devices	37,799,476	13,688,605	36.21%	12,165,515	32.18%	12,738,769	33.70%
368.00 Line Transformers	61,999,842	27,707,134	44.69%	25,759,802	41.55%	26,973,636	43.51%
369.OH Services - Overhead	8,523,830	4,334,332	50.85%	4,160,892	48.81%	4,356,958	51.12%
369.UG Services - Underground	4,877,076	1,792,586	36.76%	1,728,652	35.44%	1,810,109	37.11%
370.00 Meters	9,135,761	2,597,445	28.43%	2,456,757	26.89%	2,572,522	28.16%
373.00 Street Lighting and Signal Systems	4,107,216	953,055	23.20%	1,680,673	40.92%	1,759,868	42.85%
Total Distribution Plant	$332,000,247	$154,445,006	46.52%	$147,494,866	44.43%	$154,445,006	46.52%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$2,611,428	$791,938	30.33%	$742,883	28.45%	$766,274	29.34%
392.C1 Transportation Equipment - Class 1	147,553	(112,095)	-75.97%	30,809	20.88%	31,779	21.54%
392.C2 Transportation Equipment - Class 2	1,260,656	725,367	57.54%	426,743	33.85%	440,180	34.92%
392.C3 Transportation Equipment - Class 3	1,056,586	206,593	19.55%	468,135	44.31%	482,876	45.70%
392.C4 Transportation Equipment - Class 4	1,834,288	636,632	34.71%	961,311	52.41%	991,581	54.06%
392.C5 Transportation Equipment - Class 5	5,144,272	1,487,865	28.92%	1,377,379	26.78%	1,420,749	27.62%
396.00 Power Operated Equipment	1,879,460	806,510	42.91%	751,784	40.00%	775,456	41.26%
Total Depreciable	$13,934,243	$4,542,811	32.60%	$4,759,044	34.15%	$4,908,895	35.23%
Amortizable							
391.10 Office Furniture and Equipment	$1,574,954	$916,754	58.21%	$922,258	58.56%	$922,258	58.56%
391.20 Computer Equipment - PCs	670,109	685,432	102.29%	282,605	42.17%	282,605	42.17%
393.00 Stores Equipment	118,860	72,313	60.84%	73,180	61.57%	73,180	61.57%
394.00 Tools, Shop and Garage Equipment	2,666,594	1,207,347	45.28%	1,223,799	45.89%	1,223,799	45.89%
395.00 Laboratory Equipment	1,430,916	399,491	27.92%	404,062	28.24%	404,062	28.24%
397.CE Communication Equipment	2,175,606	642,499	29.53%	652,804	30.01%	652,804	30.01%
398.00 Miscellaneous Equipment	124,227	82,263	66.22%	81,306	65.45%	81,306	65.45%
Total Amortizable	$8,761,266	$4,006,099	45.73%	$3,640,014	41.55%	$3,640,014	41.55%
Total General Plant	$22,695,509	$8,548,909	37.67%	$8,399,058	37.01%	$8,548,909	37.67%
TOTAL UTILITY	$444,355,940	$193,348,358	43.51%	$184,859,206	41.60%	$193,348,358	43.51%

UNS ELECTRIC, INC. (Excluding Black Mountain)
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
Depreciable									
303.WP Misc. Intangible - WAPA Switchboard	$3,466,688		$3,466,688						
Total Depreciable	$3,466,688		$3,466,688						
Amortizable									
302.00 Franchises and Consents									
303.00 Miscellaneous Intangible Plant	4,219,099	2,094,492	2,124,607						
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC Misc.Intangible Plant - PC Software	1,543,417	1,145,223	398,194						
Total Amortizable	$7,447,516	$3,239,715	$4,207,801						
Total Intangible Plant	$10,914,204	$3,239,715	$7,674,489						
OTHER PRODUCTION PLANT									
341.00 Structures and Improvements	$1,969,407		$1,969,407						
342.00 Fuel Holders, Producers and Accessories	847,308		847,308						
343.00 Prime Movers	15,442,734	2,023,462	13,419,272	0.5%		10,117		10,117	0.1%
344.00 Generators	6,352,068	47,600	6,304,468						
345.00 Accessory Electric Equipment	2,732,746	219,338	2,513,408						
346.00 Miscellaneous Power Plant Equipment	1,338,893	9,619	1,329,274						
Total Other Production Plant	$28,683,156	$2,300,019	$26,383,137	0.4%		$10,117		$10,117	
TRANSMISSION PLANT									
350.RW Rights of Way	$346,016		$346,016						
352.00 Structures and Improvements	427,830		427,830						
353.00 Station Equipment	18,952,043	39,479	18,912,564						
354.00 Towers and Fixtures	521,825		521,825						
355.00 Poles and Fixtures	20,774,416	108,245	20,666,171		-10.0%		(2,066,617)	(2,066,617)	-9.9%
356.00 Overhead Conductors and Devices	14,538,514	21,659	14,516,855						
358.00 Underground Conductors and Devices	27,437		27,437		-5.0%		(1,372)	(1,372)	-5.0%
359.00 Roads and Trails	183,860		183,860						
Total Transmission Plant	$55,771,941	$169,383	$55,602,558		-3.7%		($2,067,989)	($2,067,989)	-3.7%
DISTRIBUTION PLANT									
360.RW Rights of Way	$133,365		$133,365						
361.00 Structures and Improvements	5,714,916	24,111	5,690,805	31.7%		7,643		7,643	0.1%
362.00 Station Equipment	39,880,772	402,540	39,478,232	1.8%		7,246		7,246	
364.00 Poles, Towers and Fixtures	86,126,933	1,115,482	85,011,451	16.8%	-10.0%	187,401	(8,501,145)	(8,313,744)	-9.7%
365.00 Overhead Conductors and Devices	60,166,110	1,188,050	58,978,060	-4.7%	-10.0%	(55,838)	(5,897,806)	(5,953,644)	-9.9%
366.00 Underground Conduit	16,373,456	108,323	16,265,133	0.1%	-5.0%	108	(813,257)	(813,148)	-5.0%

Statement D

UNS ELECTRIC, INC. (Excluding Black Mountain)
Average Net Salvage

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
367.00 Underground Conductors and Devices	38,131,743	332,267	37,799,476	-57.2%		(190,057)		(190,057)	-0.5%
368.00 Line Transformers	63,641,794	1,641,952	61,999,842	-28.2%	-5.0%	(463,030)	(3,099,992)	(3,563,023)	-5.6%
369.OH Services - Overhead	8,524,159	329	8,523,830						
369.UG Services - Underground	4,877,076		4,877,076						
370.00 Meters	11,382,119	2,246,358	9,135,761	0.6%	-5.0%	13,478	(456,788)	(443,310)	-3.9%
373.00 Street Lighting and Signal Systems	4,177,865	70,649	4,107,216	-2.0%		(1,413)		(1,413)	
Total Distribution Plant	$339,130,308	$7,130,061	$332,000,247	-6.9%	-5.7%	($494,462)	($18,768,988)	($19,263,450)	-5.7%
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$2,611,433	$5	$2,611,428						
392.C1 Transportation Equipment - Class 1	540,174	392,621	147,553	1.8%	10.0%	7,067	14,755	21,822	4.0%
392.C2 Transportation Equipment - Class 2	1,989,217	728,561	1,260,656	3.7%	10.0%	26,957	126,066	153,022	7.7%
392.C3 Transportation Equipment - Class 3	2,629,311	1,572,725	1,056,586	1.9%	10.0%	29,882	105,659	135,540	5.2%
392.C4 Transportation Equipment - Class 4	5,717,123	3,882,835	1,834,288	0.1%	10.0%	3,883	183,429	187,312	3.3%
392.C5 Transportation Equipment - Class 5	5,144,272		5,144,272		10.0%		514,427	514,427	10.0%
396.00 Power Operated Equipment	1,900,656	21,196	1,879,460						
Total Depreciable	$20,532,186	$6,597,943	$13,934,243	1.0%	6.8%	$67,789	$944,336	$1,012,124	4.9%
Amortizable									
391.10 Office Furniture and Equipment	$5,389,368	$3,814,414	$1,574,954						
391.20 Computer Equipment - PCs	1,543,448	873,339	670,109						
393.00 Stores Equipment	125,241	6,381	118,860						
394.00 Tools, Shop and Garage Equipment	2,864,920	198,326	2,666,594						
395.00 Laboratory Equipment	1,488,136	57,220	1,430,916						
397.CE Communication Equipment	2,295,578	119,972	2,175,606						
398.00 Miscellaneous Equipment	149,698	25,471	124,227						
Total Amortizable	$13,856,389	$5,095,123	$8,761,266						
Total General Plant	$34,388,575	$11,693,066	$22,695,509	0.6%	4.2%	$67,789	$944,336	$1,012,124	2.9%
TOTAL UTILITY	$468,888,184	$24,532,244	$444,355,940	-1.7%	-4.5%	($416,556)	($19,892,641)	($20,309,198)	-4.3%

UNS ELECTRIC, INC. (Excluding Black Mountain)

Current and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Current Parameters P-Life/ AYFR	Current Parameters Curve Shape	Current Parameters BG ASL	Current Parameters Rem. Life	Current Parameters Avg. Sal.	Current Parameters Fut. Sal.	Proposed Parameters P-Life/ AYFR	Proposed Parameters Curve Shape	Proposed Parameters BG ASL	Proposed Parameters Rem. Life	Proposed Parameters Avg. Sal.	Proposed Parameters Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc. Intangible - WAPA Switchboard	32.00	R1	32.00	30.16			32.00	R1	32.00	28.02		
Total Depreciable									32.00	28.02		
Amortizable												
302.00 Franchises and Consents	25.00	SQ	25.00						25.00			
303.00 Miscellaneous Intangible Plant	15.00	SQ	15.00				15.00	SQ	15.00	5.81		
303.WO Misc. Intangible - WAPA Fiber Optic	23.00	SQ	23.00				23.00	SQ	23.00	17.50		
303.PC Misc.Intangible Plant - PC Software	5.00	SQ	5.00				5.00	SQ	5.00	2.48		
Total Amortizable									14.29	7.82		
Total Intangible Plant									19.05	13.25		
OTHER PRODUCTION PLANT												
341.00 Structures and Improvements	49.00	S6	49.00	29.50			49.00	S6	49.00	40.31		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	32.63			40.00	S4	40.00	31.64		
343.00 Prime Movers	40.00	R3	40.00	26.17			40.00	R3	40.00	28.50	0.1	
344.00 Generators	43.00	S0	43.00	36.15			43.00	S0	43.00	38.26		
345.00 Accessory Electric Equipment	43.00	S6	43.00	29.39			43.00	S6	43.00	31.86		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	33.34			38.00	R1	38.00	34.33		
Total Other Production Plant									41.42	32.23		
TRANSMISSION PLANT												
350.RW Rights of Way	50.00	SQ	50.00	31.35			50.00	SQ	50.00	28.60		
352.00 Structures and Improvements	33.00	R3	33.00	12.75			33.00	R3	33.00	21.76		
353.00 Station Equipment	32.00	R1	32.00	21.72			32.00	R1	32.00	20.52		
354.00 Towers and Fixtures	20.00	L0	20.00	15.92			20.00	L0	20.00	14.58		
355.00 Poles and Fixtures	25.00	S5	25.00	12.68	-9.9	-10.0	25.00	S5	25.00	15.76	-9.9	-10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	23.85			38.00	L3	38.00	24.76		
358.00 Underground Conductors and Devices	22.00	SC	22.00				50.00	R4	50.00	47.50	-5.0	-5.0
359.00 Roads and Trails	50.00	SQ	50.00	35.18			50.00	SQ	50.00	32.18		
Total Transmission Plant									30.06	19.25	-3.7	-3.7
DISTRIBUTION PLANT												
360.RW Rights of Way	50.00	SQ	50.00	27.71			50.00	SQ	50.00	33.03		
361.00 Structures and Improvements	34.00	R4	34.00	25.54			34.00	R4	34.00	26.11	0.1	

Statement E

UNS ELECTRIC, INC. (Excluding Black Mountain)

Current and Proposed Parameters
Broad Group Procedure

	Current Parameters						Proposed Parameters					
Account Description	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
362.00 Station Equipment	25.00	S4	25.00	11.54			25.00	S4	25.00	13.57		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	14.83	-9.9	-10.0	27.00	S4	27.00	13.80	-9.7	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	15.16	-9.8	-10.0	27.00	S3	27.00	15.12	-9.9	-10.0
366.00 Underground Conduit	28.00	S2	26.00	18.66	-5.0	-5.0	28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.20			23.00	S3	23.00	15.52	-0.5	
368.00 Line Transformers	23.00	S4	23.00	13.46	-5.0	-5.0	23.00	S4	23.00	13.82	-5.6	-5.0
369.OH Services - Overhead	27.00	R5	27.00	14.43			27.00	R5	27.00	13.82		
369.UG Services - Underground	27.00	R5	27.00	16.26			27.00	R5	27.00	17.43		
370.00 Meters	34.00	R3	34.00	24.14	-4.8	-5.0	34.00	R3	34.00	25.56	-3.9	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	16.64			25.00	S4	25.00	14.77		
Total Distribution Plant									25.67	14.91	-5.7	-5.7
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	38.00	29.03			38.00	R2	38.00	27.19		
392.C1 Transportation Equipment - Class 1	8.00	L1.5	8.00	4.00			8.00	L1.5	8.00	5.76	4.0	10.0
392.C2 Transportation Equipment - Class 2	6.00	L2	6.00	3.02			6.00	L2	6.00	3.65	7.7	10.0
392.C3 Transportation Equipment - Class 3	5.00	S5	5.00	3.28			5.00	S5	5.00	2.41	5.2	10.0
392.C4 Transportation Equipment - Class 4	8.00	S4	8.00	1.63			8.00	S4	8.00	3.11	3.3	10.0
392.C5 Transportation Equipment - Class 5	8.00	S4	8.00	6.58			8.00	S4	8.00	5.62	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	5.16			15.00	S5	15.00	9.00		
Total Depreciable									9.25	5.78	4.9	6.8
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00				21.00	SQ	21.00	8.70		
391.20 Computer Equipment - PCs	5.00	SQ	5.00				5.00	SQ	5.00	2.89		
393.00 Stores Equipment	33.00	SQ	33.00				33.00	SQ	33.00	12.68		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00				29.00	SQ	29.00	15.69		
395.00 Laboratory Equipment	40.00	SQ	40.00				40.00	SQ	40.00	28.70		
397.CE Communication Equipment	23.00	SQ	23.00				23.00	SQ	23.00	16.10		
398.00 Miscellaneous Equipment	18.00	SQ	18.00				18.00	SQ	18.00	6.22		
Total Amortizable									19.83	11.59		
Total General Plant									11.65	7.10	-4.3	-4.5
TOTAL UTILITY									25.01	15.09	-4.3	-4.5

Including Black Mountain

Statements A through E

UNS ELECTRIC, INC. (Including Black Mountain) Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

	Current Rates (at 12/31/2008)			Proposed Rates (at 12/31/2008)		
Account Description	Investment	Net Salvage	Total	Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
INTANGIBLE PLANT						
Depreciable						
303.WP Misc. Intangible - WAPA Switchboard	3.13%		3.13%	2.82%		2.82%
Total Depreciable	3.13%		3.13%	2.82%		2.82%
Amortizable						
302.00 Franchises and Consents	← 25 Year Amortization →					
303.00 Miscellaneous Intangible Plant	← 15 Year Amortization →			← 15 Year Amortization →		
303.WC Misc. Intangible - WAPA Fiber Optic	← 23 Year Amortization →			← 23 Year Amortization →		
303.PC Misc.Intangible Plant - PC Software	← 5 Year Amortization →			← 5 Year Amortization →		
Total Amortizable	7.00%		7.00%	7.00%		7.00%
Total Intangible Plant	5.25%		5.25%	5.11%		5.11%
OTHER PRODUCTION PLANT						
341.00 Structures and Improvements	2.35%		2.35%	2.36%		2.36%
342.00 Fuel Holders, Producers and Accessories	2.53%		2.53%	2.55%		2.55%
343.00 Prime Movers	2.53%		2.53%	2.53%		2.53%
344.00 Generators	2.54%		2.54%	2.58%		2.58%
345.00 Accessory Electric Equipment	2.52%		2.52%	2.55%		2.55%
346.00 Miscellaneous Power Plant Equipment	2.58%		2.58%	2.62%		2.62%
353.00 Station Equipment	3.13%		3.13%	2.62%		2.62%
Total Other Production Plant	2.55%		2.55%	2.56%		2.56%
TRANSMISSION PLANT						
350.RW Rights of Way	2.02%		2.02%	1.91%		1.91%
352.00 Structures and Improvements	3.13%		3.13%	2.93%		2.93%
353.00 Station Equipment	3.15%		3.15%	3.02%		3.02%
354.00 Towers and Fixtures	5.03%		5.03%	4.89%		4.89%
355.00 Poles and Fixtures	4.08%	0.40%	4.48%	3.86%	0.38%	4.24%
356.00 Overhead Conductors and Devices	2.66%		2.66%	2.55%		2.55%
358.00 Underground Conductors and Devices	4.36%		4.36%	1.99%	0.10%	2.09%
359.00 Roads and Trails	2.02%		2.02%	1.93%		1.93%
Total Transmission Plant	3.38%	0.15%	3.52%	3.22%	0.14%	3.36%
DISTRIBUTION PLANT						
360.RW Rights of Way	2.03%		2.03%	1.95%		1.95%
361.00 Structures and Improvements	2.96%		2.96%	2.90%		2.90%
362.00 Station Equipment	4.09%		4.09%	3.84%		3.84%
364.00 Poles, Towers and Fixtures	3.76%	0.38%	4.14%	3.54%	0.34%	3.88%
365.00 Overhead Conductors and Devices	3.76%	0.37%	4.13%	3.57%	0.35%	3.92%
366.00 Underground Conduit	3.61%	0.18%	3.79%	3.49%	0.17%	3.66%
367.00 Underground Conductors and Devices	4.40%		4.40%	4.25%	0.02%	4.27%
368.00 Line Transformers	4.41%	0.22%	4.63%	4.21%	0.24%	4.45%
369.OH Services - Overhead	3.77%		3.77%	3.54%		3.54%
369.UG Services - Underground	3.75%		3.75%	3.61%		3.61%
370.00 Meters	2.96%	0.15%	3.11%	2.90%	0.11%	3.01%
373.00 Street Lighting and Signal Systems	4.04%		4.04%	3.87%		3.87%
Total Distribution Plant	3.95%	0.22%	4.17%	3.76%	0.21%	3.97%
GENERAL PLANT						
Depreciable						
390.00 Structures and Improvements	2.65%		2.65%	2.60%		2.60%
392.C1 Transportation Equipment - Class 1	12.75%		12.75%	12.35%	-0.46%	11.89%
392.C2 Transportation Equipment - Class 2	16.99%		16.99%	16.33%	-1.24%	15.09%
392.C3 Transportation Equipment - Class 3	20.21%		20.21%	19.32%	-0.94%	18.38%
392.C4 Transportation Equipment - Class 4	13.47%		13.47%	11.88%	-0.32%	11.56%
392.C5 Transportation Equipment - Class 5	12.55%		12.55%	12.33%	-1.23%	11.10%
396.00 Power Operated Equipment	6.92%		6.92%	6.53%		6.53%
Total Depreciable	11.04%		11.04%	10.56%	-0.68%	9.87%

UNS ELECTRIC, INC. (Including Black Mountain)

Statement A

Comparison of Current and Proposed Accrual Rates
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	Current Rates (at 12/31/2008) Investment	Net Salvage	Total	Proposed Rates (at 12/31/2008) Investment	Net Salvage	Total
A	B	C	D=B+C	E	F	G=E+F
Amortizable						
391.10 Office Furniture and Equipment	← 21 Year Amortization →			← 21 Year Amortization →		
391.20 Computer Equipment - PCs	← 5 Year Amortization →			← 5 Year Amortization →		
393.00 Stores Equipment	← 33 Year Amortization →			← 33 Year Amortization →		
394.00 Tools, Shop and Garage Equipment	← 29 Year Amortization →			← 29 Year Amortization →		
395.00 Laboratory Equipment	← 40 Year Amortization →			← 40 Year Amortization →		
397.CE Communication Equipment	← 23 Year Amortization →			← 23 Year Amortization →		
398.00 Miscellaneous Equipment	← 18 Year Amortization →			← 18 Year Amortization →		
Total Amortizable	5.04%		5.04%	5.04%		5.04%
Total General Plant	8.73%		8.73%	8.43%	-0.42%	8.01%
TOTAL UTILITY	3.88%	0.16%	4.04%	3.72%	0.13%	3.85%
OTHER PRODUCTION PLANT						
Nogales						
341.00 Structures and Improvements	2.07%		2.07%	2.05%		2.05%
342.00 Fuel Holders, Producers and Accessories	2.51%		2.51%	2.52%		2.52%
343.00 Prime Movers	2.53%		2.53%	2.53%		2.53%
344.00 Generators	2.33%		2.33%	2.33%		2.33%
345.00 Accessory Electric Equipment	2.35%		2.35%	2.35%		2.35%
346.00 Miscellaneous Power Plant Equipment	2.64%		2.64%	2.64%		2.64%
353.00 Station Equipment						
Total Nogales	2.44%		2.44%	2.43%		2.43%
Black Mountain						
341.00 Structures and Improvements	2.57%		2.57%	2.62%		2.62%
342.00 Fuel Holders, Producers and Accessories	2.57%		2.57%	2.62%		2.62%
343.00 Prime Movers						
344.00 Generators	2.57%		2.57%	2.62%		2.62%
345.00 Accessory Electric Equipment	2.57%		2.57%	2.62%		2.62%
346.00 Miscellaneous Power Plant Equipment	2.57%		2.57%	2.62%		2.62%
353.00 Station Equipment	3.13%		3.13%	2.62%		2.62%
Total Black Mountain	2.60%		2.60%	2.62%		2.62%

UNS ELECTRIC, INC. (Including Black Mountain)

Statement B

Comparison of Current and Proposed Accruals
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/08 Investment	Current 2009 Annualized Accrual Investment	Current Net Salvage	Current Total	Proposed 2009 Annualized Accrual Investment	Proposed Net Salvage	Proposed Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
INTANGIBLE PLANT								
Depreciable								
303.WP Misc. Intangible - WAPA Switchboard	$3,466,688	$108,507		$108,507	$97,761		$97,761	($10,746)
Total Depreciable	$3,466,688	$108,507		$108,507	$97,761		$97,761	($10,746)
Amortizable								
302.00 Franchises and Consents								
303.00 Miscellaneous Intangible Plant	2,124,607	141,711		141,711	141,499		141,499	(212)
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	73,298		73,298	73,298		73,298	
303.PC Misc.Intangible Plant - PC Software	398,194	79,639		79,639	79,758		79,758	119
Total Amortizable	$4,207,801	$294,648		$294,648	$294,555		$294,555	($93)
Total Intangible Plant	$7,674,489	$403,155		$403,155	$392,316		$392,316	($10,839)
OTHER PRODUCTION PLANT								
341.00 Structures and Improvements	$4,399,915	$103,231		$103,231	$104,052		$104,052	$821
342.00 Fuel Holders, Producers and Accessories	1,168,031	29,510		29,510	29,755		29,755	245
343.00 Prime Movers	13,419,272	339,508		339,508	339,508		339,508	
344.00 Generators	44,807,494	1,136,422		1,136,422	1,155,673		1,155,673	19,251
345.00 Accessory Electric Equipment	10,401,458	261,788		261,788	265,732		265,732	3,944
346.00 Miscellaneous Power Plant Equipment	10,682,020	275,459		275,459	280,135		280,135	4,676
353.00 Station Equipment	3,558,978	111,396		111,396	93,245		93,245	(18,151)
Total Other Production Plant	$88,437,168	$2,257,314		$2,257,314	$2,268,100		$2,268,100	$10,786
TRANSMISSION PLANT								
350.RW Rights of Way	$346,016	$6,990		$6,990	$6,609		$6,609	($381)
352.00 Structures and Improvements	427,830	13,391		13,391	12,535		12,535	(856)
353.00 Station Equipment	18,912,564	595,746		595,746	571,159		571,159	(24,587)
354.00 Towers and Fixtures	521,825	26,248		26,248	25,517		25,517	(731)
355.00 Poles and Fixtures	20,666,171	843,180	82,665	925,845	797,714	78,531	876,245	(49,600)
356.00 Overhead Conductors and Devices	14,516,855	386,148		386,148	370,180		370,180	(15,968)
358.00 Underground Conductors and Devices	27,437	1,196		1,196	546	27	573	(623)
359.00 Roads and Trails	183,860	3,714		3,714	3,548		3,548	(166)
Total Transmission Plant	$55,602,558	$1,876,613	$82,665	$1,959,278	$1,787,808	$78,558	$1,866,366	($92,912)

Statement B

UNS ELECTRIC, INC. (Including Black Mountain)

Comparison of Current and Proposed Accruals
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Account Description	12/31/08 Investment	Current 2009 Annualized Accrual Investment	Net Salvage	Total	Proposed 2009 Annualized Accrual Investment	Net Salvage	Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
DISTRIBUTION PLANT								
360.RW Rights of Way	$133,365	$2,707		$2,707	$2,601		$2,601	($106)
361.00 Structures and Improvements	5,690,805	168,448		168,448	165,033		165,033	(3,415)
362.00 Station Equipment	39,478,232	1,614,660		1,614,660	1,515,964		1,515,964	(98,696)
364.00 Poles, Towers and Fixtures	85,011,451	3,196,431	323,044	3,519,475	3,009,405	289,039	3,298,444	(221,031)
365.00 Overhead Conductors and Devices	58,978,060	2,217,575	218,219	2,435,794	2,105,517	206,423	2,311,940	(123,854)
366.00 Underground Conduit	16,265,133	587,171	29,277	616,448	567,653	27,651	595,304	(21,144)
367.00 Underground Conductors and Devices	37,799,476	1,663,177		1,663,177	1,606,478	7,560	1,614,038	(49,139)
368.00 Line Transformers	61,999,842	2,734,193	136,400	2,870,593	2,610,193	148,800	2,758,993	(111,600)
369.OH Services - Overhead	8,523,830	321,348		321,348	301,744		301,744	(19,604)
369.UG Services - Underground	4,877,076	182,890		182,890	176,062		176,062	(6,828)
370.00 Meters	9,135,761	270,419	13,704	284,123	264,937	10,049	274,986	(9,137)
373.00 Street Lighting and Signal Systems	4,107,216	165,932		165,932	158,949		158,949	(6,983)
Total Distribution Plant	$332,000,247	$13,124,951	$720,644	$13,845,595	$12,484,536	$689,522	$13,174,058	($671,537)
GENERAL PLANT								
Depreciable								
390.00 Structures and Improvements	$2,611,428	$69,203		$69,203	$67,897		$67,897	($1,306)
392.C1 Transportation Equipment - Class 1	147,553	18,813		18,813	18,223	(679)	17,544	(1,269)
392.C2 Transportation Equipment - Class 2	1,260,656	214,185		214,185	205,865	(15,632)	190,233	(23,952)
392.C3 Transportation Equipment - Class 3	1,056,586	213,536		213,536	204,132	(9,932)	194,200	(19,336)
392.C4 Transportation Equipment - Class 4	1,834,288	247,079		247,079	217,913	(5,870)	212,043	(35,036)
392.C5 Transportation Equipment - Class 5	5,144,272	645,606		645,606	634,289	(63,275)	571,014	(74,592)
396.00 Power Operated Equipment	1,879,460	130,059		130,059	122,729		122,729	(7,330)
Total Depreciable	$13,934,243	$1,538,481		$1,538,481	$1,471,048	($95,388)	$1,375,660	($162,821)
Amortizable								
391.10 Office Furniture and Equipment	$1,574,954	$74,968		$74,968	$74,968		$74,968	
391.20 Computer Equipment - PCs	670,109	134,022		134,022	134,089		134,089	67
393.00 Stores Equipment	118,860	3,601		3,601	3,601		3,601	
394.00 Tools, Shop and Garage Equipment	2,666,594	91,997		91,997	91,997		91,997	
395.00 Laboratory Equipment	1,430,916	35,773		35,773	35,773		35,773	
397.CE Communication Equipment	2,175,606	94,639		94,639	94,639		94,639	
398.00 Miscellaneous Equipment	124,227	6,907		6,907	6,895		6,895	(12)
Total Amortizable	$8,761,266	$441,907		$441,907	$441,962		$441,962	$55
Total General Plant	$22,695,509	$1,980,388		$1,980,388	$1,913,010	($95,388)	$1,817,622	($162,766)
TOTAL UTILITY	$506,409,971	$19,642,421	$803,309	$20,445,730	$18,845,770	$672,692	$19,518,462	($927,268)

UNS ELECTRIC, INC. (Including Black Mountain)

Comparison of Current and Proposed Accruals
Current: BG Procedure / RL Technique
Proposed: BG Procedure / RL Technique

Statement B

Account Description	12/31/08 Investment	Current 2009 Annualized Accrual Investment	Current Net Salvage	Current Total	Proposed 2009 Annualized Accrual Investment	Proposed Net Salvage	Proposed Total	Difference
A	B	C	D	E=C+D	F	G	H=F+G	I=H-E
OTHER PRODUCTION PLANT								
Nogales								
341.00 Structures and Improvements	$1,969,407	$40,767		$40,767	$40,373		$40,373	($394)
342.00 Fuel Holders, Producers and Accessories	847,308	21,267		21,267	21,352		21,352	85
343.00 Prime Movers	13,419,272	339,508		339,508	339,508		339,508	
344.00 Generators	6,304,468	146,894		146,894	146,894		146,894	
345.00 Accessory Electric Equipment	2,513,408	59,065		59,065	59,065		59,065	
346.00 Miscellaneous Power Plant Equipment	1,329,274	35,093		35,093	35,093		35,093	
353.00 Station Equipment								
Total Nogales	$26,383,137	$642,594		$642,594	$642,285		$642,285	($309)
Black Mountain								
341.00 Structures and Improvements	$2,430,508	$62,464		$62,464	$63,679		$63,679	$1,215
342.00 Fuel Holders, Producers and Accessories	320,723	8,243		8,243	8,403		8,403	160
343.00 Prime Movers								
344.00 Generators	38,503,026	989,528		989,528	1,008,779		1,008,779	19,251
345.00 Accessory Electric Equipment	7,888,050	202,723		202,723	206,667		206,667	3,944
346.00 Miscellaneous Power Plant Equipment	9,352,746	240,366		240,366	245,042		245,042	4,676
353.00 Station Equipment	3,558,978	111,396		111,396	93,245		93,245	(18,151)
Total Black Mountain	$62,054,031	$1,614,720		$1,614,720	$1,625,815		$1,625,815	$11,095

Statement C

UNS ELECTRIC, INC. (Including Black Mountain)
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
INTANGIBLE PLANT							
Depreciable							
303.WP Misc. Intangible - WAPA Switchboard	$3,466,688	$502,351	14.49%	$431,169	12.44%	$722,638	20.85%
Total Depreciable	$3,466,688	$502,351	14.49%	$431,169	12.44%	$722,638	20.85%
Amortizable							
302.00 Franchises and Consents		($113)					
303.00 Miscellaneous Intangible Plant	2,124,607	965,818	45.46%	1,302,255	61.29%	1,302,255	61.29%
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000	394,086	23.39%	402,935	23.91%	402,935	23.91%
303.PC Misc.Intangible Plant - PC Software	398,194	766,040	192.38%	200,354	50.32%	200,354	50.32%
Total Amortizable	$4,207,801	$2,125,831	50.52%	$1,905,544	45.29%	$1,905,544	45.29%
Total Intangible Plant	$7,674,489	$2,628,182	34.25%	$2,336,713	30.45%	$2,628,182	34.25%
OTHER PRODUCTION PLANT							
341.00 Structures and Improvements	$4,399,915	$361,518	8.22%	$378,051	8.59%	$378,558	8.60%
342.00 Fuel Holders, Producers and Accessories	1,168,031	178,743	15.30%	180,885	15.49%	177,112	15.16%
343.00 Prime Movers	13,419,272	3,848,955	28.68%	3,867,602	28.82%	3,754,230	27.98%
344.00 Generators	44,807,494	1,154,525	2.58%	1,150,915	2.57%	1,300,770	2.90%
345.00 Accessory Electric Equipment	10,401,458	809,265	7.78%	744,559	7.16%	760,346	7.31%
346.00 Miscellaneous Power Plant Equipment	10,682,020	282,991	2.65%	239,136	2.24%	276,723	2.59%
353.00 Station Equipment	3,558,978	69,623	1.96%	42,146	1.18%	57,880	1.63%
Total Other Production Plant	$88,437,168	$6,705,619	7.58%	$6,603,294	7.47%	$6,705,619	7.58%
TRANSMISSION PLANT							
350.RW Rights of Way	$346,016	$130,587	37.74%	$148,095	42.80%	$157,153	45.42%
352.00 Structures and Improvements	427,830	157,831	36.89%	145,721	34.06%	154,634	36.14%
353.00 Station Equipment	18,912,564	7,219,008	38.17%	6,784,882	35.88%	7,199,854	38.07%
354.00 Towers and Fixtures	521,825	171,132	32.79%	141,415	27.10%	150,064	28.76%
355.00 Poles and Fixtures	20,666,171	9,143,150	44.24%	8,415,066	40.72%	8,929,742	43.21%
356.00 Overhead Conductors and Devices	14,516,855	5,141,109	35.41%	5,057,978	34.84%	5,367,330	36.97%
358.00 Underground Conductors and Devices	27,437	2,509	9.14%	1,440	5.25%	1,529	5.57%
359.00 Roads and Trails	183,860	64,515	35.09%	65,528	35.64%	69,535	37.82%
Total Transmission Plant	$55,602,558	$22,029,840	39.62%	$20,760,126	37.34%	$22,029,840	39.62%

Statement C

UNS ELECTRIC, INC. (Including Black Mountain)
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
A	B	C	D=C/B	E	F=E/B	G	H=G/B
DISTRIBUTION PLANT							
360.RW Rights of Way	$133,365	$39,430	29.57%	$45,264	33.94%	$47,397	35.54%
361.00 Structures and Improvements	5,690,805	1,317,861	23.16%	1,324,972	23.28%	1,387,406	24.38%
362.00 Station Equipment	39,478,232	19,358,765	49.04%	18,049,448	45.72%	18,899,960	47.87%
364.00 Poles, Towers and Fixtures	85,011,451	46,789,344	55.04%	45,847,620	53.93%	48,008,017	56.47%
365.00 Overhead Conductors and Devices	58,978,060	29,819,099	50.56%	28,578,409	48.46%	29,925,059	50.74%
366.00 Underground Conduit	16,265,133	6,047,350	37.18%	5,696,863	35.03%	5,965,306	36.68%
367.00 Underground Conductors and Devices	37,799,476	13,688,605	36.21%	12,165,515	32.18%	12,738,769	33.70%
368.00 Line Transformers	61,999,842	27,707,134	44.69%	25,759,802	41.55%	26,973,636	43.51%
369.OH Services - Overhead	8,523,830	4,334,332	50.85%	4,160,892	48.81%	4,356,958	51.12%
369.UG Services - Underground	4,877,076	1,792,586	36.76%	1,728,652	35.44%	1,810,109	37.11%
370.00 Meters	9,135,761	2,597,445	28.43%	2,456,757	26.89%	2,572,522	28.16%
373.00 Street Lighting and Signal Systems	4,107,216	953,055	23.20%	1,680,673	40.92%	1,759,868	42.85%
Total Distribution Plant	$332,000,247	$154,445,006	46.52%	$147,494,866	44.43%	$154,445,006	46.52%
GENERAL PLANT							
Depreciable							
390.00 Structures and Improvements	$2,611,428	$791,938	30.33%	$742,883	28.45%	$766,274	29.34%
392.C1 Transportation Equipment - Class 1	147,553	(112,095)	-75.97%	30,809	20.88%	31,779	21.54%
392.C2 Transportation Equipment - Class 2	1,260,656	725,367	57.54%	426,743	33.85%	440,180	34.92%
392.C3 Transportation Equipment - Class 3	1,056,586	206,593	19.55%	468,135	44.31%	482,876	45.70%
392.C4 Transportation Equipment - Class 4	1,834,288	636,632	34.71%	961,311	52.41%	991,581	54.06%
392.C5 Transportation Equipment - Class 5	5,144,272	1,487,865	28.92%	1,377,379	26.78%	1,420,749	27.62%
396.00 Power Operated Equipment	1,879,460	806,510	42.91%	751,784	40.00%	775,456	41.26%
Total Depreciable	$13,934,243	$4,542,811	32.60%	$4,759,044	34.15%	$4,908,895	35.23%

UNS ELECTRIC, INC. (Including Black Mountain)
Depreciation Reserve Summary
Broad Group Procedure
December 31, 2008

Statement C

	Account Description	Plant Investment	Recorded Reserve Amount	Recorded Reserve Ratio	Computed Reserve Amount	Computed Reserve Ratio	Redistributed Reserve Amount	Redistributed Reserve Ratio
	A	B	C	D=C/B	E	F=E/B	G	H=G/B
	Amortizable							
391.10	Office Furniture and Equipment	$1,574,954	$916,754	58.21%	$922,258	58.56%	$922,258	58.56%
391.20	Computer Equipment - PCs	670,109	685,432	102.29%	282,605	42.17%	282,605	42.17%
393.00	Stores Equipment	118,860	72,313	60.84%	73,180	61.57%	73,180	61.57%
394.00	Tools, Shop and Garage Equipment	2,666,594	1,207,347	45.28%	1,223,799	45.89%	1,223,799	45.89%
395.00	Laboratory Equipment	1,430,916	399,491	27.92%	404,062	28.24%	404,062	28.24%
397.CE	Communication Equipment	2,175,606	642,499	29.53%	652,804	30.01%	652,804	30.01%
398.00	Miscellaneous Equipment	124,227	82,263	66.22%	81,306	65.45%	81,306	65.45%
	Total Amortizable	$8,761,266	$4,006,099	45.73%	$3,640,014	41.55%	$3,640,014	41.55%
	Total General Plant	$22,695,509	$8,548,909	37.67%	$8,399,058	37.01%	$8,548,909	37.67%
	TOTAL UTILITY	$506,409,971	$194,357,557	38.38%	$185,594,056	36.65%	$194,357,557	38.38%
	OTHER PRODUCTION PLANT							
	Nogales							
341.00	Structures and Improvements	$1,969,407	$322,478	16.37%	$349,268	17.73%	$339,030	17.21%
342.00	Fuel Holders, Producers and Accessories	847,308	173,591	20.49%	177,087	20.90%	171,896	20.29%
343.00	Prime Movers	13,419,272	3,848,955	28.68%	3,867,602	28.82%	3,754,230	27.98%
344.00	Generators	6,304,468	536,070	8.50%	694,958	11.02%	674,586	10.70%
345.00	Accessory Electric Equipment	2,513,408	682,563	27.16%	651,148	25.91%	632,061	25.15%
346.00	Miscellaneous Power Plant Equipment	1,329,274	132,763	9.99%	128,380	9.66%	124,617	9.37%
353.00	Station Equipment							
	Total Nogales	$26,383,137	$5,696,420	21.59%	$5,868,443	22.24%	$5,696,420	21.59%
	Black Mountain							
341.00	Structures and Improvements	$2,430,508	$39,040	1.61%	$28,782	1.18%	$39,528	1.63%
342.00	Fuel Holders, Producers and Accessories	320,723	5,152	1.61%	3,798	1.18%	5,216	1.63%
343.00	Prime Movers							
344.00	Generators	38,503,026	618,455	1.61%	455,957	1.18%	626,184	1.63%
345.00	Accessory Electric Equipment	7,888,050	126,702	1.61%	93,411	1.18%	128,285	1.63%
346.00	Miscellaneous Power Plant Equipment	9,352,746	150,228	1.61%	110,756	1.18%	152,106	1.63%
353.00	Station Equipment	3,558,978	69,623	1.96%	42,146	1.18%	57,880	1.63%
	Total Black Mountain	$62,054,031	$1,009,199	1.63%	$734,850	1.18%	$1,009,199	1.63%

UNS ELECTRIC, INC. (Including Black Mountain)
Average Net Salvage

Statement D

Account Description	Plant Investment: Additions	Plant Investment: Retirements	Plant Investment: Survivors	Salvage Rate: Realized	Salvage Rate: Future	Net Salvage: Realized	Net Salvage: Future	Net Salvage: Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
INTANGIBLE PLANT									
Depreciable									
303.WP Misc. Intangible - WAPA Switchboard	$3,466,688		$3,466,688						
Total Depreciable	$3,466,688		$3,466,688						
Amortizable									
302.00 Franchises and Consents									
303.00 Miscellaneous Intangible Plant	4,219,099	2,094,492	2,124,607						
303.WC Misc. Intangible - WAPA Fiber Optic	1,685,000		1,685,000						
303.PC Misc.Intangible Plant - PC Software	1,543,417	1,145,223	398,194						
Total Amortizable	$7,447,516	$3,239,715	$4,207,801						
Total Intangible Plant	$10,914,204	$3,239,715	$7,674,489						
OTHER PRODUCTION PLANT									
341.00 Structures and Improvements	$4,399,915		$4,399,915						
342.00 Fuel Holders, Producers and Accessories	1,168,031		1,168,031						
343.00 Prime Movers	15,442,734	2,023,462	13,419,272	0.5%		10,117		10,117	0.1%
344.00 Generators	44,855,094	47,600	44,807,494						
345.00 Accessory Electric Equipment	10,620,796	219,338	10,401,458						
346.00 Miscellaneous Power Plant Equipment	10,691,639	9,619	10,682,020						
353.00 Station Equipment	3,558,978		3,558,978						
Total Other Production Plant	$90,737,187	$2,300,019	$88,437,168	0.4%		$10,117		$10,117	
TRANSMISSION PLANT									
350.RW Rights of Way	$346,016		$346,016						
352.00 Structures and Improvements	427,830		427,830						
353.00 Station Equipment	18,952,043	39,479	18,912,564						
354.00 Towers and Fixtures	521,825		521,825						
355.00 Poles and Fixtures	20,774,416	108,245	20,666,171		-10.0%		(2,066,617)	(2,066,617)	-9.9%
356.00 Overhead Conductors and Devices	14,538,514	21,659	14,516,855						
358.00 Underground Conductors and Devices	27,437		27,437		-5.0%		(1,372)	(1,372)	-5.0%
359.00 Roads and Trails	183,860		183,860						
Total Transmission Plant	$55,771,941	$169,383	$55,602,558		-3.7%		($2,067,989)	($2,067,989)	-3.7%

UNS ELECTRIC, INC. (Including Black Mountain)
Average Net Salvage

Statement D

Account Description	Plant Investment Additions	Plant Investment Retirements	Plant Investment Survivors	Salvage Rate Realized	Salvage Rate Future	Net Salvage Realized	Net Salvage Future	Net Salvage Total	Average Rate
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
DISTRIBUTION PLANT									
360.RW Rights of Way	$133,365		$133,365						
361.00 Structures and Improvements	5,714,916	24,111	5,690,805	31.7%		7,643		7,643	0.1%
362.00 Station Equipment	39,880,772	402,540	39,478,232	1.8%		7,246		7,246	
364.00 Poles, Towers and Fixtures	86,126,933	1,115,482	85,011,451	16.8%	-10.0%	187,401	(8,501,145)	(8,313,744)	-9.7%
365.00 Overhead Conductors and Devices	60,166,110	1,188,050	58,978,060	-4.7%	-10.0%	(55,838)	(5,897,806)	(5,953,644)	-9.9%
366.00 Underground Conduit	16,373,456	108,323	16,265,133	0.1%	-5.0%	108	(813,257)	(813,148)	-5.0%
367.00 Underground Conductors and Devices	38,131,743	332,267	37,799,476	-57.2%		(190,057)		(190,057)	-0.5%
368.00 Line Transformers	63,641,794	1,641,952	61,999,842	-28.2%	-5.0%	(463,030)	(3,099,992)	(3,563,023)	-5.6%
369.OH Services - Overhead	8,524,159	329	8,523,830						
369.UG Services - Underground	4,877,076		4,877,076						
370.00 Meters	11,382,119	2,246,358	9,135,761	0.6%	-5.0%	13,478	(456,788)	(443,310)	-3.9%
373.00 Street Lighting and Signal Systems	4,177,865	70,649	4,107,216	-2.0%		(1,413)		(1,413)	
Total Distribution Plant	$339,130,308	$7,130,061	$332,000,247	-6.9%	-5.7%	($494,462)	($18,768,988)	($19,263,450)	-5.7%
GENERAL PLANT									
Depreciable									
390.00 Structures and Improvements	$2,611,433	$5	$2,611,428						
392.C1 Transportation Equipment - Class 1	540,174	392,621	147,553	1.8%	10.0%	7,067	14,755	21,822	4.0%
392.C2 Transportation Equipment - Class 2	1,989,217	728,561	1,260,656	3.7%	10.0%	26,957	126,066	153,022	7.7%
392.C3 Transportation Equipment - Class 3	2,629,311	1,572,725	1,056,586	1.9%	10.0%	29,882	105,659	135,540	5.2%
392.C4 Transportation Equipment - Class 4	5,717,123	3,882,835	1,834,288	0.1%	10.0%	3,883	183,429	187,312	3.3%
392.C5 Transportation Equipment - Class 5	5,144,272		5,144,272		10.0%		514,427	514,427	10.0%
396.00 Power Operated Equipment	1,900,656	21,196	1,879,460						
Total Depreciable	$20,532,186	$6,597,943	$13,934,243	1.0%	6.8%	$67,789	$944,336	$1,012,124	4.9%
Amortizable									
391.10 Office Furniture and Equipment	$5,389,368	$3,814,414	$1,574,954						
391.20 Computer Equipment - PCs	1,543,448	873,339	670,109						
393.00 Stores Equipment	125,241	6,381	118,860						
394.00 Tools, Shop and Garage Equipment	2,864,920	198,326	2,666,594						
395.00 Laboratory Equipment	1,488,136	57,220	1,430,916						
397.CE Communication Equipment	2,295,578	119,972	2,175,606						
398.00 Miscellaneous Equipment	149,698	25,471	124,227						
Total Amortizable	$13,856,389	$5,095,123	$8,761,266						
Total General Plant	$34,388,575	$11,693,066	$22,695,509	0.6%	4.2%	$67,789	$944,336	$1,012,124	2.9%
TOTAL UTILITY	$530,942,215	$24,532,244	$506,409,971	-1.7%	-3.9%	($416,556)	($19,892,641)	($20,309,198)	-3.8%

Statement D

UNS ELECTRIC, INC. (Including Black Mountain)
Average Net Salvage

Account Description	Plant Investment			Salvage Rate		Net Salvage			Average Rate
	Additions	Retirements	Survivors	Realized	Future	Realized	Future	Total	
A	B	C	D=B-C	E	F	G=E*C	H=F*D	I=G+H	J=I/B
OTHER PRODUCTION PLANT									
Nogales									
341.00 Structures and Improvements	$1,969,407		$1,969,407						
342.00 Fuel Holders, Producers and Accessories	847,308		847,308						
343.00 Prime Movers	15,442,734	2,023,462	13,419,272	0.5%		10,117		10,117	0.1%
344.00 Generators	6,352,068	47,600	6,304,468						
345.00 Accessory Electric Equipment	2,732,746	219,338	2,513,408						
346.00 Miscellaneous Power Plant Equipment	1,338,893	9,619	1,329,274						
353.00 Station Equipment									
Total Nogales	$28,683,156	$2,300,019	$26,383,137	0.4%		$10,117		$10,117	
Black Mountain									
341.00 Structures and Improvements	$2,430,508		$2,430,508						
342.00 Fuel Holders, Producers and Accessories	320,723		320,723						
343.00 Prime Movers									
344.00 Generators	38,503,026		38,503,026						
345.00 Accessory Electric Equipment	7,888,050		7,888,050						
346.00 Miscellaneous Power Plant Equipment	9,352,746		9,352,746						
353.00 Station Equipment	3,558,978		3,558,978						
Total Black Mountain	$62,054,031		$62,054,031						

Statement E

UNS ELECTRIC, INC. (Including Black Mountain)
Current and Proposed Parameters
Broad Group Procedure

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
INTANGIBLE PLANT												
Depreciable												
303.WP Misc. Intangible - WAPA Switchboard	32.00	R1	32.00	30.16			32.00	R1	32.00	28.02		
Total Depreciable									32.00	28.02		
Amortizable												
302.00 Franchises and Consents	25.00	SQ	25.00						25.00			
303.00 Miscellaneous Intangible Plant	15.00	SQ	15.00				15.00	SQ	15.00	5.81		
303.WO Misc. Intangible - WAPA Fiber Optic	23.00	SQ	23.00				23.00	SQ	23.00	17.50		
303.PC Misc.Intangible Plant - PC Software	5.00	SQ	5.00				5.00	SQ	5.00	2.48		
Total Amortizable									14.29	7.82		
Total Intangible Plant									19.05	13.25		
OTHER PRODUCTION PLANT												
341.00 Structures and Improvements									42.24	38.62		
342.00 Fuel Holders, Producers and Accessories									39.43	33.32		
343.00 Prime Movers									40.00	28.50	0.1	
344.00 Generators									38.63	37.64		
345.00 Accessory Electric Equipment									39.10	36.30		
346.00 Miscellaneous Power Plant Equipment									38.00	37.15		
353.00 Station Equipment									38.00	37.55		
Total Other Production Plant									38.96	36.06		
TRANSMISSION PLANT												
350.RW Rights of Way	50.00	SQ	50.00	31.35			50.00	SQ	50.00	28.60		
352.00 Structures and Improvements	33.00	R3	33.00	12.75			33.00	R3	33.00	21.76		
353.00 Station Equipment	32.00	R1	32.00	21.72			32.00	R1	32.00	20.52		
354.00 Towers and Fixtures	20.00	L0	20.00	15.92			20.00	L0	20.00	14.58		
355.00 Poles and Fixtures	25.00	S5	25.00	12.68	-9.9	-10.0	25.00	S5	25.00	15.76	-9.9	-10.0
356.00 Overhead Conductors and Devices	38.00	L3	38.00	23.85			38.00	L3	38.00	24.76		
358.00 Underground Conductors and Devices	22.00	SC	22.00				50.00	R4	50.00	47.50	-5.0	-5.0
359.00 Roads and Trails	50.00	SQ	50.00	35.18			50.00	SQ	50.00	32.18		
Total Transmission Plant									30.06	19.25	-3.7	-3.7

UNS ELECTRIC, INC. (Including Black Mountain)
Current and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
DISTRIBUTION PLANT												
360.RW Rights of Way	50.00	SQ	50.00	27.71			50.00	SQ	50.00	33.03		
361.00 Structures and Improvements	34.00	R4	34.00	25.54			34.00	R4	34.00	26.11	0.1	
362.00 Station Equipment	25.00	S4	25.00	11.54			25.00	S4	25.00	13.57		
364.00 Poles, Towers and Fixtures	27.00	S4	27.00	14.83	-9.9	-10.0	27.00	S4	27.00	13.80	-9.7	-10.0
365.00 Overhead Conductors and Devices	27.00	S3	27.00	15.16	-9.8	-10.0	27.00	S3	27.00	15.12	-9.9	-10.0
366.00 Underground Conduit	28.00	S2	26.00	18.66	-5.0	-5.0	28.00	S2	28.00	18.66	-5.0	-5.0
367.00 Underground Conductors and Devices	23.00	S3	23.00	14.20			23.00	S3	23.00	15.52	-0.5	
368.00 Line Transformers	23.00	S4	23.00	13.46	-5.0	-5.0	23.00	S4	23.00	13.82	-5.6	-5.0
369.OH Services - Overhead	27.00	R5	27.00	14.43			27.00	R5	27.00	13.82		
369.UG Services - Underground	27.00	R5	27.00	16.26			27.00	R5	27.00	17.43		
370.00 Meters	34.00	R3	34.00	24.14	-4.8	-5.0	34.00	R3	34.00	25.56	-3.9	-5.0
373.00 Street Lighting and Signal Systems	25.00	S4	25.00	16.64			25.00	S4	25.00	14.77		
Total Distribution Plant									25.67	14.91	-5.7	-5.7
GENERAL PLANT												
Depreciable												
390.00 Structures and Improvements	38.00	R2	38.00	29.03			38.00	R2	38.00	27.19		
392.C1 Transportation Equipment - Class 1	8.00	L1.5	8.00	4.00			8.00	L1.5	8.00	5.76	4.0	10.0
392.C2 Transportation Equipment - Class 2	6.00	L2	6.00	3.02			6.00	L2	6.00	3.65	7.7	10.0
392.C3 Transportation Equipment - Class 3	5.00	S5	5.00	3.28			5.00	S5	5.00	2.41	5.2	10.0
392.C4 Transportation Equipment - Class 4	8.00	S4	8.00	1.63			8.00	S4	8.00	3.11	3.3	10.0
392.C5 Transportation Equipment - Class 5	8.00	S4	8.00	6.58			8.00	S4	8.00	5.62	10.0	10.0
396.00 Power Operated Equipment	15.00	S5	15.00	5.16			15.00	S5	15.00	9.00		
Total Depreciable									9.25	5.78	4.9	6.8

UNS ELECTRIC, INC. (Including Black Mountain)

Current and Proposed Parameters
Broad Group Procedure

Statement E

Account Description	Current Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	Proposed Parameters P-Life/ AYFR	Curve Shape	BG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
A	B	C	D	E	F	G	H	I	J	K	L	M
Amortizable												
391.10 Office Furniture and Equipment	21.00	SQ	21.00				21.00	SQ	21.00	8.70		
391.20 Computer Equipment - PCs	5.00	SQ	5.00				5.00	SQ	5.00	2.89		
393.00 Stores Equipment	33.00	SQ	33.00				33.00	SQ	33.00	12.68		
394.00 Tools, Shop and Garage Equipment	29.00	SQ	29.00				29.00	SQ	29.00	15.69		
395.00 Laboratory Equipment	40.00	SQ	40.00				40.00	SQ	40.00	28.70		
397.CE Communication Equipment	23.00	SQ	23.00				23.00	SQ	23.00	16.10		
398.00 Miscellaneous Equipment	18.00	SQ	18.00				18.00	SQ	18.00	6.22		
Total Amortizable									19.83	11.59		
Total General Plant									11.65	7.10	-3.8	-3.9
TOTAL UTILITY									26.10	16.98	-3.8	-3.9
OTHER PRODUCTION PLANT												
Nogales												
341.00 Structures and Improvements	49.00	S6	49.00	29.50			49.00	S6	49.00	40.31		
342.00 Fuel Holders, Producers and Accessories	40.00	S4	40.00	32.63			40.00	S4	40.00	31.64		
343.00 Prime Movers	40.00	R3	40.00	26.17			40.00	R3	40.00	28.50	0.1	
344.00 Generators	43.00	S0	43.00	36.15			43.00	S0	43.00	38.26		
345.00 Accessory Electric Equipment	43.00	S6	43.00	29.39			43.00	S6	43.00	31.86		
346.00 Miscellaneous Power Plant Equipment	38.00	R1	38.00	33.34			38.00	R1	38.00	34.33		
353.00 Station Equipment												
Total Nogales									41.42	32.23		
Black Mountain												
341.00 Structures and Improvements							2048	200-SC	38.00	37.55		
342.00 Fuel Holders, Producers and Accessories							2048	200-SC	38.00	37.55		
343.00 Prime Movers												
344.00 Generators							2048	200-SC	38.00	37.55		
345.00 Accessory Electric Equipment							2048	200-SC	38.00	37.55		
346.00 Miscellaneous Power Plant Equipment							2048	200-SC	38.00	37.55		
353.00 Station Equipment							2048	200-SC	38.00	37.55		
Total Black Mountain									38.00	37.55		

UNS Electric, Inc.
Docket No. E-04204A-12-0504
Attachment RCS-4
Copies of Confidential UNSE's Responses to Data Requests
and Workpapers Referenced in the Direct Testimony and Schedules of
Ralph C. Smith

****UNSE Confidential Pages Have Been Redacted****

Data Request/ Workpaper No.	Subject	Confidential	No. of Pages	Page No.
STF 5.3	Impacts of UNSE's dismantlement cost estimates for Valencia and BMGS on the Company's proposed depreciation expense (without voluminous confidential attachment)	Yes	3	2 - 4
STF 8.9	UNSE provided copies of the M. Sheehan PPFAC Forecast used to derive the 0.05174 PPFAC rate and the most current PPFAC rate forecast that had been made for UNSE	Yes	11	5 - 15
	Total Pages Including this Page		15	

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-12-0504 May 21, 2013

STF 5.3

Dismantlement Studies. Refer to Mr. DeConcini's Direct Testimony at page 24.

a. Identify and provide a complete copy of each dismantlement study upon which UNSE is relying.

b. At page 24, lines 19-21, Mr. DeConcini states that each study estimates the cost of entirely dismantling all existing generating units ... and restoring the land to its pre-construction condition." Identify and provide all support being relied upon by the Company that this level of decommissioning is required.

c. Identify and fully explain all legal requirements on UNSE to decommission and dismantle the Valencia and BMGS plants.

d. Identify and provide the documents which are relied upon for your response to part c.

e. Identify and explain all plans the Company has for the use of the Valencia generating plant site for as far into the future as such plans exist.

f. Identify and explain all plans the Company has for the use of the BMGS plant site for as far into the future as such plans exist.

g. To the Company's knowledge, has any electric utility in Arizona restored a generating plant site or the land on which a generating plant was situated to its pre-construction condition? If not, explain fully why not. If so, please identify and explain each such instance of which the Company is aware.

h. Identify, quantify and explain the impact on UNSE's proposed depreciation expense for Valencia of the dismantlement cost estimates. Include all supporting workpapers and Excel files.

i. Identify, quantify and explain the impact on UNSE's proposed depreciation expense for BMGS of the dismantlement cost estimates. Include all supporting workpapers and Excel files.

RESPONSE:

THE FILES LISTED BELOW CONTAIN CONFIDENTIAL INFORMATION AND ARE BEING PROVIDED PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. Please see STF 5.3 TEPDecom 12-2011-Confidential.pdf, Bates Nos. UNSE\013866-013908, for the decommissioning (or dismantlement) study prepared for TEP that includes the Black Mountain Generating Station ("BMGS") and the Valencia Generating Station ("Valencia").

b. When dismantling generating units, the Company has Asset Retirement Obligations ("ARO"). AROs are different for each generating unit depending on location, leases, permits and other regulations or contracts particular to it. Please see the response to (c) below.

c. The legal ARO at BMGS involves remediation of the evaporation pond. BMGS's Aquifer Protection Permit ("APP") No. P 105929 requires remediation of the evaporative pond upon closure of the plant. The legal ARO at the Valencia plant involves potential

UNS ELECTRIC INC.'S RESPONSE TO STAFF'S FIFTH SET OF DATA REQUESTS REGARDING THE 2012 UNS ELECTRIC RATE CASE DOCKET NO. E-04204A-12-0504 May 21, 2013

disposal of asbestos and lead paint. (Due the era in which the plant was constructed, it is likely that asbestos and lead paint will be encountered.) Valencia is located in an urban area and it would be better to dismantle the entire site rather than just fence it off because a non-operational plant can attract graffiti and invite trespass by people who should not be in the station. If Valencia is completely dismantled, the Company will have to abide by requirements contained in 40 CFR Part 61 Subpart M for asbestos and 40 CFR Part 260-299 for lead paint.

d. Please see STF 5.3 (d) Legal Requirements.pdf, Bates Nos. UNSE\013909-013914, for the requested information.

e. See UNS Electric's Integrated Resource Plan in Docket No. E-00000A-11-0113. Valencia is intended to provide local generation for the Nogales area. The site also has a substation and switchyard which are required to provide safe and reliable service for the Nogales area. Unit 4 at Valencia has the capability to provide 45 megawatts of output by only increasing the size of the turbine, if additional generation is required in the future. However, at this point, UNS Electric has no specific plan to expand Valencia.

f. See UNS Electric's Integrated Resource Plan in Docket No. E-00000A-11-0113. BMGS is intended to provide generation for the Northern UNS Electric service territory. The site also has a substation and switchyard which are required for system operations. BMGS has room to install additional generation if required. However, at this time, UNS Electric has no specific plan to install additional generation at BMGS.

g. TEP's DeMoss/Petrie plant (formerly located at Grant Rd and I-10) was returned to its pre-construction state. Arizona Public Service Company ("APS") completely removed two oil burning units (formerly located in the Phoenix area) and returned them to preconstruction condition. Salt River Project ("SRP") was involved with a complete decommissioning and return to preconstruction condition at the Mojave Station. Mojave is located in Laughlin Nevada but an Arizona Utility was involved.

h. Please see UNS Electric's responses to part a, above, and UDR 1.73. Additionally, please see STF 5.3-Confidential.xlsx. UNS Electric is requesting the inclusion of dismantlement cost of $41.1k in yearly depreciation expense for Valencia.

i. Please see UNS Electric's responses to part a, above, and UDR 1.73. Additionally, please see STF 5.3-Confidential.xlsx. UNS Electric is requesting the inclusion of dismantlement cost of $49.0k in yearly depreciation expense for BMGS.

RESPONDENT:

Mark Mansfield

WITNESS:

Michael DeConcini

PAGE 4 IS CONFIDENTIAL AND HAS BEEN REDACTED

**UNS ELECTRIC INC.'S RESPONSE TO STAFF'S EIGHTH SET OF DATA REQUESTS
REGARDING THE 2012 UNS ELECTRIC RATE CASE
DOCKET NO. E-04204A-12-0504
June 13, 2013**

STF 8.9

PPFAC. Refer to UNSE(0504)003944 (Income - PPFAC Adjustment.pdf). The source listed for the proposed PPFAC Rate of 0.05174 is "M. Sheehan PPFAC Forecast."

a. Provide a copy of the M. Sheehan PPFAC Forecast used to derive the 0.05174 PPFAC rate.

b. Provide the most current PPFAC rate forecast in UNSE's possession and/or that has been made for UNSE.

RESPONSE:

THE FILES LISTED BELOW CONTAIN COMPETITIVELY-SENSITIVE CONFIDENTIAL INFORMATION THAT ARE ONLY BEING PROVIDED TO THE REQUESTING PARTY PURSUANT TO THE TERMS OF THE PROTECTIVE AGREEMENT.

a. Please see STF 8.9(a)-Confidential.xlsx for the requested information.

b. Please see STF 8.9(b)-Confidential.xlsx for the requested information.

The Excel files are not identified by Bates numbers.

RESPONDENT:

Michael Sheehan and Raymondo Robey

WITNESS:

Dallas Dukes

PAGES 6-15 ARE CONFIDENTIAL AND HAVE BEEN REDACTED

UNS Electric, Inc.
Docket No. E-04204A-12-0504
Attachment RCS-5
Copies of Regulatory Commission Order Excerpts Addressing Sharing of Directors & Officers Liability Insurance Cost Between Shareholders and Ratepayers

Jurisdiction	Docket No.	Order Date	Utility	No. of Pages	Page No.
Florida	090079-EI; 090144-EI; 090145-EI	March 5, 2010	Progress Energy Florida, Inc.	4	2 - 5
Connecticut	08-07-04	February 4, 2009	United Illuminating Company	3	6 - 8
Connecticut	07-07-01	January 28, 2008	Connecticut Light and Power Company	3	9 - 11
Connecticut	05-06-04	January 27, 2006	United Illuminating Company	3	12 - 14
Connecticut	03-07-02	December 17, 2003	Connecticut Light and Power Company	3	15 - 17
Connecticut	98-1-02	February 5, 1999	Connecticut Light and Power Company	2	18 - 19
Connecticut	99-09-03	May 25, 2000	Connecticut Natural Gas Corporation	3	20 - 22
Arkansas	06-101-U	June 15, 2007	Entergy Arkansas, Inc.	3	23 - 25
Arkansas	04-121-U	September 19, 2005	Centerpoint Energy Resources Corp	3	26 - 28
Arkansas	04-176-U	October 31, 2005	Arkansas Western Gas Company	3	29 - 31
			Total Pages Including this Page	31	

BEFORE THE FLORIDA PUBLIC SERVICE COMMISSION

In re: Petition for increase in rates by Progress Energy Florida, Inc.	DOCKET NO. 090079-EI
In re: Petition for limited proceeding to include Bartow repowering project in base rates, by Progress Energy Florida, Inc.	DOCKET NO. 090144-EI
In re: Petition for expedited approval of the deferral of pension expenses, authorization to charge storm hardening expenses to the storm damage reserve, and variance from or waiver of Rule 25-6.0143(1)(c), (d), and (f), F.A.C., by Progress Energy Florida, Inc.	DOCKET NO. 090145-EI ORDER NO. PSC-10-0131-FOF-EI ISSUED: March 5, 2010

The following Commissioners participated in the disposition of this matter:

NANCY ARGENZIANO, Chairman
LISA POLAK EDGAR
NATHAN A. SKOP
DAVID E. KLEMENT
BEN A. "STEVE" STEVENS III

APPEARANCES:

R. ALEXANDER GLENN, JOHN T. BURNETT, ESQUIRES, Progress Energy Service Company, LLC, P.O. Box 14042, St. Petersburg, Florida 33733-4042; JAMES MICHAEL WALLS, DIANNE M. TRIPLETT, and MATTHEW BERNIER, ESQUIRES, Carlton Fields, P.A., Post Office Box 3239, Tampa, Florida 33601-3239; RICHARD D. MELSON, ESQUIRE, 705 Piedmont Drive, Tallahassee, Florida 32312
On behalf of Progress Energy Florida, Inc. (PEF).

CHARLES REHWINKEL, Associate Public Counsel, CHARLIE BECK, Deputy Public Counsel, and PATRICIA A. CHRISTENSEN, Associate Public Counsel, ESQUIRES, Office of the Public Counsel, c/o the Florida Legislature, 111 West Madison Street, Room 812, Tallahassee, Florida 32399-1400
On behalf of the Citizens of the State of Florida (OPC).

STEPHANIE ALEXANDER, ESQUIRE, 200 West 200 West College Avenue, Suite 216, Tallahassee, Florida 32301
On behalf of the Florida Association for Fairness in Rate Making (AFFIRM).

costs have been removed. Accordingly, we find that PEF has made the appropriate adjustments to remove aviation cost for the test year.

H. Advertising Expenses

PEF removed promotional advertising costs in the amount of $3,388,000, as reflected in MFR Schedule C-2. The jurisdictional amount, net of tax, is $2,081,000. The explanation given by PEF is to exclude the cost of promotional advertising in order to comply with our guidelines.

We note an excerpt from the procedures followed by our auditors for the 2008 base year:

> We reviewed additional samples of utility advertising expenses, industry dues, economic development expenses, outside services, sales expenses, customer service expenses and administrative and general service expenses to ensure that amounts supporting non-utility operations were removed.

The Company's advertising expense is one of the areas specifically examined by our auditors. There were no findings with respect to this issue. Therefore, we find that PEF has made the appropriate adjustments to remove advertising expenses for the test year.

I. Directors and Officers (D&O) Liability Insurance

PEF argued that OPC witness Schultz is incorrect in his assertion that D&O liability insurance does not benefit ratepayers, and thus should be disallowed. PEF cited to the most recent TECO case in which this Commission decided that D&O liability insurance is a necessary and reasonable business expense and is appropriately included in customers' rates.[40] PEF asserted that we have already rejected the argument that Mr. Schultz raises in other cases and there is no valid reason for us to depart from its previous findings in this case.

OPC witness Schultz questioned whether the cost of D&O liability insurance is a necessary and appropriate expense to pass on to ratepayers. He stated that the expense protects shareholders from the decisions they made when they hired the Company's Board of Directors and the Board of Directors in turn hired the officers of the Company. He noted that the Company included $2.2 million in Account 925 for D&O liability insurance, but he believes the correct amount to be $2,750,650 for $300,000,000 in coverage. He disagreed with our recent Peoples Gas case in which the expense was allowed as a legitimate business expense.[41] The witness testified that the pertinent issue is whether the cost is beneficial to ratepayers, not whether it is a legitimate business expense. He stated that we have disallowed the cost in the past.

OPC witness Schultz testified that other jurisdictions have disallowed the expense. He stated, for example, that a Connecticut decision limited recovery by Connecticut Light and

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[40] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.
[41] Order No. PSC-09-0411-FOF-GU, issued June 9, 2009, in Docket No. 080318-GU, In re: Petition for rate increase by Peoples Gas System, p. 37-38.

Power to thirty percent, because ratepayers should not be required to protect shareholders from the decisions they make in electing the Board of Directors. He added that Consolidated Edison was not allowed to recover the full amount in a New York case. He explained that the disallowance was due to excessive coverage in part, and that a portion of the amount found to be reasonable was also disallowed. He stated the reason for the additional disallowance was that D&O Liability insurance provides protection to shareholders from matters in which the customers have no influence.

OPC witness Schultz recommended disallowance of the total cost of D&O liability insurance of $2,750,650 ($2,412,100 jurisdictional) because the purpose of the insurance is to protect shareholders, not ratepayers. He stated that he does not take the position that the Company should not have the insurance, but that it should be paid for by those who benefit from the insurance; that is, the shareholders.

OPC argued that PEF did not offer any testimony in rebuttal to OPC witness Schultz that the D&O liability insurance should be disallowed. OPC stated that, in each of the cases cited by witness Schultz in his testimony, the Company argued that D&O liability insurance is a necessary and prudent cost required to attract and retain competent directors and officers, yet a disallowance was made. OPC challenged the cost for $300,000,000 of coverage as being excessive, and questioned whether the cost for that level of coverage is appropriate to pass on to ratepayers.

OPC noted in particular a Consolidated Edison Company Case. OPC stated that in the final decision, the New York Commission (NYC) ruled that $300,000,000 of coverage was excessive based on the comparisons to similar companies and disallowed the premium associated with $100,000,000 excess, and then disallowed 50 percent of the premium associated with the $200,000,000 that was determined to be reasonable. OPC stated that, in the discussion, the NYC noted that D&O insurance provides substantial protection to shareholders who elect directors and have influence over whether competent directors and officers are in place, while customers have no influence. OPC noted that the NYC further stated at page 91 of its order that:

> We find no particularly good way to distinguish and quantify the benefits of D&O insurance to ratepayers from the benefits to shareholders, especially taking into account the advantage that shareholders have in control over directors and officers. We believe the fairest and most reasonable way to apportion the cost of D&O insurance therefore is to share it equally between ratepayers and shareholders.

FIPUG argued that the amount should be disallowed, because the expense directly benefits only PEF's shareholders.

We agree with OPC witness Schultz that this Commission has disallowed D&O insurance in water and wastewater cases in the past.[42] We do not agree with OPC that the ratepayers do not

[42] See Order Nos. PSC-09-0385-FOF-WS, issued May 29, 2009, in Docket No. 080121-WS, In re: Application for increase in water and wastewater rates in Alachua, Brevard, DeSoto, Highlands, Lake, Lee, Marion, Orange, Palm

benefit from D&O liability insurance. We believe that D&O liability insurance has become a necessary part of conducting business for any company or organization and it would be difficult for companies to attract and retain competent directors and officers with out it. We also believe that ratepayers receive benefits from being part of a large public company, such as easier access to capital which may result in lower rates. As stated in the TECO order:

> We find that [D&O liability] insurance is a part of doing business for a publicly-owned Company. It is necessary to attract and retain competent directors and officers. Corporate surveys indicate that virtually all public entities maintain [D&O liability] insurance, including investor-owned electric utilities. . . . We do not agree with OPC that the ratepayers do not benefit from [D&O liability] insurance. It is not realistic to expect a large public company to operate effectively without [D&O liability] insurance.[43]

We agree with PEF that the amount of the D&O liability insurance provided in discovery responses is $2.2 million, not $2.75 million as adjusted by OPC witness Schultz. However, we note that the amount of the premium for the test year is projected to be higher than the premium for 2008-2009, but lower than the previous three years, even though the amount of coverage was increased from $280 million to $300 million.

In summary, we believe that D&O liability insurance has become a necessary part of conducting business for any publicly owned company and it would be difficult for companies to attract and retain competent directors and officers without it. We also believe that ratepayers receive benefits from being part of a large public company including, among other things, easier access to capital. Because D&O liability insurance benefits both the ratepayer and the shareholder, it should be a shared cost. Thus, we find that O&M expense shall be reduced by $964,913 jurisdictional to reflect the sharing of costs between the ratepayers and the shareholders.

J. Injuries and Damages Expense

PEF stated that FERC Account 925 on MFR Schedule C-4, p. 44 of 48, reflects an expense of $8,882,000 for injuries and expenses. PEF stated that the numbers were audited by our auditors who reconciled the amounts on the MFRs for 2008 expenses to the Company's actual book and records. PEF stated that it based its 2010 budget for injuries and damages expense on the Company's actual historical 2008 expenses. PEF argued that it is, therefore, entitled to recover this expense.

Beach, Pasco, Polk, Putnam, Seminole, Sumter, Volusia, and Washington Counties by Aqua Utilities Florida, Inc., p. 81; PSC-07-0505-SC-WS, issued June 13, 2007, in Docket No. 060253-WS, In re: Application for increase in water and wastewater rates in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p.44; PSC-03-1440-FOF-WS, issued December 22, 2003, in Docket No. 020071-WS, In re: Application for rate increase in Marion, Orange, Pasco, Pinellas, and Seminole Counties by Utilities, Inc. of Florida, p. 84; and PSC-99-1912-FOF-SU, issued September 27, 1999, in Docket No. 971065-SU, In re: Application for rate increase in Pinellas County by Mid-County Services, Inc., p. 20-22.

[43] Order No. PSC-09-0283-FOF-EI, issued April 30, 2009, in Docket No. 080317-EI, In re: Petition for rate increase by Tampa Electric Company, p. 64.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 08-07-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

February 4, 2009

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Anthony J. Palermino

DECISION

TABLE P/R - 5

CORRECTED TABLE

(in $000s)

Compensation Expense	2009	2010
Proposed Base Payroll	$56,627	$59,115
Department Adjustment	($3,880)	($4,565)
Allowed Base Payroll	$52,747	$54,550
Overtime and Premium Pay	$6,754	$7,024
Department Adjustment	($1,672)	($1,942)
Allowed O/T and Premium Pay	$5,082	$5,082
Capitalized Overhead Pay	($4,083)	($4,207)
Department Adjustment	$80	$63
Allowed Cap. O/H	($4,003)	($4,144)
Incentive Compensation	$7,665	$7,791
Department Adjustment	($3,671)	($3,797)
Allowed Incent. Comp.	$3,994	$3,994
Total Compensation Proposed	**$66,963**	**$69,723**
Total Dept. Adjustments	**($9,143)**	**($10,241)**
Total Allowed Compensation	**$57,820**	**$59,482**
Allocated Incentive Comp.	**$1,154**	**$1,146**
Total Department Adjustments	**($553)**	**($559)**
Allowed Alloc. Inc. Comp.	**$601**	**$587**
Total Compensation Adjustments	**($9,696)**	**($10,800)**

To address the public's concern that customers are paying 100% of the compensation paid to the top officers of the Company, the Department offers that, for example, the adjustments made in this Decision reduce the amount of compensation paid to the Company President and Chief Operating Officer, that are actually included in rates and paid by customers, by approximately 33% and 31%, respectively.

2. Directors and Officers Liability Insurance

In its Application UI requested the Department authorize $844 thousand for 2009 and 2010 Directors and Officers Liability Insurance (DOL) ($852 thousand less $8 thousand allocated to non-regulated entities). Schedule WP C-3.31 A&B. The Company's position is that DOL is a business expense of having a public corporation, and the customers pay for all of the ordinary business expenses that a company would incur. Tr. 10/14/08, pp 62 and 63.

The OCC stated that in the past two rate decisions involving UI, the Department has determined that a portion of UI's DOL insurance costs should be funded by ratepayers. Despite this fact, UI is proposing to recover 100% of its DOL insurance costs in this proceeding. The OCC cited its previous arguments that corporate scandals have increased costs dramatically, that ratepayers do not elect the Board of Directors (BOD) and officers of the Company, and that shareholders, who are protected by the insurance, should not be subsidized by ratepayers for DOL insurance costs that are designed to protect shareholders from their own decisions. The facts and circumstances regarding the DOL insurance have not changed since UI's last rate case. The OCC recommends that the DOL insurance be reduced by 75% with only 25% being passed on to customers, but stated that its absolute preference would be to disallow the cost completely. OCC Brief, pp. 79 and 80.

The AG indicates that the amount requested is roughly six times the amount that the Department approved in the 2006 Decision. In the 2006 Decision, the Department specifically agreed with both the AG and OCC that "DOL insurance protects only shareholders from the actions of management that they selected." Although the Department allowed UI to collect one-quarter of its requested amount in the 2006 Decision, the Company requested the entire amount be funded by ratepayers. The AG stated that this bold act of indifference to the Department's clear precedent and to the financial stresses facing its customers should be firmly rejected. At the very most, the Department should authorize only the levels for DOL insurance that it approved in the 2006 Decision. AG Brief, p. 18.

In the 2006 Decision, the Department noted the OCC's and AG's positions, as well as the position of the Company who stated that if there was no insurance and there was a huge claim, it could put the Company in financial peril, which would potentially impair its ability to serve. Therefore, the Department allocated 75% of DOL costs to the shareholders, with the residual 25% to be funded by ratepayers. 2006 Decision, pp. 46 and 47. The Department rejects the Company's current proposal that ratepayers fund 100% of DOL insurance costs, and reconfirms the precedent afforded by the 2006 Decision. Accordingly, the Department allows $211 thousand of DOL insurance costs to be funded by ratepayers in years 2009 and 2010 ($844 thousand times 25%). This results in DOL insurance expense decreases of $633 thousand in each of years 2009 and 2010.

3. Fringe Benefits

a. Compensation Adjustment to Fringe Benefits

In Section III.1.f., the Department made adjustments to compensation of $12.033 million and $13.655 million in 2009 and 2010, respectively. This also results in an adjustment to fringe benefits that accompany compensation. The Company indicates that its composite fringe benefit rate for 2009 and 2010 is 45%. Responses to Interrogatories EL-30-2; EL-31-2; and EL 33-1.

In its Written Exceptions, the Company argues, against its own filed and sworn record evidence of a 45% fringe benefit expense related to compensation, that the "correct compensation-driven benefits loader from an expense standpoint" is 20.6% and attempts to justify that amount by listing greatly reduced expense amounts for certain "Compensation Driven Employee-Related Benefits Loader." UI Exceptions, pp. 29 and 30. The Department notes that the Company's Response to Interrogatory EL-33 that

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 07-07-01 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND RATE SCHEDULES

January 28, 2008

By the following Commissioners:

Anthony J. Palermino
Anne C. George
John W. Betkoski, III

DECISION

expenses by $2.232 million to remove the non payroll projected costs in excess of the original budget.

2. Insurance Expense

The test year expense for insurance expense was $6.817 million. The Company proposed a rate year increase of $.65 million or a rate year expense of $7.467 million. Application, Schedule C-3.10. CL&P revised the request and reduced the insurance expense by $17,000. The revision was a result of recent premium information. The change is a combination of increases and decreases in different types of insurance. Response to Interrogatory EL-80-SP01.

The Department accepts the Company's revisions except for the Directors and Officers insurance expense and capital allocation as discussed in detail below.

a. Director and Officer Insurance Expense

The test year expense for Director and Officer (D&O) insurance expense was $1.423 million. The Company proposed a rate year increase of $0.164 million or a rate year expense of $1.587 million. Application, WP C-3.10. As indicated above, CL&P revised its rate year insurance expense and decreased the rate year D&O insurance expense amount by $.270 million to $1.317 million. Response to Interrogatory EL-80-SP01 and Late Filed Exhibit No. 112SP-01.

CL&P claims that D&O insurance is a legitimate and customary operating expense and that no director or officer with the necessary knowledge and experience would take the risks associated with serving CL&P without this type of protection. CL&P states that the Sarbanes-Oxley Act requires that certain skill-sets be reflected in the Board of Directors (BOD), and in order to attract and retain individuals that meet these requirements CL&P must offer D&O coverage to its BOD. CL&P indicated that the Department has already confirmed that D&O is a necessary operating expense that is recoverable. CL&P Brief, p. 39.

The AG argues for the removal of the entire $1.587 million. The AG states that it is inappropriate to force customers to fund a plan that benefits only shareholders. D&O insurance protects shareholders from their own decisions and is intended to protect directors and officers from lawsuits brought by shareholders. AG Brief, p. 20.

The OCC states that premiums for insurance excluding D&O insurance decreased from $9.4 million to $8.41 million while D&O insurance is estimated to increase 11.5% from $1.423 million to $1.587 million. Further, the OCC believes that the D&O insurance requested amount is excessive, ignores the Department's prior rulings, and ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. The OCC argues that Sarbanes-Oxley merely requires officers & directors who have a fiduciary duty to acknowledge responsibility by signing their names. It was not the implementation of Sarbanes-Oxley that caused an increase in premiums, it's the claims filed that caused the increase. The OCC adds that D&O insurance has drastically increased from 5.67% of the aggregate insurance amount in 2002 to 13.15% in 2006 and projected to cost 15.87% in the rate year. The OCC recommends a D&O insurance reduction of $1.202 million to $0.385 million. The OCC calculated this amount by using the 2002 test year amount increased by inflation. OCC Brief, p. 44.

In Docket No. 03-07-02, CL&P requested a rate year amount of $1.043 million and was allowed the test year amount of $.330 million. 03-07-02 Decision, pp. 48-49. This allowed 33% of the requested amount. In that decision, the Department indicated that it does allow some level of D&O insurance expense in rates to assure some level of ratepayer protection from lawsuits. In the UI Decision, the Department allowed 25% of the D&O insurance expense to be allocated to customers. In the Decision dated February 5, 1999, n Docket No. 98-01-02, DPUC Review of the Connecticut Light and Power Company's Rates and Charges – Phase II, the Department took the OCC approach and calculated the 1999 expense by inflating the 1996 level. This allowed 46.7% of the requested amount. In the Decision dated May 25, 2000, in Docket No. 99-09-03, Application of Connecticut Natural Gas Corporation for a Rate Increase, the Department allowed 20% of the premium amount.

The Department agrees in part with the OCC that ratepayers should not be required to protect shareholders from the decisions they make in electing the BOD. However, the Department historically has allocated a percentage to ratepayers to protect from catastrophic lawsuits. Accordingly, the Department finds it appropriate to allocate 30% to ratepayers and 70% to shareholders. This allocation is fair and consistent with the level allowed in Docket No. 03-07-02. Therefore, the Department allows $.395 million ($1.317 million x 30%) and disallows $.922 million to be collected in rates.

b. Insurance Expense - Capital Allocation

CL&P originally proposed a rate year capitalization factor of 25.3%. Application, Schedule WPC-3.10. The Company revised this amount to 26.6% in order to reflect updates based on recent invoices. Response to EL-80-SP01 and Late Filed Exhibit No. 112. The test year before pro forma adjustment was 35.6%. Application, Schedule WPC-3.10. A majority of the pro forma adjustment was to remove a non-recurring charge for the public liability reserve. This adjustment was based on an independent study performed by Mercer, Inc. The remaining pro forma adjustment included the addition of $284,000 that was for a non-recurring credit or refund received from USICO, a mutual property insurance company. Response to Interrogatory EL-43.

The OCC claims that CL&P has included a significant increase in the percent of costs being charged to expense as opposed to capital. Specifically, the Company's proposed reduction of more than 10% to the capital allocation is significant considering CL&P's focus on system improvements. The OCC argues that the Company did not present any evidence to justify an allocation change. OCC Brief, p. 41. The OCC recommends using the test year capitalization factor of 35.6%. That capitalized amount reduces the aggregate insurance expense to $5.802 million for a total disallowance of $1.665 million. OCC Brief, pp. 43-44.

As indicated below, the Company's insurance capitalization percents have ranged from a low of 25.6% to a high of 40.5% in the years 2002 through 2006.

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DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 05-06-04 APPLICATION OF THE UNITED ILLUMINATING COMPANY TO INCREASE ITS RATES AND CHARGES

January 27, 2006

By the following Commissioners:

John W. Betkoski, III
Donald W. Downes
Jack R. Goldberg
Anne C. George
Anthony J. Palermino

DECISION

Description	2006	2007	2008	2009
Benchmarking studies	$ 72,000	$ 72,000	$ 73,000	$ 74,000
BPL	$ 98,000	$ 98,000	$ 98,000	$ 98,000
Regulatory consulting	$ 131,000	$ 138,000	$ 145,000	$ 152,000
Client services support	$ 275,000	$ 296,000	$ 311,000	$ 329,000
Total professional services expense disallowed	$ 576,000	$ 604,000	$ 627,000	$ 653,000

8. Outside Services - Audit and Accounting Expense

UI originally projected $533,000, $552,000, $573,000 and $594,000 for audit and accounting expense for rate years 2006 through 2009, respectively. Schedule C-3.16 A–D. UI later increased the projected expenses by $149,000, $164,000, $177,000 and $194,000 for rate years 2006 through 2009, respectively, citing the Company's response to Interrogatory EL-159. Late Filed Exhibit No. 1, Revised.

However, the response to Interrogatory EL-159 only identified a potential increase of $100,000 for 2006. The Company's response to Interrogatory EL-159 and the testimony on 10/14/05 state that the original projection was strictly an estimate and that UI is in negotiations with Pricewaterhouse Coopers for a new contract. UI is seeking to enter into a long term fixed price contract for SEC reporting audit services to mitigate the potential increase. UI testified that the Company is still negotiating and trying to get the price increase down, but, the increase could be greater than the original estimate. Response to Interrogatory EL-159; Tr. 10/14/05, pp. 174 and 175. UI later testified that they negotiated a new contract and the increases in Late Filed Exhibit No. 1 are based on the cost of the new contract. Tr. 11/9/05, p. 2394.

The OCC believes that the response to Interrogatory EL-159 does not support the amount of increase apparently requested by UI in Late Filed Exhibit No. 1 and leaves unanswered questions regarding the certainty of the projected increases. Therefore, the OCC has removed the increases identified in Late Filed Exhibit No. 1. OCC Brief, pp. 63 and 64, Exhibit 5.

The Department takes into account the entire record evidence on a given expense in determining if it is proper for the rate year. Therefore, based on the testimony given during the late filed exhibit hearing, the Department approves the increase to accounting and audit expense as shown in Late Filed Exhibit No. 1, Revised.

9. Directors and Officers Liability Insurance

The Company proposes expenses for Directors and Officers Liability Insurance (DOL) of $533,879 for 2006, and $559,612 for each of the years 2007 through 2009. Response to Interrogatory OCC-104. UI contends that it could not attract a director if it didn't have DOL. It is a cost of doing business. Tr. 10/12/05, p. 868. Further, the Company asserts that, taken to the extreme, "if there was no insurance and there was a huge claim, it could put the company in financial peril, which would potentially impair its ability to serve." Tr. 10/11/05, p. 801.

The OCC indicates that "the numerous corporate scandals since 2001 has caused the cost of the DOL insurance to skyrocket." Schultz and DeRonne PFT, p. 48. Further, "DOL insurance provides shareholders protection from their decision. Ratepayers in general do not elect the Board of Directors and do not appoint officers to run the Company. Shareholders are protected by this insurance against their own decision in the selection of management. Ratepayers should not pay for the cost of insurance designed to protect shareholders from their own decisions." OCC Brief, p. 93; Tr. 10/12/05, pp. 867 and 868. Therefore, the OCC recommends that all of the DOL amounts during the rate period be excluded from rates and be covered completely by shareholders, not ratepayers.

The AG agrees with the OCC's reasoning that DOL insurance protects only shareholders from the actions of management that they selected. Thus, DOL insurance expense should be eliminated from UI's rates entirely. AG Brief, pp. 24 and 25.

The Department partially agrees with the OCC, the AG and the Company. In the 03-07-02 Decision, the Department allowed a portion of that company's proposed expense and stated that "the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits." 03-07-02 Decision, p. 49. The Department also notes that the annual gross DOL premium (before credits and allocations) was $134, 430 in years 2001 and 2002, increasing to $1,029,516 in years 2007 through 2009, lending credence to the OCC's assertion regarding corporate scandals, above. The Department agrees with the OCC that the shareholders should bear the weight of their decisions in appointing directors (who appoint the officers of the Company). Accordingly, the Department allows $140,000 of DOL expense, or approximately ¼ of the total company expense, to be collected in rates as the customers' responsibility.

The Department, therefore, disallows DOL expenses of $393,879 in 2006, and $419,612 in each of 2007, 2008 and 2009.

10. Postage Expense

UI projected postage expense in the amounts of $1,475,000, $1,479,000, $1,485,000, and $1,491,000 for rate years 2006 though 2009, respectively. UI increased the test year expense of $1,361,000 by $74,000 for an anticipated 5.4% increase from the USPS and $31,000 for volume and usage increase. Schedule C-3.20 A – D.

The Governors of the U.S. Postal Service have accepted the recommendation to increase most postal rates and fees by 5.4% effective January 8, 2006, including an increase in the rate for first-class mail from 37 cents to 39 cents. See http://www.usps.com/ratecase/welcome.htm.

UI states that the volume and usage increase is due to items such as increase in collection letters due to higher disconnect for nonpayment activity, new program mailings and increased economic development activity. Response to Interrogatory EL-220.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 03-07-02 APPLICATION OF THE CONNECTICUT LIGHT AND POWER COMPANY TO AMEND ITS RATE SCHEDULES

December 17, 2003

By the following Commissioners:

Donald W. Downes
Jack R. Goldberg
John W. Betkoski, III
Linda J. Kelly
Anne C. George

DECISION

The Department, therefore, accepts the Company's revision to computer and other expenses as indicated in the Response to Interrogatory OCC-93. Accordingly, the Department reduces computer expenses by $.348 million ($10.119 million less $9.771 million) and other O&M expenses related to the test year processing and storage balance of $.596 million, for a total O&M adjustment for these items of $.944 million ($.348 million plus $.596 million).

2. Insurance Expense

a. Directors and Officers Liability Insurance

The Company requested Directors & Officers Liability Insurance Expense (D&O Insurance) of $1.043 million in the rate year. This included a test year pro forma adjustment of $.029 million and a rate year adjustment of $.684 million above the test year actual amount of $.330 million based on the actual renewal premiums for the policy period 4/23/03 to 4/23/04. Schedule WP C-3.12; Response to Interrogatory OCC-101.

The OCC argues for the removal of the entire $1.043 million of D&O Insurance expense. The OCC states:

> Ratepayers should not be forced to pay a cost that protects shareholders from the shareholders' own decisions. Shareholders determine who the Board of Directors are and the Board of Directors are responsible for appointing officers of the Company. The officers are highly compensated to provide quality leadership with the utmost integrity. Ratepayers are responsible for paying for the directors and officers services. The shareholders, not ratepayers, determine who the directors and officers are. Therefore, the shareholder should assume the risk associated with their decision regarding the management of the Company. The cost to obtain insurance to protect the shareholders investment from their choice of management should be the responsibility of the shareholders.

OCC Brief, p. 64

The OCC also cites that the escalation in D&O Insurance rates stem from the insurers' need to continue to reserve for litigation and settlement expenses in connection with an influx of claims arising from such entities as Worldcom, Enron, Kmart, etc. Response to Interrogatory OCC-101. The increases in D&O Insurance and the related costs are due to the failures of directors and officers to ensure the Company operated prudently and reasonably. An alternative to total disallowance of cost would be to allow the test year cost of $.330 million. OCC Brief, p. 65.

The Department is sympathetic with OCC's arguments and generally agrees that the increased premiums are, at least in part, caused by Officer/Director mismanagement or misconduct in major corporations. Further, the Department notes that CL&P's recent claims experience includes settlement of eight federal and state shareholder class action lawsuits that stemmed from the Nuclear Regulatory Commission's Watch List of problems at its Millstone Nuclear Plant in 1996 that resulted in a $20.050 million settlement by its insurer. Further, a $33 million settlement was reached with the non-NU joint owners of Millstone 3 related to the Company's operation of that plant. Late Filed Exhibit 73 and 73-SP01. However, the Department has historically allowed some level of expense for D&O Insurance in rates to assure some level of ratepayer protection from catastrophic lawsuits. Therefore, the Department will allow the test year cost of $.330 million and reduce the Company's D&O Insurance expense by $.713 million ($1.043 million less $.330 million).

b. Public Liability Expense

The Company requested Public Liability Expense of $2.591 million in the rate year in Account 925.02. This Account includes the cost of the reserve accrual to protect the utility against injuries and damages claims of employees or others, losses of such character not covered by insurance, and expenses incurred in settlement of injuries and damages claims. It also includes the cost of labor and related supplies and expenses incurred in injuries and damages activities. Uniform System of Accounts prescribed for Electric Utilities, Public Utilities Control Authority State of Connecticut, 1/1/63, p. 177 (USOC). In its calculation of this expense, CL&P removed $1.497 million of test year expense that was capitalized, thus reducing the overall test year expense of $2.591 million to $1.094 million. Schedule WP C-3.12.

In response to an OCC data request, the OCC questioned why CL&P should no longer treat the public liability expense as an overhead cost, subject to capitalization. In the Company's response it indicated "[u]pon further review it was determined that public liability insurance is an appropriate cost to be capitalized under the FERC Electric Plant instructions." CL&P determined that the payroll overhead rate is the best vehicle for capitalizing these costs and changed the overhead rate for the remainder of 2003 to include these costs. Response to Interrogatory OCC-99. Accordingly, the OCC recommends that $1.497 million of public liability expense be capitalized, thereby reducing CL&P's proposed expense.

The Department agrees with the OCC and the Company that a portion of public liability expense, particularly as it relates to construction projects, is properly capitalizable. The USOC provides, for example, that the cost of injuries and damages or reserve accruals capitalized shall be charged to construction directly or by transfer to construction work orders from this account. USOC, p. 177. The Department also notes that it has been CL&P's consistent practice to capitalize a portion of public liability expense. Response to Interrogatory OCC-100. The Company provided a revised schedule that calculated the capitalized portion of Public Liability Expense using a capitalization rate of 38.5% that resulted in a capitalization amount of $.998 million. Schedule WP C-3.12 Revised. The Department notes that the capitalization percentage is consistent with other payroll-related capitalizations. Schedule WP C-3.28a. The Department, therefore, reduces public liability expense by $.998 million to reflect such capitalization.

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 98-01-02 DPUC REVIEW OF THE CONNECTICUT LIGHT AND POWER COMPANY'S RATES AND CHARGES - PHASE II

February 5, 1999

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold
Donald W. Downes
John W. Betkoski, III

DECISION

amount. OCC analyzed the storm expense data and found that there is no relationship between total storm expense and inflation. For example, storm expenses were higher in 1992 and 1993 compared to 1994 and expenses in 1995 and 1996 were higher compared to 1997. Therefore, OCC also believes that there is no justification for an escalation factor in the storm budget. PRO Brief, pp. 9 and 10; OCC Brief, pp. IV-52 and 53.

The Department often uses a historical average, excluding the highest and lowest years' costs, to calculate a rate year expense and believes that is the appropriate method for storm expense. The Department agrees with OCC's analysis on the escalation factor. The Department calculates 1999 storm expense to be $8.483 million by averaging storm costs for 1992 - 1997, excluding the lowest and highest costs in 1994 and 1996. Therefore, the Department reduces expenses by $3.169 million ($11.652 million - $8.483 million).

27. Directors' and Officers' Insurance

CL&P has requested $1.391 million in directors' and officers' (D&O) liability insurance premiums for the rate year. Response to Interrogatory OCC-70. D&O insurance expenses for the years 1994 - 1997 were $497,000, $456,000, $630,000 and $1,022,000, respectively. Expenses increased due to claims paid and higher liability limits. CL&P projects 1999 expenses will be higher for the same reasons. Responses to Interrogatories OCC-312 and PRO-6; Late Filed Exhibit No. 5, AR-DPUC-14. The Company indicated that the two reasons were actually one and the same. As claims are paid, the insurance available in the future is reduced by that amount. Because of the claims already paid and potential claims, the Company purchased higher limits to restore its liability coverage to previous amounts. This would give the Company enough coverage for potential future claims. Tr. 10/20/98, pp. 4005 and 4006; Late Filed Exhibit No. 162. A Company witness testified that all of the shareholder lawsuits are well known to CL&P and the Department and any damage claims would be borne by shareholders. Tr. 9/10/98, pp. 430-432.

PRO, AG and OCC argue that D&O costs have increased from 1995 to 1997 as a direct result of management imprudence and the nuclear outages. The claims paid and pending relate to the nuclear outages. OCC and PRO believe the expense should be reduced to the 1996 level. Even though the outages occurred during 1996, PRO believes this would allow for some increase due to inflation. OCC Brief, p. IV-39; PRO Brief, p. 12; AG Brief, p. 15.

Ratepayers should not have to fund higher liability limits for directors and officers when it is those directors and officers who failed to ensure that the Company operated prudently and reasonably. The Department reduces D&O liability insurance premiums to a level that does not reflect the nuclear outages. The Department agrees that the 1999 expense should be based on the 1996 level. However, the Department also believes that this is an expense that is typically influenced by inflation and sets the 1999 allowed expense at $.65 million, which is the 1996 actual expense adjusted for inflation. Therefore, 1999 expenses are reduced by $.741 million ($1.391 million - $.65 million).

STATE OF CONNECTICUT

DEPARTMENT OF PUBLIC UTILITY CONTROL
TEN FRANKLIN SQUARE
NEW BRITAIN, CT 06051

DOCKET NO. 99-09-03 APPLICATION OF CONNECTICUT NATURAL GAS CORPORATION FOR A RATE INCREASE

May 25, 2000

By the following Commissioners:

Glenn Arthur
Jack R. Goldberg
Linda Kelly Arnold

DECISION

tax rate of 8.3% in the rate year. Tr. 2/16/00, p. 1775. Accordingly, the Department will reduce payroll taxes by an additional $42,746 ($515,017 x 8.3%).

In Version B, CNG made a vacancy adjustment of $160,493. However, the Company failed to make a corresponding adjustment for payroll taxes and the O&M allocation factor of 83.6%. Schedule WPC-3.28. Accordingly, the Department will further reduce this expense by $13,321 ($160,493 x 8.3%). The Department's total reduction to payroll taxes is $255,260 ($199,193 + $42,746 + $13,321).

c. Gross Receipts Tax

Gas distribution companies are subject to the Connecticut gross receipts tax (GRT). GRT rates of 4% and 5% apply to residential customers and commercial/industrial customers, respectively. CNG's initial application projected a pro forma GRT expense of $10,599,786 for pro forma taxes at present rates. Schedule WPC-3.41. The Company's request for a $15,738,284 increase in its revenue requirement added $675,684 for a total pro forma GRT of $11,275,470. Schedule C1/C2. Subsequently, the Company increased its pro forma revenues by $8,010,815. Late Filed Exhibit No. 4, Version B. This increased pro forma GRT by $343,924. Together, the changes increased pro forma GRT by $709,958 to $11,619,394.

The Company calculated a 4.29% blended GRT rate by combining the calculated taxes on residential revenues and commercial revenues. Schedule WPC-3.41. CNG's calculation of its blended GRT rate properly excluded taxes on non-taxable interruptible service revenues. Tr. 1/11/00, p. 137.

In Section II.C, above, the Department adjusted CNG's revenues for firm transportation by $58,700, and for an additional customer by $109,000. The Department will make an adjustment to GRT at the rate of 4.29%. Therefore, the Department will increase CNG's GRT by $7,194 ([$58,700 + $109,000] x 4.29%).

d. Summary of Other Tax Adjustments

The Department's total adjustment for other taxes is $(1,055,804), $(255,260) for payroll tax, $(807,738) for property tax, and $7,194 for gross receipts tax.

9. Insurance

a. Directors and Officers Liability

CNG has included the cost of D&O liability policies in pro forma insurance expense. The D&O insurance provides the Company with coverage for certain types of wrongful acts by directors or officers of the corporation. Its intent is to safeguard the assets of the corporation so that the Company can continue to provide service to its customers and earn a fair return for its shareholders. The Company has two such policies. The first provides regular coverage and has a $84,100 annual premium. The Company included $70,308 of that premium (83.6%) in its pro forma expense. The second policy provides excess coverage and has a $87,900 annual premium. The

Company included $73,397 of that premium in its pro forma expense for a total pro forma D&O insurance cost of $143,705 ($70,308 + $73,397). Schedule WPC-3.32.

OCC recommends that CNG's adjusted expenses be reduced by $81,807 to reflect the allocation of 20% of regular D&O liability insurance and 100% of the excess D&O liability insurance to shareholders. OCC would prefer that the cost be split equally between ratepayers and shareholders. Not withstanding that action, the OCC believes it appropriate to remain consistent with the Previous Rate Decision where 20% of the regulated premium was disallowed. OCC Brief, pp. 11, 37. Based on CNG testimony, PRO recommends a $7,031 reduction to this expense. PRO Brief, p. 11.

In the Previous Rate Decision, the Department found that the Company needed D&O insurance to attract and keep qualified directors and officers. However, because shareholders could also initiate suits against the directors and officers, the Department disallowed 20% of the premium of regular coverage. Additionally, the Department found that the Company had not justified allowance of premiums of excess D&O coverage in rates. Decision, p. 33.

The Company has not presented any evidence in the instant docket to warrant dissimilar treatment. Accordingly, the Department again disallows the cost of the excess coverage policy premium in its entirety and 20% of the regular policy. Accordingly, the Department will reduce this expense by $14,062 (20% x $70,308) to eliminate costs attributable to shareholders. The resultant allowed premium of $56,246 requires an adjustment of $14,062. Adding that to the disallowed excess coverage premium of $73,397 produces a total reduction to D&O insurance expense of $87,459.

b. Weather Stabilization Insurance

CNG seeks to recover $993,063 in premiums for a weather stabilization insurance (WSI) policy covering the 2000/2001 heating season. Schedule C-3.32. This approximates the cost of the policy for the 1999/2000 season but is more than the cost of the policy in the 1998/1999 season. The witness stated that the Company obtained this insurance coverage to mitigate large swings in the Company's earnings in periods of extremely warm weather. CNG also proposed to set up a deferred account to allow true-ups of insurance premium costs in future rate proceedings. Bolduc PFT, pp. 7, 10.

AG proposes that the Department reject CNG's proposal to recover any costs associated with WSI because it is not a cost that ratepayers should bear. Additionally, AG points out that shareholders have already been compensated for weather in the allowed ROE. Furthermore, the Company has failed to show that the WSI provides any real benefits to ratepayers. Brief, p. 6.

OCC opposes the inclusion of WSI premiums above the line. Brief, p. 44. OCC agrees with AG that weather related risks are reflected in a company's ROE, and further states that eliminating that risk would require a fundamental reassessment of the cost of doing business. Cotton PFT, p. 12.

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF)
ENTERGY ARKANSAS, INC. FOR APPROVAL)
OF CHANGES IN RATES FOR RETAIL)
ELECTRIC SERVICE)

DOCKET NO. 06-101-U
ORDER NO. 10

ORDER

Summary

On August 15, 2006, Entergy Arkansas, Inc. ("EAI") filed in this Docket its Application seeking an increase in the rates it charges its Arkansas retail electric customers. As later amended, EAI seeks a retail revenue requirement increase of $106,534,000 or approximately 11.79% above its current authorized retail revenue requirement. However, based upon the evidence presented in this Docket, the Commission finds that EAI's retail revenue requirement is excessive and should be reduced by approximately $5.67 million effective as of June 15, 2007. Among other adjustments the Commission denied EAI's request for an 11.25% return on equity. Instead, the Commission set EAI's return on equity at 9.9%.

The Commission also denied EAI's request to recover a number of expenses from its ratepayers, including reducing the level of incentive pay and stock options requested by EAI by over $21 million, and by rejecting EAI's request for its ratepayers to pay for entertainment expenses which included tickets to sporting events and concerts, golf balls and golf tournament expenses, and dinners and alcohol to entertain political figures.

Further, the Commission approved EAI's request to recover costs relating to projects and organizations that promote new technologies and research and

Having found no direct or measurable benefit to ratepayers of these types of incentives, the Commission directs that these costs not be included in rates.

As to Mr. Marcus' recommendation to disallow certain perquisites provided EAI's Chief Executive Officer and the five top executives at Entergy Corp. which include club dues, financial counseling, the corporate airplane, and a tax "gross-up", the Commission finds no substantial evidence to support the recovery of such expenditures from EAI's ratepayers. The Commission finds that, as noted by Mr. Marcus, these types of expenditures are unreasonable in light of the salaries paid Entergy's top executives. The Commission therefore disallows these perquisites.

Director and Officer Liability Insurance

EAI's application included $191,580[38] in expenses for Director and Officer Liability ("D&O") Insurance. Staff witness Plunkett recommends a 50% sharing of these costs, pursuant to past Commission practice and based on the benefits that D&O insurance provides for both stockholders and ratepayers. (T. 1472) Ms. Plunkett further testifies that her recommendation does not presuppose that this expenditure is unreasonable nor does it imply it is not useful in shielding officers and directors from shareholder litigation. Rather, she continues, her recommendation recognizes that the protection afforded officers and directors is primarily a benefit to shareholders, with EAI providing little evidence of benefits to ratepayers. (T. 1505)

AG witness Marcus, noting similar Commission findings in other dockets, also recommends that these costs be shared equally between shareholders and ratepayers,

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[38]Ms. Plunkett removed $95,790 in D&O Insurance from EAI per book, representing 50% of actual expenses. Actual per book expenses would be twice that amount or $191,580.

testifying that the shareholders are the beneficiaries of such policies when mismanagement is the subject of litigation by shareholders. (T. 702, 767)

Mr. McDonald recommends that the Commission reject the Staff's and the AG's proposed adjustment, arguing that the cost is "a reasonable and legitimate cost...to encourage qualified individuals to serve as a member of the board of directors." Mr. McDonald also testifies that the positions taken by Staff and the AG, on this and other similar recommendations would, if carried to every EAI cost, result in leaving EAI without "its legal right to recover the reasonable costs it incurs to provide electric service to its customers." (T. 155)

The Commission agrees that ratepayers, as well as shareholders, benefit from good utility management, which D&O Insurance helps secure. However, as found in prior dockets, the direct monetary benefits of D&O Insurance flow to shareholders as recipients of any payment made under these policies. That monetary protection is not enjoyed by ratepayers. The Commission therefore finds that, because shareholders materially benefit from this insurance, the costs of D&O Insurance should be equally shared between shareholder and ratepayer.[39]

Civic Dues, Donations, and Club Memberships

Both Staff witness Plunkett and AG witness Marcus recommend disallowance of all costs related to civic club dues, club memberships, donations, and other costs such as "institutional advertising, lobbying, and donations, including support and sponsorship of local community organizations and local events." (T. 695.697, 1471) Ms. Plunkett notes that both FERC, which requires these items be listed as non-utility expenses, and

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF AN APPLICATION FOR A GENERAL CHANGE OR MODIFICATION IN CENTERPOINT ENERGY ARKLA, A DIVISION OF CENTERPOINT ENERGY RESOURCES CORP'S RATES, CHARGES, AND TARIFFS	)	DOCKET NO. 04-121-U ORDER NO. 16

ORDER

On November 24, 2004, CenterPoint Energy Arkla ("Arkla" or the "Company") filed an Application for approval of a general change or modification in its rates and tariffs.[1] Arkla's initial Application reflects that it was seeking a non-gas rate increase of $33,996,382 based on an overall non-gas revenue requirement of $182,525,265. Order No. 4, entered on December 16, 2004, suspended Arkla's proposed rates, charges, and tariffs pending further investigation by the Commission.

The parties to this proceeding are Arkla, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Arkansas Gas Consumers ("AGC"), and the Commercial Energy Users Group ("CEUG").

Arkla filed the written testimonies of Jeffrey A. Bish, Charles J. Harder, F. Jay Cummings, Samuel C. Hadaway, Alan D. Henry, Michael TheBerge, Gerald W. Tucker, Steve Malkey, Michael J. Adams, Walter L. Fitzgerald, Michael Hamilton, and John J. Spanos. The Staff filed the written testimonies of Robert Booth, Alice D. Wright, Alisa Williams[2], Don E. Martin, Gail P. Fritchman, Don Malone, L.A. Richmond, Gayle Frier, Johnny Brown, Robert H. Swaim, and Adrienne R.W. Bradley. The AG filed the written testimony of William B. Marcus.

[1] Arkla filed additional revisions to its Application on December 27, 2004, January 10, 2005, and January 13, 2005.
[2] On August 3, 2005, the Staff filed Notice that Jeff Hilton, Manager of Staff's Audit Section, was adopting the pre-filed testimony of Staff witness Alisa Williams.

adjustments were calculated by applying the contribution rate to each party's respective payroll adjustments.

The Commission finds that the employee savings plan contribution rate should be applied to the amount determined for regular salaries and wages, overtime, and incentive pay consistent with the Commission's decision on these issues. The Commission accepted Arkla's position on regular salaries and wages, and overtime, and the Staff's position on incentive pay. (Adjustment No. IS-20).

Director's and Officer's Insurance ("D&O")

The purpose of D&O insurance is to protect officers and directors of a corporation from liability in the event of a claim or lawsuit against them asserting wrongdoing in connection with the Company's business. AG witness Marcus has two concerns with Arkla's treatment of this expense: (1) Arkla's revised allocation methodology from an asset-based to an O&M-based allocation has doubled Arkla's costs; and (2) the costs should be split on a 50-50 basis to recognize that shareholders are the major beneficiaries of policy payouts when something goes wrong. (T. 1376-1377) Arkla Witness Harder testified that the use of an O&M allocation factor is appropriate for an expense that bears no relation to the level of plant. He contended that this is a necessary business expense which enables the Company to attract and retain qualified management. (T. 152-153) Mr. Marcus disagreed, stating that the expense is not related to O&M expense either, the allocation shifts the cost to Arkla away from Arkla's electric affiliate, and utility profits are asset-based. Also, since shareholders receive the benefit of insurance payouts, they should bear a portion of the cost of buying the insurance. (T. 1465-1466) Mr.

Harder responded, contending that: (1) the AG cites no evidence to show shareholders are the primary beneficiaries of these insurance proceeds; (2) litigation often involves past stockholders, in which instance they are no different than other individuals filing tort claims; and (3) when current shareholders are involved, payments are made to the corporation in which case customers are the ultimate beneficiaries. (T. 1227-1229)

The Commission finds that Arkla has not justified its change in allocation factors nor has it justified why this expense should not be split equally between stockholders and ratepayers. Arkla did not adequately explain why, at this time, it changed from a asset-based to an O&M expense-based allocation factor. Arkla's explanation that it is an expense to attract qualified management does not establish a justifiable relationship between the cost and the cost expense allocation factor the Company used. Mr. Marcus testified that D&O insurance costs are part of general corporate overhead to protect Company profits which are largely asset-based for a utility. (T. 167-169) Mr. Marcus' testimony that this insurance protects corporate profits also lends support for sharing the insurance costs between shareholders and ratepayers. The news (T. 1040) is replete with stories about companies experiencing lawsuits by shareholders. The Commission agrees with the AG that more often than not it is the current shareholders who sue management and who receive a large portion of the proceeds from the D&O insurance payouts. Accordingly, the Commission finds that Arkla's existing asset-based allocation for D&O insurance should be maintained and that the expense for D&O insurance should be shared on a 50-50 basis between shareholders and ratepayes.

ARKANSAS PUBLIC SERVICE COMMISSION

IN THE MATTER OF THE APPLICATION OF ARKANSAS WESTERN GAS COMPANY FOR APPROVAL OF A GENERAL CHANGE IN RATES AND TARIFFS	))))	**DOCKET NO. 04-176-U ORDER NO. 6**

ORDER

PROCEDURAL HISTORY

On December 29, 2004, Arkansas Western Gas Company ("AWG" or the "Company") filed an application for approval of a general change or modification in its rates and tariffs. AWG requested that its rates be increased by $9,739,459 annually. Order No. 2, entered January 10, 2005, suspended AWG's proposed rates, charges, and tariffs pending further investigation by the Commission. Order No. 2 also established a procedural schedule for the purposes of investigating AWG's application.

The parties to this proceeding are AWG, the General Staff of the Arkansas Public Service Commission ("Staff"), the Attorney General of Arkansas ("AG"), Northwest Arkansas Gas Consumers ("NWAGC"), and the Commercial Energy Users Group ("CEUG").

On December 29, 2004, AWG filed the Direct Testimony and Exhibits of Alan N. Stewart, Executive Vice-President of AWG, Donna R. Campbell, Manager, Rates and Regulation Department of AWG, Ricky A. Gunter, Vice President of Rates and Regulation for AWG, Glenn M. Morgan, Controller and Treasurer for AWG, and Dr. Roger A. Morin,[1] Principal, Utility Research International, in support of its application.

[1]Professor of Finance, Georgia State University and Professor of Finance for Regulated Industry at the Center for the Study of Regulated Industry at Georgia State University, Atlanta, Georgia.

3. **Payroll Taxes**:

Differences between Staff's and the Company's calculation of payroll taxes and that of the AG relate entirely to the differences between the parties regarding the appropriate level of payroll to include in revenue requirement.

In view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for FICA and other payroll taxes is appropriate and should be adopted.

C. Fringe Benefits

As with payroll taxes, any differences among the parties for fringe benefits, including worker's compensation, medical insurance, pension expense, and employee savings plan/life insurance relate to the level of proposed payroll. Therefore, as with payroll taxes, in view of the foregoing findings on payroll, the Commission finds that Staff's adjustments for any fringe benefits should be adopted.

D. Directors and Officers Insurance ("D & O")

The AG and AWG also disagree about inclusion in revenue requirement of 100% of the liability insurance provided by AWG and SWN for its directors and officers. Mr. Marcus argues that the major beneficiaries of this type of insurance will be the stockholders and its issuance provides no assurances of better management or decision making by officers and directors for the benefit of ratepayers. He also testifies that, in AWG's last rate case, Docket No. 02-227-U, the Commission approved a sharing of the cost between ratepayers and stockholders and he recommends that the Commission require equal sharing here. (Tr. at 72-73) Mr. Morgan disputes the AG's view of the benefits provided by this expense, noting that this type of insurance is essential to the operation of AWG, without which it could not attract the necessary management personnel to operate the Company. (Tr. at 350)

As it has held in previous rate cases, most notably in AWG's last rate case in Docket No. 02-227-U, the Commission finds that D&O insurance benefits both stockholders and ratepayers. Therefore, as recommended by AG witness Marcus this expense should be split 50/50 between stockholders and ratepayers.

E. Uncollectible Accounts Expense

Uncollectible accounts expense has been calculated by the parties, each using a percent of uncollectible accounts to revenues applied to pro forma operating revenues as explained by Staff witness Williams. (Tr. at 1442) As discussed in the following section on the revenue conversion factor, the calculation of that percent remains in dispute. The Commission has found in its discussion of the revenue conversion factor that Staff's calculated factor for uncollectible accounts expense is appropriate. In view of that finding, the Commission, therefore, also approves Staff's calculated level of uncollectible accounts expense.

F. Revenue Conversion Factor

Revenue conversion factor issues still in contention among the parties include: the term over which uncollectible accounts as a percent of revenues are averaged in order to estimate a normal level; a proposal to incorporate late payment charge revenues in the conversion factor as a percent of revenues; and a proposal to calculate and apply separate conversion factors by class to recognize each class's distinctive level of uncollectible accounts.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

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

DOCKET NO. E-04204A-12-0504

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2013

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ATTACHMENT

SCHEDULES

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-12-0448

My direct testimony provides my estimate of the cost of capital for UNS Electric, Inc. ("UNS Electric"). My cost of capital recommendation is as follows:

	Percent	Cost	Return
Long-term Debt	47.40%	5.97%	2.83%
Common Equity	52.60%	9.25%	4.87%
Total Capital	100.00%		7.70%

The only difference between my 7.70 percent recommendation and the 8.35 percent cost of capital request of UNS Electric is the cost of common equity – I propose a cost of equity of 9.25 percent and UNS Electric requests a cost of equity of 10.50 percent.

My 9.25 percent cost of common equity is derived from my application of three cost of equity models:

	Range	Mid-Point
Discounted Flow	8.5 – 10.0%	9.25%
Capital Asset Pricing Model	6.5 – 6.8%	6.65%
Comparable Earnings	9.0 – 9.50%	9.25%

In addition, my direct testimony addresses the Fair Value Rate of Return ("FVROR") which should be applied to the Fair Value Rate Base of UNS Electric. I recommend two alternative FVROR values for UNS Electric – a 5.79 percent value using a zero percent return on the Fair Value Increment (differential between Fair Value Rate Base and Original Cost Rate Base) and 5.91 percent value using a 0.50 percent inflation-adjusted risk-free return.

I. INTRODUCTION

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

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 580, 9030 Stony Point Parkway, Richmond, Virginia 23235.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings, dating back to 1972. In connection with this, I have previously filed testimony and/or testified in about 500 utility proceedings before over 50 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Utilities Division Staff ("Staff") to evaluate the cost of capital aspects of the current filing of UNS Electric, Inc. ("UNS Electric" or "Company"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Electric. In addition, since UNS Electric is a subsidiary of UNS Energy Corporation ("UNS Energy"), I have also evaluated UNS Energy in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, made up of 15 Schedules, identified as Schedule 1 through Schedule 15. These Schedules were prepared either by me or under my direction. The information contained in these schedules is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for UNS Electric are:

	Percent	Cost	Return
Long-Term Debt	47.40%	5.97%	2.83%
Common Equity	52.60%	9.25%	4.87%
Total	100.00%		7.70%

UNS Electric's application requests a return on common equity of 10.5 percent and overall rate of return of 8.35 percent. I propose a return on common equity of 9.25 percent and an overall rate of return of 7.70 percent.

Q. Please summarize your cost analyses and related conclusions for UNS Electric.

A. This proceeding is concerned with UNS Electric's regulated electric utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing an analysis of the Company's cost of capital is the development of the appropriate capital structure. UNS Electric's proposed capital structure is comprised of 52.60 percent common equity and 47.40 percent long-term debt. This capital structure is the June 30, 2012 test period capital structure of the Company. I also use this same capital structure in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of debt. UNS Electric's application uses a cost rate of 5.97 percent, which reflects the Company's cost at June 30, 2012. I have used the same rate for this item as is proposed by the Company.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Electric. Each of these methodologies is applied to two groups of proxy utilities. These three methodologies and my findings are:

Methodology	Range	Mid-Point
Discounted Cash Flow	8.5-10.0%	9.25%
Capital Asset Pricing Model	6.5-6.8%	6.65%
Comparable Earnings	9.0-9.5%	9.25%

Based upon these findings, I conclude that the cost of common equity for UNS Electric is within a range of 8.5 percent to 10.0 percent. I recommend the mid-point of my cost of equity range (9.25 percent).

Combining these three steps into a weighted cost of capital results in an overall rate of return range of 7.56 percent to 7.83 percent. My recommended 9.25 percent cost of equity results in an overall cost of capital of 7.70 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a fair rate of return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow for the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets used and useful (i.e., rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return (including income taxes).

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an *ex post* (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an *ex ante* (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, I reviewed, among other items, two United States Supreme Court decisions which provide guidance on standards for a fair rate of return. The first decision is <u>Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia</u>, 262 U.S. 679 (1923). In this decision, the Court stated:

> "What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally". **[Emphasis added.]**

It is my understanding that the Bluefield decision discussed the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> "The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**." **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise, on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company, 294 P.2d 378 (1956) the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that Congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return is computed might be arrived at.'"

My testimony does not advocate that the Commission ignore the Simms holding in this regard, or the fair value of UNS Electric's property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions can be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that UNS Electric Witness Bulkley also cites the Hope and Bluefield cases as guidelines for evaluating the cost of capital for the Company.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Comparable Earnings ("CE") and Risk Premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. Which methods have you employed in your analyses of the cost of common equity in this proceeding?

A. I have utilized three methodologies to determine UNS Electric's cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as I indicate later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Are economic and financial conditions important in determining the cost of capital for a public utility?

A. Yes. The cost of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the cost of capital:

- The level of economic activity (i.e., growth rate of the economy);
- The stage of the business cycle (i.e., recession, expansion, or transition);
- The level of inflation;

- The level and trend of interest rates; and,
- Expected economic conditions.

My understanding is that this position is consistent with the *Bluefield* decision that noted "[a] rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally." *Bluefield*, 262 U.S. at 693.

Q. What indicators of economic and financial activity did you evaluate in your analyses?

A. I examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over four full business cycles, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences, and thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the four prior business cycles and the current cycle.

A. The four prior complete cycles and current cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
2001-2009	Dec. 2001-Nov. 2007	Dec. 2007-June 2009
Current	July 2009-	

Source: National Bureau of Economic Research, "Business Cycle Expansions and Contractions."

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. Until the end of 2007, the United States economy had enjoyed general prosperity and stability since the early 1980s.[1] This period had been characterized by longer economic expansions, relatively tame contractions, low and declining inflation, and declining interest rates and other capital costs.

However, in 2008 and 2009, the economy declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and the related liquidity crisis in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline, initially based on a substantial increase in petroleum prices and a dramatic decline in the U.S. financial sector, culminating with the collapse and/or bailouts of a significant number of well-known institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. The recession also witnessed the demise of national companies such as Circuit City and the bankruptcies of automotive manufacturers such as Chrysler and General Motors.

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1 There was a "Tech Bubble" in 1999-2000, in which prices of many technology stocks encountered a dramatic run-up that was followed by an equally dramatic decline in 2001-2002.

This decline has been described as the worst financial crisis since the Great Depression and has been referred to as the "Great Recession." Since 2008, the U.S. and other governments have implemented and continue to implement unprecedented actions to attempt to correct or minimize the scope and effects of this recession.

The recession reached its low point in mid-2009 and the economy has since begun to expand again, although at a slow and uneven rate. However, the length and severity of the recession, as well as a relatively slow and uneven recovery, indicate that the impacts of the recession have been and will be felt for an extended period of time. As an example of this, even in the fourth year of the recovery/expansion, the U.S. unemployment rate still stands at nearly 8 percent—close to the highest unemployment rate experienced over the last several decades.

Q. Please describe recent and current economic and financial conditions and their impact on the cost of capital.

A. Schedule 2 shows several sets of relevant economic data for the cited time periods. Pages 1 and 2 contain general macroeconomic statistics; pages 3 and 4 show interest rates; and pages 5 and 6 contain equity market statistics.

Pages 1 and 2 show that 2007 was the sixth year of an economic expansion but, as I previously noted, the economy subsequently entered a significant decline, as indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and an increase in the unemployment rate. This recession lasted until mid-2009, making it a longer-than-normal recession, as well as a deeper recession.

Since then, economic growth has been erratic and lower than the initial periods of prior expansions.

Pages 1 and 2 also show the rate of inflation. As reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially beginning in 1981, and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 2008, the CPI has been 3 percent or lower, with 2012 being only 1.7 percent. It is thus apparent that the rate of inflation has generally been declining over the past several business cycles. Current levels of inflation are at the lowest levels of the past 35 years and are indicative of low inflation, which is reflective of lower capital costs.

Q. What have been the trends in interest rates over the four prior business cycles and at the current time?

A. Pages 3 and 4 of Schedule 2 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates during the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their then-lowest levels since the 1960s.

Since 2008, the Federal Reserve has lowered the Federal Funds rate (i.e., short-term rate) to 0.25 percent, an all-time low. The Federal Reserve has also acted to stimulate the economy by purchasing U.S. Treasury Securities. In 2008 and early 2009, there was a pronounced decline in short-term rates, as well as long-term U.S. Treasury Securities yields, and an increase in corporate bond yields, reflecting the "flight to safety," wherein there was a reluctance of investors to purchase common stocks and corporate bonds while concomitantly moving their money into very safe government bonds. Since then, as seen on page 4 of Schedule 2, both U.S. and corporate bond yields have declined to their lowest levels in the past four business cycles and in more than 35 years, with even corporate lending rates remaining at historically low levels, again reflective of lower capital costs.

Q. What trends does Schedule 2 show for trends of common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These indicate that stock prices were essentially stagnant during the high inflation/high interest rate environment of the late 1970s and early 1980s. The 1983-1991 business cycle and the more recent cycles witnessed a significant upward trend in stock prices. The beginning of the recent financial crisis saw stock prices decline precipitously, as stock prices in 2008 and early 2009 were down significantly from 2007 levels, reflecting the financial/economic crisis. Beginning in the second quarter of 2009, prices have recovered substantially and have ultimately reached and exceeded the levels achieved prior to the "crash."

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. It is apparent that recent economic and financial circumstances have been different from any that have prevailed since at least the 1930s. The late 2008-early 2009 deterioration in stock prices, the decline in U.S. Treasury bond yields, and an increase in corporate bond yields were evidenced in the then-evident "flight to safety." On the other side of this "flight to safety" is the negative perception of the recent declines in capital costs and returns, which significantly reduced the value of most retirement accounts, investment portfolios and other assets. One significant aspect of this has been a decline in investor expectations of returns, including stock returns. Finally, as noted above, utility interest rates are currently at levels below those prevailing prior to the financial crisis of late 2008 to early 2009 and are near the lowest level in the past 35 years.

V. UNS ELECTRIC'S OPERATIONS AND RISKS

Q. Please summarize UNS Electric and its operations.

A. UNS Electric is a public utility that provides electric utility services to some 92,000 customers in Mohave and Santa Cruz Counties of Arizona. UNS Electric was formerly the Arizona electric utility operations of Citizens Communications Company ("Citizens"), prior to its 2003 acquisition by UNS Energy. When UNS Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Electric and UNS Gas.

Q. Please describe UNS Energy.

A. UNS Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UNS Energy also owns UNS Energy Services ("UES"), which is the parent company of both UNS Electric and UNS Gas. UNS Energy presently operates through three primary business segments – TEP, UNS Electric and UNS Gas.

Q. What have been the business segment ratios of UNS Energy in recent years?

A. This is shown on Schedule 3. As this indicates, as of 2012, UNS Electric accounted for about 13 percent of the revenues of UNS Energy, about 19 percent of operating income, and 9 percent of total assets.

Q. What are the current bond ratings of UNS Energy, UNS Electric and TEP?

A. The current ratings of UNS Energy, UNS Electric, UNS Gas and TEP are:

	Standard & Poor's	Moody's	Fitch
UNS Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
UNS Electric Credit Ratings			
Senior Unsecured Debt		Baa2	
UNS Gas Credit Ratings			
Senior Unsecured Debt		Baa2	
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB+	Baa1	BBB-
Senior Unsecured Debt	BBB-	Baa3	BBB
Issuer Rating	BB+	Baa3	BBB-

Source: UNS Energy Web Site.

UNS Electric now has its own security ratings by Moody's but not S&P and Fitch. The debt of UNS Electric is guaranteed by UES. As such, the debt of UNS Electric is related to the overall credit strength of UNS Energy.

Q. Did the acquisition of the assets currently comprising UNS Electric have any impact on the security ratings of UNS Energy or TEP?

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and **gas transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UNS Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured as a wholly owned subsidiary of UNS Energy called UniSource Energy Services.
>
> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support, mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. What have been the subsequent descriptions of UNS Electric by rating agencies?

A. In July of 2008, Moody's assigned a rating of Baa3 to UNS Electric. In its report, Moody's stated:

> Corporate Profile
>
> UNS Electric, Inc. (UNSE: Baa3 guaranteed revolving credit facility, stable outlook) is an electric transmission and distribution utility serving approximately 90,000 retail customers in Mohave and Santa Cruz counties of Arizona. UNSE is a subsidiary of UniSource Energy Services ("UES') which is also the parent of UNS Gas, Inc. ("UNSG"), a gas utility serving approximately 146,000 customers in an area covering approximately 50% of the state of Arizona. UES is a wholly owned subsidiary of UniSource Energy Corporation (UNS: Ba1 senior secured bank credit facility (security limited to stock of certain subsidiaries), stable outlook). UNS'

> largest subsidiary is Tucson Electric Power (TEP: Baa3 senior unsecured, stable outlook), a vertically integrated electric utility serving approximately 400,000 retail customers in southeastern Arizona and also engaged in wholesale power marketing in the western U.S.
>
> Recent Developments
>
> On July 8, 2008, Moody's assigned a rating of Baa3 to UNSE and UNSG joint $60 million senior unsecured guaranteed credit facility. The facility is guaranteed by UNSE's and UNSG's intermediate parent company UES. The rating outlook is stable.
>
> Rating Rationale
>
> The **Baa3 rating for the shared guaranteed credit facility is driven by the relatively stable and predictable nature of UNSE's and UNSG's regulated cash flows, as well as their strong combined financial profile which provide the basis of the UES guarantee. For the past several years, cash flow credit metrics at both UNSE and USE have been at or above the ranges demonstrated by electric utilities rated within the Baa range**. [Emphasis added]

More recently, Moody's made the following comments about UNS Electric in a May 25, 2012 Credit Opinion:

> **Summary Rating Rationale**
>
> UNSE's Baa2 senior unsecured rating reflects the improved regulatory environment in Arizona, the interdependence that currently exists between UNSG and its affiliate UNSE as a result of their shared credit facility and parental guarantee and the relatively small size of the utility. The rating also reflects relatively strong credit metrics.
>
> **Detailed Rating Considerations**
>
> Improved regulatory environment in Arizona.
>
> The evaluation of the ratings for UNS and its subsidiaries was driven by the recent favorable rate settlement of UNSG, which along with two other recent supportive settlements for Southwest Gas and Arizona Public Service indicates an improvement in the Arizona regulatory environment.

> UNS Electric achieved a supportive outcome in its 2010 rate decision, in which it received a rate increase of $7.4 million, over 50% of its initial request, reflecting a 9.75% ROE and an equity ratio of 46%. In that rate case, the company was also allowed to recover in rates the cost of acquiring the Black Mountain Generation Station, a 90 MW gas peaking facility, from UNS's development arm in 2011. While UNS Electric is required to make an administrative filing with the ACC this year, it has not announced an intention to file for a rate increase this year.
>
> Recovery mechanisms supportive to credit quality
>
> UNSE procures most of its power from the market via a portfolio of committed long and short-term contracts and spot purchases. UNSE's purchased power and fuel adjustment clause (PPFAC) has two components: a capped forward component and an uncapped true-up component that allows recovery of actual power costs over the subsequent twelve month period. We view the PPFAC as credit supportive. Our rating assumes the PPFAC will continue to function appropriately and deferral balances remain manageable.
>
> In addition, UNSE is allowed to include a surcharge to recover its renewable investments and above-market cost of PPAs through a Renewable Energy Standard and Tariff ("REST").
>
> Cross support of debt within UES
>
> The rating recognizes the position of UNSE and UNSG as subsidiaries of UES. UES guarantees the debt at the utilities and their shared credit facility. UNSE contributes about 60% of UES' earnings. Due to the cross-support of debt and comparable size, the ratings of UNSE and UNSG are expected to remain the same.

These quotes by Moody's indicate that the ratings of UNS Electric are:

Positively impacted by ACC regulations;

Tied to UNS Gas; and

Based on consolidated credit profile of UES.

Q. Is UNS Electric requesting any regulatory mechanisms that have the effect of enhancing the recovery of its investments?

A. Yes, it does. UNS Electric has several existing and proposed regulatory mechanisms that are beneficial to the Company's recovery of investments and expenses.

UNS Electric has had, since its last rate proceeding in 2010, a purchased power and fuel adjustment clause ("PPFAC") that provides for the full recovery of these costs. As noted above, Moody's has indicated that the PPFAC is "credit supportive".

In addition, in the present proceeding UNS Electric is requesting approval of two new regulatory mechanisms. These are:

- Lost Fixed Cost Recovery Mechanism ("LFCR"); and,
- Transmission Cost Adjustment Mechanism ("TCA").

Q. Have the rating agencies commented favorably on the approval and implementation of the types of regulatory mechanisms proposed and utilized by UNS Electric?

A. Yes, they have. Standard & Poor's made the following statements in a March 9, 2009 RatingsDirect report titled "Regulatory Mechanisms Help Smooth Electric Utility Cash Flow and Support Ratings":

> We believe innovative ratemaking techniques and alternatives to traditional base rate case applications and large rate hikes will become more critical to the utilities' ability to maintain cash flow, earnings power, and ultimately credit quality. That's why **Standard & Poor's Ratings Services views rate recovery mechanisms that allow for the timely adjustment of rates to changing commodity prices and other expenses, outside of a fully litigated rate proceeding, as beneficial to utility creditworthiness.**
> **[Emphasis added]**

This view has been reiterated by Moody's, which made the following statements in a June 18, 2010, Special Comment titled "Cost Recovery Provisions Key To Investor Owned Utility Ratings and Credit Quality":

> **Moody's views automatic adjustment clauses**, the most common of which is for fuel and purchased power, the largest component of utility operating expenses, **as supportive of utility credit quality and important in reducing a utility's cash flow volatility, liquidity requirements, and credit risk.**
>
> Generally, the more of these clauses a utility has in place, the stronger its scoring should be on this ratings factor and the lower the credit risk.
> [Emphasis added]

Q. How are UNS Electric's risks reduced by the current and proposed regulatory mechanisms?

A. The Company's risks are significantly reduced by the cited regulatory mechanisms. One risk faced by all businesses, including utility companies, is the risk of revenues covering all costs. Revenue collections that are volatile and/or subject to seasonal/weather influences often do not match cost causation, resulting in periodic erosion of earnings.

Q. Should this risk reduction be reflected in a lower cost of equity for UNS Electric?

A. Yes. Given the significance of the risk reduction to UNS Electric resulting from these riders, I recommend that no more than the mid-point of the cost of equity developed in my cost of equity analysis be approved in setting the Company's cost of capital.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (*i.e.*, the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of UNS Electric?

A. I have first examined the historic (2004-2013) capital structure ratios of UNS Electric. These are shown on Page 1 of Schedule 4. I have summarized below the common equity ratios for UNS Electric:

	Including S-T Debt	Excluding S-T Debt
2004	40.3%	40.5%
2005	45.2%	45.4%
2006	45.0%	45.1%
2007	48.0%	48.1%
2008	43.8%	43.8%
2009	47.5%	47.5%
2010	50.2%	50.2%
2011	51.2%	51.2%
2012	52.3%	52.3%
March 31, 2013	51.8%	52.7%

It is evident that the common equity ratios of UNS Electric have increased significantly since 2004.

Page 2 of Schedule 4 shows the historic capital structure ratios of UNS Energy on a consolidated basis. This indicates the following common equity ratios.

	Including S-T Debt	Excluding S-T Debt
2004	31.6%	31.6%
2005	33.6%	33.7%
2006	34.9%	35.8%
2007	40.7%	41.0%
2008	33.8%	34.0%
2009	35.7%	36.3%
2010	37.1%	37.1%
2011	36.8%	36.9%
2012	41.6%	41.6%
March 31, 2013	40.9%	41.3%

These common equity ratios are somewhat lower than those of UNS Electric.

Page 3 of schedule 4 shows the December 31, 2012 capital structures of UNS Energy and its utility subsidiaries. UNS Electric and UNS Gas are seen to have higher equity ratios than TEP and UNS Energy.

Q. How do these capital structures compare to those of investor-owned electric utilities?

A. Schedule 5 shows the common equity ratios (excluding short-term debt in capitalization) for the two groups of proxy utilities utilized in my cost of equity analyses. These are:

Year	Proxy Group	Bulkley Group
2008	50.9%	50.4%
2009	49.1%	48.6%
2010	50.1%	49.8%
2011	50.0%	51.5%
2012	50.5%	52.2%

These common equity ratios for the proxy groups are similar to those of UNS Electric.

Q. What capital structure ratios has UNS Electric requested in this proceeding?

A. The Company requests use of the following capital structure:

Long-Term Debt	47.40%
Common Equity	52.60%

According to UNS Electric's filing, this is the test year capital structure of the Company at June 30, 2012.

Q. What capital structure do you propose to use in this proceeding?

A. I use the capital structure ratios as proposed by UNS Electric.

Q. What is the cost rate of debt in the Company's application?

A. The Company's filing cites a cost of long-term debt of 5.97 percent. This is represented to be the Company's actual cost at June 30, 2012. I also use this cost of long-term debt in my cost of capital analyses.

Q. Can the cost of common equity be determined with the same degree of precision as the costs of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for UNS Electric?

A. UNS Electric is not a publicly-traded company. UNS Energy, UNS Electric's parent company, is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to UNS Electric. However, it is generally desirable to analyze groups of comparison, or "proxy," companies as a substitute for UNS Electric to determine its cost of common equity.

I have examined two such groups for comparison to UNS Electric and UNS Energy. I have first selected a group of electric utilities similar to UNS Electric and UNS Energy using the criteria listed on Schedule 6.

Second, I have conducted studies of the cost of equity for the proxy group of electric utilities selected by UNS Electric's witness Ann E. Bulkley.

VIII. DISCOUNTED CASH FLOW ("DCF") ANALYSIS

Q. What is the theory and methodological basis of the DCF model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework, cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where:

K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; *i.e.*, current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (March-May, 2013). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2008-2012 (5-year average) earnings retention, or fundamental growth (per Value Line);

2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);

3. 2013, 2014, and 2016-2018 projections of earnings retention growth (per Value Line);

4. 2010-2012 to 2016-2018 projections of EPS, DPS, and BVPS (per Value Line); and

5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the DCF calculations, which are presented on several bases: mean, median, and low/high values. These results can be summarized as follows:

			Composite			
			Mean		Median	
	Mean	Median	Low	High	Low	High
Proxy Group	8.5%	8.1%	7.0%	9.7%	5.7%	10.1%
Bulkley Group	8.0%	7.8%	7.0%	9.0%	6.5%	8.9%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy group; rather, the individual values shown should be interpreted as alternative information considered by investors. The individual DCF calculations also demonstrate how the focus on a single growth rate, such as EPS projections, can produce a DCF conclusion that is not reflective of a broader perspective of available information.

The results in Schedule 7 indicate average (mean and median) DCF cost rates of 7.8 percent to 8.5 percent. The range of DCF rates (i.e., using the lowest and highest growth rates only) is 5.7 percent to 10.1 percent.

Q. What do you conclude from your DCF analyses?

A. This analysis reflects a DCF range of about 5.7 percent to about 10.1 percent for the proxy group. This is indicated by the average/mean values for the proxy groups examined in the previous analysis. I give less weight to the lower end of the results. I believe that 8.5 percent to 10.0 percent reflects the proper DCF cost for UNS Electric. This range includes the high mean and median results at the top end and includes the top mean and median results as the lower end.

IX. CAPITAL ASSET PRICING MODEL ("CAPM") ANALYSIS

Q. Please describe the theory and methodological basis of the CAPM.

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of Modern Portfolio Theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where:

K = cost of equity

R_f = risk-free rate

R_m = return on market

β = beta

R_m-R_f = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (*i.e.*, beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. Please explain the risk-free rate as used in your CAPM and indicate what rate you employed.

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (March-May, 2013) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 2.69 percent.

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component in your CAPM analysis?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2011 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (*i.e.*, risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.46 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term (i.e., 20-year) government bonds, as tabulated by MorningStar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2012 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.8%	6.1%	5.7%
Geometric	9.8%	5.7%	4.1%

I conclude from this that the expected risk premium is about 5.42 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Q. What are your CAPM results?

A. Schedule 9 shows my CAPM calculations. The results are:

	Mean	Median
Proxy Group	6.8%	6.6%
Bulkley Group	6.5%	6.5%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of 6.5 percent to 6.8 percent for the groups of comparison utilities. I conclude that the CAPM cost of equity for UNS Electric is 6.5 percent to 6.8 percent.

X. COMPARABLE EARNINGS ("CE") ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of UNS Electric's common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (*i.e.,* 100%) reflect a situation where a company is able to attract new equity capital without dilution (*i.e.*, above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2012 (*i.e.,* the last twenty-one years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on three periods: 2009-2012 (the current business cycle), 2002-2008 (the recent business cycle) and 1992-2001 (the prior business cycle).

Q. Please describe your CE analysis.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Bulkley Group
Historic ROE		
Mean	7.7-11.8%	8.5-11.6%
Median	7.2-11.7%	8.5-11.9%
Historic M/B		
Mean	119-154%	125-159%
Median	131-156%	121-160%
Prospective ROE		
Mean	8.6-9.3%	8.8-9.4%
Median	9.0-9.3%	8.8-9.0%

These results indicate that historic returns of 7.2 percent to 11.9 percent have been adequate to produce market-to-book ratios of 119 percent to 160 percent for the groups of proxy utilities. Furthermore, projected returns on equity for 2013, 2014 and 2016-2018 are within a range of 8.6 percent to 9.4 percent for the utility groups. These relate to 2012 market-to-book ratios of 135 percent or higher.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past twenty years. As this Schedule indicates, over the three periods, this group's average earned returns ranged from 12.4 percent to 14.7 percent with market-to-book ratios ranging between 201 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for UNS Electric?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.0 percent to 9.5 percent. Recent returns of 7.2 percent to 11.9 percent have resulted in market-to-book ratios of 119 and greater. Prospective returns of 8.6 percent to 9.4 percent result in anticipated market-to-book ratios of over 135 percent, again with the higher returns being associated with much higher market-to-book ratios. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 9.0 percent to 9.5 percent should thus result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

Please also note that my CE analysis is not based on a mathematical formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100%, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.0 percent to 9.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for UNS Electric. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

	Range	Mid-Point
Discounted Cash Flow	8.5-10.0%	9.25%
Capital Asset Pricing Model	6.5-6.8%	6.65%
Comparable Earnings	9.0-9.50%	9.25%

Q. What is your cost of equity recommendation for UNS Electric?

A. I recommend a broad cost of equity of 8.5 percent to 10.0 percent for UNS Electric. This range contains the results of two of my three cost of equity model results (i.e., DCF 8.5-10.0% and CE 9.0-9.5%). Within this range, I recommend a 9.25 percent level.

Q. It appears that your CAPM results are somewhat lower than your DCF results. Does this indicate that the CAPM results should not be considered at this time?

A. No. It is apparent that the CAPM results are less than the DCF and CE results. There are two reasons for the lower CAPM results. First, risk premiums are lower currently than was the case in prior years. This is also reflective of a decline in investor expectations of equity returns and risk premiums. Second, the level of interest rates on U.S. Treasury bonds (i.e., the risk free rate) has been lower in recent years. This is partially the result of the actions of the Federal Reserve System to stimulate the economy. This also impacts investor expectations of return in a negative fashion. I note, that initially, investors may have believed that the decline in Treasury yields was a temporary factor that would soon be replaced by a rise in interest rates. However, this has not been the case as interest rates have remained low and continued to decline for the past four-plus years. As a result, it cannot be maintained that lower interest rates (and low CAPM results) are temporary and do not reflect investor expectations. Consequently, the CAPM results should be considered as one factor in determining the cost of equity for UNS Electric. At the very least, the CAPM results indicate the capital costs continue at historically low levels and that UNS Electric's cost of equity is less than in prior years.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for UNS Electric?

A. Schedule 1 reflects the total cost of capital for the Company using UNS Electric's proposed capital structure and cost of debt along with the range of common equity costs that my analyses support. The resulting total cost of capital is a range of 7.56 percent to 7.83 percent. I recommend that a 7.70 percent total cost of capital be established for UNS Electric.

Q. Does your cost of capital recommendation provide the Company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 13 shows the pre-tax coverage that would result if UNS Electric earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level within the benchmark range for an A rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for an A rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony and cost of capital recommendation of UNS Electric witness Ann E. Bulkley?

A. Yes, I have. Ms. Bulkley is recommending cost of equity for UNS Electric of 10.30 percent to 10.75 percent, with a specific recommendation of 10.50 percent.

Ms. Bulkley's 10.50 percent cost of common equity recommendation is derived as follows:

Constant Growth DCF

	Mean Low	Mean	Mean High
30-Day Average Price	9.00%	10.55%	12.81%
90-Day Average Price	8.97%	10.51%	12.78%
180-Day Average Price	9.06%	10.61%	12.88%
	Median Low	Median	Median High
30-Day Average Price	9.47%	10.57%	11.54%
90-Day Average Price	9.42%	10.53%	11.53%
180-Day Average Price	9.52%	10.63%	11.64%

Multi-Stage DCF

	Mean Low	Mean	Mean High
30-Day Average Price	9.93%	10.38%	11.19%
90-Day Average Price	9.89%	10.35%	11.15%
180-Day Average Price	9.99%	10.45%	11.28%
	Median Low	Median	Median High
30-Day Average Price	9.93%	10.21%	10.81%
90-Day Average Price	9.84%	10.15%	10.74%
180-Day Average Price	9.92%	10.26%	10.81%

Capital Asset Pricing Model

	Current Risk-Free Rate (2.87%)	2012-2014 Projected Risk-Free Rate (3.15%)	2014-2018 Projected Risk-Free Rate (5.10%)
Bloomberg Beta	9.87%	9.95%	10.53%
Value Line Beta	10.03%	10.11%	10.66%

Bond Yield Plus Risk Premium

	Current Risk-Free Rate (2.87%)	2012-2014 Projected Risk-Free Rate (3.15%)	2014-2018 Projected Risk-Free Rate (5.10%)
Bond Yield Plus Risk Premium	10.01%	10.12%	10.86%

Q. Do you have any general comments about Ms. Bulkley's testimony and conclusions?

A. Yes, I do. Ms. Bulkley's testimony significantly over-states the cost of capital for UNS Electric. Each of her methods, and virtually all of the inputs used in her methods, is systematically biased upward in a manner that significantly inflates her return on equity conclusions.

Q. What are your disagreements with Ms. Bulkley's constant growth DCF analyses?

A. Ms. Bulkley's constant growth DCF analyses are based on 30-day, 90-day and 180-day average stock prices for the periods ending November 16, 2012, annualized dividends per share as of November 16, 2012 and the average of Value Line, First Call and Zack's EPS projections. Her DCF analyses are applied to her group of fourteen electric utilities.

Even though Ms. Bulkley purports to examine three alternative growth rates in her constant growth DCF analyses, in reality each of the three focuses on a single statistic: analysts' forecasts of EPS. As a result, all of Ms. Bulkley's constant growth rates focus exclusively on EPS forecasts and exclude everything else.

Q. Why is it improper to rely exclusively on EPS forecasts in a DCF analysis?

A. There are several reasons why it is not appropriate to rely exclusively on analysts' forecasts in a DCF context. First, it is not realistic to believe that investors rely exclusively on a single factor, such as analysts' forecasts, in making their investment decisions. Investors have an abundance of available information to assist them in evaluating stocks; EPS forecasts are only one of many such statistics.

Second, Value Line – one of Ms. Bulkley's sources of EPS projections – publishes both historic and forecasted data, as well as ratios, for a large number of publicly-traded companies. Presumably, both types of information are published for the consideration of its subscribers/investors. Yet, Ms. Bulkley considers only *one* factor -- the *forecast* version of EPS in her analyses.

Third, the vast majority of information available to investors, by both individual companies in the form of annual reports and offering circulars, and by investment publications such as Value Line, is historic data. It is neither realistic nor logical to maintain that investors only consider projected (estimated) data to the exclusion of historic (actual) data.

Fourth, there have been a number of academic studies that indicate that analysts' forecasts have been overly-optimistic in the past. See, for example, a 1998 article in *Financial Analysts Journal*, Vol. 54, No. 6, Nov./Dec. 1998, 35-42, titled "Why So Much Error In Analysts' Earnings Forecasts?" by Vijay Kumer Chopra. In this article, the author concludes "Analysts' forecasts of EPS and growth in EPS tend to be overly optimistic." He reasons that analysts' forecasts of EPS over the past 13 years have been more than twice the actual growth rate. Investors are aware of the propensity of analysts to over-estimate EPS forecasts. In addition, the presumption that investors rely *only* on a single projection, as was made by Ms. Bulkley, implies that investors are unsophisticated and unable to make their own decisions. This also is not realistic.

Fifth, the experience over the past several years should be a clear signal to investors that analysts cannot accurately predict EPS levels. Few, if any, analysts predicted the decline in security prices in the tech market crash of 2000-2002, as well as the financial crisis of 2008 and 2009.[2] Thus, relying only on forecasted EPS levels, while ignoring historic EPS levels, cannot and will not produce accurate results.

In summary, investors are now very much aware of recent inabilities of security analysts to accurately predict EPS growth. These problems clearly call into question the reliance on analysts' forecasts as the *only* source of growth in a DCF context. As a result, the landscape has changed in recent years and investors have ample reasons to doubt the reliability of such forecasts at the present time. In light of the above, it is problematic to rely exclusively on such forecasts in determining the cost of equity for UNS Electric.

Q. Are you aware of any recent analyses and comments on the accuracy of analysts' forecasts?

A. Yes, I am. A 2010 study by McKinsey & Company, titled, "Equity Analysts: Still Too Bullish" concludes that "after almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic." I have attached a copy of this study as Schedule 14. The significance of this study, as well as the points I raised previously, is

[2] As demonstration of this, see "Security Analysts and their Recommendations," (http://thismatter.com/money/stocks/valuation/security-analysts.htm).

that investors should be hesitant to rely exclusively on analysts' forecasts in making investment decisions.

Q. Please now turn to Ms. Bulkley's second DCF analysis.

A. Ms. Bulkley's second DCF model, which is a multi-stage DCF analysis, also relies exclusively on EPS projections as the short-term growth rate. As such, it is subject to the same over-statements as her constant growth DCF. In addition, her long-term growth rate relies on the 5.55 percent GDP projections as the DCF growth rate. As such, it also results in an over-statement of the DCF cost of equity.

Q. What is the source of this 5.55 percent GDP figure?

A. According to Ms. Bulkley's testimony on page 20, this 5.55 percent GDP growth is based on the historic growth of GDP from 1929 to 2011, plus a projected inflation rate.

Q. Is there anything inconsistent with Ms. Bulkley's use of historic GDP growth in her DCF analyses?

A. Yes, there is. All of Ms. Bulkley's growth rates in her constant growth DCF analyses (i.e., EPS growth) reflect projections of future growth. On the other hand, Ms. Bulkley only uses historic GDP rates in her GDP growth input. Apparently, Ms. Bulkley believes it is not proper to use historic growth rates of financial indicators (i.e., EPS growth), but it is proper to use only historic growth rates in her GDP input.

Q. Are you aware of any projections of GDP growth?

A. Yes, I am. There are at least two sources of projections of GDP growth. These are:

- Social Security Administration (SSA), and

- Energy Information Administration (EIA).

The two organizations cited above are U.S. government-sponsored organizations.

Q. What are the projections of GDP growth by these two organizations?

A. The projections of GDP growth by these two organizations are:

SSA – 2010-2085 – 4.6% (see Schedule 15)

EIA – 2008-2035 – 4.4% (see Schedule 15)

Each of these projections is about 100 basis points below the 5.55 percent GDP figure used by Ms. Bulkley.

Q. Would it be more appropriate to use historic or projected growth rates of GDP in a DCF analysis such as that being used by Ms. Bulkley?

A. It would be appropriate to use projections of GDP growth, since Ms. Bulkley is using projections of the other growth rate indicators.

Q. Is it reasonable to believe that investors would expect GDP growth to be 5.55 percent, in spite of much lower projections by the U.S. government forecasting organizations?

A. No, it is not. It would be expected that the government's forecasts of GDP would be considered by investors as the most unbiased and reliable estimate.

Q. Are you aware of any utility regulatory agencies that utilize GDP growth as a component in a DCF analysis?

A. The only regulatory agency of which I am aware that directly and formally uses GDP growth in a DCF context is the Federal Energy Regulatory Commission ("FERC"). The FERC regularly uses a two-stage DCF model in establishing the cost of equity for interstate natural gas pipelines. The first stage of the FERC two-stage DCF model is 5-year EPS forecasts, while the second stage is GDP projections for 6-25+ years into the future.

Q. How much weight does FERC give to the GDP growth rate in its two-stage DCF model?

A. Thirty-three percent.

Q. Are you aware of any regulatory agencies that use historic GDP growth in a DCF context?

A. No, not in the same context as Ms. Bulkley does.

Q. Do you agree with Ms. Bulkley's risk premium component of the CAPM?

A. No. Ms. Bulkley's CAPM analysis utilizes a risk premium that is based on the "expected return on the S&P 500 Index" using a constant growth DCF analysis (12.85%) and three measures of the risk free rate (two of which are projections of interest rates). She thus derives three risk premium values:

Current interest rate (2.90%)	9.98%
Short-Term projected interest rate (3.15%)	9.75%
Longer-Term projected interest rate (5.10%)	7.75%

Each of these greatly exceeds the long-term experience (e.g., 1929 to present) of investment return differential between common stocks and government bonds, as I described earlier in my testimony. Over this period, risk premiums have averaged less than 6 percent. Ms. Bulkley offered no evidence or rational to explain why investors would expect such a large increase in risk premiums over historic levels. Again, Ms. Bulkley chooses data that produce higher and excessive results.

Q. Do you have any responses to Ms. Bulkley's risk premium analyses?

A. Yes. Ms. Bulkley's risk premium approach compares the allowed ROEs for electric utilities and 30-Year U.S. Government Bond yields over the period 1992 through 2012. She then performs a regression analysis to develop an expected relationship between 30-year U.S. Government Bond yields and the cost of equity for electric utilities. She applies this regression result to the three levels of 30-year U.S. Treasury Bonds and correspondingly arrives at her 10.01-10.86 percent conclusion.

It is apparent from Ms. Bulkley's Exhibit AEB-6 that the preponderance of decisions since 2005 are well below the 10.50 percent return on equity she is recommending in this proceeding. Not since the fourth quarter of 2009 has the average ROE award been as high as 10.5 percent.

XIV. FAIR VALUE RATE BASE COST OF CAPITAL

Q. What is your understanding of UNS Electric's position on the issue of fair value rate base ("FVRB") and related cost of capital implications?

A. It is my understanding that UNS Electric is requesting that a 6.71 percent cost of capital be applied to the level of its FVRB. This 6.71 percent return incorporates a 1.61 percent cost rate of the "fair value increment" as well as a 10.5 percent cost of equity.

Q. What is your understanding of the Commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. Are you aware that in 2008 the Commission conducted a "remand" hearing on the issue of regulatory treatment of FVRB for Chaparral City Water Company?

A. Yes, I am. In January of 2008, the Commission conducted a public hearing in response to a remand by the Arizona Appeals Court (Appeals No. CA-CC 05-002) decision[3] in Chaparral City Water Company (Docket No. W-02113A-04-0616). The purpose of this hearing was to determine the appropriate cost of capital to be applied to an Arizona utility's fair value rate base. The Commission's Decision No. 70441 in this proceeding established a FVROR by subtracting the inflation rate from the cost of equity.

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[3] CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

Q. What is your understanding of the use of FVRB in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals in the Chaparral City case that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a FVRB?

A. Yes, I do. It is my personal experience, based upon over 40 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary Weighted Cost of Capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 40 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for UNS Electric?

A. Yes, I do. Since the increment between the FVRB and OCRB is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to UNS Electric's FVRB.

Item	Percent 1/	Cost	Fair Value Return
Long-term Debt	35.65%	5.97%	2.13%
Common Equity	39.56%	9.25%	3.66%
FVRB Increment	24.80%	0.00%	0.00%
Total FVRB Capital	100.00%		5.79%

1/ As developed in Testimony of Commission Staff Witness Ralph Smith.

Applying this 5.79 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

Q. Have you developed an alternative method with which to apply a FVROR to a FVRB?

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the fair value increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, I recognize that the Commission might choose to evaluate this issue from both a financial and a public policy perspective. I am aware that UNS Electric may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.10 percent (short-term) to 3.2 percent (long-term) in nominal terms. I also note that 2013-2014 forecasts of U.S. Treasury securities are about 0.1 percent to 3.6 percent with most of the forecasts being at or below 3.0 percent. As a result, I use 3.0 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real risk-free rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2012, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 1.7 percent. Forecasts of the CPI for 2013-2014 are about 1.5 percent to 2.3 percent. As a result, I propose to use a 2.0 percent inflation rate (the approximate mid-point) for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	3.0%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	1.0%

Q. Please explain why UNS Electric's FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of UNS Electric are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation. It would be double-counting to also include the inflation components in the return to be applied to the FVRB Increment.

Q. What return on the fair value increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal incorporates a return on the Fair Value Increment with a maximum value of 1.0 percent, as developed above. However, I wish to emphasize that this 1.0 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 1.0 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 0.50 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for UNS Electric:

Capital Item	Percent	Cost	Return
Long-term Debt	35.65%	5.97%	2.13%
Common Equity	39.56%	9.25%	3.66%
FVRB Increment	24.80%	0.50%	0.12%
Total	100.00%		5.91%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of UNS Electric, and provides for an overall fair value rate of return of 5.91 percent on the FVRB.

Q. What is your understanding of how the two FVROR options you have developed will be used in the development of the Staff's revenue requirement recommendations?

A. As I indicated above, I have developed two FVROR calculations – Option 1 that includes a zero percent return on the FVRB increment (5.79% FVROR) and Option 2 that includes a 0.50 percent return on the FVRB increment (5.91% FVROR). The Staff revenue requirement, as developed in the Direct Testimony of Ralph Smith, calculates an "Equivalent ROE on OCRB" for each of these options. The Equivalent ROE for Option 1 is 9.25 percent, which matches the mid-point of my return on equity range and my specific return on equity recommendation. The Equivalent ROE for Option 2 is 9.56 percent, which is above my return on equity range. Staff's revenue requirement recommendation is based on a FVROR of 5.81 percent, which equates to a 9.30 percent ROE that is within my recommended range.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATION

Certified Rate of Return Analyst - Founding Member

RELEVANT EXPERIENCE

<u>Financial Economics</u> -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of

National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

<u>Insurance Economics</u> -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

<u>Special Studies</u> -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.

Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.

<u>Franchise, Merger & Anti-Trust Economics</u> -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified

in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

<u>Transportation Economics</u> -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.

<u>Economic Loss Analyses</u> -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.

The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit___(DCP-1)
Schedule 1

UNS ELECTRIC INC
TOTAL COST OF CAPITAL
TEST YEAR ENDED JUNE 30, 2012

Item	Percent	Cost			Weighted Cost		
Long-Term Debt	47.40%		5.97%			2.83%	
Common Equity	52.60%	9.00%	-	9.50%	4.73%	-	5.00%
Total	100.00%				7.56%		7.83%
						7.70%	**With 9.25% ROE**

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
		1975 - 1982 Cycle			
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
		1983 - 1991 Cycle			
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
		1992 - 2001 Cycle			
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.4%	6.9%	2.7%	0.2%
1994	4.0%	5.5%	6.1%	2.7%	1.7%
1995	3.7%	4.8%	5.6%	2.5%	2.3%
1996	4.5%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.3%	4.9%	1.7%	-1.2%
1998	4.2%	5.8%	4.5%	1.6%	0.0%
1999	3.7%	4.5%	4.2%	2.7%	2.9%
2000	4.1%	4.0%	4.0%	3.4%	3.6%
2001	1.1%	-3.4%	4.7%	1.6%	-1.6%
		2002 - 2009 Cycle			
2002	1.8%	0.2%	5.8%	2.4%	1.2%
2003	2.5%	1.2%	6.0%	1.9%	4.0%
2004	3.5%	2.3%	5.5%	3.3%	4.2%
2005	3.1%	3.2%	5.1%	3.4%	5.4%
2006	2.7%	2.2%	4.6%	2.5%	1.1%
2007	1.9%	2.5%	4.6%	4.1%	6.2%
2008	-0.3%	-3.4%	5.8%	0.1%	-0.9%
2009	-3.1%	-11.3%	9.3%	2.7%	4.3%
		Current Cycle			
2010	2.4%	5.7%	9.6%	1.5%	3.8%
2011	1.8%	3.4%	8.9%	3.0%	4.7%
2012	2.2%	3.6%	8.1%	1.7%	1.4%

*GDP=Gross Domestic Product

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

ECONOMIC INDICATORS

Year	Real GDP* Growth	Industrial Production Growth	Unemploy-ment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	4.1%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	1.7%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.1%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	2.1%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	5.4%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	1.4%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.1%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	3.0%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.9%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	3.2%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	2.3%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	2.9%	1.7%	4.8%	6.4%	10.8%
2008					
1st Qtr.	-1.8%	1.9%	4.9%	2.8%	9.6%
2nd Qtr.	1.3%	0.2%	5.3%	7.6%	14.0%
3rd Qtr.	-3.7%	-3.0%	6.0%	2.8%	-0.4%
4th Qtr.	-8.9%	6.0%	6.9%	-13.2%	-28.4%
2009					
1st Qtr.	-5.3%	-11.6%	8.1%	2.4%	-0.4%
2nd Qtr.	-0.3%	-12.9%	9.3%	3.2%	9.2%
3rd Qtr.	1.4%	-9.3%	9.6%	2.0%	-0.8%
4th Qtr.	4.0%	-4.5%	10.0%	2.5%	8.8%
2010					
1st Qtr.	2.3%	2.7%	9.7%	0.9%	6.5%
2nd Qtr.	2.2%	6.5%	9.7%	-1.2%	-2.4%
3rd Qtr.	2.6%	6.9%	9.6%	2.8%	4.0%
4th Qtr.	2.4%	6.2%	9.6%	2.8%	9.2%
2011					
1st Qtr.	0.1%	5.4%	9.0%	4.8%	9.6%
2nd Qtr.	2.5%	3.6%	9.0%	3.2%	3.6%
3rd Qtr.	1.3%	3.3%	9.1%	2.4%	6.4%
4th Qtr.	4.1%	4.0%	8.7%	0.4%	-1.2%
2012					
1st Qtr.	2.0%	4.5%	8.3%	3.2%	2.0%
2nd Qtr.	1.3%	4.7%	8.2%	0.0%	-2.8%
3rd Qtr.	3.1%	3.4%	8.1%	4.0%	9.6%
4th Qtr.	0.4%	2.8%	7.8%	0.0%	-3.6%
2013					
1st Qtr.	2.4%	2.5%	7.7%	2.0%	0.8%

*GDP=Gross Domestic Product

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

INTEREST RATES

Year	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.44%	5.02%	7.47%	7.59%	7.78%	8.02%
			2002 - 2009 Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.01%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%
2009	3.25%	0.16%	3.26%		5.75%	6.04%	7.06%
			Current Cycle				
2010	3.25%	0.14%	3.22%		5.24%	5.46%	5.96%
2011	3.25%	0.06%	2.78%		4.78%	5.04%	5.57%
2012	3.25%	0.09%	1.80%		3.83%	4.13%	4.86%

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

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

INTEREST RATES

	Prime Rate	US Treasury T Bills 3 Month	US Treasury T Bonds 10 Year	Utility Bonds Aaa [1]	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2007							
Jan	8.25%	4.96%	4.76%		5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%		5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%		5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%		5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%		5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%		6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%		6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%		6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%		6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%		6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%		5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%		6.03%	6.16%	6.51%
2008							
Jan	6.00%	2.86%	3.74%		5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%		6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%		5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%		5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%		6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%		6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%		6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%		6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%		6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%		6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%		6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%		5.93%	6.54%	8.13%
2009							
Jan	3.25%	0.12%	2.52%		6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%		6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%		6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%		6.20%	6.48%	8.03%
May	3.25%	0.15%	3.29%		6.23%	6.49%	7.76%
June	3.25%	0.17%	3.72%		6.13%	6.20%	7.30%
July	3.25%	0.19%	3.56%		5.63%	5.97%	6.87%
Aug	3.25%	0.18%	3.59%		5.33%	5.71%	6.36%
Sept	3.25%	0.13%	3.40%		5.15%	5.53%	6.12%
Oct	3.25%	0.08%	3.39%		5.23%	5.55%	6.14%
Nov	3.25%	0.05%	3.40%		5.33%	5.64%	6.18%
Dec	3.25%	0.07%	3.59%		5.52%	5.79%	6.26%
2010							
Jan	3.25%	0.06%	3.73%		5.55%	5.77%	6.16%
Feb	3.25%	0.10%	3.69%		5.69%	5.87%	6.25%
Mar	3.25%	0.15%	3.73%		5.64%	5.84%	6.22%
Apr	3.25%	0.15%	3.85%		5.62%	5.81%	6.19%
May	3.25%	0.16%	3.42%		5.29%	5.50%	5.97%
June	3.25%	0.12%	3.20%		5.22%	5.46%	6.18%
July	3.25%	0.16%	3.01%		4.99%	5.26%	5.98%
Aug	3.25%	0.15%	2.70%		4.75%	5.01%	5.55%
Sept	3.25%	0.15%	2.65%		4.74%	5.01%	5.53%
Oct	3.25%	0.13%	2.54%		4.89%	5.10%	5.62%
Nov	3.25%	0.13%	2.76%		5.12%	5.37%	5.85%
Dec	3.25%	0.15%	3.29%		5.32%	5.56%	6.04%
2011							
Jan	3.25%	0.15%	3.39%		5.29%	5.57%	6.06%
Feb	3.25%	0.14%	3.58%		5.42%	5.68%	6.10%
Mar	3.25%	0.11%	3.41%		5.33%	5.56%	5.97%
Apr	3.25%	0.06%	3.46%		5.32%	5.55%	5.98%
May	3.25%	0.04%	3.17%		5.08%	5.32%	5.74%
June	3.25%	0.04%	3.00%		5.04%	5.26%	5.67%
July	3.25%	0.03%	3.00%		5.05%	5.27%	5.70%
Aug	3.25%	0.05%	2.30%		4.44%	4.69%	5.22%
Sept	3.25%	0.02%	1.98%		4.24%	4.48%	5.11%
Oct	3.25%	0.02%	2.15%		4.21%	4.52%	5.24%
Nov	3.25%	0.01%	2.01%		3.92%	4.25%	4.93%
Dec	3.25%	0.02%	1.98%		4.00%	4.33%	5.07%
2012							
Jan	3.25%	0.02%	1.97%		4.03%	4.34%	5.06%
Feb	3.25%	0.08%	1.97%		4.02%	4.36%	5.02%
Mar	3.25%	0.09%	2.17%		4.16%	4.48%	5.13%
Apr	3.25%	0.08%	2.05%		4.10%	4.40%	5.11%
May	3.25%	0.09%	1.80%		3.92%	4.20%	4.97%
June	3.25%	0.09%	1.62%		3.79%	4.08%	4.91%
July	3.25%	0.10%	1.53%		3.58%	3.93%	4.85%
Aug	3.25%	0.11%	1.68%		3.65%	4.00%	4.88%
Sept	3.25%	0.10%	1.72%		3.69%	4.02%	4.81%
Oct	3.25%	0.10%	1.75%		3.68%	3.91%	4.54%
Nov	3.25%	0.11%	1.65%		3.60%	3.84%	4.42%
Dec	3.25%	0.08%	1.72%		3.75%	4.00%	4.56%
2013							
Jan	3.25%	0.07%	1.91%		3.90%	4.15%	4.66%
Feb	3.25%	0.10%	1.98%		3.95%	4.18%	4.74%
Mar	3.25%	0.90%	1.96%		3.90%	4.15%	4.66%
Apr	3.25%	0.60%	1.76%		3.74%	4.00%	4.49%
May	3.25%	0.50%	1.93%		3.91%	4.17%	4.65%

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

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

STOCK PRICE INDICATORS

	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	$599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	2,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		2002 - 2009 Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.54%
2009	948.05	1,845.38	8,876.15	2.40%	1.86%
		Current Cycle			
2010	1,139.97	2,349.89	10,662.80	1.98%	6.04%
2011	1,268.89	2,677.44	11,966.36	2.05%	6.77%
2012	1,379.35	2,965.56	12,967.08	2.24%	6.20%

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

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

STOCK PRICE INDICATORS

	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.55%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.05%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	0.86%
2nd Qtr.	892.23	1,731.41	8,327.83	2.45%	0.82%
3rd Qtr.	996.68	1,985.25	9,229.93	2.16%	1.19%
4th Qtr.	1,088.70	2,162.33	10,172.78	1.99%	4.57%
2010					
1st Qtr.	1,121.60	2,274.88	10,454.42	1.94%	5.21%
2nd Qtr.	1,135.25	2,343.40	10,570.54	1.97%	6.51%
3rd Qtr.	1,096.39	2,237.97	10,390.24	2.09%	6.30%
4th Qtr.	1,204.00	2,534.62	11,236.02	1.95%	6.15%
2011					
1st Qtr.	1,302.74	2,741.01	12,024.62	1.85%	6.13%
2nd Qtr.	1,319.04	2,766.64	12,370.73	1.97%	6.35%
3rd Qtr.	1,237.12	2,613.11	11,671.47	2.15%	7.69%
4th Qtr.	1,225.65	2,600.91	11,798.65	2.25%	6.91%
2012					
1st Qtr.	1,347.44	2,902.90	12,839.80	2.12%	6.29%
2nd Qtr.	1,350.39	2,928.62	12,765.58	2.30%	6.45%
3rd Qtr.	1,402.21	3,029.86	13,118.72	2.27%	6.00%
4th Qtr.	1,418.21	3,001.69	13,142.91	2.28%	6.07%
2013					
1st Qtr.	1,514.41	3,177.10	14,000.30	2.21%	5.59%

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

Exhibit___(DCP-1)
Schedule 3

UNS ENERGY CORPORATION
SEGMENT FINANCIAL INFORMATION
2010 - 2012
($millions)

Segment	Operating Revenues	Net Income	Total Assets
		2010	
Tucson Electric Power Co	$1,096	$108	
	76.9%	95.6%	#DIV/0!
UNS Gas	$144	$9	
	10.1%	8.0%	#DIV/0!
UNS Electric	$185	$15	
	13.0%	13.3%	#DIV/0!
Unisource Energy	$1,426	$113	
		2011	
Tucson Electric Power Co	$1,141	$85	$3,278
	77.1%	77.3%	82.2%
UNS Gas	$149	$10	$320
	10.1%	9.1%	8.0%
UNS Electric	$188	$18	$370
	12.7%	16.4%	9.3%
Unisource Energy	$1,479	$110	$3,989
		2012	
Tucson Electric Power Co	$1,145	$65	$3,461
	78.3%	71.4%	83.6%
UNS Gas	$129	$9	$310
	8.8%	9.9%	7.5%
UNS Electric	$189	$17	$370
	12.9%	18.7%	8.9%
Unisource Energy	$1,462	$91	$4,140

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

Source: UNS Energy Corporation, 2012 Form 10-K.

UNS ELECTRIC
CAPITAL STRUCTURE RATIOS
2004 - 2013
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$40,900	$60,000	$600
	40.3%	59.1%	0.6%
	40.5%	59.5%	
2005	$49,900	$60,000	$500
	45.2%	54.3%	0.5%
	45.4%	54.6%	
2006	$64,900	$79,000	$400
	45.0%	54.7%	0.3%
	45.1%	54.9%	
2007	$79,800	$86,000	$400
	48.0%	51.7%	0.2%
	48.1%	51.9%	
2008	$84,297	$108,000	$200
	43.8%	56.1%	0.1%
	43.8%	56.2%	
2009	$90,321	$100,000	$0
	47.5%	52.5%	0.0%
	47.5%	52.5%	
2010	$100,848	$100,000	$0
	50.2%	49.8%	0.0%
	50.2%	49.8%	
2011	$136,127	$130,000	$0
	51.2%	48.8%	0.0%
	51.2%	48.8%	
2012	$142,760	$130,000	$0
	52.3%	47.7%	0.0%
	52.3%	47.7%	
March 31, 2013	$145,069	$130,000	$5,000
	51.8%	46.4%	1.8%
	52.7%	47.3%	

Sources: Response to STF 1.4, information provided in prior rate proceedings.

UNS ENERGY CORP.
CAPITAL STRUCTURE RATIOS
2004 - 2013
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$581	$1,258	$0
	31.6%	68.4%	0.0%
	31.6%	68.4%	
2005	$617	$1,212	$5
	33.6%	66.1%	0.3%
	33.7%	66.3%	
2006	$654	$1,171	$50
	34.9%	62.5%	2.7%
	35.8%	64.2%	
2007	$690	$994	$10
	40.7%	58.7%	0.6%
	41.0%	59.0%	
2008	$679	$1,320	$10
	33.8%	65.7%	0.5%
	34.0%	66.0%	
2009	$751	$1,320	$35
	35.7%	62.7%	1.7%
	36.3%	63.7%	
2010	$831	$1,410	$0
	37.1%	62.9%	0.0%
	37.1%	62.9%	
2011	$888	$1,517	$10
	36.8%	62.8%	0.4%
	36.9%	63.1%	
2012	$1,065	$1,498	$0
	41.6%	58.4%	0.0%
	41.6%	58.4%	
March 31, 2013	$1,059	$1,504	$25
	40.9%	58.1%	1.0%
	41.3%	58.7%	

Sources: Response to STF 1.4, information provided in prior rate proceedings.

UNS ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
DECEMBER 31, 2012
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
UNS Energy	$1,065.5	$1,598.4	$0.0
consolidated	40.0%	60.0%	0.0%
	40.0%	60.0%	
UNS Gas	$92.2	$100.0	$0
	48.0%	52.0%	0.0%
	48.0%	52.0%	
UNS Electric	$142.8	$130.0	$0
	52.3%	47.7%	0.0%
	52.3%	47.7%	
TEP	$860.9	$1,223.4	$0.0
	41.3%	58.7%	0.0%
	41.3%	58.7%	

Source: Response to STF 1.4.

PROXY GROUPS
COMMON EQUITY RATIOS

COMPANY	2008	2009	2010	2011	2012	Average	2014-2016
Parcell Proxy Group							
Cleco Corp	48.9%	45.8%	48.5%	51.5%	54.4%	49.8%	60.0%
El Paso Electric Co.	46.2%	47.3%	48.8%	48.2%	45.2%	47.1%	42.0%
Great Plains Energy, Inc.	49.6%	46.2%	49.2%	51.6%	54.4%	50.2%	55.0%
Hawaiian Electric	52.7%	50.7%	54.3%	53.9%	53.1%	52.9%	51.5%
Otter Tail Corp	65.6%	59.8%	58.4%	54.0%	54.4%	58.4%	54.0%
Pepco Holdings	43.8%	46.2%	51.0%	50.9%	52.7%	48.9%	50.0%
PNM Resources	54.0%	51.0%	49.2%	48.1%	48.7%	50.2%	49.0%
UIL Holdings	46.4%	46.0%	41.6%	41.4%	41.1%	43.3%	45.5%
Average	50.9%	49.1%	50.1%	50.0%	50.5%	50.1%	50.9%
Bulkley Proxy Group							
ALLETE	58.4%	57.2%	55.8%	55.7%	56.3%	56.7%	57.5%
American Electric Power Xo,	40.7%	45.4%	46.7%	49.3%	49.4%	46.3%	54.5%
Cleco Corp	48.9%	45.8%	48.5%	51.5%	54.4%	49.8%	60.0%
Empire District Electric	46.4%	48.4%	48.7%	50.1%	50.9%	48.9%	51.0%
First Energy Corp	47.7%	41.8%	40.5%	45.8%	46.3%	44.4%	44.5%
Great Plains Energy, Inc.	49.6%	46.2%	49.2%	51.6%	54.4%	50.2%	55.0%
Hawaiian Electric Industries, Inc	52.7%	50.7%	54.3%	53.9%	53.1%	52.9%	51.5%
IDACORP, Inc.	52.4%	49.8%	50.7%	54.4%	54.5%	52.4%	54.0%
Otter Tail Corp	65.6%	59.8%	58.4%	54.0%	54.4%	58.4%	54.0%
Pepco Holdings, Inc.	43.8%	46.2%	51.0%	50.9%	52.7%	48.9%	50.0%
Pinnacle West Capital Corp	53.2%	49.6%	54.7%	55.9%	55.4%	53.8%	59.5%
Portland General Electric	53.8%	49.7%	47.0%	50.4%	52.9%	50.8%	52.0%
Southern Company	42.6%	43.6%	45.7%	47.1%	47.3%	45.3%	44.5%
Westar Energy	49.7%	46.1%	46.0%	50.1%	48.8%	48.1%	50.0%
Average	50.4%	48.6%	49.8%	51.5%	52.2%	50.5%	52.7%

Source: Value Line.

Exhibit___(DCP-1)
Schedule 6

PROXY COMPANIES
BASIS FOR SELECTION

Company	Market Capitalization ($ millions)	Percent Reg Electric Revenues	Common Equity Ratio	Value Line Safety	S&P Bond Rating	Moody's Bond Rating
UNS Energy	$2,100,000	91%	38%	3	BBB-	Baa2
Parcell Proxy Group						
Cleco Corp	$2,700,000	95%	54%	1	BBB	Baa2
El Paso Electric Co.	$1,400,000	100%	45%	2	BBB	Baa2
Great Plains Energy, Inc.	$3,500,000	100%	54%	3	BBB/BBB-	Baa1/Baa2
Hawaiian Electric	$2,700,000	92%	53%	2	BBB-	Baa2
Otter Tail Corp	$1,100,000	71%	54%	3	BBB-/BB+	Baa2
Pepco Holdings	$4,500,000	83%	51%	3	A-/BBB+	Baa1/Baa2
PNM Resources	$1,900,000	100%	49%	3	BBB	Baa1/Baa2
UIL Holdings	$1,900,000	53%	42%	2	BBB	Baa2
Bulkley Proxy Group						
ALLETE	$1,900,000	91%	56%	2	A-	A2
American Electric Power Xo,	$23,000,000	92%	49%	3	BBB	Baa2
Cleco Corp	$2,700,000	95%	54%	1	BBB	Baa2
Empire District Electric	$925,000	92%	51%	2	A-	A3
First Energy Corp	$17,000,000	63%	46%	3	BBB	Baa2
Great Plains Energy, Inc.	$3,500,000	100%	54%	3	BBB/BBB-	Baa1/Baa2
Hawaiian Electric Industries, Inc.	$2,700,000	92%	53%	2	BBB-	Baa2
IDACORP, Inc.	$2,400,000	100%	55%	3	A-	A2
Otter Tail Corp	$1,100,000	71%	54%	3	BBB-/BB+	Baa2
Pepco Holdings, Inc.	$4,500,000	83%	51%	3	A-/BBB+	Baa1/Baa2
Pinnacle West Capital Corp	$6,600,000	100%	55%	1	BBB+	Baa1
Portland General Electric	$2,400,000	100%	53%	2	A-	A3
Southern Company	$39,000,000	95%	46%	1	A	A2/A3
Westar Energy	$4,000,000	100%	49%	2	BBB+	A3

Sources: AUS Utility Reports, Value Line.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	Qtr DPS	March - May, 2013 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group						
Cleco Corp	$0.36	$1.45	$49.52	$43.57	$46.55	3.1%
El Paso Electric Co.	$0.25	$1.00	$38.91	$32.47	$35.69	2.8%
Great Plains Energy, Inc.	$0.22	$0.87	$24.44	$21.59	$23.02	3.8%
Hawaiian Electric	$0.31	$1.24	$28.30	$26.06	$27.18	4.6%
Otter Tail Corp	$0.30	$1.19	$31.70	$27.09	$29.40	4.0%
Pepco Holdings	$0.27	$1.08	$22.72	$20.10	$21.41	5.0%
PNM Resources	$0.17	$0.66	$24.01	$21.77	$22.89	2.9%
UIL Holdings	$0.43	$1.73	$42.14	$38.35	$40.25	4.3%
Average						**3.8%**
Bulkley Proxy Group						
ALLETE	$0.48	$1.90	$52.25	$46.56	$49.41	3.8%
American Electric Power Xo,	$0.49	$1.96	$51.60	$45.57	$48.59	4.0%
Cleco Corp	$0.36	$1.45	$49.52	$43.57	$46.55	3.1%
Empire District Electric	$0.25	$1.00	$23.35	$21.19	$22.27	4.5%
First Energy Corp	$0.55	$2.20	$46.77	$38.83	$42.80	5.1%
Great Plains Energy, Inc.	$0.22	$0.87	$24.44	$21.59	$23.02	3.8%
Hawaiian Electric Industries, Inc.	$0.31	$1.24	$28.30	$26.06	$27.18	4.6%
IDACORP, Inc.	$0.38	$1.52	$50.16	$46.09	$48.13	3.2%
Otter Tail Corp	$0.30	$1.19	$31.70	$27.09	$29.40	4.0%
Pepco Holdings, Inc.	$0.27	$1.08	$22.72	$20.10	$21.41	5.0%
Pinnacle West Capital Corp	$0.55	$2.18	$61.89	$55.56	$58.73	3.7%
Portland General Electric	$0.27	$1.08	$32.91	$29.43	$31.17	3.5%
Southern Company	$0.51	$2.03	$48.74	$43.71	$46.23	4.4%
Westar Energy	$0.34	$1.36	$34.96	$31.01	$32.99	4.1%
Average						**4.1%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2008	2009	2010	2011	2012	Average	2013	2014	2016-'18	Average
Parcell Proxy Group										
Cleco Corp	4.5%	4.7%	6.1%	6.3%	5.5%	5.4%	4.5%	4.5%	5.0%	4.7%
El Paso Electric Co.	11.2%	9.3%	11.1%	10.0%	6.3%	9.6%	6.0%	5.5%	5.5%	5.7%
Great Plains Energy, Inc.	0.0%	0.9%	3.4%	2.0%	2.2%	1.7%	3.0%	2.5%	3.0%	2.8%
Hawaiian Electric	0.5%	0.0%	1.4%	2.1%	4.2%	1.6%	2.0%	2.5%	2.5%	2.3%
Otter Tail Corp	0.0%	0.0%	0.0%	0.0%	0.0%		1.0%	1.5%	3.0%	1.8%
Pepco Holdings	4.2%	0.0%	0.8%	0.3%	0.8%	1.2%	0.5%	1.0%	2.5%	1.3%
PNM Resources	0.0%	0.4%	2.2%	3.3%	3.8%	1.9%	3.5%	3.5%	4.0%	3.7%
UIL Holdings	1.0%	1.2%	1.7%	1.1%	1.5%	1.3%	2.0%	2.5%	3.0%	2.5%
Average						**3.3%**				**3.1%**
Bulkley Proxy Group										
ALLETE	3.9%	0.5%	1.5%	2.9%	2.3%	2.2%	2.0%	2.5%	4.0%	2.8%
American Electric Power Xo,	5.1%	4.6%	3.1%	4.2%	3.5%	4.1%	3.5%	4.0%	4.0%	3.8%
Cleco Corp	4.5%	4.7%	6.1%	6.3%	5.5%	5.4%	4.5%	4.5%	5.0%	4.7%
Empire District Electric	0.0%	0.0%	0.0%	4.1%	1.9%	1.2%	2.5%	2.5%	3.0%	2.7%
First Energy Corp	8.1%	4.0%	3.8%	0.0%	0.0%	3.2%	1.5%	2.0%	2.5%	2.0%
Great Plains Energy, Inc.	0.0%	0.9%	3.4%	2.0%	2.2%	1.7%	3.0%	2.5%	3.0%	2.8%
Hawaiian Electric Industries, Inc.	0.5%	0.0%	1.4%	2.1%	4.2%	1.6%	2.0%	2.5%	2.5%	2.3%
IDACORP, Inc.	3.4%	4.8%	5.5%	6.5%	5.7%	5.2%	4.5%	4.5%	4.0%	4.3%
Otter Tail Corp	0.0%	0.0%	0.0%	0.0%	0.0%		1.0%	1.5%	3.0%	1.8%
Pepco Holdings, Inc.	4.2%	0.0%	0.8%	0.3%	0.8%	1.2%	0.5%	1.0%	2.5%	1.3%
Pinnacle West Capital Corp	0.3%	0.7%	3.1%	2.8%	4.1%	2.2%	3.5%	3.5%	3.5%	3.5%
Portland General Electric	2.0%	1.5%	3.0%	4.1%	3.5%	2.8%	3.5%	3.5%	3.5%	3.5%
Southern Company	3.5%	3.2%	3.0%	3.4%	3.6%	3.3%	3.5%	3.5%	4.0%	3.7%
Westar Energy	1.2%	0.8%	3.1%	2.7%	4.0%	2.4%	3.0%	3.0%	4.0%	3.3%
Average						**2.8%**				**3.0%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates EPS	DPS	BVPS	Average	Est'd '10-'12 to '16-'18 Growth Rates EPS	DPS	BVPS	Average
Parcell Proxy Group								
Cleco Corp	10.0%	2.0%	10.0%	7.3%	7.0%	10.5%	5.5%	7.7%
El Paso Electric Co.	13.0%		8.5%	10.8%	3.0%	nmf	5.0%	4.0%
Great Plains Energy, Inc.	-6.0%	-12.5%	5.0%	-4.5%	6.5%	6.0%	2.5%	5.0%
Hawaiian Electric	2.0%		2.0%	2.0%	5.5%	2.0%	4.5%	4.0%
Otter Tail Corp	-18.5%	0.5%	-1.0%	-6.3%	20.0%	1.5%	2.0%	7.8%
Pepco Holdings	-4.5%	1.5%	0.5%	-0.8%	6.0%	1.0%	2.0%	3.0%
PNM Resources	-4.0%	-9.0%	-1.0%	-4.7%	12.0%	12.5%	4.0%	9.5%
UIL Holdings	3.5%		2.0%	2.8%	4.0%	0.0%	4.5%	2.8%
Average				**0.8%**				**5.5%**
Bulkley Proxy Group								
ALLETE	-2.5%	4.5%	5.5%	2.5%	7.0%	3.5%	4.0%	4.8%
American Electric Power Xo,	1.0%	4.0%	4.5%	3.2%	4.5%	4.0%	4.0%	4.2%
Cleco Corp	10.0%	2.0%	10.0%	7.3%	7.0%	10.5%	5.5%	7.7%
Empire District Electric	2.0%	-5.5%	1.0%	-0.8%	5.5%	3.5%	2.5%	3.8%
First Energy Corp	-8.0%	3.5%	1.0%	-1.2%	3.5%	0.0%	2.5%	2.0%
Great Plains Energy, Inc.	-6.0%	-12.5%	5.0%	-4.5%	6.5%	6.0%	2.5%	5.0%
Hawaiian Electric Industries, Inc.	2.0%		2.0%	2.0%	5.5%	2.0%	4.5%	4.0%
IDACORP, Inc.	10.0%	1.0%	5.5%	5.5%	2.0%	7.0%	4.5%	4.5%
Otter Tail Corp	-18.5%	0.5%	-1.0%	-6.3%	20.0%	1.5%	2.0%	7.8%
Pepco Holdings, Inc.	-4.5%	1.5%	0.5%	-0.8%	6.0%	1.0%	2.0%	3.0%
Pinnacle West Capital Corp	2.5%	2.5%		2.5%	5.0%	2.0%	3.5%	3.5%
Portland General Electric	4.0%	14.5%	2.0%	6.8%	3.5%	3.5%	3.5%	3.5%
Southern Company	3.0%	4.0%	5.5%	4.2%	4.5%	3.5%	4.0%	4.0%
Westar Energy	1.5%	5.0%	4.5%	3.7%	5.0%	3.0%	4.0%	4.0%
Average				**1.7%**				**4.4%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
Cleco Corp	3.2%	5.4%	4.7%	7.3%	7.7%	8.0%	6.6%	9.8%
El Paso Electric Co.	2.9%	9.6%	5.7%	10.8%	4.0%	3.7%	6.7%	9.6%
Great Plains Energy, Inc.	3.8%	1.7%	2.8%		5.0%	6.3%	3.9%	7.8%
Hawaiian Electric	4.6%	1.6%	2.3%	2.0%	4.0%	3.3%	2.7%	7.3%
Otter Tail Corp	4.1%		1.8%		7.8%	6.0%	5.2%	9.4%
Pepco Holdings	5.1%	1.2%	1.3%		3.0%	4.8%	2.6%	7.7%
PNM Resources	3.0%	1.9%	3.7%		9.5%	6.2%	5.3%	8.3%
UIL Holdings	4.4%	1.3%	2.5%	2.8%	2.8%	8.6%	3.6%	8.0%
Mean	3.9%	3.3%	3.1%	5.7%	5.5%	5.8%	4.6%	**8.5%**
Median	4.0%	1.7%	2.7%	5.0%	4.5%	6.1%	4.6%	**8.1%**
Composite - Mean		7.2%	**7.0%**	9.6%	9.4%	**9.7%**	8.5%	
Composite - Median		**5.7%**	6.7%	9.0%	8.5%	**10.1%**	8.6%	
Bulkley Proxy Group								
ALLETE	3.9%	2.2%	2.8%	2.5%	4.8%	6.0%	3.7%	7.6%
American Electric Power Xo,	4.1%	4.1%	3.8%	3.2%	4.2%	3.6%	3.8%	7.9%
Cleco Corp	3.2%	5.4%	4.7%	7.3%	7.7%	8.0%	6.6%	9.8%
Empire District Electric	4.6%	1.2%	2.7%		3.8%	3.0%	2.7%	7.2%
First Energy Corp	5.2%	3.2%	2.0%		2.0%	2.9%	2.5%	7.7%
Great Plains Energy, Inc.	3.8%	1.7%	2.8%		5.0%	6.3%	3.9%	7.8%
Hawaiian Electric Industries, Inc.	4.6%	1.6%	2.3%	2.0%	4.0%	3.3%	2.7%	7.3%
IDACORP, Inc.	3.2%	5.2%	4.3%	5.5%	4.5%	4.0%	4.7%	7.9%
Otter Tail Corp	4.1%		1.8%		7.8%	6.0%	5.2%	9.4%
Pepco Holdings, Inc.	5.1%	1.2%	1.3%		3.0%	4.8%	2.6%	7.7%
Pinnacle West Capital Corp	3.8%	2.2%	3.5%	2.5%	3.5%	6.0%	3.5%	7.3%
Portland General Electric	3.5%	2.8%	3.5%	6.8%	3.5%	4.8%	4.3%	7.8%
Southern Company	4.5%	3.3%	3.7%	4.2%	4.0%	4.8%	4.0%	8.5%
Westar Energy	4.2%	2.4%	3.3%	3.7%	4.0%	4.8%	3.6%	7.8%
Mean	4.1%	2.8%	3.0%	4.2%	4.4%	4.9%	3.8%	**8.0%**
Median	4.1%	2.4%	3.1%	3.7%	4.0%	4.8%	3.7%	**7.8%**
Composite - Mean		**7.0%**	7.2%	8.3%	8.6%	**9.0%**	8.0%	
Composite - Median		**6.5%**	7.2%	7.8%	8.1%	**8.9%**	7.9%	

Note: negative values not used in calculations.

Sources: Prior pages of this schedule.

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

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.49%	4.86%	7.63%
2008	$14.88	$451.37	3.03%	4.45%	-1.42%
2009	$50.97	$513.58	10.56%	3.47%	7.09%
2010	$77.35	$579.14	14.16%	4.25%	9.91%
2011	$86.58	$613.14	14.52%	3.81%	10.71%
Average					**6.46%**

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

Exhibit___(DCP-1)
Schedule 9

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
Cleco Corp	2.69%	0.65	5.42%	6.2%
El Paso Electric Co.	2.69%	0.70	5.42%	6.5%
Great Plains Energy, Inc.	2.69%	0.75	5.42%	6.8%
Hawaiian Electric	2.69%	0.70	5.42%	6.5%
Otter Tail Corp	2.69%	0.90	5.42%	7.6%
Pepco Holdings	2.69%	0.75	5.42%	6.8%
PNM Resources	2.69%	0.95	5.42%	7.8%
UIL Holdings	2.69%	0.70	5.42%	6.5%
Mean				**6.8%**
Median				**6.6%**
Bulkley Proxy Group				
ALLETE	2.69%	0.70	5.42%	6.5%
American Electric Power Xo,	2.69%	0.65	5.42%	6.2%
Cleco Corp	2.69%	0.65	5.42%	6.2%
Empire District Electric	2.69%	0.65	5.42%	6.2%
First Energy Corp	2.69%	0.75	5.42%	6.8%
Great Plains Energy, Inc.	2.69%	0.75	5.42%	6.8%
Hawaiian Electric Industries, Inc.	2.69%	0.70	5.42%	6.5%
IDACORP, Inc.	2.69%	0.70	5.42%	6.5%
Otter Tail Corp	2.69%	0.90	5.42%	7.6%
Pepco Holdings, Inc.	2.69%	0.75	5.42%	6.8%
Pinnacle West Capital Corp	2.69%	0.70	5.42%	6.5%
Portland General Electric	2.69%	0.75	5.42%	6.8%
Southern Company	2.69%	0.55	5.42%	5.7%
Westar Energy	2.69%	0.70	5.42%	6.5%
Mean				**6.5%**
Median				**6.5%**

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

20-year Treasury Bonds	
Month	Rate
March, 2013	2.78%
April, 2013	2.55%
May, 2013	2.73%
Average	2.69%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	1992-2001 Average	2002-2008 Average	2009-2012 Average	2013	2014	2016-18
Parcell Proxy Group																											
Cleco Corp	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.4%	8.2%	9.9%	9.7%	11.4%	11.4%	11.2%	13.4%	11.0%	10.9%	10.0%	10.5%	11.0%
El Paso Electric Co.					9.9%	10.5%	10.7%	12.0%	14.1%	14.9%	6.3%	6.5%	6.3%	6.7%	10.5%	11.9%	11.4%	9.4%	11.7%	13.0%	11.4%	12.0%	8.5%	11.4%	11.0%	10.5%	10.5%
Great Plains Energy, Inc.	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	12.4%	11.6%	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	11.6%	12.7%	6.1%	6.5%	7.0%	8.0%
Hawaiian Electric	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	5.9%	7.7%	9.1%	10.4%	11.0%	9.4%	8.3%	9.5%	9.0%	9.0%
Otter Tail Corp	15.0%	15.0%	15.1%	14.7%	14.7%	14.7%	14.0%	14.7%	15.1%	15.1%	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	14.8%	10.9%	3.9%	9.0%	9.0%	10.5%
Pepco Holdings	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	5.5%	6.5%	6.0%	6.5%	11.0%	8.4%	6.1%	6.0%	6.5%	8.0%
PNM Resources	4.6%	8.6%	11.7%	8.5%	9.9%	10.0%	11.3%	9.1%	10.2%	15.8%	6.3%	6.7%	7.9%	8.6%	8.4%	3.4%	0.5%	3.1%	4.8%	5.8%	6.6%	10.0%	6.0%	5.1%	7.0%	7.0%	8.5%
UIL Holdings	9.2%	10.4%	10.5%	11.8%	10.1%	10.4%	9.5%	11.6%	12.8%	12.1%	8.9%	6.1%	7.1%	5.7%	9.1%	10.1%	10.1%	10.2%	9.8%	9.1%	9.4%	10.8%	8.2%	9.6%	9.5%	9.5%	9.0%
Average	10.6%	11.6%	12.0%	11.9%	11.5%	11.4%	11.8%	11.5%	12.3%	13.6%	10.9%	9.8%	9.9%	9.5%	9.3%	8.8%	7.6%	6.6%	7.7%	7.9%	8.6%	11.8%	9.4%	7.7%	8.6%	8.6%	9.3%
Median	10.6%	12.0%	11.7%	11.8%	11.1%	10.7%	11.4%	11.7%	12.6%	13.5%	10.9%	9.4%	8.6%	9.2%	9.4%	9.2%	8.5%	5.7%	7.5%	7.6%	8.2%	11.7%	9.3%	7.2%	9.3%	9.0%	9.0%
Bulkley Proxy Group																											
ALLETE													12.7%	12.0%	13.2%	13.4%	11.4%	7.3%	8.2%	9.5%	8.7%		12.5%	8.4%	8.0%	8.5%	10.0%
American Electric Power Xo,	11.1%	11.9%	12.0%	12.4%	13.2%	13.5%	11.3%	10.5%	4.1%	12.9%	12.3%	12.4%	12.7%	11.9%	12.2%	11.7%	11.6%	11.0%	9.3%	10.7%	9.7%	11.3%	12.1%	10.2%	9.5%	10.0%	10.0%
Cleco Corp	14.0%	12.4%	12.9%	13.4%	13.8%	12.8%	12.6%	12.9%	15.0%	14.6%	13.5%	11.5%	12.6%	11.6%	9.4%	8.2%	9.9%	9.7%	11.4%	11.4%	11.2%	13.4%	11.0%	10.9%	10.0%	10.5%	11.0%
Empire District Electric	10.3%	9.4%	10.6%	9.4%	9.6%	9.9%	11.6%	8.4%	10.0%	4.3%	8.4%	8.7%	5.7%	6.2%	9.2%	6.9%	7.4%	7.5%	7.4%	8.1%	7.9%	9.4%	7.5%	7.7%	8.0%	8.0%	9.0%
First Energy Corp	10.9%	11.9%	13.2%	13.2%	13.0%	11.3%	10.6%	13.0%	13.3%	12.5%	10.4%	6.0%	10.8%	10.5%	13.6%	14.6%	15.5%	12.0%	11.6%	6.3%	9.8%	12.3%	11.6%	9.9%	8.5%	9.0%	8.5%
Great Plains Energy, Inc.	9.8%	12.0%	11.7%	13.4%	11.6%	11.7%	13.2%	8.9%	12.4%	11.6%	15.6%	16.6%	16.9%	13.7%	9.8%	10.6%	5.9%	4.9%	7.3%	5.8%	6.2%	11.6%	12.7%	6.1%	6.5%	7.0%	8.0%
Hawaiian Electric Industries, Inc.	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	7.0%	5.9%	7.7%	9.1%	10.4%	11.0%	9.4%	8.3%	9.5%	9.0%	9.0%
IDACORP, Inc.	9.0%	11.2%	10.1%	11.6%	12.1%	12.4%	12.4%	12.3%	16.7%	14.9%	7.1%	4.2%	8.2%	7.3%	9.4%	7.1%	8.0%	9.3%	9.8%	10.5%	9.9%	12.3%	7.3%	9.9%	9.0%	8.5%	8.5%
Otter Tail Corp	15.0%	15.0%	15.1%	14.7%	14.7%	14.7%	14.0%	14.7%	15.1%	15.1%	15.2%	12.0%	10.8%	11.6%	10.4%	10.4%	5.9%	3.7%	2.1%	2.7%	6.9%	14.8%	10.9%	3.9%	9.0%	9.0%	10.5%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.9%	5.5%	6.5%	6.0%	6.5%	11.0%	8.4%	6.1%	6.0%	6.5%	8.0%
Pinnacle West Capital Corp	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	6.1%	6.8%	9.3%	8.7%	9.8%	11.5%	7.9%	8.7%	9.5%	9.5%	10.0%
Portland General Electric	12.9%	12.0%	11.3%	13.4%	13.9%										5.9%	11.5%	6.5%	6.2%	8.0%	9.0%	8.3%	12.7%	8.0%	7.9%	8.0%	8.0%	8.0%
Southern Company	13.4%	13.4%	12.4%	13.0%	12.6%	11.4%	12.3%	13.1%	13.6%	11.9%	15.7%	15.6%	15.2%	15.0%	14.2%	14.5%	13.5%	13.2%	12.6%	12.9%	13.0%	12.7%	14.8%	12.9%	13.0%	13.0%	12.5%
Westar Energy	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.7%	6.3%	8.6%	8.2%	9.5%	6.7%	8.7%	8.2%	8.5%	9.0%	9.0%
Average	11.5%	11.9%	11.7%	12.1%	12.2%	10.8%	11.6%	11.2%	11.2%	11.1%	11.1%	10.4%	10.7%	10.3%	10.3%	10.2%	9.0%	7.8%	8.6%	8.5%	9.1%	11.6%	10.2%	8.5%	8.8%	9.0%	9.4%
Median	10.9%	12.0%	11.3%	12.4%	12.1%	11.6%	11.6%	12.0%	12.4%	12.5%	11.2%	10.9%	10.8%	10.5%	9.6%	10.2%	7.7%	7.1%	8.4%	8.9%	9.6%	11.9%	10.1%	8.5%	8.8%	9.0%	9.0%

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

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	1992-2001 Average	2002-2008 Average	2009-2012 Average
Parcell Proxy Group																								
Cleco Corp	177%	175%	156%	162%	167%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	132%	129%	139%	151%	169%	181%	157%	147%
El Paso Electric Co.					109%	115%	129%	118%	153%	161%	140%	120%	148%	176%	179%	179%	134%	102%	134%	164%	163%	131%	154%	141%
Great Plains Energy, Inc.	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	189%	181%	173%	113%	73%	87%	89%	97%	178%	176%	87%
Hawaiian Electric	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	113%	140%	150%	164%	147%	170%	142%
Otter Tail Corp	116%	120%	207%	213%	209%	195%	198%	201%	221%	243%	245%	209%	185%	183%	178%	200%	167%	108%	120%	123%	152%	192%	195%	126%
Pepco Holdings	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	92%	98%	100%	150%	118%	91%
PNM Resources	72%	84%	87%	95%	108%	106%	106%	85%	94%	123%	95%	93%	124%	147%	134%	125%	72%	50%	68%	86%	100%	96%	113%	76%
UIL Holdings	123%	157%	127%	123%	114%	111%	151%	144%	141%	139%	126%	113%	133%	135%	174%	189%	168%	127%	136%	150%	161%	133%	148%	144%
Average	140%	146%	143%	150%	150%	149%	161%	150%	159%	168%	148%	140%	159%	164%	166%	167%	133%	97%	115%	126%	138%	**151%**	**154%**	**119%**
Median	160%	157%	141%	149%	154%	149%	158%	155%	147%	153%	147%	127%	163%	177%	176%	170%	133%	105%	127%	137%	157%	**152%**	**156%**	**131%**
Bulkley Proxy Group																								
ALLETE													322%	212%	219%	195%	156%	113%	127%	138%	136%		221%	129%
American Electric Power Xo,	143%	159%	143%	156%	176%	187%	191%	154%	147%	179%	138%	124%	155%	165%	161%	190%	145%	112%	118%	128%	134%	164%	154%	123%
Cleco Corp	177%	175%	156%	162%	167%	171%	183%	172%	223%	224%	154%	134%	177%	177%	162%	162%	132%	129%	139%	151%	169%	181%	157%	147%
Empire District Electric	184%	178%	143%	142%	143%	138%	168%	177%	183%	162%	132%	133%	144%	148%	149%	150%	122%	100%	127%	128%	124%	162%	140%	120%
First Energy Corp	137%	154%	131%	137%	137%	140%	166%	144%	124%	136%	131%	132%	154%	169%	195%	230%	221%	161%	145%	138%	142%	141%	176%	147%
Great Plains Energy, Inc.	160%	173%	151%	168%	181%	198%	209%	178%	173%	185%	163%	198%	218%	189%	181%	173%	113%	73%	87%	89%	97%	178%	176%	87%
Hawaiian Electric Industries, Inc.	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166%	166%	113%	140%	150%	164%	147%	170%	142%
IDACORP, Inc.	155%	172%	146%	148%	168%	177%	177%	158%	189%	185%	134%	112%	125%	122%	139%	132%	104%	94%	113%	119%	123%	168%	124%	112%
Otter Tail Corp	116%	120%	207%	213%	209%	195%	198%	201%	221%	243%	245%	209%	185%	183%	178%	200%	167%	108%	120%	123%	152%	192%	195%	126%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141%	115%	75%	92%	98%	100%	150%	118%	91%
Pinnacle West Capital Corp	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127%	100%	90%	113%	125%	141%	136%	121%	117%
Portland General Electric	115%	125%	112%	140%	199%										153%	140%	101%	83%	97%	109%	117%	138%	131%	102%
Southern Company	154%	180%	161%	174%	176%	167%	198%	186%	188%	209%	230%	233%	227%	238%	229%	230%	211%	182%	186%	208%	219%	179%	228%	199%
Westar Energy	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	140%	107%	91%	111%	119%	133%	118%	119%	114%
Average	149%	156%	143%	152%	163%	163%	176%	158%	161%	169%	148%	146%	174%	168%	168%	170%	140%	109%	123%	130%	139%	**158%**	**159%**	**125%**
Median	154%	159%	143%	148%	167%	160%	179%	162%	160%	171%	136%	133%	155%	169%	162%	164%	127%	104%	119%	127%	135%	**160%**	**149%**	**121%**

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

Exhibit___(DCP-1)
Schedule 11

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2011

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
2008	3.0%	224%
2009	10.6%	187%
2010	14.2%	208%
2011	14.6%	208%
Averages:		
1992-2001	14.7%	341%
2002-2008	12.4%	275%
2009-2011	13.1%	201%

Source: Standard & Poor's Analyst's Handbook, 2012 edition, page 1.

RISK INDICATORS

COMPANY	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FINANCIAL STRENGTH		S& P STOCK RANKING	
Parcell Proxy Group						
Cleco Corp	1	0.65	A	4.00	B	3.00
El Paso Electric Co.	2	0.70	B++	3.67	B	3.00
Great Plains Energy, Inc.	3	0.75	B+	3.33	B	3.00
Hawaiian Electric	2	0.70	B++	3.67	B	3.00
Otter Tail Corp	3	0.90	B+	3.33	B	3.00
Pepco Holdings	3	0.75	B	3.00	B	3.00
PNM Resources	3	0.95	B	3.00	B	3.00
UIL Holdings	2	0.70	B++	3.67	B	3.00
	2.4	0.76	B+	3.46	B	3.00
Bulkley Proxy Group						
ALLETE	2	0.70	A	4.00	B	3.00
American Electric Power Xo,	3	0.65	B++	3.67	B	3.00
Cleco Corp	1	0.65	A	4	B	3
Empire District Electric	2	0.65	B++	3.67	B+	3.33
First Energy Corp	3	0.75	B+	3.33	B+	3.33
Great Plains Energy, Inc.	3	0.75	B+	3.33	B	3
Hawaiian Electric Industries, Inc.	2	0.70	B++	3.67	B	3
IDACORP, Inc.	3	0.70	B+	3.33	B+	3.33
Otter Tail Corp	3	0.90	B+	3.33	B	3
Pepco Holdings, Inc.	3	0.75	B	3	B	3
Pinnacle West Capital Corp	1	0.70	A	4.00	B	3.00
Portland General Electric	2	0.75	B++	3.67	NR	
Southern Company	1	0.55	A	4.00	A-	3.67
Westar Energy	2	0.70	B++	3.67	B+	3.33
Average	2.2	0.71	B++	3.62	B+	3.15

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.4	0.76	B+	B
Bulkley Proxy Group	2.2	0.71	B++	B+

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

Definitions:

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

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

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

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

I)

Exhibit___(DCP-1)
Schedule 13

UNS ELECTRIC INC
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	47.40%	5.97%	2.83%	2.83%	
Common Equity	52.60%	9.25%	4.87%	8.11%	
Total	100.00%		7.70%	10.94%	1/

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

Pre-Tax coverage = **3.87** =10.94% /2.83%

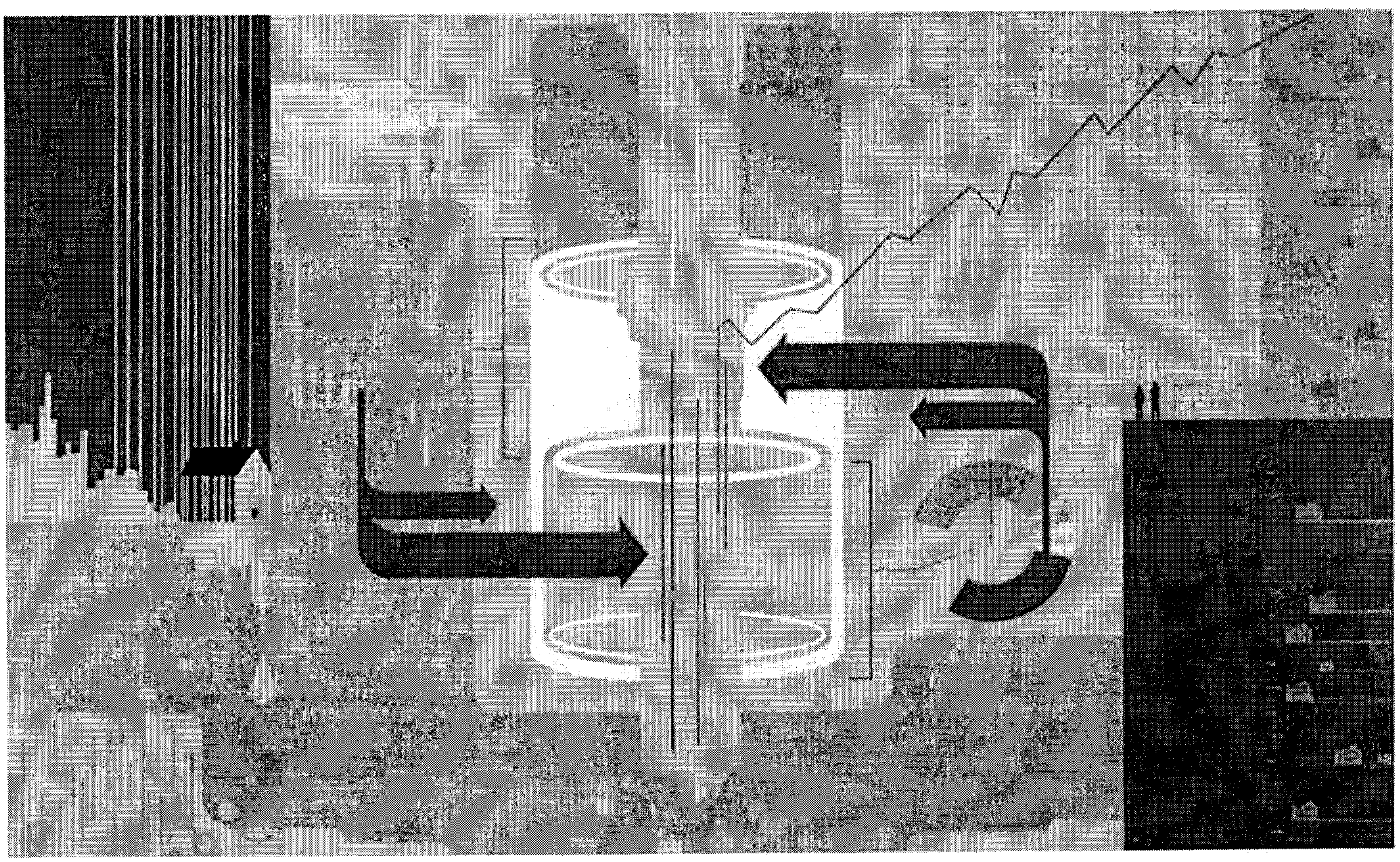
Standard & Poor's Utility Benchmark Ratios: Business Profile of "4"	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%

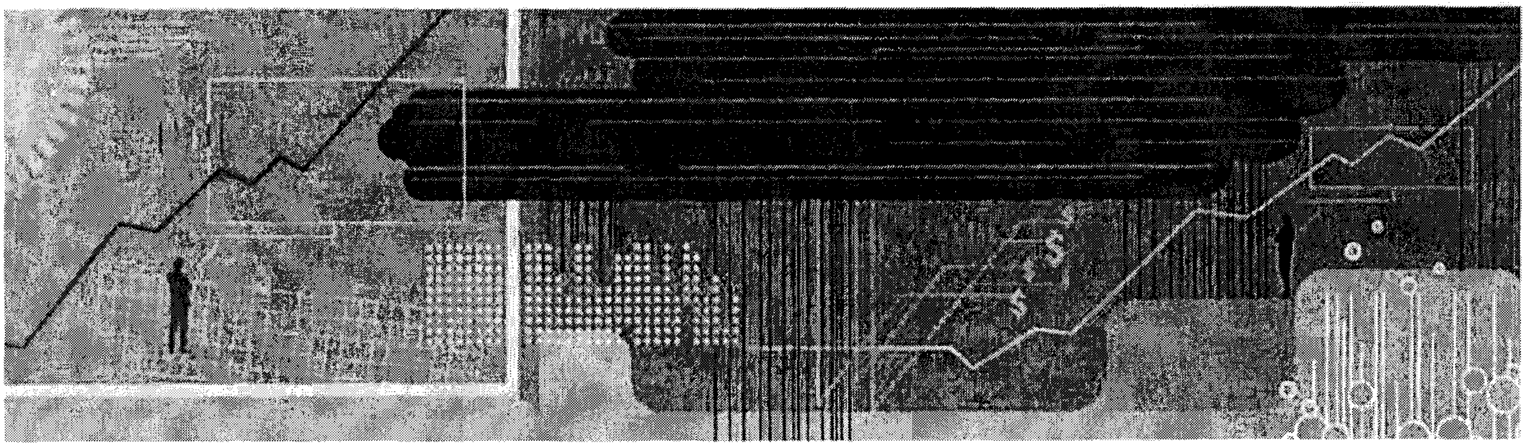
Exhibit ___(DCP-1)
Schedule 14
Page 1 of 5

McKinsey on Finance

Number 35,
Spring 2010

Perspectives on Corporate Finance and Strategy





Equity analysts: Still too bullish

After almost a decade of stricter regulation, analysts' earnings forecasts continue to be excessively optimistic.

Marc H. Goedhart, Rishi Raj, and Abhishek Saxena

No executive would dispute that analysts' forecasts serve as an important benchmark of the current and future health of companies. To better understand their accuracy, we undertook research nearly a decade ago that produced sobering results. Analysts, we found, were typically overoptimistic, slow to revise their forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined.[1]

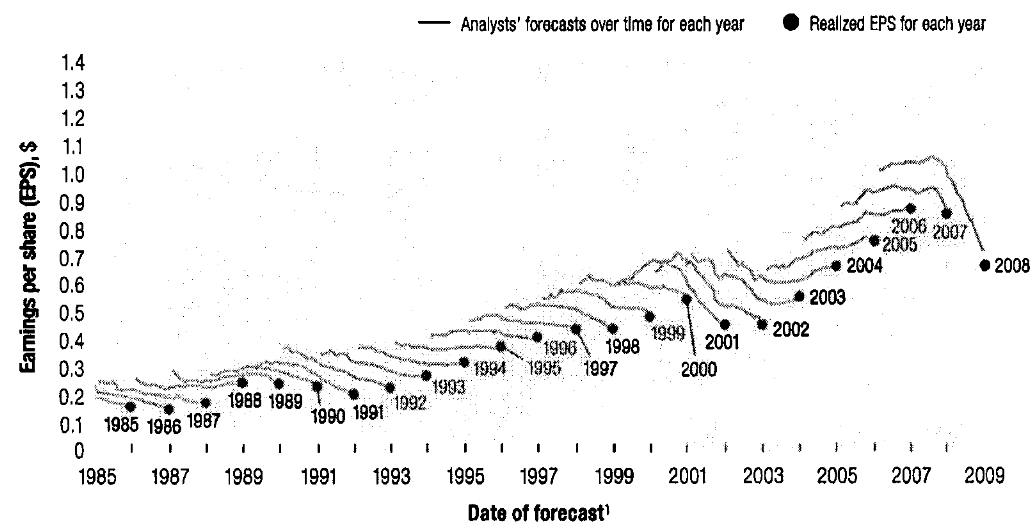
Alas, a recently completed update of our work only reinforces this view—despite a series of rules and regulations, dating to the last decade, that were intended to improve the quality of the analysts' long-term earnings forecasts, restore investor confidence in them, and prevent conflicts of interest.[2] For executives, many of whom go to great lengths to satisfy Wall Street's expectations in their financial reporting and long-term strategic moves, this is a cautionary tale worth remembering.

Exceptions to the long pattern of excessively optimistic forecasts are rare, as a progression of consensus earnings estimates for the S&P 500 shows (Exhibit 1). Only in years such as 2003 to 2006, when strong economic growth generated actual earnings that caught up with earlier predictions, do forecasts actually hit the mark.

Exhibit 1
Off the mark

With few exceptions, aggregate earnings forecasts exceed realized earnings per share.

S&P 500 companies



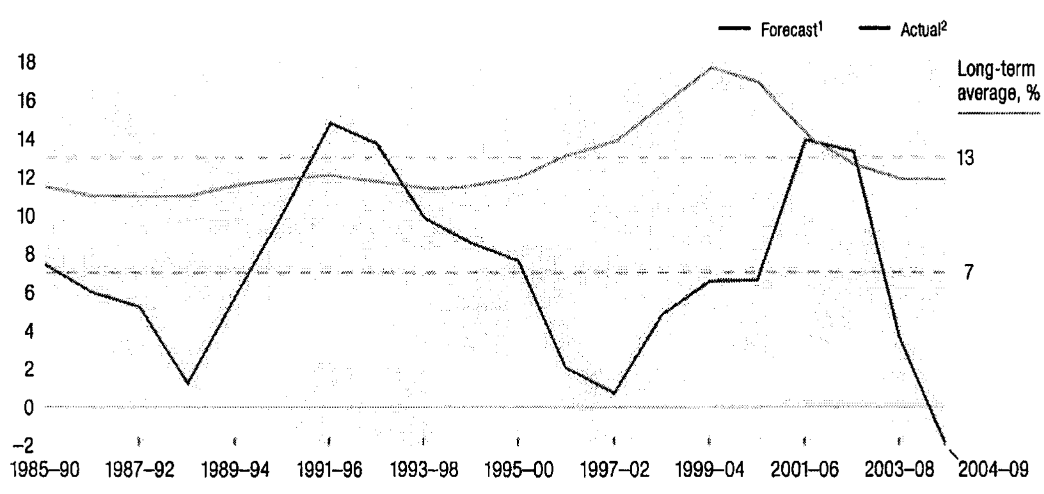
[1]Monthly forecasts.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit 2
Overoptimistic

Actual growth surpassed forecasts only twice in 25 years—both times during the recovery following a recession.

Earnings growth for S&P 500 companies, 5-year rolling average, %



[1]Analysts' 5-year forecasts for long-term consensus earnings-per-share (EPS) growth rate. Our conclusions are same for growth based on year-over-year earnings estimates for 3 years.

[2]Actual compound annual growth rate (CAGR) of EPS; 2009 data are not yet available, figures represent consensus estimate as of Nov 2009.

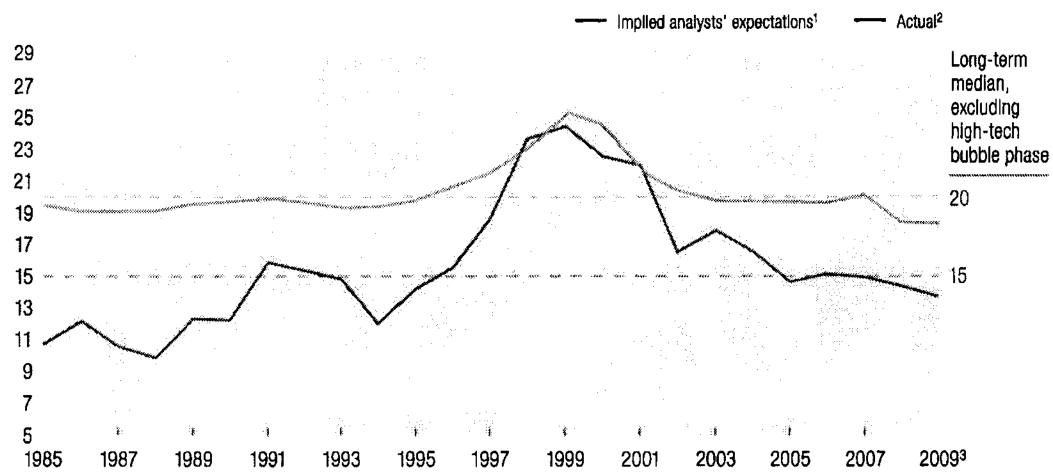
Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

Exhibit ___(DCP-1)
Schedule 14
Page 4 of 5

Exhibit 3
Less giddy

Capital market expectations are more reasonable.

Actual P/E ratio vs P/E ratio implied by analysts' forecasts, S&P 500 composite index



[1]P/E ratio based on 1-year-forward earnings-per-share (EPS) estimate and estimated value of S&P 500. Estimated value assumes: for first 5 years, EPS growth rate matches analysts' estimates then drops smoothly over next 10 years to long-term continuing-value growth rate; continuing value based on growth rate of 6%; return on equity is 13.5% (long-term historical median for S&P 500), and cost of equity is 9.5% in all periods.
[2]Observed P/E ratio based on S&P 500 value and 1-year-forward EPS estimate.
[3]Based on data as of Nov 2009.

Source: Thomson Reuters I/B/E/S Global Aggregates; McKinsey analysis

This pattern confirms our earlier findings that analysts typically lag behind events in revising their forecasts to reflect new economic conditions. When economic growth accelerates, the size of the forecast error declines; when economic growth slows, it increases.[3] So as economic growth cycles up and down, the actual earnings S&P 500 companies report occasionally coincide with the analysts' forecasts, as they did, for example, in 1988, from 1994 to 1997, and from 2003 to 2006.

Moreover, analysts have been persistently overoptimistic for the past 25 years, with estimates ranging from 10 to 12 percent a year,[4] compared with actual earnings growth of 6 percent.[5] Over this time frame, actual earnings growth surpassed forecasts in only two instances, both during the earnings recovery following a recession (Exhibit 2). On average, analysts' forecasts have been almost 100 percent too high.[6]

Capital markets, on the other hand, are notably less giddy in their predictions. Except during the market bubble of 1999–2001, actual price-to-earnings ratios have been 25 percent lower than implied P/E ratios based on analyst forecasts (Exhibit 3). What's more, an actual forward P/E ratio[7] of the S&P 500 as of November 11, 2009—14—is consistent with long-term earnings growth of 5 percent.[8] This assessment is more reasonable, considering that long-term earnings growth for the market as a whole is unlikely to differ significantly from growth in GDP,[9] as prior McKinsey research has shown.[10] Executives, as the evidence indicates, ought to base their strategic decisions on what they see happening in their industries rather than respond to the pressures of forecasts, since even the market doesn't expect them to do so. o

[1] Marc H. Goedhart, Brendan Russell, and Zane D. Williams, "Prophets and profits," mckinseyquarterly.com, October 2001.

[2] US Securities and Exchange Commission (SEC) Regulation Fair Disclosure (FD), passed in 2000, prohibits the selective disclosure of material information to some people but not others. The Sarbanes–Oxley Act of 2002 includes provisions specifically intended to help restore investor confidence in the reporting of securities' analysts, including a code of conduct for them and a requirement to disclose knowable conflicts of interest. The Global Settlement of 2003 between regulators and ten of the largest US investment firms aimed to prevent conflicts of interest between their analyst and investment businesses.

[3] The correlation between the absolute size of the error in forecast earnings growth (S&P 500) and GDP growth is –0.55.

[4] Our analysis of the distribution of five-year earnings growth (as of March 2005) suggests that analysts forecast growth of more than 10 percent for 70 percent of S&P 500 companies.

[5] Except 1998–2001, when the growth outlook became excessively optimistic.

[6] We also analyzed trends for three-year earnings-growth estimates based on year-on-year earnings estimates provided by the analysts, where the sample size of analysts' coverage is bigger. Our conclusions on the trend and the gap vis-à-vis actual earnings growth does not change.

[7] Market-weighted and forward-looking earnings-per-share (EPS) estimate for 2010.

[8] Assuming a return on equity (ROE) of 13.5 percent (the long-term historical average) and a cost of equity of 9.5 percent—the long-term real cost of equity (7 percent) and inflation (2.5 percent).

[9] Real GDP has averaged 3 to 4 percent over past seven or eight decades, which would indeed be consistent with nominal growth of 5 to 7 percent given current inflation of 2 to 3 percent.

[10] Timothy Koller and Zane D. Williams, "What happened to the bull market?" mckinseyquarterly.com, November 2001.

Marc Goedhart (Marc_Goedhart@McKinsey.com) is a consultant in McKinsey's Amsterdam office; **Rishi Raj** (Rishi_Raj@McKinsey.com) and **Abhishek Saxena** (Abhishek_Saxena@McKinsey.com) are consultants in the Delhi office.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Social Security Administration

Year	Real GDP	GDP Index	Nominal GDP	Year	Real GDP	GDP Index	Nominal GDP
				2051	2.10%	2.40%	4.50%
				2052	2.10%	2.40%	4.50%
2017	3.30%	2.04%	5.34%	2053	2.10%	2.40%	4.50%
2018	3.00%	2.17%	5.17%	2054	2.10%	2.40%	4.50%
2019	2.40%	2.38%	4.78%	2055	2.10%	2.40%	4.50%
2020	2.20%	2.41%	4.61%	2056	2.10%	2.40%	4.50%
2021	2.10%	2.40%	4.50%	2057	2.10%	2.40%	4.50%
2022	2.10%	2.40%	4.50%	2058	2.10%	2.40%	4.50%
2023	2.10%	2.40%	4.50%	2059	2.10%	2.40%	4.50%
2024	2.10%	2.40%	4.50%	2060	2.10%	2.40%	4.50%
2025	2.10%	2.40%	4.50%	2061	2.10%	2.40%	4.50%
2026	2.10%	2.40%	4.50%	2062	2.10%	2.40%	4.50%
2027	2.10%	2.40%	4.50%	2063	2.10%	2.40%	4.50%
2028	2.10%	2.40%	4.50%	2064	2.10%	2.40%	4.50%
2029	2.10%	2.40%	4.50%	2065	2.10%	2.40%	4.50%
2030	2.20%	2.40%	4.60%	2066	2.10%	2.40%	4.50%
2031	2.20%	2.40%	4.60%	2067	2.10%	2.40%	4.50%
2032	2.20%	2.40%	4.60%	2068	2.10%	2.40%	4.50%
2033	2.20%	2.40%	4.60%	2069	2.10%	2.40%	4.50%
2034	2.20%	2.40%	4.60%	2070	2.10%	2.40%	4.50%
2035	2.20%	2.40%	4.60%	2071	2.10%	2.40%	4.50%
2036	2.20%	2.40%	4.60%	2072	2.10%	2.40%	4.50%
2037	2.20%	2.40%	4.60%	2073	2.10%	2.40%	4.50%
2038	2.20%	2.40%	4.60%	2074	2.10%	2.40%	4.50%
2039	2.20%	2.40%	4.60%	2075	2.10%	2.40%	4.50%
2040	2.20%	2.40%	4.60%	2076	2.10%	2.40%	4.50%
2041	2.20%	2.40%	4.60%	2077	2.10%	2.40%	4.50%
2042	2.20%	2.40%	4.60%	2078	2.10%	2.40%	4.50%
2043	2.20%	2.40%	4.60%	2079	2.10%	2.40%	4.50%
2044	2.20%	2.40%	4.60%	2080	2.00%	2.40%	4.40%
2045	2.20%	2.40%	4.60%	2081	2.00%	2.40%	4.40%
2046	2.20%	2.40%	4.60%	2082	2.00%	2.40%	4.40%
2047	2.20%	2.40%	4.60%	2083	2.00%	2.40%	4.40%
2048	2.20%	2.40%	4.60%	2084	2.00%	2.40%	4.40%
2049	2.20%	2.40%	4.60%				
2050	2.10%	2.40%	4.50%				
				Average			**4.6%**

Source: 2012 OASDI Trustees Report.

LONG-TERM PROJECTIONS OF GROSS DOMESTIC PRODUCT GROWTH

Energy Information Administration

Annual Growth (2012-2035):

Real GDP	2.5%
GDP Chain-type Price Index	1.9%
Nominal GDP Growth	**4.4%**

Source: Energy Information Administration, Annual Energy Outlook 2012 with Projections to 2035.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC., FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND RELATED APPROVAL	)	DOCKET NO. E-04204A-12-0504

DIRECT

TESTIMONY

OF

MICHAEL J. MCGARRY, SR.

ON BEHALF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2013

TABLE OF CONTENTS

ATTACHMENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-12-0504

ENERGY EFFICIENCY RESOURCE PLAN ("EERP")

UNS Electric, Inc. ("UNSE" or "Company") is proposing an alternative approach to Energy Efficiency Standard compliance. This alternative approach includes a three-year pilot program that the Company maintains will allow it to invest in and deliver cost-effective Energy Efficiency ("EE") programs to its customers. The Company would recover the cost of its EE investments, including a return on those costs, through UNSE's existing Demand-Side Management ("DSM") Surcharge ("DSMS"). UNSE is proposing that the EERP will include the same type of program-related costs that are currently being recovered through the DSMS, including the costs of developing, implementing, and administering DSM/EE measures and programs along with a return on UNSE's investments in DSM/EE.

UNSE's 2013 Energy Efficiency Implementation Plan is currently being litigated in Arizona Corporation Commission Docket No. E-04204A-12-0219. In that case, a resolution of the issues and Commission approval of the plan has not yet occurred. The issue of whether the Company will be able to achieve the energy efficiency goals for 2013 as required by Arizona Administrative Code ("A.A.C.") R14-2-2404 and certain new energy efficiency programs are still outstanding.

The Company maintains that it is undertaking an innovative departure, similar to that which was proposed by its sister company, Tucson Electric Power Company ("TEP") in Docket No. E-01933A-12-0291, from the way in which it traditionally finances and implements EE programs and measures because it believes that the adoption of cost-effective EE measures significantly enhances the Company's ability to develop a balanced and low-cost resource portfolio. The Company states that its goal is to develop and deploy measures that provide the greatest operating efficiencies to UNSE's generation, transmission, and distribution systems; reduce reliance on more costly generating resources; and provide customers with the most cost-effective DSM/EE programs.

The Company also argues that its proposal would reduce and stabilize the rate impacts to customers, better synchronize the benefits of EE with their associated costs, provide a base level of certainty to program offerings, and eliminate the need to provide a performance incentive.

The Company is requesting that the Commission approve a three-year, forward-looking budget that totals $23,027,119, which includes $7,279,921, $7,697,093, and $8,050,105 for 2014 through 2016, respectively. This results in average annual incremental costs of $7.68 million to

UNSE's customers. Additionally, UNSE is requesting that the Weighted Average Cost of Capital used be based on the debt and capital structure approved by the Commission in this proceeding. The Company is seeking an overall weighted cost of capital of 8.35 percent, which includes a cost of equity ("ROE") of 10.50 percent. However, the Company is requesting that the ROE should be increased by 200 basis points or 12.50 percent.

Staff has a number of regulatory and policy concerns that lead to the conclusion that the Commission should reject the Company's proposed EERP:

(1) The Commission should reject the forward-looking concept proposed by UNSE.

(2) The 200-basis-point increase to the ROE is excessive, unnecessary, and should be rejected.

(3) Since cost recovery would be virtually secured, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs.

(4) The Company's proposal would require that the Commission issue one or more waivers of the various requirements of A.A.C. R14-2, including:

- A.A.C. R14-2-2405 – annual implementation plan
- A.A.C. R14-2-2410 – monitoring plan

At the Commission's Open Meeting on June 11, 2013, the Commission ordered, as part of its decision in TEP's rate case and related EERP proposal in Docket No. E-01933A-12-0291, that a generic docket be opened to review energy efficiency and cost recovery mechanisms for all Arizona utilities. As a result of the Commission's determination in the TEP case, Staff is deferring proposing a cost recovery methodology to that generic docket.

TRANSMISSION COST ADJUSTOR

UNSE is proposing a *Transmission Cost Adjustor* ("TCA") that will provide a mechanism to recover transmission costs on a more timely basis. As proposed, UNSE's retail base rates will include a transmission cost element reflective of the current Federal Energy Regulatory Commission Open Access Transmission Tariff ("FERC OATT") rate. As the OATT rate changes, UNSE is requesting that the TCA will be adjusted to collect any difference between the base rate amount and the new rate. UNSE proposes that the TCA will apply to all of UNSE's retail electric rate schedules and will be similar to the transmission cost adjustor originally approved for Arizona Public Service in Decision No. 67744 (April 7, 2005) and as modified in Decision No. 73183 (May 24, 2012). UNSE is proposing that the annual TCA adjustments be effective without affirmative Commission approval unless Staff requests review or the Commission orders otherwise. Staff is recommending approval of the TCA.

INTRODUCTION

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

A. My name is Michael J. McGarry, Sr. I am President and CEO of Blue Ridge Consulting Services, Inc. My business address is 2131 Woodruff Road, Suite 2100, PMB 309, Greenville, SC 29607.

BACKGROUND AND QUALIFICATIONS

Q. Please state your experience and educational background.

A. I have been President of Blue Ridge Consulting Services, Inc. since 2004. In my career, I have overseen or been part of numerous rate case audits, prudency reviews, and management and operational audits. I have worked with clients to manage various aspects of the regulatory and rate case process; prepared supporting analyses and testimony for submission to regulatory bodies and intervenors; prepared revenue requirement and cost of service analyses; and developed complex revenue requirement models to present alternative positions to utilities' proposed rate requests. Prior to assuming my present position, I was Vice President of East Coast Operations from July 2003 to June 2004 with Hawks, Giffels & Pullin ("HGP"), Inc. In that position, I was responsible for developing and overseeing client engagements in utility regulatory affairs, management audits, and rate case management. From August 2001 to July 2003, I was an independent consultant working on a number of different projects, including a renewal/update of delivery service tariffs for Illinois Power and several utility street lighting cost benefit assessment projects. From June 2000 until August 2001, I was a senior consultant with Denali Consulting, Inc., a utility supply chain and e-procurement strategy and implementation firm. From October 1997 through June 2000, I was employed by Navigant Consulting, Inc. and several of its predecessors or acquired firms, working on a number of different projects, including a management audit of Southern Connecticut Gas Company and the original delivery service tariff filing for Illinois Power. From July 1985 through October 1997, I was employed by the New York State Department of Public Service ("NYSDPS") in its Utility Operational Audit Section in which the staff conducted focused operational audits in many facets of utility operations for all sectors of the utility industry, including gas, electric, telecommunications, and water. Prior to my employment with the NYSDPS, I was a rate analyst with Orange and Rockland Utilities (1981 to 1983) and then with Seminole Electric Cooperative (1983 to 1985). I received my Masters of Business Administration from the State University of New York ("SUNY") at Buffalo in 1996 and a Bachelor of Arts in Economics from Potsdam College in 1981.

Q. Have you prepared an attachment summarizing your educational background and regulatory experience?

A. Yes. Attachment MJM-1 provides details concerning my experience and qualifications.

Q. Have you previously testified before the Arizona Corporation Commission?

A. Yes. I recently testified in Tucson Electric Company's base rate filing in Docket No. E-01933A-12-0291, where I proffered testimony on TEP's proposed energy efficiency resource plan, its related cost recovery mechanism, and the Company's proposed environmental cost adjustor ("ECA"). In addition, I also testified in Arizona Public Service Company's ("APS") base rate filing in Docket No. E-01345A-11-0224, where I proffered testimony on APS' proposed infrastructure tracking mechanism, power supply adjustor, and tariffs.

Q. Have you testified before commissions in other jurisdictions?

A. Yes. I have testified in Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, and Utah. These proceedings included testimony involving revenue requirements, power supply costs, management decisions and prudence impacts, operations and maintenance expenses, capital investments, and project management. A complete list is included in Attachment MJM-1.

I have also presented topics before staff groups from regulatory commissions, NARUC sub-committee groups, and as a program faculty member for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, company service costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, and price regulation theory.

PURPOSE OF TESTIMONY

Q. On whose behalf are you testifying?

A. I am appearing on behalf of the Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff").

Q. What is the purpose of the testimony you are presenting?

A. I am presenting the Staff's position with respect to (1) UNS Electric, Inc.'s ("UNSE" or "Company") proposed Energy Efficiency Resource Plan ("EERP") and (2) Transmission Cost Adjustor ("TCA").

Q. Was this testimony and the supporting analyses prepared by you or under your direct supervision?

A. Yes, it was.

Q Please briefly describe the information you reviewed in preparation for your testimony.

A. I have reviewed the Company's testimony and exhibits and data request responses provided by the Company to the various parties to this proceeding.

CONTENT OF ATTACHMENTS TO TESTIMONY

Q. Have you attached any exhibits to your testimony?

A. Yes. The following exhibit is included with my testimony.

MJM-1 Michael J. McGarry, Sr. Experience and Qualifications

ENERGY EFFICIENCY RESOURCE PLAN ("EERP")

Q. Please describe the EERP proposed by the Company.

A. The Company is proposing what it describes as an alternative and "improved approach to Energy Efficiency Standard ("EES") compliance."[1] This "improved approach" includes a three-year pilot program that the Company maintains will allow it to invest in and deliver cost-effective Energy Efficiency ("EE") programs to its customers. The Company would recover the cost of its EE investments, including a return on those costs, through UNSE's existing Demand-Side Management ("DSM") Surcharge ("DSMS"). UNSE is proposing that the EERP will include the same type of program-related costs that are currently being recovered through the DSMS including the costs of developing, implementing, and administering DSM/EE measures and programs along with a return on UNSE's investments in DSM/EE.[2]

[1] Direct testimony of Denise A. Smith, Page 2, Lines 14-15
[2] Direct testimony of Denise A. Smith, Page 15, Lines 19-22

Q. Does the EERP include a performance incentive?

A. No. The Company has eliminated the performance incentive in this plan.

Q. What does UNSE proffer as the benefits of the Company's proposed plan?

A. Company Witness Denise A. Smith states,

> "UNS Electric's EE Resource Plan is a win-win proposition for all stakeholders. Customers would benefit from predictable DSMS that allows them to plan for their energy expenses while gaining greater assurance that UNS Electric's EE programs will be available over a multi-year timeframe. The local contractors who manage such programs will enjoy greater certainty regarding program funding levels. The Commission and its Staff would benefit from a reduction in the administrative burden associated with annual reviews of UNS Electric's EE Implementation Plans. Finally, UNS Electric will have more certainty about the energy savings to incorporate into its resource and system planning and will realize a reasonable return from its EE investments."[3]

The rate that customers would be charged would be based on a three-year planning horizon for UNSE's EE programs. The Company is proposing that the DSMS rate would be set in advance and recover the cost of the UNSE's investment plus a return, resulting in "moderate, predictable year-over-year increases to ease customers into the increasing costs of EES compliance."[4] Witness Smith argues, "[T]he most efficient way to provide cost-effective EE is to treat it like any other resource in our IRP process."[5] As Witness Smith states,

> "Under UNS Electric's proposal, the Company would determine the most cost-effective EE option appropriate for its particular system, invest its capital to procure that resource, and recover the associated costs – including the amortization expense and an appropriate return on investment – through the DSMS."[6]

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[3] Direct Testimony of Denise A. Smith, page 5, lines 22-27, page 6 lines 1-4.
[4] Direct Testimony of Denise A. Smith, page 5, lines 6-7.
[5] Direct Testimony of Denise A. Smith, page 5, lines 10-11.
[6] Direct Testimony of Denise A. Smith, page 5, line 11-15.

Witness Smith points out that the capital invested in such programs will be considered a regulatory asset and amortized over a four-year term.[7]

Q. What are the EE plan costs that are being proposed for inclusion in the plan?

A. As mentioned above, the Company is requesting that the Commission approve a three-year, ***forward-looking budget*** that totals $23,027,120, which includes $7,279,921, $7,697,093, and $8050105 for 2014 through 2016, respectively.[8] This results in average annual incremental costs of $7.68 million to UNSE's customers. The current budget is approximately $5.5 million per year.

Q. What rate of return on EE investments is UNSE requesting?

A. UNSE is requesting the Weighted Average Cost of Capital used be based on the debt and capital structure approved by the Commission in this proceeding. The Company is seeking an overall weighted cost of capital of 8.35 percent, which includes a cost of equity (ROE) of 10.5 percent.[9] However, the Company is requesting that the ROE should be increased by 200 basis points or 12.5 percent to "reflect the nature of the investment."[10] To support this 200-basis-point increase, Witness Smith states:

> Unlike its investments in power plants, buildings, computers and other assets with independent market value, UNS Electric's EE expenditures produce only intangible assets with no value outside of the Commission's rules. That is why the creation of a regulatory asset – the value of which is derived solely from the Commission's authorization – is required to allow UNS Electric to recover and earn a return on its EE investment. The nature of this investment justifies this higher rate of return, since intangible assets do not necessarily provide UNS Electric with the same financial benefits as tangible, saleable assets.[11]

[7] Direct Testimony of Denise A. Smith, page 5, line 15-18.
[8] Direct Testimony of Denise A. Smith, page 7, Lines 1-5.
[9] UNSE Application, page 5, lines 17-19.
[10] Direct Testimony of Denise A. Smith, page 6 line 10.
[11] Direct Testimony of Denise A. Smith, page 6 lines 10-18.

Q. What does the Company conclude regarding its proposed EE Resource Plan?

A. Witness Smith makes the following statement:

> UNS Electric is undertaking an innovative departure from the way in which we traditionally finance and implement EE programs and measures, because we believe that the adoption of cost-effective EE measures significantly enhances the Company's ability to develop a balanced and low cost resource portfolio, which is certainly in the best interest of our customers. Our goal is to develop and deploy measures that provide the greatest operating efficiencies to UNS Electric's generation, transmission and distribution systems; reduce reliance on more costly generating resources; and provide customers with the most cost effective DSM/EE programs. By "putting our skin in the game" the Company is taking on additional risk by investing in a regulatory asset that derives value only as a result of an order of the Commission authorizing UNS Electric to recover its costs from customers.[12]

Q. Do you recommend that the Commission approve the EERP as proposed by the Company as in the best interest of the customer at this time?

A. No.

Q. Please describe your understanding of the Commission's recent directives related to EE in Arizona.

A. At the Commission's "Open Meeting" held on Tuesday June 11, 2013, the Commission directed that a generic docket be opened for all interested parties and stakeholders to address EE and cost recovery methodologies. This directive came out of the Commission's deliberations related to TEP's EE Plan and proposed cost recovery methodology in Docket No. E-01933A-12-0291. However, it is my understanding that this directive applies equally to UNSE and the other utilities in Arizona under the Commission's jurisdiction. As a result, the Commission approved the status quo for

[12] Direct Testimony of Denise A. Smith, page 13, Lines 24-27 & Page 14, Lines 1-8

TEP's EE programs and cost recovery mechanism but deferred discussion of energy efficiency and associated cost recovery mechanisms to this generic proceeding. As a result, Staff will provide its position related to EE and/or cost recovery methodologies in that generic docket.

Q. Are your criticisms of UNSE's proposed cost recovery mechanism similar to that of what you stated in the TEP case – E-01933A-12-0291?

A. With reserving the flexibility to modify or adopt contrary positions based on further analysis in the generic docket, I have a number of regulatory and policy concerns that I believe the Commission should consider that lead me to the conclusion that the Commission should reject the Company's EERP as proposed in this Docket.

(1) The Commission should reject the forward-looking concept proposed by UNSE.

(2) The 200-basis-point increase to the ROE is excessive, unnecessary, and should be rejected.

(3) Since cost recovery would be virtually secured, it is unclear that the proposed EERP would provide incentives to maximize the results of the program and, at the same time, provide cost-effective and efficient implementation of the programs.

(4) The Company's proposal would require that the Commission issue one or more waivers of the various requirement of Arizona Administrative Code R14-2, including:

- A.A.C. R14-2-2405 – annual implementation plan
- A.A.C. R14-2-2410 – monitoring plan

Q. Are you recommending an alternative plan?

A. Not at this time. Given the Commission's directive at the June 11, 2013 Open Meeting, I believe that discussion is best left to that proceeding.

Q. Do you have any recommendations regarding EE?

A. Yes. Consistent with the Commission's action in the TEP rate case, Staff has the following recommendations:

(1) The methodology for recovery of approved EE/DSM costs should be reviewed, established and approved as part of the Commission's EE Implementation Plan proceedings for UNSE, consistent with the outcome of the generic docket proceedings.

(2) The performance incentives, tied to the cost-effective energy savings, should be reviewed, established and approved as part of the Commission's EE Implementation Plan proceedings for UNSE, consistent with the outcome of the generic docket proceedings.

Q. Does this conclude your testimony on the EERP?

A. Yes, it does.

TRANSMISSION COST ADJUSTOR ("TCA")

Q. What is the transmission cost adjustor?

A. As identified in the Company's proposed TCA Plan of Administration ("POA"), the TCA is "a mechanism to recover transmission costs associated with serving retail customers at the level approved by [FERC] at the same time as new transmission rates become effective for [UNS Electric] transmission customers."[13]

Q. Please describe your understanding of the Company's proposal regarding the TCA.

A. UNSE proposes that retail base rates will include a transmission cost element reflective of the current FERC Open Access Transmission Tariff ("OATT") rate. As the OATT rate changes (annually) and prior to new base rates, the difference between the transmission cost element in current base rates and the changed OATT rate will result in a TCA adjustment of retail rates.[14]

Q. What reasons does the Company proffer for the proposed TCA?

A. In its application, UNSE states that its proposed TCA (along with its other proposals to moderate future rate impacts) will help customers to better manage their energy expenses, assist the Company to synchronize recovery of costs, improve its opportunity to earn the authorized rate of return, and manage its capital expenditures and related financing needs, thus reducing the borrowing costs ultimately borne by its customers.[15].

Q. Do you agree?

A. Cost trackers, such as the TCA, are becoming more prevalent in the industry. However, as I have testified before this Commission, I and many industry experts caution against the

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[13] Company Exhibit CAJ-6, 1. General Description
[14] Company Application, 6:19-23.
[15] Company Application, 6:13-17.

overuse of these trackers. Several disadvantages are related to cost tracker overuse, such as (1) weakening the incentive of a utility to control costs, (2) undercutting the positive effects of regulatory lag, (3) biasing a utility's technological and investment decisions, (4) motivating utilities to shift more costs to functions subject to trackers, (5) diluting frequency and quality of cost reviews, (6) having the tendency to be more complicated and burdensome to both the Commission staff and to consumers, and (6) producing a negative perception by consumers due to more frequent press reports of "rate increase." Although all of these reasons certainly do not apply in the Company's specific proposal in this case, they are concerns which should be considered as the Commission determines whether to approve cost trackers such as the TCA.

Q. Please continue.

A. In my opinion, there should be certain eligibility criteria for creating and expanding cost trackers. One criterion would be to allow a cost tracker only for extraordinary circumstances, such as costs outside a utility's control, costs that are unpredictable and volatile, and costs that are substantial and recurring. Additionally, another criterion for allowing a cost tracker would be to mitigate severe financial consequences. In the current case, UNSE believes the change in the FERC OATT rates is a cost beyond its control. In its most recent rate case (Docket No. E-01345A-11-0224), APS made a similar claim, and the Commission granted it the TCA modifications it sought.[16]

Q. Is the Company's proposed TCA similar to the APS TCA approved by the Commission in Decision No. 73183?

A. Yes. The UNSE-proposed TCA is similar to the TCA approved for APS in the original Decision No. 67744 (April 7, 2005) and then modified in Decision No. 73183 (May 24,

[16] Arizona Corporation Commission, Decision No. 73183, May 24, 2012.

2012). In fact, a side-by-side comparison of the POAs of both TCAs reveals that they are basically the same with mostly only minor differences (e.g., company identification and effective dates, but one substantive difference.

Q. What is the single substantive difference to which you refer between the APS POA and the proposed UNS Electric POA?

A. Under Section 3 "Filing and Procedural Deadlines," the proposed POA states, "The new TCA rates shall be effective in the first billing cycle after the date of the Informational Filing unless otherwise ordered by the Commission." In a similar statement of the Commission-approved APS TCA POA, the words "Staff requests Commission review or" are inserted between "unless" and "otherwise."

Q. Why do you think the Company failed to include that phrase in its proposed TCA?

A. The Company did include the phrase in its Application.[17] Therefore, I believe its absence in the POA was simply an oversight.

Q. What is your recommendation?

A. I recommend approval of the TCA mechanism as described by the Company in its Application and corresponding testimony. I also recommend approval of the TCA POA with the one modification of including the phrase "Staff requests Commission review or" between the words "unless" and "otherwise" in section 3, "Filing and Procedural Deadlines."

Q. Does this conclude your testimony related to TCA?

A. Yes. It does.

[17] UNS Electric Application, 6:26-27.

MJM-1
Experience and Qualification of Michael J. McGarry, Sr.

Summary

Mr. McGarry's professional experience spans thirty-one years within the private and public sectors. He has conducted over thirty comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities. These audits have included comprehensive management audits and/or operational audits on most utility functions including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Project Management

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

Testimony and Witness Preparation

Mr. McGarry has proffered and/or supported testimony in Arizona, Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania and Utah. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Utility Management and Operational Audits

Mr. McGarry has conducted over thirty comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions within the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget processes and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Restructuring, Unbundling, and Cost Allocation

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010 & 2011) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, price regulation theory, and cost trackers.

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Regulatory Experience

Before the Arizona Corporation Commission (AZCC)

Docket No. 12-0291 *Application of Tucson Electric Power Company for Just and Reasonable rates and charges to realize a reasonable rate of return in Arizona*, before the AZCC. August 2012 - present
Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, cost of capital and return on equity, and energy efficiency mechanisms. Will provide written testimony in support of Staff's position regarding energy efficiency mechanisms and environmental compliance adjustor.

Docket No. 11-0224 *Arizona Public Service Company Rate Case*, before the AZCC. July 2011-March 2012
Project Manager and Testifying Witness. Analyzed the company's proposed Infrastructure Tracking Mechanism, power supply adjustor, and tariffs. Testimony filed November 2011.

Before the Connecticut Public Utilities Regulatory Authority (PURA)

Docket 10-02-13 *Application of Aquarion Water Company to Amend its Rate Schedules*
On behalf of the PURA. April-August 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement specifically related to cash working capital and test year expenses.

Assisted with analysis of specific issues and preparation of Commission's recommended decision.

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light & Power Company.* On behalf of the Staff of the PURA. July 2008-June 2009
Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122 million customer information system known as CustomerCentral or C2.

Before the Delaware Public Service Commission (DEPSC)
Docket No. 11-528 *On behalf of the Staff of the DEPSC in the matter of the application Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* January-July 2012
Project Manager and Testifying Witness. Oversaw rate case analysis and assessment of the company's proposed inter-company allocations. Provided expert testimony regarding the impact of the sale of Conectiv Energy on inter-company allocations and the resulting impact on revenue requirements.

Docket No. 09-414 *On behalf of the Staff of the DEPSC in the matter of the application of Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* September 2009-May 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.

Docket No. 07-239F *On behalf of the Staff of the DEPSC in the matter of the application DPL for approval of modifications to its gas cost rates.* October 2007-April 2008
Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program and testified to the findings and conclusions.

Docket No. 06-287 *On behalf of the Staff of the DEPSC in the matter of Chesapeake Utilities Corporation's implementation of a Gas Hedging program.* June-August 2007
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the company.

Docket No. 06-284 *On behalf of the Staff of the DEPSC in the matter of DPL's request for a $15M increase in gas base rates.* October 2006-March 2007
Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).

Before the District of Columbia Public Service Commission (DCPSC)

Formal Case No. 1093 *In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's (WGL) Existing Rates and charges for Gas Service*
On Behalf of the DCPSC. June 2012-present
Project Manager and Lead Consultant. Managed team of consultants providing advisory services to Commissioners and Staff on proposed revenue requirements, rate base, and rate design. Led analysis of revenue requirements, fuel costs, uncollectibles, environmental issues affecting rate base, inventory adjustments, plant in service, construction work in progress, research and development issues, safety initiatives, affiliate allocations, and energy funds.

Formal Case No. 1087 *In the Matter of the Application of the Potomac Electric Power Company (PEPCO) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*
On Behalf of the DCPSC. September 2011-present
Project Manager and Lead Consultant. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.

Formal Case No. 1076 *In the Matter of the Application of PEPCO for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.*
On Behalf of the DCPSC. July 2009-June 2010
Project Manager. Advised Commission Staff on the company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.

Formal Case No. 1053 - *Technical consultant for the DCPSC in the matter of PEPCO's request for a $50.4 million increase in base rates.* February 2007-June 2008
Project Manager. Provided technical expertise to Commission in evaluating PEPCO's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Formal Case No. 1032 *In the Matter of the Investigation into PEPCO's Distribution Service Rates*
On Behalf of the DCPSC. January-March 2005
Project Manager. Review and evaluation of PEPCO compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Formal Case No. 1016 *In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*
On Behalf of the DCPSC. June-December 2003

Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

Before the Hawaii Public Utilities Commission

Docket No. 05-0075 *In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework.* June 2005-January 2006

Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the company.

Before the Illinois Commerce Commission (ILCC)

Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago.* November 2005-May 2006

Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Before Maine Public Utilities Commission (MEPUC)

Case No 2008-151 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*

On behalf of Maine Public Advocate. July 2008-July 2010

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase I)*

On behalf of Maine Public Advocate. November 2004-March 2005

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities. Participated in panel testimony regarding cost and risk of the program.

Before the Maryland Public Service Commission
Case No. 9092/9093 (Phase II) *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO and Delmarva Power & Light Company.* December-March 2008
Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

Case No. 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO.* January-June 2007
Project Manager. Reviewed and analyzed the company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of the company's original request.

Case No. 9062 *On behalf of the Maryland Office of People's Counsel in the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service.* May-August 2006
Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.

Before the Massachusetts Department of Public Utilities (MADPU)
Case No. D.P.U. 08-110 *On behalf of the MDPU regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company.* February-August 2010
Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the company's revenue requirements calculations in the company's base rate request.

Before the Michigan Public Service Commission
Case No. U-16655 *On behalf of the Attorney General of the State of Michigan (MIAG) in the matter of the application of Consumers Energy Company (CECO) for authority to reconcile its renewable energy plan (REP) costs associated with the plan approved in Case No. U-15805 and Case No. U-16543.* September 2012-present
Project Manager and Testifying Witness. Review the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Testified regarding the company's methodology used to calculate its proposed PSCR expense.

Case No. U-16656 *On behalf of the MIAG in the matter of the application of The Detroit Edison Company (DetEd) for authority to reconcile its REP costs associated with the amended plan approved in Case No. U-16582.* September 2012-present

Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Expected to testify at upcoming hearing.

Case No. U-16434-R *On behalf of the MIAG in the matter of the Application of DetEd for reconciliation of its 2011 power supply cost recovery (PSCR) plan.* June 2012-present
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, over-refund of the company's residual Self-Implementation Refund, the company's claimed credit to PSCR costs related to credit claimed by affiliate, RARS asset and liability balance resulting in over recovery, and Reduced Emissions Fuel (REF) prudency and calculation of REF impacts.

Case No. U-17026 *On behalf of the MIAG in the matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations* June-September 2012
Project Manager. Managed review of certificate of necessity, evaluation of company's prudency in obtaining alternative power supply options, and review of the company's implementation of and prudency in management of its nuclear plant Life Cycle Management project in comparison to industry standards.

Case No. U-16892 *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for 2010.* November 2011-May 2012
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-16047-R *On behalf of the MIAG in the matter of the application of DetEd for its PSCR plan for 2011.* August 2011-March 2012
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, under-recovery of cumulative Pension Equalization Mechanism costs, and the over-refund of the company's residual Self-Implementation Refund.

Case No. U-16432 *On behalf of the MIAG in the matter of CECO's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager. Reviewed cost recovery plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses as part of PSCR process.

Case No. U-16434 *On behalf of the MIAG in the matter of DetEd's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and

purchased power, purchased power agreements, emission control expenses including appropriateness of coal refinement expenses as part of PSCR process.

Case No. U-16472 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* February-June 2011
Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and testifying witness to same.

Case No. U-16407 *On behalf of the MIAG in the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system*. October 2010-May 2011
Project Manager and Testifying Witness. Reviewed the company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.

Case No. U-16300 *On behalf of the MIAG in the matter of the application of CECO for authority to reconcile its REP costs associated with the plan approved in Case No. U-15805*. November 2010-January 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure the adherence to approved processes and reasonable and prudent costs. Testified as to significant concerns with respect to the transfer price for renewable energy resources proposed by the company.

Case No. U-16356 *On behalf of the MIAG in the matter of the application of DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS.* October 2010-March 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure adherence to approved processes and reasonable and prudent costs and testified to those issues.

Case No. U-15675-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2009.* October 2010-January 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to transfer price, replacement power costs, and reasonableness of including excess fuel and variable O&M expenses proffered by various intervenors.

Case No. U-15677-R *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for the calendar year 2009.* September-December 2010

Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified with respect to the transfer price for renewable energy source flowing into the PSCR proposed by the company.

Case No. U-16047 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR Plan in its rate schedules for 2010 metered jurisdictional sales of electricity.* January-May 2010
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2008 and for other relief related to pension and OPEB costs.* May-November 2009
Project Manager and Testifying Witness. Reviewed PSCR reconciliation, provided analysis of potential issues, and developed recommendations including basis, past precedence, and/or industry expertise. Testified regarding Karn 1 outage delay and Rate E-1 discount recovery.

Case No. U-15806/U-15890 *On behalf of the MIAG in the matter of DetEd's and MichCon's compliance with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP).* March-June 2009
Project Manager and Testifying Witness. Reviewed the EOPs of both companies and provided analysis and testimony regarding issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15805/15889 *On behalf of the MIAG in the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP.* March-June 2009
Project Manager and Testifying Witness. Reviewed the company's EOP and provided analysis and testimony of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15677 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR plan in its rate schedules for 2009 metered jurisdictional sales of electricity.* January-June 2009
Project manager. Reviewed PSCR plan requirements for appropriateness of specific components of that factor.

Case No. U-15415 *On behalf of the MIAG in the matter of the application of CECO for approval of a PSCR plan and for authorization of monthly PSCR factors for the year 2008.* January-March 2008
Project Manager. Reviewed PSCR plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *On behalf of the MIAG in the matter of the application of Midland Cogeneration Venture Limited Partnership (MCV) for the Commission to eliminate the*

"availability caps" which limit CECO's recovery of capacity payments with respect to its power purchase agreement with MCV. October 2007-June 2008
Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* July 2007-April 2008
Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce the company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its electric base rates.* September 2007-October 2008
Project Manager and Testifying Witness. Testified regarding revenue requirements.

Case No U-15190 *On behalf of the MIAG in Base Rate Proceeding for CECO.* March-September 2007
Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the MIAG in GCR 2007/08 Plan proceeding of Michigan Gas Utilities Corporation.* March-August 2007
Project Manager and Testifying Witness. Reviewed GCR plan requirements and provided analysis of the potential benefits of gas procurement hedging program. Testified regarding the GCR clause plan 2007-08.

Case No. U-14231 *On behalf of the MIAG in the matter, on the Commission's own motion, to commence an investigation into future capacity requirements.* February-May 2007
Project Manager. Reviewed and provided a formal written report on the Michigan Public Service Commission's 21st Century Energy Plan Report.

Case No. U-15001 *On behalf of the MIAG in PSCR 2007/08 Plan proceeding.* November 2006-August 2007
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified regarding the company's projected PSCR under-recoveries for 2005 and 2006.

Case No. U-14701-R *On behalf of the MIAG in PSCR 2006/07 reconciliation proceeding.* June-November 2007
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified to eliminate some expenses used in the company's calculation of its under-recovery PSCR reconciliation for 2006.

Case No. U-14547 *On behalf of the MIAG in the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief.* December 2005-April 2006
Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.

Case No. U-14347 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* April-September 2005.
Project Manager. Managed project team and supported testimony on cost of service, revenue allocation and rate design issues.

Before the Missouri Public Service Commission (MOPSC)
Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri (Case No. HR-2011-0241). July-September 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the MOPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

New Mexico Public Regulation Commission (NMPRC)
Special Case Study: Public Service Company of New Mexico (PNM) NM PRC Docket No. 10-00086-UT. August 2010
Blue Ridge worked with QSI Consulting, Inc. to conduct a training session for the NMPSC Staff and develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the pending PNM rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Before the North Dakota Public Service Commission (NDPSC)
Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota (Case No. PU-10-657/PU-11-55). April-October 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Before the Nova Scotia Utility and Review Board

Case No. P-888 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power.* December 2006-March 2007
Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the company's management performance and operational efficiency within the context of that proceeding.

Before the Public Utilities Commission of Ohio (PUCO)

Case No. 11-5428-EL-RDR *On behalf of the Staff of the Public Utilities Commission of Ohio In the matter of the application of Delivery Capital Recovery (DCR) Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies).* November 2011-April 2012
Project Manager and Expert Witness. Led a team of consultants engaged to audit and attest to the accuracy and reasonableness of the Companies' compliance with their Commission-approved DCR Riders with regard to the return earned on plant-in-service since the Companies' last distribution rate case.

Case No. 08-0917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service.* (Hired by Ohio Hospital Association's attorney for utility matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric Power). September 2008-March 2009
Evaluated revenue and rate impact on member hospitals.

On behalf of the Staff of the PUCO:

- Case #08-0072-GA-AIR Columbia Gas of Ohio for an increase in gas rates, April-August 2008
- Case #07-0829-GA-AIR Dominion East Ohio for an increase in gas rates, November 2007-July 2008
- Case #07-0589-GA-AIR Duke Energy Ohio for an increase in gas rates, November 2007-Februrary 2008

Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of FirstEnergy Ohio (and its operating companies Ohio Edison, Cleveland Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval.* August 2007-April 2008
Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing FirstEnergy's application

with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.

Case No. 06-0986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service offer.* May-August 2007
Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the company's proposal and impact on City's project energy costs.

<u>Oregon Public Utility Commission (OPUC)</u>
Docket No UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues* Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board. August 2005-January 2006
Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure the company's compliance with orders, rules and regulations of the OPUC, with company policy and with Generally Accepted Accounting Principles.

<u>Utah Division of Public Utilities</u>
Docket No. 09-035-23 *In the Matter of the Application of Rocky Mountain Power (RMP) for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.* June-December 2009
Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.

Docket No. 09-035-15 *In the Matter of the Application of RMP for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case.* July-December 2009
Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the company and testified to hedging issues.

Before the Washington Utilities and Transportation Commission (WUTC)
Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the WUTC Staff. Phase I: July-October 2009; Phase II: October 2009-September 2010
Project Manager. Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.

Before the Public Utilities Commission of the State of Colorado (COPUC)
Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo)*
On behalf of the COPUC Staff. March-September 2004
Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

South Carolina State Senator
Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

Southern Connecticut Gas
Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the company, completed the capital budgeting area of the audit.

Before the New York Public Service Commission
Case: 94-C-0657
Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between the company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry.

Case: 97-M-0567

Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of Long Island Lighting Company (LILCO)/Brooklyn Union Gas. Analyzed proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO*
Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company (NIMO)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills.

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*
Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding of the Operations and Management of Jamaica Water*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Operations and Management*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Case: 92-M-0973 *Management Audit of RG&E*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

Case: 93-E-0918 *Operational Audit of the Demand Side Management Function at RG&E*

Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

Case: 88005 *Operational Audit of Materials and Supply Function at National Fuel Gas*
Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

Operational Audit of the Fuel Procurement and Contracting of LILCO
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

Operational Audit of the Fuel Procurement and Contracting of ConEd
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of RG&E
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.

Case: 88-E-115 *Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant (HCCCP)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

Case: 87003 *Operational Audit of the HCCCP*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

Case: 87003 *Operational Audit of the Fuel Procurement and Contracting of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

Case: 86007 *Operational Audit of the Field Crew Supervision and Utilization of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

Case: 86005 *Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO*
Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Case: 86005 *Operational Audit of the Fuel Procurement and Contracting of NIMO*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

Case: 85001 *Operational Audit of the Research and Development Function of ConEd*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Testimony filed by Mr. McGarry

<u>Before the Arizona Corporation Commission</u>

- Arizona Public Service Company - Docket No. E-01345A-11-0224

<u>Before the Delaware Public Service Commission</u>

- Delmarva Power and Light Company - Docket No. 11-528
- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

<u>Before the Illinois Commerce Commission</u>

- Commonwealth Edison - Case: 05-0597

<u>Before Maine Public Utilities Commission</u>

- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission

- PEPCO and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission

- Consumers Energy Company - Case No. U-16655
- Detroit Edison Company - Case No. U-16434-R
- Detroit Edison Company - Case No. U-16047-R
- Detroit Edison Company - Case No. U-16434
- Detroit Edison Company - Case No. U-16892
- Detroit Edison Company - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison Co. and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Missouri Public Service Commission

- Veolia Energy Company - Case No. HR-2011-0241

Before the New York Public Service Commission

- Long Island Lighting Company - Case: 96-E-0132
- Niagara Mohawk Power Company - Case: 96-M-0858
- Jamaica Water - Case: 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case: 88-E-115

Before the North Dakota Public Service Commission

- Northern States Power Company - Case Nos. PU-10-657 and PU-11-55

Before the Nova Scotia Utility and Review Board

- Nova Scotia Power - Case No. P-888

Before the Utah Division of Public Utilities

- Rocky Mountain Power - Docket No. 09-035-23

Speaking Engagements

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, CAPEX Trackers, March 28, 2012.

Institute of Public Utilities, Michigan State University, East Lansing, MI; Advanced Regulatory Studies Program, training session on Management Audits and Prudency Reviews; September 27, 2011, and September 30, 2010.

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, service company costs and allocations to regulated entities, September 15, 2010.

New Mexico Public Regulation Commission Staff, Santa Fe, NM - In cooperation with QSI Consulting; service companies and related cost allocations, benchmarking, and rate case planning; June 29, 2010.

Colorado Public Utilities Commission Staff – In cooperation with QSI Consulting; future of regulation and deregulation, revenue requirements, rate base, rate of return, cost of service, determining net operating income, cost of capital, staff audits, and affiliate transactions; June 22, 2006.

MJM-1

Experience and Qualification of Michael J. McGarry, Sr.

Summary

Mr. McGarry's professional experience spans thirty-one years within the private and public sectors. He has conducted over thirty comprehensive management and operational audits of investor-owned energy, telecommunications, and water utilities. These audits have included comprehensive management audits and/or operational audits on most utility functions including corporate governance, strategic planning, internal auditing, capital and operating budget process and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Project Management

Mr. McGarry's experience includes management of multi-discipline teams for a wide range of client engagements, development and implementation of detailed work plans and project schedules. He has analyzed and planned interdivisional resource utilization; supervised, developed and coached interdivisional team members; and created numerous executive reports, briefings, and presentations.

Regulatory and Rate Case Management

Mr. McGarry has worked with clients to manage all aspects of the regulatory and rate case process. He has developed efficient processes to prepare supporting analyses and testimony for submission to the regulatory bodies and interveners. He is a seasoned project manager and has analytical expertise to respond to interrogatories and data requests from all rate case interveners in a timely manner. Mr. McGarry has assisted a number of clients in preparing revenue requirement and cost of service analyses. He has also developed rate structure and billing determinant information analyses, time of day and interruptible rates analyses, fuel and purchased power reports, and annual wholesale rates for member cooperatives. He has developed complex revenue requirement models to present alternative positions to a utility's proposed rate request.

Testimony and Witness Preparation

Mr. McGarry has proffered and/or supported testimony in Arizona, Colorado, Delaware, Illinois, Maine, Maryland, Michigan, Missouri, New York, North Dakota, Nova Scotia, Ohio, Pennsylvania and Utah. These proceedings included testimony involving management decision and prudence impacts, operations and maintenance expenses, capital investments, revenue requirements, project management, and others.

Utility Management and Operational Audits

Mr. McGarry has conducted over thirty comprehensive management and operational audits of investor-owned energy and telecommunications utilities. These audits have included comprehensive management audits and/or operational audits on most functions within the utility environment including corporate governance, strategic planning, internal auditing, capital and operating budget processes and practices, distribution operations and maintenance, fuel procurement, supply chain management, demand side management, crew operations, affiliates transactions, commodity trading, and construction program practices.

Restructuring, Unbundling, and Cost Allocation

Mr. McGarry has developed the supporting analyses and regulatory filing requirements needed to support unbundling rates for utilities. This has included detailed studies where the company's plant-in-service and depreciation reserve was allocated to each unbundled function. He has assessed utility management actions to prepare the company for competition, including the processes and practices used by the utility to prepare to enter new markets and offer new services.

Training and Public Speaking

Mr. McGarry has presented topics before Commission staff groups, NARUC sub-committee groups, and as a program faculty member (2010 & 2011) for the Institute of Public Utilities at Michigan State University. Topics presented include management auditing and prudence reviews, service company costs and allocations, forecasting methodology and modeling, revenue requirements, rate base, price regulation theory, and cost trackers.

Education

Potsdam College, B.A., Economics, 1981
University at Buffalo School of Management, MBA, 1996

Regulatory Experience

Before the Arizona Corporation Commission (AZCC)

Docket No. 12-0291 *Application of Tucson Electric Power Company for Just and Reasonable rates and charges to realize a reasonable rate of return in Arizona*, before the AZCC. August 2012 - present
Project Manager and Testifying Witness. Oversaw analysis and assessment of the company's proposed cost of service and rate design, cost of capital and return on equity, and energy efficiency mechanisms. Will provide written testimony in support of Staff's position regarding energy efficiency mechanisms and environmental compliance adjustor.

Docket No. 11-0224 *Arizona Public Service Company Rate Case*, before the AZCC. July 2011-March 2012
Project Manager and Testifying Witness. Analyzed the company's proposed Infrastructure Tracking Mechanism, power supply adjustor, and tariffs. Testimony filed November 2011.

Before the Connecticut Public Utilities Regulatory Authority (PURA)

Docket 10-02-13 *Application of Aquarion Water Company to Amend its Rate Schedules*
On behalf of the PURA. April-August 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement specifically related to cash working capital and test year expenses.

Assisted with analysis of specific issues and preparation of Commission's recommended decision.

Docket 07-07-01 *Diagnostic Management Audit of Connecticut Light & Power Company.*
On behalf of the Staff of the PURA. July 2008-June 2009
Project Manager. Performed overall day to day project management responsibilities to conduct a diagnostic management audit of the Connecticut Light & Power Company (CL&P). Managed a project team of accountants, engineers and industry specialists who were responsible for evaluating the effectiveness of the management and operations of all aspects of the company. In addition, managed a focused prudency review of Northeast Utilities' (CL&P's parent company) development and implementation of a $122 million customer information system known as CustomerCentral or C2.

Before the Delaware Public Service Commission (DEPSC)
Docket No. 11-528 *On behalf of the Staff of the DEPSC in the matter of the application Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* January-July 2012
Project Manager and Testifying Witness. Oversaw rate case analysis and assessment of the company's proposed inter-company allocations. Provided expert testimony regarding the impact of the sale of Conectiv Energy on inter-company allocations and the resulting impact on revenue requirements.

Docket No. 09-414 *On behalf of the Staff of the DEPSC in the matter of the application of Delmarva Power & Light Company (DPL) for approval of modifications to its electric base rates.* September 2009-May 2010
Project Manager. Oversaw rate case analysis and assessment of the company's proposed revenue requirement. Assisted with analysis of specific issues and preparation of witness testimony.

Docket No. 07-239F *On behalf of the Staff of the DEPSC in the matter of the application DPL for approval of modifications to its gas cost rates.* October 2007-April 2008
Project Manager and Testifying Witness. Oversaw review of DPL gas hedging program and testified to the findings and conclusions.

Docket No. 06-287 *On behalf of the Staff of the DEPSC in the matter of Chesapeake Utilities Corporation's implementation of a Gas Hedging program.* June-August 2007
Project Manager. Provided industry expertise and suggestions to the Commission on a proposal plan to implement a gas hedging procurement program at the company.

Docket No. 06-284 *On behalf of the Staff of the DEPSC in the matter of DPL's request for a $15M increase in gas base rates.* October 2006-March 2007
Project Manager and Testifying Witness. Testified on several rate base and revenue requirement issues. Recommended Commission reduce proposed rate increase request to $8.4M (56%).

Before the District of Columbia Public Service Commission (DCPSC)

Formal Case No. 1093 *In the Matter of the Investigation into the Reasonableness of Washington Gas Light Company's (WGL) Existing Rates and charges for Gas Service*
On Behalf of the DCPSC. June 2012-present
Project Manager and Lead Consultant. Managed team of consultants providing advisory services to Commissioners and Staff on proposed revenue requirements, rate base, and rate design. Led analysis of revenue requirements, fuel costs, uncollectibles, environmental issues affecting rate base, inventory adjustments, plant in service, construction work in progress, research and development issues, safety initiatives, affiliate allocations, and energy funds.

Formal Case No. 1087 *In the Matter of the Application of the Potomac Electric Power Company (PEPCO) for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service*
On Behalf of the DCPSC. September 2011-present
Project Manager and Lead Consultant. Advised Commissioners and Staff on proposed revenue requirements, rate base, rate design, reliability projects, and cost recovery mechanism.

Formal Case No. 1076 *In the Matter of the Application of PEPCO for Authority to Increase Existing Retail Rates and Charges for Electric Distribution Service.*
On Behalf of the DCPSC. July 2009-June 2010
Project Manager. Advised Commission Staff on the company's and intervener's filings and testimony regarding revenue requirements, rate base, cost of service, rate design, bill stabilization, and depreciation.

Formal Case No. 1053 - *Technical consultant for the DCPSC in the matter of PEPCO's request for a $50.4 million increase in base rates.* February 2007-June 2008
Project Manager. Provided technical expertise to Commission in evaluating PEPCO's rate case filing. Commission accepted adjustments which reduced the allowed increase by a significant percentage.

Formal Case No. 1032 *In the Matter of the Investigation into PEPCO's Distribution Service Rates*
On Behalf of the DCPSC. January-March 2005
Project Manager. Review and evaluation of PEPCO compliance filings for class cost of service and revenue requirements for distribution service pursuant to a settlement approved in May 2002. Provided analysis and recommended adjustments to Staff on 23 designated issues and 13 company proposed adjustments. Proceeding was settled in anticipation of a full rate case for rates to be effective August 8, 2007.

Formal Case No. 1016 *In the Matter of the Application of Washington Gas Light Company (WGL), District of Columbia Division, for Authority to Increase Existing Rates and Charges for Gas Service*
On Behalf of the DCPSC. June-December 2003

Project Manager and Consultant to Commissioners and Staff. Project Manager for the analysis of WGL's rate filings. Provided analysis and recommended adjustments to the DCPSC Staff on WGL's proposed increase to base rates. Advised the Commission during deliberations on party positions and possible recommendations.

Before the Hawaii Public Utilities Commission

Docket No. 05-0075 *In the matter of a proceeding to investigate Kauai Island Utility Coop's Proposed Revised Integrated Resource Plan and Demand Side Management Framework.* June 2005-January 2006

Project Manager. Managed a team of consultants responsible for evaluating the impact of the changes proposed by the company.

Before the Illinois Commerce Commission (ILCC)

Case: 05-0597 *On behalf of the Illinois Citizens Utility Board, Cook County States Attorney's Office and City of Chicago.* November 2005-May 2006

Project Manager and Testifying Witness. Provided analysis and recommended adjustments in the general rate increase of 20.1% or $320 million filed by ComEd.

Consultant to Illinois Power Company. Conducted mandated compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Consultant to Illinois Power Company. Prepared 2001 required update filing for the ILCC compliance filing to un-bundle utility's rate tariffs. Prepared filing requirements and all support schedules analysis to justify allocation of generation, transmission and distribution. Prepared testimony on behalf of the company's controller.

Before Maine Public Utilities Commission (MEPUC)

Case No 2008-151 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase II)*

On behalf of Maine Public Advocate. July 2008-July 2010

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to follow-up on investigation for the need for the program and the company's management of the repair or replacement of its cast iron facilities.

Case No 2004-813 *MEPUC Investigation into Maintenance and Replacement Program for Northern Utilities Inc.'s Cast Iron Facilities (Phase I)*

On behalf of Maine Public Advocate. November 2004-March 2005

Project Manager and Testifying Witness. Litigated proceeding and led a consultant team to assist the State of Maine Public Advocate to investigate the need for the program and the company's management of the repair or replacement of its cast iron facilities. Participated in panel testimony regarding cost and risk of the program.

Before the Maryland Public Service Commission

Case No. 9092/9093 (Phase II) *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO and Delmarva Power & Light Company.* December-March 2008
Project Manager and Testifying Witness. Provided rebuttal testimony on behalf of the Commission related to the reasonableness of the costs and charges of Pepco Holdings, Inc. Service Company.

Case No. 9092 *On behalf of the Staff of the Commission in Base Rate Proceeding for PEPCO.* January-June 2007
Project Manager. Reviewed and analyzed the company's base increase request and all pro formas, adjustments to test year revenue requirement and supported witness testimony. Commission approved less than 20% of the company's original request.

Case No. 9062 *On behalf of the Maryland Office of People's Counsel in the matter of the application of Chesapeake Utilities Corporation for authority to revise its rates and charges for gas service.* May-August 2006
Project Manager. Managed a project team responsible for providing expert witness testimony in the areas of revenue requirements, rate base, cost of service, revenue allocation, rate design, revenue normalization, and cost of capital.

Before the Massachusetts Department of Public Utilities (MADPU)

Case No. D.P.U. 08-110 *On behalf of the MDPU regarding the Petition and Complaint of the Massachusetts Attorney General for an Audit of New England Gas Company.* February-August 2010
Project Manager. Managed a project team of accountants and industry specialists who were responsible for evaluating the accuracy of the accounting records, practices and procedures used in the development of the company's revenue requirements calculations in the company's base rate request.

Before the Michigan Public Service Commission

Case No. U-16655 *On behalf of the Attorney General of the State of Michigan (MIAG) in the matter of the application of Consumers Energy Company (CECO) for authority to reconcile its renewable energy plan (REP) costs associated with the plan approved in Case No. U-15805 and Case No. U-16543.* September 2012-present
Project Manager and Testifying Witness. Review the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Testified regarding the company's methodology used to calculate its proposed PSCR expense.

Case No. U-16656 *On behalf of the MIAG in the matter of the application of The Detroit Edison Company (DetEd) for authority to reconcile its REP costs associated with the amended plan approved in Case No. U-16582.* September 2012-present

Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2011 to ensure the adherence to approved processes and reasonable and prudent costs. Expected to testify at upcoming hearing.

Case No. U-16434-R *On behalf of the MIAG in the matter of the Application of DetEd for reconciliation of its 2011 power supply cost recovery (PSCR) plan.* June 2012-present
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, over-refund of the company's residual Self-Implementation Refund, the company's claimed credit to PSCR costs related to credit claimed by affiliate, RARS asset and liability balance resulting in over recovery, and Reduced Emissions Fuel (REF) prudency and calculation of REF impacts.

Case No. U-17026 *On behalf of the MIAG in the matter of the application of Indiana Michigan Power Company for a certificate of necessity pursuant to MCL 460.6s and related accounting authorizations* June-September 2012
Project Manager. Managed review of certificate of necessity, evaluation of company's prudency in obtaining alternative power supply options, and review of the company's implementation of and prudency in management of its nuclear plant Life Cycle Management project in comparison to industry standards.

Case No. U-16892 *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for 2010.* November 2011-May 2012
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-16047-R *On behalf of the MIAG in the matter of the application of DetEd for its PSCR plan for 2011.* August 2011-March 2012
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis and testimony concerning prior year under-recovery of power supply costs, under-recovery of cumulative Pension Equalization Mechanism costs, and the over-refund of the company's residual Self-Implementation Refund.

Case No. U-16432 *On behalf of the MIAG in the matter of CECO's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager. Reviewed cost recovery plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and purchased power, purchased power agreements, emission control expenses including appropriateness of mercury filter expenses as part of PSCR process.

Case No. U-16434 *On behalf of the MIAG in the matter of DetEd's Application to Implement a PSCR Plan for 2011.* February-June 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and provided analysis concerning prior year under-recovery, generation dispatch and

purchased power, purchased power agreements, emission control expenses including appropriateness of coal refinement expenses as part of PSCR process.

Case No. U-16472 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its rates, amend its rate schedules and rules governing the distribution and supply of electric energy, and for miscellaneous accounting authority.* February-June 2011
Project Manager and Testifying Witness. Review of Advanced Metering Infrastructure program cost benefits and tariffs filed and testifying witness to same.

Case No. U-16407 *On behalf of the MIAG in the matter of the application of Michigan Consolidated Gas Company (MichCon) for approval of a detailed plan for main renewal, including a long-term plan to significantly reduce the amount of cast iron main in its system.* October 2010-May 2011
Project Manager and Testifying Witness. Reviewed the company's proposed plan with respect to whether a cost recovery mechanism can be designed to minimize the impact on ratepayers. Testified as to the reasonableness of cost benefit of replacements as well as to the capital cost recovery as it affects future rate cases.

Case No. U-16300 *On behalf of the MIAG in the matter of the application of CECO for authority to reconcile its REP costs associated with the plan approved in Case No. U-15805.* November 2010-January 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure the adherence to approved processes and reasonable and prudent costs. Testified as to significant concerns with respect to the transfer price for renewable energy resources proposed by the company.

Case No. U-16356 *On behalf of the MIAG in the matter of the application of DetEd for authority to reconcile its REP costs associated with the plan approved in Case No. U-15806-RPS.* October 2010-March 2011
Project Manager and Testifying Witness. Reviewed the company's REP Cost Reconciliation for 2009 to ensure adherence to approved processes and reasonable and prudent costs and testified to those issues.

Case No. U-15675-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2009.* October 2010-January 2011
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified to transfer price, replacement power costs, and reasonableness of including excess fuel and variable O&M expenses proffered by various intervenors.

Case No. U-15677-R *On behalf of the MIAG in the matter of the application of DetEd for reconciliation of its PSCR plan for the calendar year 2009.* September-December 2010

Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified with respect to the transfer price for renewable energy source flowing into the PSCR proposed by the company.

Case No. U-16047 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR Plan in its rate schedules for 2010 metered jurisdictional sales of electricity.* January-May 2010
Project manager and Testifying Witness. Reviewed PSCR plan requirements and testified to appropriateness of specific components of that factor.

Case No. U-15415-R *On behalf of the MIAG in the matter of the application of CECO for the reconciliation of PSCR costs and revenues for the calendar year 2008 and for other relief related to pension and OPEB costs.* May-November 2009
Project Manager and Testifying Witness. Reviewed PSCR reconciliation, provided analysis of potential issues, and developed recommendations including basis, past precedence, and/or industry expertise. Testified regarding Karn 1 outage delay and Rate E-1 discount recovery.

Case No. U-15806/U-15890 *On behalf of the MIAG in the matter of DetEd's and MichCon's compliance with Public Acts 286 and 296 regarding their REP and Energy Optimization Plan (EOP).* March-June 2009
Project Manager and Testifying Witness. Reviewed the EOPs of both companies and provided analysis and testimony regarding issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15805/15889 *On behalf of the MIAG in the matter of CECO to comply with Public Acts 286 and 295 regarding its REP and EOP.* March-June 2009
Project Manager and Testifying Witness. Reviewed the company's EOP and provided analysis and testimony of issues and shortcomings concerning the plans in relation to the specifications of the Act and the benefit to customers.

Case No. U-15677 *On behalf of the MIAG in the matter of the application of DetEd for authority to implement a PSCR plan in its rate schedules for 2009 metered jurisdictional sales of electricity.* January-June 2009
Project manager. Reviewed PSCR plan requirements for appropriateness of specific components of that factor.

Case No. U-15415 *On behalf of the MIAG in the matter of the application of CECO for approval of a PSCR plan and for authorization of monthly PSCR factors for the year 2008.* January-March 2008
Project Manager. Reviewed PSCR plan requirements and provided summary briefing to Michigan Attorney General.

Case No. U-15320 *On behalf of the MIAG in the matter of the application of Midland Cogeneration Venture Limited Partnership (MCV) for the Commission to eliminate the*

"availability caps" which limit CECO's recovery of capacity payments with respect to its power purchase agreement with MCV. October 2007-June 2008
Project Manager. Oversaw project to provide industry expertise to evaluate issue in case and recommend alternative arguments.

Case No. U-15245 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* July 2007-April 2008
Project Manager and Testifying Witness. Provided expert testimony on partial and interim rate relief, CECO's decision to acquire Zeeland Power Company from Broadway Gen Funding, LLC. Provided testimony in permanent phase to reduce the company's net operating income to more closely reflect the expected costs in 2008.

Case No U-15244 *On behalf of the MIAG in the matter of the application of DetEd for authority to increase its electric base rates.* September 2007-October 2008
Project Manager and Testifying Witness. Testified regarding revenue requirements.

Case No U-15190 *On behalf of the MIAG in Base Rate Proceeding for CECO.* March-September 2007
Project Manager. Reviewed the revenue decoupling proposal and supported the witness testimony.

Case No U-15040 *On behalf of the MIAG in GCR 2007/08 Plan proceeding of Michigan Gas Utilities Corporation.* March-August 2007
Project Manager and Testifying Witness. Reviewed GCR plan requirements and provided analysis of the potential benefits of gas procurement hedging program. Testified regarding the GCR clause plan 2007-08.

Case No. U-14231 *On behalf of the MIAG in the matter, on the Commission's own motion, to commence an investigation into future capacity requirements.* February-May 2007
Project Manager. Reviewed and provided a formal written report on the Michigan Public Service Commission's 21st Century Energy Plan Report.

Case No. U-15001 *On behalf of the MIAG in PSCR 2007/08 Plan proceeding.* November 2006-August 2007
Project Manager and Testifying Witness. Reviewed PSCR plan requirements and testified regarding the company's projected PSCR under-recoveries for 2005 and 2006.

Case No. U-14701-R *On behalf of the MIAG in PSCR 2006/07 reconciliation proceeding.* June-November 2007
Project Manager and Testifying Witness. Reviewed PSCR reconciliation and testified to eliminate some expenses used in the company's calculation of its under-recovery PSCR reconciliation for 2006.

Case No. U-14547 *On behalf of the MIAG in the matter of the application of CECO for authority to increase rates for the distribution of natural gas and for other relief.* December 2005-April 2006
Expert Witness and Project Manager. Provided analysis, recommended adjustments, and filed testimony for the Attorney General on CECO's proposed increase to base rates.

Case No. U-14347 *On behalf of the MIAG in the matter of the application of CECO for authority to increase its rates for the generation and distribution of electricity and for other relief.* April-September 2005.
Project Manager. Managed project team and supported testimony on cost of service, revenue allocation and rate design issues.

Before the Missouri Public Service Commission (MOPSC)
Veolia Energy Company (Veolia) 2011 and 2012 Request for Authority to Increase Electric Rates in Missouri (Case No. HR-2011-0241). July-September 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review Veolia's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated Veolia's proposed revenue requirement and testified before the MOPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Consultant to Ameren UE. Conducted revenue requirement analysis in preparation of Missouri Public Service Commission compliance filing to un-bundle utility's rate tariffs. Prepared the filing requirements and all support schedules analysis to justify allocations of generation, transmission and distribution.

New Mexico Public Regulation Commission (NMPRC)
Special Case Study: Public Service Company of New Mexico (PNM) NM PRC Docket No. 10-00086-UT. August 2010
Blue Ridge worked with QSI Consulting, Inc. to conduct a training session for the NMPSC Staff and develop training materials for presentation to Staff on the basic elements of future test year proceedings, how those may differ from traditional rate cases, and how to apply and interpret the forecasting methodologies and modeling that will come into play; and analyze the pending PNM rate case and provide an analytic framework for Staff to apply to the forecasting issues in the case.

Before the North Dakota Public Service Commission (NDPSC)
Northern States Power Company (NSP) 2011 and 2012 Request for Authority to Increase Electric Rates in North Dakota (Case No. PU-10-657/PU-11-55). April-October 2011
Project Manager and Testifying Witness. Led a team of consultants engaged to review NSP's proposed adjustments, rate base, revenues and expenses, affiliate transactions and allocations, revenue requirement, cost of capital, and cost of service and rate design. Evaluated NSP's proposed revenue requirement and testified before the NDPSC to proposed adjustments to the revenue requirements filed by the company in its application.

Before the Nova Scotia Utility and Review Board
Case No. P-888 *On behalf of the Consumer Advocate of the Province of Nova Scotia in the base rate proceeding of Nova Scotia Power.* December 2006-March 2007
Project Manager and Testifying Witness. Provided an evaluation of a management audit of Nova Scotia Power and that report's usefulness to assess the company's management performance and operational efficiency within the context of that proceeding.

Before the Public Utilities Commission of Ohio (PUCO)
Case No. 11-5428-EL-RDR *On behalf of the Staff of the Public Utilities Commission of Ohio In the matter of the application of Delivery Capital Recovery (DCR) Rider Contained in the Tariffs of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company (collectively, Companies).* November 2011-April 2012
Project Manager and Expert Witness. Led a team of consultants engaged to audit and attest to the accuracy and reasonableness of the Companies' compliance with their Commission-approved DCR Riders with regard to the return earned on plant-in-service since the Companies' last distribution rate case.

Case No. 08-0917-EL-SSO *On behalf of the Ohio Hospital Association in the matter of the Application of American Electric Power of Ohio for authority to increase rates for distribution of electric service.* (Hired by Ohio Hospital Association's attorney for utility matters, Bricker and Eckler, to provide expertise in negotiating rate with American Electric Power). September 2008-March 2009
Evaluated revenue and rate impact on member hospitals.

On behalf of the Staff of the PUCO:

- Case #08-0072-GA-AIR Columbia Gas of Ohio for an increase in gas rates, April-August 2008
- Case #07-0829-GA-AIR Dominion East Ohio for an increase in gas rates, November 2007-July 2008
- Case #07-0589-GA-AIR Duke Energy Ohio for an increase in gas rates, November 2007-Februrary 2008

Project Manager. Oversaw multi-discipline team of accountants, auditors, engineers and analysts to conduct a comprehensive rate case audit of the company's gas base rate filing. Primary goal of project was to validate information in filing, provide findings conclusions and recommendations concerning the reliability of information and data in the filing and support Staff in its evaluation of the reasonableness of the filing.

Case No. 07-0551-EL-UNC *On behalf of the Ohio Schools Council in the matter of the Application of FirstEnergy Ohio (and its operating companies Ohio Edison, Cleveland Electric and Toledo Edison) for authority to Increase rates for distribution service, modify certain accounting practices and for tariff approval.* August 2007-April 2008
Project Manager. Hired by Ohio Schools Council's attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing FirstEnergy's application

with respect to cost of service and rate design and the resulting impact on Council's member school systems' energy costs.

Case No. 06-0986-EL-UNC *On behalf of the City of Cincinnati in the matter of the Application of Duke Energy Ohio, Inc., to modify its market-based Standard service offer.* May-August 2007
Project Manager. Hired by City of Cincinnati's Water and Sewer District attorney for utility matters (Bricker and Eckler, LLP) to provide industry expertise in reviewing the company's proposal and impact on City's project energy costs.

Oregon Public Utility Commission (OPUC)
Docket No UP205 *Examination of NW Natural's Rate Base and Affiliated Interests Issues* Co-sponsored between NW Natural, Staff, Northwest Industrial Gas Users, Citizens Utility Board. August 2005-January 2006
Project Manager. Led a team that conducted a management audit of NW Natural Gas that included an evaluation of rate base issues for Financial Instruments (gas and financial hedging) Deferred Taxes, Tax Credits, Cost for a Distribution System, Security Issuance Costs and AFUDC calculations as well as Affiliate Transactions for Cost Allocations and Transfer Pricing, Labor Loading, Segregation of Regulated Rate Base and Subsidiary Investments and Properties, and validation of tax paid from/to affiliates are proper. Audit was to ensure the company's compliance with orders, rules and regulations of the OPUC, with company policy and with Generally Accepted Accounting Principles.

Utah Division of Public Utilities
Docket No. 09-035-23 *In the Matter of the Application of Rocky Mountain Power (RMP) for Authority to Increase its Retail Electric Utility Service Rates in Utah and for Approval of its Proposed Electric Service Schedules and Electric Service Regulations.* June-December 2009
Project Manager and Testifying Witness. Verified the reasonableness of the revenue requirements as provided by the company in its application and testified before the Public Service Commission of Utah.

Docket No. 09-035-15 *In the Matter of the Application of RMP for Approval of its Proposed Energy Cost Adjustment Mechanism (ECAM) - Net Power Cost Evaluation (NPC), RMP 2009 General Rate Case.* July-December 2009
Project Manager and Testifying Witness. Analyzed the reasonableness and technical accuracy of the RMP's NPC request, performed a comprehensive review of the company's NPC estimate and developed recommendations to ensure an accurate baseline for the ECAM, analyzed special issues addressed in the NPC portion of the case, analyzed the company's fuel price hedging policies and provided recommendations appropriate for the ECAM, and reviewed intervener NPC issues as well as analyzing additional issues as raised by the company and testified to hedging issues.

Before the Washington Utilities and Transportation Commission (WUTC)

Independent Third-Party Evaluation of Puget Sound Energy's (PSE) Conservation Incentive Mechanism (ECIM) under the co-direction of PSE and the WUTC Staff. Phase I: July-October 2009; Phase II: October 2009-September 2010

Project Manager. Assess the extent to which the design and implementation of the incentive mechanism addressed key issues and objectives required by the Commission: accuracy of implementation in calculations of incentives or penalties, compliance with the conditions and requirements of the pilot program, proper use of the calculation methodology, and which assumptions or methods were used to calculate and verify the savings report.

Before the Public Utilities Commission of the State of Colorado (COPUC)

Docket No. 04A-050E *Review of the Electric Commodity Trading Operations of Public Service Company of Colorado (PSCo)*

On behalf of the COPUC Staff. March-September 2004

Project Manager. Focused operational audit within the bounds of a litigated proceeding to determine if ratepayers were subsidizing or negatively impacted by PSCo's energy trading function.

South Carolina State Senator

Advised Senator on regulatory process for requesting States Public Service Commission for a comprehensive review of Duke Power Company's storm and restoration and right of way management. Reviewed and advised Senator of results of report finding.

Southern Connecticut Gas

Consultant. As part of a team that conducted a comprehensive management audit of the management and operations of the company, completed the capital budgeting area of the audit.

Before the New York Public Service Commission

Case: 94-C-0657

Commission Staff. Proceeding to evaluate the compliance of NYNEX with Commission rules and orders related to operational support system costs to competitors. Part of staff panel to facilitate discussion between the company and potential competitors (i.e., users of operational support systems) and report back to Commission.

Focused review of the preparedness of Rochester Gas and Electric (RG&E) and Consolidated Edison (ConEd) for competition in the electric industry. Evaluated all aspects of the company's management actions to prepare for competition including strategic planning, goals and objectives and senior management's attention to the company operations in a de-regulated industry.

Case: 97-M-0567

Commission Staff. Litigated proceeding to determine the benefits of a proposed merger of Long Island Lighting Company (LILCO)/Brooklyn Union Gas. Analyzed proposed synergy savings.

Case: 96-E-0132 *Show Cause Proceeding Regarding Rate Relief for Ratepayers of LILCO*
Commission Staff and Testifying Witness. Litigated proceeding where Staff proffered testimony containing a benchmark study showing that LILCO's operations and maintenance expenses were excessive compared to a peer group of 24 utilities. Panel testimony concerning the findings and conclusions resulting from the benchmark study.

Case: 96-M-0858 *Prudence Investigation into the Scrap Handling Practices in the Western Division of Niagara Mohawk Power Company (NIMO)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of allegations of bribery and corruption in company practices related to a specific vendor who purchased company scrap metal. Lead team of 10 staff examiners to quantify the extent to which the company paid excessive rates to this vendor. Testified to the findings of the analysis. Case settled with ratepayers receiving a credit to bills.

Case: 91-C-0613 *Operational Audit of the Outside Plant Construction and Rehabilitation Program of New York Telephone Company*
Commission Staff. Comprehensive operational audit of the company's management and implementation of a $150M capital program to rehabilitate the outside plant distribution network. Served as Staff Examiner responsible for crew supervision, goals monitoring, contractor oversight, and report preparation.

Case: 91-W-0583 *Prudence Proceeding of the Operations and Management of Jamaica Water*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive costs to rate payers. Testified on a Staff panel to the excessive costs associated with management's inattention to sound business practices related to the design, purchase and installation of the company customer information system.

Case: 92-W-0030 *Operational Audit of Jamaica Water Operations and Management*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, and specific topics areas including engineering, contracting, and information technology. Findings led to prudence proceeding.

Case: 92-M-0973 *Management Audit of RG&E*
Commission Staff. Comprehensive management audit of company operations. Responsible for work plan development, supervision of staff and specific topics areas including purchasing and internal controls.

Case: 93-E-0918 *Operational Audit of the Demand Side Management Function at RG&E*

Commission Staff. Comprehensive operational audit of the demand side management function including program planning, management and energy savings verification. Developed and supervised the implementation of the work plan.

Case: 88005 *Operational Audit of Materials and Supply Function at National Fuel Gas*
Commission Staff. Comprehensive operational audit of the materials and supplies function including warehouse operations, inventory control and procurement. Developed and implemented the work plan for this project.

Operational Audit of the Fuel Procurement and Contracting of LILCO
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project.

Operational Audit of the Fuel Procurement and Contracting of ConEd
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Case: 90007 Operational Audit of the Fuel Procurement and Contracting of Central Hudson Gas and Electric
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of Fuel Procurement and Contracting of Orange & Rockland Utilities
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Provided research and data evaluation expertise to the project

Operational Audit of the Fuel Procurement and Contracting of RG&E
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on nuclear fuel. Provided research and data evaluation expertise.

Case: 88-E-115 *Prudence Proceeding to Investigate the Construction Costs Associated with the Homer City Coal Cleaning Plant (HCCCP)*
Commission Staff and Testifying Witness. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive construction charges related to the HCCCP. Testified on a Staff panel to the fuel price differential costs resulting from the failure of the coal cleaning plant to function as designed as well as surrebuttal testimony on the cost of a flu-gas de-sulfurization plant and ancillary equipment and facilities. Case settled. Customers received $125M credit.

Case: 87003 *Operational Audit of the HCCCP*

Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on the construction of the HCCCP jointly owned by New York State Electric and Gas (NYSEG) and Penelec. Responsible for fuel and construction costs analysis, benchmarking costs and alternative methods for meeting EPA Clean air restrictions, contracting practices and report preparation.

Case: 87003 *Operational Audit of the Fuel Procurement and Contracting of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis, benchmarking costs, contracting practices and report preparation.

Case: 86007 *Operational Audit of the Field Crew Supervision and Utilization of NYSEG*
Commission Staff. Comprehensive operational audit to determine effectiveness of field crew utilization and supervision. Staff examiner responsible for verifying supervisor activities, reporting, goals attainment and report preparation.

Case: 86005 *Prudence Proceeding to Investigate the Fuel Procurement and Contracting Practices at NIMO*
Commission Staff. Litigated proceeding as a result of audit to determine extent to which management inattention and inappropriate practices resulted in excessive fuel charges to customers. Responsible for fuel cost analysis and benchmarking costs, contracting practices, and testimony preparation. Case settled with customers receiving $66M credit.

Case: 86005 *Operational Audit of the Fuel Procurement and Contracting of NIMO*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on non-nuclear fuel. Responsible for fuel cost analysis and benchmarking costs, contracting practices and report preparation.

Case: 85001 *Operational Audit of the Research and Development Function of ConEd*
Commission Staff. Comprehensive operational audit to determine effectiveness of ratepayer funds spent on R&D activities. Staff examiner on the project responsible for reviewing projects documentation and control, outside contracting a report preparation.

Testimony filed by Mr. McGarry

Before the Arizona Corporation Commission

- Arizona Public Service Company - Docket No. E-01345A-11-0224

Before the Delaware Public Service Commission

- Delmarva Power and Light Company - Docket No. 11-528
- Delmarva Power and Light Company - Docket No. 07-239F
- Delmarva Power and Light Company - Docket No. 06-284

Before the Illinois Commerce Commission

- Commonwealth Edison - Case: 05-0597

Before Maine Public Utilities Commission

- Northern Utilities Inc. - Case No. 2008-151
- Northern Utilities Inc. - Case No. 2004-813

Before the Maryland Public Service Commission

- PEPCO and Delmarva Power and Light Company - Case No. 9092/9093

Before the Michigan Public Service Commission

- Consumers Energy Company - Case No. U-16655
- Detroit Edison Company - Case No. U-16434-R
- Detroit Edison Company - Case No. U-16047-R
- Detroit Edison Company - Case No. U-16434
- Detroit Edison Company - Case No. U-16892
- Detroit Edison Company - Case No. U-16472
- Michigan Consolidated Gas Company - Case No. U-16407
- Detroit Edison Company - Case No. U-16356
- Consumers Energy Company - Case No. U-16300
- Detroit Edison Company - Case No. U-16047
- Detroit Edison Co. and Michigan Consolidated Gas - Case No. U-15806/U-15890
- Consumers Energy Company - Case No. U-15805/15889
- Detroit Edison Company - Case No. U-15677-R
- Consumers Energy Company - Case No. U-15675-R
- Consumers Energy Company - Case No. U-15415-R
- Consumers Energy Company - Case No. U-15245
- Detroit Edison Company - Case No. U-15244
- Michigan Gas Utilities Corporation - Case No. U-15040
- Consumers Energy Company - Case No. U-15001
- Consumers Energy Company - Case No. U-14701-R
- Consumer Energy Company - Case No. U-14547

Before the Missouri Public Service Commission

- Veolia Energy Company - Case No. HR-2011-0241

Before the New York Public Service Commission

- Long Island Lighting Company - Case: 96-E-0132
- Niagara Mohawk Power Company - Case: 96-M-0858
- Jamaica Water - Case: 91-W-0583
- New York State Electric & Gas Homer City Prudence Review - Case: 88-E-115

Before the North Dakota Public Service Commission

- Northern States Power Company - Case Nos. PU-10-657 and PU-11-55

Before the Nova Scotia Utility and Review Board

- Nova Scotia Power - Case No. P-888

Before the Utah Division of Public Utilities

- Rocky Mountain Power - Docket No. 09-035-23

Speaking Engagements

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, CAPEX Trackers, March 28, 2012.

Institute of Public Utilities, Michigan State University, East Lansing, MI; Advanced Regulatory Studies Program, training session on Management Audits and Prudency Reviews; September 27, 2011, and September 30, 2010.

National Association of Regulatory Utility Commissioners - Before the NARUC sub-committee on Accounting and Finance, service company costs and allocations to regulated entities, September 15, 2010.

New Mexico Public Regulation Commission Staff, Santa Fe, NM - In cooperation with QSI Consulting; service companies and related cost allocations, benchmarking, and rate case planning; June 29, 2010.

Colorado Public Utilities Commission Staff – In cooperation with QSI Consulting; future of regulation and deregulation, revenue requirements, rate base, rate of return, cost of service, determining net operating income, cost of capital, staff audits, and affiliate transactions; June 22, 2006.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-12-0504

DIRECT

TESTIMONY

OF

W. MICHAEL LEWIS, P.E.

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2013

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ATTACHMENTS

EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-12-0504

Staff's testimony in this proceeding describes and presents evaluations, observations and recommendations regarding the above captioned matter to the Arizona Corporation Commission pursuant to our investigation on behalf of Utilities Division Staff. We were to evaluate the service quality and reliability of the distribution system, observe and evaluate the major items of investment proposed for post-test year inclusion into rate base, and review the operations and maintenance practices of UNS Electric Inc. ("UNS Electric" or "Company") in providing electric services to its customers. A field investigation and analysis of the Company's service quality indices comprised a major component of our evaluation. Other aspects included on-sight discussions with Company personnel, review of filed testimony and the Company's application, preparation of data requests and analysis of the Company's responses to same and responses to data requests by others. The results of these investigations and analysis are presented in our testimony.

UNS Electric's quality of service and reliability of its distribution system are reflected by the values of indices of customer average frequency and duration of outages as defined by Institute of Electrical and Electronics Engineers ("IEEE") Standard 1366. These indices were requested in STF 4.38 for the period of 2010-2012 by calendar year. In addition, we reviewed records of customer complaints concerning outages and restoration of outages and a listing of outages of a duration of 4 hours or more affecting 200 or more customers during each outage. Based upon our analyses of the service quality indices provided by UNS Electric, we have concluded that the quality of service provided by the Company is generally acceptable for each of the three years reviewed. However, there is a discernible trend toward less reliability in the more recent two years. We recommend that the Company's indices for 2013 be reviewed to determine if the trend has improved and that the Company compile its service indices results by separate services areas and by individual circuits. Further, to improve the service quality, we recommend that the Company base its future distribution maintenance and restoration efforts on an individual circuit basis as indicated by each circuit's service quality indices. We note that such a program has recently been initiated by Tucson Electric Power Company ("TEP").

UNS Electric's grid operation and control is provided by the control center operated by TEP personnel. Similarly, the TEP Customer Call Center also serves the Company's customers. We had recently evaluated and observed the operation and procedures of the control center and call center during the most recent TEP rate proceeding and found them acceptable and competently operated. That remains our opinion as those operations relate to the present UNS Electric proceeding.

The Company is requesting an increase of about $23.6 million in adjusted rate base since 2008 and of about $13.1 million of post-test year plant additions be included in this proceeding. A significant item of the post-test year addition requested is that of the Rio Rico Solar photovoltaic facility in the amount of $5.755 million.

Field investigations were made of many of these projects including 4 projects in the Nogales service area and 5 projects in the Kingman/Lake Havasu service areas. Of these, 3 in the Kingman/Lake Havasu area are part of the post-test year added plant requested as are all 4 of those in the Nogales area. Our investigations indicate that all of these, with one exception, can be properly included in rate base in this proceeding. The Rio Rico Solar Project will not be in service as of June 30, 2013 and, therefore, does not meet the standard by which the Commission should allow this investment into rate base in this proceeding.

The Company has requested adjustment to its current depreciation for the Valencia and Black Mountain Generating Stations ("BMGS") to reflect future decommissioning requirements. The Company provided a study by others titled "Decommissioning Study of TEP Generating Assets," apparently in support of its requested adjustments. However, UNS Electric has not introduced a modified depreciation study in this proceeding.

Our review of the decommissioning study indicates that the costs for Valencia and BMGS as requested are based upon a projected total clearing of the sites except for the associated substations, followed by a restoration of the sites to a "green field" status. We question the reasonableness of these projections as it seems much more likely that both sites will be maintained as generation assets with replacement of major equipment components as may be required. The Company argues that either or both sites could be retired as a result of new developments in generation with resulting higher heat rate. In this event, certain aspects of the plants are required to be restored by regulatory permitting. We find this unconvincing. Given the lack of a modified depreciation schedule and insufficient justification for the estimated decommissioning, we are recommending that the Commission reject the request for the inclusion of these projected costs in this proceeding.

In conclusion, we found the Company's reliability and service quality of its distribution system to be acceptable but that the trend in service quality indices requires review for the results of 2013 when available. We accept the Company's request for its claimed additions to rate base for the post-test year period with the exception of the Rio Rico Solar Project. We find the O&M practices to be acceptable and that they can be improved by the addition of a program of targeted circuit betterment using the service indices on an individual circuit basis as a guide. We also find to be acceptable with good procedures, the operation and control of the UNS Electric grid and the operations of the call center. We conclude that the allowance of additional depreciation for the projected decommissioning of Valencia and BMGS is not justified.

Our recommendations to the Commission are as follows:

1. We recommend that UNS Electric have its distribution quality of service indices available, upon request, for review by Staff on a monthly and calendar year basis. Additionally, we recommend that these indices be by calendar year on a service area by service area basis, as well as on an overall system-wide basis. These indices are the Customer Average Interruption Duration Index ("CAIDI"), the System Average Interruption Frequency Index ("SAIFI"), and the System Average Interruption Duration Index ("SAIDI").

2. We recommend that UNS Electric submit its quality of service indices for calendar year 2013 for Commission Staff review by March 31, 2014, to determine if the trend of the indices is improving.

3. We recommend that UNS Electric prepare on an annual basis a listing of the worst performing circuits identified by service area and reliability indices and adopt a program similar to that implemented by TEP to target annual circuit maintenance toward circuits identified by indices value and survey as representing the most efficient means of improving SAIFI values.

4. UNS Electric has proposed a total of $14.417 million for post-test year gross utility plan in service. We have no objection to the Commission accepting UNS Electric's proposed post-test year gross utility plant in service amount of $8.662 million (ACC jurisdictional amount of the $8.770 million shown on application, Schedule B-2) requested by UNS Electric for inclusion into rate base from an engineering standpoint. However, recommend that the Commission not approve UNS Electric's proposed post-test year plant-of $5.755 million associated with the Rio Rico Solar Project requested by UNS Electric for inclusion into rate base.

5. UNS Electric maintenance scheduling should continue to include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, including the BMGS.

6. We recommend that UNS Electric's request that expected costs of decommissioning of certain of its generating assets not be approved for inclusion in depreciation rates at this time. In this regard, should the Commission wish to consider allowing these costs, we recommend that the Commission direct UNS Electric to file a definite plan and support for its current claims, and as well with regard to any anticipated future claims, as to the need for the inclusion of such decommissioning costs as a cost of removal component of depreciation rates.

I. INTRODUCTION

Q. Please state your name and business address.

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

Q. What is your present employment?

A. I am employed by the firm of W. M. Lewis and Associates, Inc. ("WML&A"). I am the President of the firm.

Q. Please describe the nature of the firm.

A. WML&A is a Consulting Engineering firm which provides various engineering services, primarily in areas of electrical power and electric utility operation, to a range of clients including investor-owned electric utilities, municipal utilities, international investment organizations, and regulatory bodies. The firm was established in 1958.

Q. Please describe your background, education, and experience.

A. I have been employed by WML&A since 1979. Prior employment was with Goodyear Atomic Corp. and Westinghouse Electric. Positions that I have held at WML&A include Sr. Engineer, Manager of Engineering, Vice-President, and President. I hold a BSEE degree from Ohio State University and an MBA from Ohio University. For the past 15 years, much of my work has involved foreign assignments on behalf of the Asian Development Bank and World Bank in project post-evaluation, feasibility studies, and reviews of operation and maintenance of various generating stations, urban and rural transmission and distribution systems, and utility management. Additional tasks included the design of facilities and preparation of agreements for the interconnection of utilities, preparing operating agreements between utilities and independent power producers, and various tasks related to the privatization of electric utilities in the South Asian area. Additional aspects of my experience and education are presented in my resume, which is attached to this testimony as Attachment 1.

Q. Are you filing direct testimony on behalf of Arizona Corporation Commission ("Commission") Utilities Division Staff ("Staff")?

A. Yes.

Q. What is the nature of your testimony in this proceeding?

A. My testimony describes and presents evaluations, observations and recommendations regarding the above captioned matter to the Commission on behalf of Commission Staff. We evaluated the service quality and reliability of the distribution system, observed and evaluated some of the major items of investment proposed for post-test year inclusion into rate base, and reviewed the operations and maintenance practices of UNS Electric, Inc. ("UNS Electric" or "Company") in providing electric services to its customers.

Q. What was the major component of your evaluation?

A. Consistent with the authorization from Staff, a major component of the investigation was the field inspections of UNS Electric facilities in the Kingman, Lake Havasu, and Nogales areas. Field inspections were made on May 20, 2013 through May 25, 2013, accompanied by UNS Electric and Tucson Electric Power Company ("TEP") personnel.

Q. Who participated in the field investigations with you?

A. I performed the field inspections with the assistance of Kenneth Strobl, P.E. of the firm of Technical Associates, Inc. Ed Stoneburg Staff also participated on May 23 in Nogales. Mr. Strobl also contributed to the preparation of this testimony.

Q. Please describe the major elements of your investigation.

A. The major elements of our investigation focused on UNS Electric's service quality distribution system indices, and the operations of selected transmission and distribution facilities currently in service and under construction. The field inspections included discussions with the Company's engineering and other technical personnel, as well as field supervisory personnel responsible for the operations of the Company's electrical transmission and distribution network assets. In anticipation of and in conjunction with these activities, we reviewed portions of UNS Electric's prefiled application and testimony in this case, as well as public documents such as its Federal Energy Regulatory Commission ("FERC") Form 1. Additionally, we prepared data requests to the Company that addressed service quality, electric distribution and generation system operations; i.e., Staff data requests Set No. 4, STF 4.01 through 4.38.

II. WORK ACTIVITIES AND EVALUATIONS

Q. Please describe your evaluations and the role of your field investigations.

A. Our work activities began with reviews and analyses of UNS Electric's application and prefiled testimony and exhibits in this proceeding. In addition to the information in the application and prefiled materials, we reviewed the Company's responses to data requests, as well as other supplemental documents filed in support of the application.

Information was acquired and analyses undertaken through UNS Electric's responses to data requests in Staff Set No. 4. For example, the Company's response to STF 4.01 and STF 4.02 provided the listing of UNS Electric's construction and installation projects the Company is requesting as post-test year investment for inclusion in rate base in this case. The Company's response to STF 4.02 provided in-service dates for projects completed or yet to be completed since the last UNS Electric base rate case.

Responses to Staff data request STF 4.38 provided information and analyses addressing the Company's distribution system performance, operations, and reliability indices.

UNS Electric's responses to STF 4.07 through STF 4.10 provided operational information regarding certain of UNS Electric's transmission, distribution, and operating and maintenance information relating to the Company's overhead and underground lines and substation facilities. Additionally, the Company's response to STF 4.11 through 4.16 addressed the installation, operations and performance of metering programs and plans for the UNS Electric system for the near future.

A. Quality of Service/Distribution Performance

Q. Please discuss the determination of the Company's Quality of Service as it relates to Distribution Performance.

A. The electric utility industry has developed various indices as indicators of distribution performance and reliability. These include measures of customer average outage duration and average frequency of outages. These indices are defined by the Institute of Electrical and Electronics Engineers ("IEEE") standard P1366 which has set a 5-minute disruption of service as the threshold to be considered an outage for the calculation of the various indices. In 2003, IEEE 1366 included the concept of a "Major Event Day" ("MED") to account for outages deemed to be caused by unusually severe weather and similar incidents so that such incidents could be considered separately from normal operating conditions. MED thresholds are calculated on a 5-year (rolling) average. The quality of service indices of most interest are Customer Average Interruption Duration Index ("CAIDI"), System Average Interruption Frequency Index ("SAIFI"), and System Average Interruption Duration Index ("SAIDI"). In response to Staff data request STF 4.38, UNS Electric provided the determinations of its system monthly indices for the years 2010, 2011, and 2012. In STF 4.19, we also requested that the Company provide a listing of service interruptions of at least 4 hours and that affected more than 200 customers in each of the calendar years 2009 through 2012.

Q. Please discuss the Company's responses to your Request For Service Interruptions.

A. The Company's response to STF 4.19 provided outage forms from the customer-hour outage reports on file with the Commission which are derived from the Company's geospatial information system. The response included four outage forms for 2009, two outage forms for 2010, none for 2011, and one for each of 2012 and 2013 through February.

Staff data request STF 4.20 requested that the Company provide a list of informal complaints to the Company regarding service outages and/or poor power quality. UNS Electric provided copies of "Utility Complaint Forms" for the period 2010 to 2013 (last one dated February 2013). In my opinion, there were not a lot of informal complaints over the period 2010 to 2013 as reflected in the Company's response to STF 4.20.

Q. Please describe the nature of the Company's response to Staff Data Request STF 4.38.

A. The Company's response included the monthly determinations for SAIFI, CAIDI and SAIDI evaluated at the five (5) minute interval level for its combined system. In addition, the analyses of the indices were presented excluding MED periods for each of the months of 2010, 2011, and 2012. MEDs, however, only occurred in the months of January of 2010 and August of 2012.

Q. Did UNS Electric provide determinations of these indices in its last rate case?

A. Yes. The Company provided determinations for SAIFI and CAIDI in the last case for the years 2007, 2008 and 2009 for each of its service areas. Its Mohave service area was separated into the Kingman and Lake Havasu areas.

Q. What are the physical characteristics of a distribution system that affect its indices?

A. The values of SAIFI, i.e., the frequency of outages to an average customer, are affected by the circuit configuration, circuit lengths, and the relative severity of lightning and weather events in the service area. In general, overhead radial circuits tend to have a higher frequency of outages as compared to network or looped network configurations. Longer circuit line lengths tend to have more exposure to various physical damage such as wind, ice, birds, etc. Moreover, the greater the number of lightning strikes in a given area, the greater the likelihood of an outage for longer circuit line lengths. CAIDI values (i.e., the duration of an outage to an average customer) is affected by the physical size and terrain of the service area, as that tends to increase the distance between the cause of the outage and the location of repair personnel. The availability of replacement equipment and their placement can also have an adverse effect.

Q. Given your observations of the service areas and facilities of the Company, what aspects would affect the performance of the Company's electric system?

A. The Company's typical circuit configuration is of an overhead radial design which is well suited for its customer base and density. However, as stated above, this configuration tends to be less reliable than others. In addition, all of the three service areas include extensive rural areas where customers are remote from the central maintenance facilities, and most likely, from the assigned "troubleman" who will be charged with responding to reported outages. The nature of the service areas and the circuit configurations would tend to result in elevated indices values for both frequency and duration of outages, as well as the fact that the southwest areas of the country are recognized as having high lightning frequency and those are of above average intensity.

Q. Did the Company provide separate evaluations of the service quality indices for each of its service areas?

A. No. The Company's analyses of service quality indices were provided on a total system basis. While the Company's total system analyses are acceptable, not presenting these indices for each service area prevents comparative evaluation of outages and their restoration within their diverse service areas; e.g., comparisons of Mohave, Santa Cruz and Lake Havasu service areas. This is discussed further hereafter and will be the basis of one of our recommendations.

Q. What observations and comments do you have regarding UNS Electric's Service Quality Indices for the period 2010-2012?

A. The indicies provided, including the effects of Major Event Days, are as follows:

	2010	2011	2012	3-Year Average
CAIDI	61.17	71.04	68.79	67.00
SAIFI	0.88	1.51	1.46	1.28
SAIDI	53.92	107.26	100.51	87.23

These values indicate that for the three years of record, the average customer experienced between one and two service outages per year with an outage duration of about one hour to about one hour and 11 minutes. Restoration of system outages, on average, took between slightly less than one hour to almost two hours. System performance and restoration were very good during CY 2010, significantly less so in CY 2011, and trended back toward the CY 2010 values during CY 2012.

Q. You say that the performance was "very good" for CY 2010, what constitutes "very good" in your opinion?

A. In my opinion, a company goal should be to limit the average customer outages to one or less than one in a calendar year with a duration of one hour or less. From the data above, we can see that the performance during CY 2010 was of that quality.

Q. What can you say as to the performance in the following two years?

A. The values presented for CY 2011 and CY 2012 are indicative of a less reliable system and are trending in the "wrong" direction. This is especially evident in the approximate 100% increase in the SAIDI values for each of the later years and the corresponding increases in SAIFI compared to CY 2010. Interestingly, the CAIDI values indicate a much smaller deterioration, on the order of about 15%.

Q. Based upon the averages of the three-year indices values, how would you evaluate the system reliability?

A. Based upon the average over the three years considered, I would consider the reliability of the UNS Electric distribution system to be acceptable. Staff recommends that the Company determine what the underlying factors for the increases in the system interruption frequency and duration during the later years and take steps to reverse the trend relative to 2010. Staff also recommends, that UNS Electric develop and present its indices separately for the Kingman/Lake Havasu and the Nogales service areas to allow for a comparative evaluation of outages and their restoration within their diverse service areas.

Q. Do you have a recommendation as to a methodology by which that might be expedited?

A. Yes. During the most recent case with TEP we were informed of how TEP has addressed this. It is our understanding that TEP develops the indicies on an individual distribution circuit basis. The circuits with the higher SAIFI are then surveyed by experienced linemen to identify needs for betterment and replacement to improve the circuit outage performance. The survey results combined with the prior year indices values are then used to select circuits for improvement, and funds are allocated toward that improvement on the targeted circuits. Staff recommends that this procedure be implemented by UNS Electric.

Q. How do the indices for UNS Electric compare to those of other utilities of similar size, service areas, and circuit configurations and how would you make such a comparison?

A. The three-year average values for UNS Electric would probably place them above average for comparable utilities.

Q. What would you consider a reasonable result for the Company for SAIDI?

A. I would consider a value for SAIDI of between 80-100 to be reasonable for the present with demonstrated improvement toward the lower end of that range to be reasonable going forward.

Q. Would you expect that for the Company to reach and maintain a SAIDI of between 80-100 that level would require significant increases in operational expenditures?

A. No. In my opinion, instituting a program of monitoring and evaluating outage reports and identifying the more problematic circuits that require mitigation would be sufficient to reach and maintain such levels of distribution reliability and performance indices and in customer satisfaction without a significant increase in annual expenditures.

Q. Do you have any further comments as to the reported indices?

A. Not on the indices per se, but due to the trend of UNS Electric's reported indices, we would recommend that UNS Electric present its results for calendar year 2013 to the Commission for Staff review to determine if the trend has improved.

Q. What other aspects of the Company's operations and development would tend to improve its reliability indices?

A. As the Company continues to replace the older circuit facilities and standardize its distribution substations, there should be corresponding decreases in the frequency of outages. We have previously reviewed the operation of the Call Center which serves both TEP and UNS Electric and consider its procedures to handle outage and other trouble calls to be acceptable in efforts to minimize response times and outage durations.

B. In Service Operations and Facilities Investment

Q. Please discuss the Company's Construction Work In Progress investments and its request for inclusion of these in rate base in this proceeding.

A. The Direct Testimony of UNS Electric witness DeConcini states that since 2008 the Company's rate base has increased by $23.6 million as a result of capital investment excluding the Black Mountain Generating Station ("BMGS"). Mr. DeConcini states that since the last rate case test year (12 months ending December 31, 2008) UNS Electric's capital investment has been $157 million (2009 through June 30, 2012) which includes $63 million for the purchase of BMGS. Moreover, he indicates that the Company is requesting about $13 million of post-test year net plant additions be included in rate base in this case.

UNS Electric witness Dukes has likewise addressed the post-test year request in his Direct Testimony. Specifically, he has stated that the Company has "adjusted its ACC jurisdictional rate base to include approximately $13.1 million of used and useful solar projects and other plant additions that have been, or are expected to be, placed in service between July 1, 2012 and June 30, 2013." As stated previously, the Company's response to STF 4.01 provides a listing of individual projects, the dollars of which equate to the amount of "other plant additions" referred to by Mr. Dukes.

Q. Please continue.

A. One of the objectives of our field investigations of May 20 through May 25 was to observe many of the projects, and discuss them with the UNS Electric and TEP personnel responsible for their development and performance. Our focus during the field investigations was on some of the largest and most expensive projects that are contained in the list of projects provided by UNS Electric in response to STF 4.01 and STF 4.02.

With regard to these projects, UNS Electric personnel took us on a tour of a portion of the 138 KV line project between the Vail and Valencia substations being undertaken by UNS Electric in the Rio Rico area (north of Nogales) of its service territory.

Q. Please describe the projects listed in the Company's Response To STF 4.01 and STF 4.02 which were discussed and viewed during your visit to Arizona.

A. The following is a listing and brief description of UNS Electric projects that were discussed and, in some instances, viewed with UNS Electric/TEP personnel during our field investigations. Our field visits and discussions with UNS Electric and TEP personnel were separated between the Kingman and Lake Havasu, and the Nogales portions of the Company's service areas.

Projects in the Kingman and Lake Havasu areas ---

(1) Project No. 304061B - Replacement of Meters and Metering Equipment: Meter replacements and installs of Automated Meter Reading ("AMR") are currently at

about 6,000 meters in the Kingman area. UNS Electric is replacing about 1,000 meters per year in the Kingman and Lake Havasu areas. The Company's goal is to have the AMR install program completed in 4 or 5 years. The data from the new meters is sent to control servers in the UNS Electric facilities in Kingman for routing over communications lines to Tucson for billing.

(2) Project No. 312661B - 69 KV Transmission System Replacement: Single pole structures and cross-arm configuration replacement work undertaken by UNS Electric local crews. UNS Electric is upgrading the conductors to meet increased capacity requirements and future growth. The cross-arm replacements are of a polymer material being used in contrast to the traditional wood material. The easiest portion of the project has been completed, with the more difficult, mountainous routes yet to be done; i.e., completed about 40 miles of this 50 mile project.

(3) Project No. 313361A - Recon Casson 5008-Sierra Vst/Benton: Reconductoring of distribution line on a current right-of-way. UNS Electric is undertaking the work with the line energized to minimize disruption of service in the Kingman area. The work also includes the replacement of poles wherein the Company is setting both wood and steel poles.

(4) Project No. 314561S - 69 KV Tie-Line and Breakers System Replacement: The tie-line and breakers work was undertaken to integrate the new generation installed at the Mercator Mine facility outside of Kingman. The primary purpose of the new installation was to provide adequate isolation and outage control in this area of UNS Electric's network.

(5) Project No. 331062B - Distribution Replacement and Betterment ("R&B"): This project reflects on-going R&B of distribution facilities in the Kingman and Lake Havasu areas since 2009. This continuing project consists of replacement and upgrading of portions of the Company's primary and secondary overhead and underground conductors and associated transformer facilities. This project also consists of emergency repairs and replacements of damaged overhead and underground facilities.

Q. Which of these projects that you have briefly described in the Kingman/Lake Havasu areas are included in the Post-Test Year Plant Requests of UNS Electric?

A. Three (3) of the Kingman/Lake Havasu projects are part of the post-test year plant requested by UNS Electric for inclusion in rate base in this case. The projects are listed in the Company's response to STF 4.01/ RUCO 1.07: Project Nos. 304061B, 313361S and 331062B. As shown in the response to STF 4.01/RUCO 1.07, these projects totaling about $1.5 million are part of the other plant category of post-test year gross utility plant investment of $8.662 million presented in Schedule B-2 of the Company's application.

Q. Please continue.

A. Projects in the Nogales area --

(1) Project No. 311164S - Valencia Transformer Replacement: Part of several projects at the Valencia Substation undertaken by UNS Electric included a transformer replacement. UNS Electric also installed reverse-osmosis equipment at the Valencia Substation to support an adequate treated water supply. The latter was a problem; i.e., an adequate supply of treated water, when we visited the Substation in conjunction with the Company's last base rate case.

(2) Project No. 312164A - Building Acquisition for Operations: UNS Electric acquired a building to be used for local offices and repair/maintenance staging facility in Nogales. The building was a one-time auto dealership and is undergoing remodeling by UNS Electric with almost all of the facility functional at this time. The property surrounding the building provides adequate paved space for parking for personnel, as well as for maintenance vehicles and equipment and for storage of supplies.

(3) Project No. 383064A - Valencia Turbine: Project consisted of the installation of a new turbine unit at the Valencia Substation.

(4) Project No. 392064S - Vail to Valencia 138 KV Line: UNS Electric is currently undertaking an upgrading of the existing 115kV line using the existing right-of-way. Numerous steel double-circuit poles have been set with poles continuously being set, and conductor stringing will commence soon. Much of the work is being undertaken by contractors.

Q. Which of these projects that you have briefly described in the Nogales area are included in the Post-Test Year Plant Requests of UNS Electric?

A. All four of the Nogales projects are part of the post-test year plant requested by UNS Electric for inclusion in rate base in this case. The projects are listed in the Company's response to STF 4.01/RUCO 1.07. These projects totaling about $4.3 million are part of the other plant category of post-test year gross utility plant investment of $8.662 million presented in Schedule B-2 of the Company's application.

Q. Please briefly describe any other construction and maintenance activities that were undertaken and discussed with UNS Electric personnel during your field investigations.

A. During our discussions of the on-going meter replacements and the operation of the AMR system in the Kingman service area, we noted that the transmission of metering data in the Lake Havasu area to the Kingman collection point is dependent on a single T1 data link. During later discussion with UNS Electric personnel we questioned the reliability of this condition and were informed that UNS Electric recognizes this to be a problem and is actively pursuing various ways of adding a fiber link between Lake Havasu and Kingman. We agree with UNS Electric that this is a concern and should be addressed in an expedited manner.

Q. Please continue.

A. We also discussed the use of thermal imaging as a periodic check on bus bars and overhead conductors as we had recommended this in the last base rate case of UNS Electric. We were informed that UNS Electric performs such routine maintenance and has discovered that the thermal imaging can now also detect SF6 leakages on circuit breakers of that type. This is a significant development and we commend UNS Electric for adopting thermal imaging as a periodic maintenance tool and for extending this methodology to include SF6 facility maintenance.

Q. UNS Electric's Post-Test Year Gross Utility Plant request includes an amount of renewable plant of $5.755 million. Please discuss this request.

A. This portion of post-test year plant sought by the Company relates to the Rio Rico Project. This project is a utility scale solar, photovoltaic generation facility. The project is located north of Nogales in Rio Rico and consists of a fixed axis structural support system for the photovoltaic panels. The project is described by UNS Electric personnel as a phased project with the initial phase generation output at about 5.7 MW. Currently, structural supports for the panels are being set at the site. UNS Electric personnel have stated that completion of a portion of three projects is expected by the end of 2013. Given that single-axis solar panels can be installed fairly quickly, we have no reason to question the projected completion by the end of 2013, but note that very little installation was observed during our field observations and certainly the project will not be available by the end of the post-test year period (June 30, 2013).

Q. Please continue.

A. UNS Electric has stated that its post-test year plant requests to be included in rate base are represented by plant investment projects expected to be completed and in-service to serve customers within the time period July 2012 through June 2013. Based on our view of the project, and particularly our discussion with UNS Electric personnel, the Rio Rico Project should not be allowed in rate base in this case. Mr. Smith also addresses this in his testimony.

B.1 Electric Grid Operations and Call Center Procedures

Q. What is your opinion of the electric grid operations and control of the facilities of UNS Electric?

A. We have reviewed the operations of the control center which manages the grid operations of both TEP and UNS Electric during TEP's recent rate case. We found them to be acceptable and competently operated, and that opinion has not changed.

Q. How would you assess the operation of the call center as it relates to management and responding to trouble calls?

A. As with the grid operations, we reviewed the operations and procedures of the call center serving UNS Electric customers during our field investigations in TEP's rate case. We found the operation and procedures to be well performed and acceptable, and we have not changed our opinion in this proceeding.

III. DECOMMISSIONING COSTS

Q. What comments do you have related to UNS Electric's request that certain decommissioning costs be included in depreciation of generating assets at the Valencia Generating Station and at BMGS?

A. While UNS Electric has not introduced a new depreciation study in this case, the Company is requesting adjustments to its current generation depreciation for certain assets at its Valencia Generating Station and at BMGS. The Company provided the Decommissioning Study of TEP Generating Assets ("Decommissioning Study") in response to STF 5.3, which includes an assessment of Valencia and BMGS. This study is apparently in support of its requested adjustments.

Q. Have you reviewed the Decommissioning Study?

A. Yes. I have reviewed the Decommissioning Study and discussed its contents with UNS Electric personnel in Tucson during our field investigation last month. It is my opinion that the costs presented in the Decommission Study are based on total clearing of the sites and the restoration to a "green field" state at the generating stations. On its face, this does not seem to be a reasonable projection.

UNS Electric argues, for example, that the Valencia Station and BMGS could be retired as a result of advancements in the development of a higher heat rate technology. Even if this were to happen, it should not result in a total clearing of a generating site since the switchyard, the grid connections, the availability of natural gas and water, the control facilities, etc. would remain useful. That is, at the end of the life of the present generating units, the generating equipment would be replaced and the site would continue as a location of UNS Electric generating assets.

Q. Do you have any final comments and a recommendation regarding the Company's proposal related to the decommissioning of certain generating assets?

A. In my opinion, UNS Electric's justification for the inclusion of decommissioning of the Valencia Station and BMGS is not convincing and reasonable. UNS Electric has not presented any precedent or specific requirement as to why this "clean slate" site clearance is necessary or appropriate. Accordingly, I recommend that the Commission reject UNS Electric's request that these expected costs of decommissioning be included in its depreciation rates in this case.

IV. RECOMMENDATIONS TO THE COMMISSION

Q. Please summarize your recommendations to the Commission.

A. Our recommendations to the Commission are as follows:

1. We recommend that UNS Electric have its distribution quality of service indices available, upon request, for review by Staff on a monthly and calendar year basis. Additionally, we recommend that these indices be by calendar year on a service area by service area basis, as well as on an overall system-wide basis. These indices are the Customer Average Interruption Duration Index ("CAIDI"), the System Average Interruption Frequency Index ("SAIFI"), and the System Average Interruption Duration Index ("SAIDI").

2. We recommend that UNS Electric submit its quality of service indices for calendar year 2013 for Commission Staff review by March 31, 2014, to determine if the trend of the indices is improving.

3. We recommend that UNS Electric prepare on an annual basis a listing of the worst performing circuits identified by service area and reliability indices and adopt a program similar to that implemented by TEP to target annual circuit maintenance toward circuits identified by indices value and survey as representing the most efficient means of improving SAIFI values.

4. UNS Electric has proposed a total of $14.417 million for post-test year gross utility plan in service. We have no objection to the Commission accepting UNS Electric's proposed post-test year gross utility plant in service amount of $8.662 million (ACC jurisdictional amount of the $8.770 million shown on application, Schedule B-2) requested by UNS Electric for inclusion into rate base from an engineering standpoint. However, recommend that the Commission not approve UNS Electric's proposed post-test year plant-of $5.755 million associated with the Rio Rico Solar Project requested by UNS Electric for inclusion into rate base.

5. UNS Electric maintenance scheduling should continue to include thermal scanning of the substation/switchyard bus and connected lines on a regular basis, including the BMGS.

6. We recommend that UNS Electric's request that expected costs of decommissioning of certain of its generating assets not be approved for inclusion in depreciation rates at this time. In this regard, should the Commission wish to consider allowing these costs, we recommend that the Commission direct UNS Electric to file a definite plan and support for its current claims, and as well with regard to any anticipated future claims, as to

> the need for the inclusion of such decommissioning costs as a cost of removal component of depreciation rates.

Q. Does this complete your direct testimony?

A. Yes, it does.

ATTACHMENT 1

BACKGROUND & EXPERIENCE PROFILE
W. MICHAEL LEWIS, P.E.
PRESIDENT
W.M. LEWIS & ASSOCIATES, INC.

EDUCATION

1981 - 1988	Master of Business Administration, Ohio University, Athens Office
1971 - 1971	B.S., Electrical Engineering, Ohio State University, Columbus, Ohio
Special Courses:	Power Circuit Breakers, Ohio State University Modern Power System Analysis, University of Wisconsin Digital Electronics for Power Application, IEEE Modern Methods of Analysis and Protection of Electric Power Systems, IEEE Project Management and Planning, University of Wisconsin Construction Contract Administration, University of Wisconsin High Voltage Testimony, Pennsylvania State Lighting Solution and Design, IIT/AEE Cogeneration Theory and Design, University of Wisconsin Planning, Procurement, and Installation of SCADA Systems, University of Wisconsin, 1989

REGISTRATIONS Registered Professional Engineer in Kentucky and Ohio
Registered Consultant to the Asian Development Bank, Manila, Philippines

POSITIONS

1979 - Present	President and Manager of Engineering of W.M. Lewis & Associates, Inc.
1974 - 1979	Electric Power Engineer, Goodyear Atomic Corporation (now Martin Marietta Energy Systems)

EXPERIENCE

Summary -- Extensive experience in utility practice, including serving as an expert witness on topics of planning, design, construction, operation, and maintenance of high-voltage transmission lines and facilities, (overhead and underground); high-voltage transformer and circuit breaker loading, operation, and maintenance; working and design clearances on facilities at 230 kV and above and other aspects of utility practice before the State Corporation Commission of Virginia; and on aspects of electric utility design and operation before the Federal Energy Regulatory Commission. Also served as an expert witness in numerous electrical accident litigation concerning interpretation of the NESC, OSHA regulations, and the concept of "Prudent Utility Practice." Has performed reviews of rural electric utilities in 14 countries.

In addition to experience and expertise in engineering, operation, and code application, prepared operation manuals for client utilities and industries, prepared training curriculum for power operators, trained power operators and linemen, and prepared PM program criteria for utilities and industry. Experienced in HV and EH V testing techniques of transformers and cables and circuit breakers, including OCB and SF_6 designs.

Graduate level studies include concentrated studies of staffing level theory and the use of statistical techniques in electric rate design and preparation of tariffs for electric utilities. Training in safety audits and compliance plans.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONALBE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS	DOCKET NO. E-04204A-12-0504

DIRECT

TESTIMONY

OF

HOWARD SOLGANICK

FOR THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2012

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EXHIBIT

EXECUTIVE SUMMARY
UNS ELECTRIC CORPORATION
DOCKET NO. E-04204A-12-0504

Mr. Solganick's direct testimony reviews the UNS Electric ("Company") Lost Fixed Cost Recovery ("LFCR") proposal.

Mr. Solganick presents Staff's recommendation based on a review of the Company's application and responses to Staff data requests. Staff recommends that the Commission modify the Company's LFCR proposal to (1) allow the Company to recover only transmission and distribution (delivery) service fixed charges, (2) cap the increased revenue allowed for each year at one percent, (3) recover the lost fixed cost revenue on a percentage of revenue basis, and (4) make the LFCR mechanism consistent with the recently approved Tucson Electric Power Company LFCR mechanism.

QUALIFICATIONS

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

A. My name is Howard Solganick. I am a Principal at Energy Tactics & Services, Inc. My business address is 810 Persimmon Lane, Langhorne, PA 19047. I am performing this assignment under subcontract to Blue Ridge Consulting Services, Inc. on behalf of the Arizona Corporation Commission ("Commission") Utilities Division ('Staff").

Q. **Please summarize your qualifications and experience.**

A. I am licensed as a Professional Engineer in Pennsylvania (active) and New Jersey (inactive). I hold a Professional Planner's license (inactive) in New Jersey. I served on the Electric Power Research Institute's Planning Methods Committee and on the Edison Electric Institute Rate Research Committee. I have been appointed as an arbitrator in cases involving a pricing dispute between a municipal entity and an on-site power supplier and a commercial landlord-tenant case concerning submetering and billing. I previously served on two New Jersey Zoning Boards of Adjustment as Chairman and member and a Pennsylvania Township Planning Commission as Chairman and member.

I have been actively engaged in the utility industry for over 35 years, holding utility management positions in generation, rates, planning, operational auditing, facilities permitting, and power procurement. I have delivered expert testimony in utility planning and operations, including rate design and cost of service, tariff administration, generation, transmission, distribution and customer service operations, load forecasting, demand side management, capacity and system planning, and regulatory issues.

I have led and/or participated in consulting projects to develop, design, optimize, and implement both traditional utility operations and e-commerce businesses. These projects focused on the marketing, sale and delivery of retail energy, energy related products and services, and support services provided to utilities and retailers.

I have been engaged by clients to review proposed distributed generation contracts and the operation and integration of generating assets within power pool operations, and have advised the Board of Directors of a public power utility consortium. For a period of four years I was engaged by a multiple site commercial real estate organization to manage its solicitation for the purchase of retail energy. As a subcontractor, I have performed management audits for the Connecticut Department of Public Utility Control and the Public Utilities Commission of Ohio. I also provide (as a subcontractor) support for the Staff and Commissioners of the District of Columbia Public Service Commission for electric and gas rate cases.

I have also been engaged (as a subcontractor) to review utility performance before, during and after outages resulting from major storms including Hurricane Ike and the two 2011 storms that affected New Jersey.

From 1994 to the present, I have been President of Energy Tactics & Services, Inc. From 1996 to 1998, I was a Managing Consultant for AT&T Solutions. From 1990 to 1994, I was Vice President of Business Development for Cogeneration Partners of America. In that position, I was responsible for the development of independent power facilities, most of which were fueled by natural gas and oil.

From 1978 to 1990, I held progressively increasing positions of responsibility with Atlantic City Electric Company in generation, regulatory, performance, planning, major procurement, and permitting areas.

From 1971 to 1978, I was an Engineer or Project Engineer for Univac, Soabar, Bickley Furnaces and deLaval Turbine, designing card handling equipment, tagging and printing machines, high temperature industrial furnaces, and utility and industrial power generation equipment, respectively.

I received a Bachelor of Science in Mechanical Engineering (minor in Economics) from Carnegie-Mellon University and a Master of Science in Engineering Management (minor in Law) from Drexel University. I have also taken courses on arbitration and mediation presented by the American Arbitration Association, scenario planning presented by the Electric Power Research Institute and load research presented by the Association of Edison Illuminating Companies. I have also taken courses in zoning and planning theory, practice and implementation in both New Jersey and Pennsylvania.

Q. **Have you previously submitted testimony in regulatory proceedings?**

A. Yes. I have testified and/or presented testimony (summarized in Exhibit HS-1) before the following regulatory bodies:

- Arizona Corporation Commission
- Delaware Public Service Commission
- Georgia Public Service Commission
- Jamaica (West Indies) Electricity Appeals Tribunal
- Maine Public Utilities Commission
- Maryland Public Service Commission
- Michigan Public Service Commission
- Missouri Public Service Commission

- New Jersey Board of Public Utilities
- Public Utilities Commission of Ohio
- Pennsylvania Public Utility Commission
- Public Utility Commission of Texas

DIRECT TESTIMONY

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Utilities Division Staff ("Staff") of the Arizona Corporation Commission ("Commission".

Q. What is the purpose of your testimony?

A. My testimony analyzes the Lost Fixed Cost Recovery ("LFCR") proposal of UNS Electric, Inc. ("UNSE" or "Company").

- Based on my review of the Company's application, supporting testimony, and responses to data requests, I recommend that the Commission modify the Company's LFCR proposal as follows:
    - Allow the Company to receive recovery for only transmission and distribution (delivery) service fixed costs
    - Cap the increased revenue allowed for each year at 1%
    - Recover the lost fixed cost revenue on a percentage of revenue basis
    - Adjust the LFCR mechanism to be consistent with the recently approved Tucson Electric Power Company ("TEP") LFCR

Q. What is revenue decoupling?

A. Decoupling is the term used to define a rate design that is designed to disconnect a utility's earnings or revenue from sales of energy or commodity. Decoupled rates can be designed to eliminate or reduce the utility's disincentive to encourage energy conservation, the impacts of the business cycle and/or the effects of weather.

Q. Have you reviewed specific decoupled rate design proposals in other jurisdictions?

A. I have reviewed proposals for decoupled electric and gas rate designs in Delaware for the Staff of the Delaware Public Service Commission where I also assisted in the pre-implementation education process. I have also reviewed decoupling proposals by gas utilities and offered testimony in Maryland for the People's Counsel and in Michigan for the Attorney General. In addition, I assisted the Staff of the District of Columbia Public Service Commission in the evaluation and implementation of a decoupled rate design for delivery of electricity. I also sponsored a LFCR mechanism in the most recent Arizona Public Service ("APS") rate case (Docket No. E-01345A-11-0224) and the recent TEP rate case (Docket No. E-01933A-12-0291), on behalf of Staff.

Q. Please describe the Company's LFCR proposal.

A. The Company's proposal is to establish a LFCR mechanism focused on recovering its estimate of the fixed costs that are unrecovered due to energy efficiency and distributed generation. The Company's LFCR mechanism would exclude fuel and purchased power charges because those areas are already subject to an adjustment mechanism or annual formula.[1] Customer charges and 50% of demand-based charges would also be excluded.[2]

The Company's LFCR is proposed to include all customer classes except for street lighting.[3]

The calculation of any lost fixed costs by class is based on the actual kWh metered at the distributed generation facilities (or sites)[4] and the estimated kWh not consumed based on

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[1] Exhibit CAJ-4 – LFCR Plan of Administration, page 1, Delivery Revenue
[2] Exhibit CAJ-4 – LFCR Plan of Administration, page 1, Delivery Revenue and Jones Direct 49:15
[3] Exhibit CAJ-4 – LFCR Plan of Administration, page 2, Excluded Rate Schedules
[4] Jones Direct 49:5

an independent Measurement Evaluation and Research ("MER") of the Company's energy efficiency program[5].

To determine the Lost Fixed Cost Revenue the Company's LFCR mechanism uses a Lost Fixed Cost Rate ($/kWh)[6] multiplied by the Recoverable Savings (kWh) (EE and DG).[7] This calculation is made individually for each rate class.[8] The Company is proposing a true-up mechanism for LFCR that would add in any past over or under recovery[9] and recover the amount from all customers covered by the Company's LFCR on a per kWh basis.[10]

The Company's LFCR Plan of Administration refers to Delivery Revenue[11] and delivery charges as inputs into the Company's LFCR mechanism and therefore might be interpreted as focusing on lost distribution costs. The Company's testimony[12] focuses on "tail block margin rate" costs other than customer charge and power purchase and fuel. This definition effectively includes generation and transmission costs.

The Company's LFCR mechanism annual cap would be 2%[13] (except during the initial period)[14] with the remaining balance plus interest carried to the next period.[15] Subject to the annual cap, the Company's LFCR mechanism aggregates all under-recovery or over

[5] Jones Direct 49:2
[6] Exhibit CAJ-4 – LFCR Plan of Administration, Page 3
[7] Exhibit CAJ-4 – LFCR Plan of Administration, Page 3
[8] Exhibit CAJ-4 – LFCR Plan of Administration, Page 3
[9] Exhibit CAJ-4 – LFCR Plan of Administration, Page 3
[10] Exhibit CAJ-4 – LFCR Plan of Administration, Page 3
[11] Exhibit CAJ-4 – LFCR Plan of Administration, Page 1, Delivery Revenue
[12] Jones Direct 47:5
[13] Jones Direct 48:2
[14] Jones Direct 48:11
[15] Jones Direct 48:4

recovery on an annual basis and recovers or repays those sums over the following twelve-month period beginning July 1st (the Effective Period per Exhibit CAJ-4).[16]

The Company is also proposing a fixed charge alternative for residential customers who may want a cost certain option. This alternative has a monthly cost of either $2.50 or $6.50 depending on whether the monthly consumption is less than 2,000 kWh or more than 2,000 kWh.[17] A gap (at exactly 2,000 kWh) exists on the proposed residential tariffs RES-01 and RES-01 TOU.[18] This minor item will need to be addressed at implementation if the Company's LFCR mechanism is approved as proposed.

Q. Is the Company's proposed LFCR mechanism the same as the LFCR mechanism approved by the Commission for APS in Decision No. 73183?

A. No. The Company's testimony characterized the LFCR as "…very similar to the Commission-approved mechanisms in the APS and UNS Gas rate cases that were decided earlier this year."[19]

In response to a Staff data request, the Company further defined the differences as:[20]

- Recovery of lost revenues through a kWh charge instead of a percentage-based charge
- Use of an annual true-up mechanism for prior years
- A 2% cap
- Exclusion of the lighting rate class[21]

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[16] Jones Direct 47:24
[17] Jones Direct 48:19
[18] Exhibit CAJ-8
[19] Jones Direct 46:20
[20] UNS Response to STF 2.64
[21] Exhibit CAJ-4 – LFCR Plan of Administration, Page 2

Q. Are there other differences that were not enumerated by the Company?

A. Yes, there are the following differences:

- Lost revenue would be based on tail-block revenue[22] that includes generation costs
- An effective date at the end of the Test Year (7/1/12)[23] rather than the beginning of the rate effective period

Q. Has the Company estimated the impact of the LFCR mechanism?

A. The Company estimated the impact of its LFCR mechanism at approximately $2.5 million for the last six months of 2012 (after the Test Year) and all of 2013.[24]. The Company provided Exhibit CAJ-5 that estimates the annual impact of its proposed LFCR mechanism. The supporting documentation demonstrates that the Company's generation costs are included in its calculations.[25]

The Company's proposed LFCR mechanism differentiates between lost fixed costs before and after the rate effective date by recognizing the different tail block rates effective before and after the expected rate change.[26]

Q. Do you support the adoption of the Company's LFCR mechanism as proposed?

A. No. Due to the timing of the UNS filing compared to the proposed Settlement Agreement for TEP there are differences between the LFCR for TEP and for UNS that should be resolved.

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[22] Jones Direct 49:14
[23] Jones Direct 50:6
[24] Jones Direct 50:19-23 and Exhibit CAJ-5 (D6)
[25] UNS Response to STF 2.65
[26] UNS Response to STF 2.65

Q. Why should the UNS LFCR be similar to the TEP LFCR?

A. On June 11, 2013, the Commission approved the TEP Settlement including the LFCR. Although there are differences between UNS and TEP, for administrative economy at the Commission including Staff resources, and consistent application by UNS and TEP, which should lead to lower implementation costs, the UNS LFCR should, where possible, be the same as or very similar to the TEP LFCR.

Q. What areas of the Company's revenue do not require some form of revenue decoupling to deal with the impact of energy efficiency programs and distributed generation?

A. The following cost areas do not require decoupling protection in whole or in part:

- Generation and Purchased Power (including capacity)
- Energy
- Distribution *(partial)*
- Customer Management
  - Customer Accounts and Sales
  - Metering
  - Billing
  - Meter Reading

Q. Is some form of revenue decoupling needed for transmission charges?

A. Absent an adjustment mechanism to true-up transmission charges, some form of limited decoupling is appropriate. If the Company's Transmission Cost Adjuster ("TCA") is approved then the transmission component of the LFCR should only include the transmission costs in base rates.[27]

[27] UNS Response to STF 2.19

Q. Is decoupling needed for distribution revenue?

A. Distribution costs are not as fungible and some distribution assets cannot serve other customers within the short term. Therefore, a reduction in per customer sales may result in a shortfall in revenues to cover fixed costs. Decoupling is needed to recapture the portion of distribution costs that are collected on a volumetric (per kWh) basis. Some of the Company's rate schedules collect distribution costs using demand charges, which will remain constant or change slower than a straight volumetric rate.

Q. Why is revenue decoupling not necessary for the Customer Charges?

A. As a customer takes advantage of energy efficiency or distributed generation the Customer Charge is collected regardless of the customer's usage.

Q. Is the Company subject to an energy efficiency goal?

A. Yes. The rules[28] (the "Rules") set cumulative (and incremental) savings (based on prior year sales) as follows:

Year	Cumulative Savings %[29]	Incremental Savings %
2011	1.25	1.25
2012	3.00	1.75
2013	5.00	2.00
2014	7.25	2.25
2015	9.50	2.25

Q. Has the Company developed an energy efficiency forecast?

A. Yes. The supporting workpapers to Exhibit CAJ-5 contain the Company's estimate of the results of its energy efficiency efforts under the title "EE related KWh".[30]

[28] Arizona Administrative Code R14-2-2401, et seq (effective January 1, 2011)
[29] Arizona Administrative Code R14-2-2404, Table 1 (effective January 1, 2011)
[30] UNS Response to STF 2.65

Q. Has the Company developed a forecast of the impact of distributed generation?

A. Yes. The supporting workpapers to Exhibit CAJ-5 contain the Company's estimate of the impact of distributed generation under the title "DG related KWh".[31]

Q. Without some mechanism would the Company's Plan have a measureable impact on the Company's revenue?

A. Yes. The Rules require reductions in the Company's sales compared to each prior year. If the Company meets those goals then a portion of the Company's transmission and distribution revenue could be impacted.

Q. After reviewing the Company's LFCR mechanism what changes would you recommend?

A. I recommend changes to the Company's LFCR mechanism that would align the LFCR for the Company to the recently approved TEP LFCR as follows:

- Remove the Company's recovery of generation charges
- Change the recovery basis from a $/kWh basis to a percentage of revenue basis, with separate charges for EE and DG
- Ensure that any transmission costs included in the LFCR mechanism are not double counted within a transmission adjustment
- Reduce the annual cap to 1%
- Revise the following proposed definitions to be consistent with the TEP LFCR as approved
    - Delivery Revenue to change to Distribution and Transmission Revenue
    - Include a reference to kW of capacity under DG Savings
- Revise the proposed calculations to be consistent with the TEP LFCR as approved

[31] UNS Response to STF 2.65

- Develop and execute a customer education program

Q. Why is decoupling not necessary for generation and purchased power?

A. The Company's purchased power program[32] appears to have a significant amount of flexibility that would allow the Company to adjust its purchases to match its short-term needs, and purchased power is fungible. Purchased power is not affected if energy is delivered to a new customer, an existing customer using slightly more energy or sold off-system. Therefore, the Company has many opportunities to adjust its energy supply.

Q. What is the Company's forecast for sales?

A. The Company's load forecast shows a trend of increasing total numbers of customers[33] and the reference case (without the effects of EE and DG) shows increasing sales to retail customers.[34] The reference case for peak demand also shows increasing customer demand.[35]

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[32] UNS CONFIDENTIAL Response to STF 2.32, Technical conference May 14, 2013 and UNS 2012 Integrated Resource Plan (pages 56-58) and Chart 11 (page 52

[33] UNS 2012 Integrated Resource Plan (Docket No. E-00000A-11-0113) Chart 6 (page 38)

[34] UNS 2012 Integrated Resource Plan Chart 8 (page 41)

[35] UNS 2012 Integrated Resource Plan Chart 10 (page 43)

Q. Why do you recommend that the LFCR mechanism collect the lost fixed costs on a percentage of base rate revenue basis?

A. The LFCRs approved for APS and TEP and the Company's proposed LFCR mechanism require the same data and/or estimates. Lost fixed costs include both energy and demand impacts. The use of revenue based recovery (rather than a per kWh basis) preserves the relationship between customer, demand and energy revenues collected from customers and therefore does not shift the LFCR impact towards high load factor customers.

Q. How should PPFAC costs be treated?

A. If the PPFAC is approved as the Company requested, then there is a separate mechanism to recover and adjust for the changes in the Company's sales and energy production. However, if the Company's request for full costs within the PPFAC is rejected then the "Delivery Charge" must be reduced by the amount of fuel and purchased power in base rates. The net effect is zero on the calculations made and impact to the Company.

Q. What concerns do you have about including transmission costs within the LFCR?

A. To avoid potential double recovery of lost transmission costs, any changes to the transmission rate mechanism must recognize that a LFCR mechanism that includes transmission costs will protect the Company from cumulative lost sales.

Q. Why are you suggesting that the annual cap be reduced to 1%?

A. Using the information developed by the Company and provided in STF 2.65 the Company is now forecasting incremental impacts of less than 1%.[36] Although the generation components shown and used by the Company are minor, the elimination of the fungible

[36] Exhibit CAJ-5

generation costs would further reduce the annual impact. With those changes, I have calculated the impact of the LFCR and there is no need for a 2% cap. A 1% cap is more appropriate.

Q. Do you recommend a customer education plan for the LFCR?

A. Yes. If a LFCR mechanism is approved for implementation, the Company should submit a plan to Staff and other parties for customer education. In my experience, this helps to make a significant rate change understandable and acceptable to customers.

Any customer education plan should use a variety of methods to deliver information to customers, as customers may be more receptive to one form or another. Some of the methods might include bill inserts, bill messages, customer service representatives, energy advisors, website explanations and internet postings as the Company suggests.[37] I recommend additional approaches such as print and TV (both in paid advertisements and articles or features written by reporters), meeting with customers in small groups (Speaker's Bureau) and educating community leaders and organizations to further explain the concept.

Q. What changes to the Company's proposed LFCR are required in order to reflect the amended and approved TEP Settlement?

A. During the July 11, 2013, Open Meeting, the Commission directed TEP to "split" the LFCR into two parts. One part for a LFCR for Energy Efficiency ("EE") and the other part for a LFCR for Distributed Generation ("DG").

[37] STF 2.63

The TEP Plan of Administration ("POA") for the LFCR as filed with the Settlement Agreement already contains the definitions needed to implement the required change, and the data needed to perform the calculations are identified.

The change required by the Commission Decision does not change the impact on a customer as the two LFCR parts are algebraically identical to the original LFCR.

The TEP Settlement Agreement POA added the DG Savings and the EE Savings together to calculate the Recoverable kWh Savings ("DG+EE"). The Recoverable kWh Savings is then multiplied by the Lost Fixed Cost Rate ("A") to calculate the Lost Fixed Cost Revenue. Finally, the Lost Fixed Cost Revenue is divided by the Applicable Company Revenue ("B") to calculate the LFCR Adjustment. Algebraically the formula is:

Original LFCR Adjustment = (DG+EE)*A/B

The two new formulae are:

DG LFCR Adjustment = DG*A/B

EE LFCR Adjustment = EE*A/B

Because the original TEP POA defined the DG Savings and the EE Savings the changes to the TEP POA required by the Commission Decision are not complicated. The term Recoverable kWh Savings is no longer needed and there will be two LFCR Adjustments. The worksheets provided will also need to be rearranged to show the two calculations.

The 1% LFCR Annual Incremental Cap will still apply but to the sum of the two adjustments.

When the two LFCR adjustments are applied to the customer's bill, the Company will have to ensure that the two calculations are done in parallel to avoid applying the second LFCR adjustment to the bill that includes the first LFCR adjustment.

Q. How would all of the changes that need to be accomplished to implement a LFCR be finalized?

A. At the resolution of any rate case, unless the Company was to receive its exact request, the Company will have to file rates that conform to the Commission's decision. If a settlement occurs, this calculation process would occur before the settlement is presented to the Commission. In either event, the Company has to prepare new rates for approval by the Staff as the result of a Commission decision or acceptance by the parties to the settlement document.

The Company's technical conference has helped to set the stage for this final effort by opening the lines of communication, and the prior performance of the Company's affiliate, TEP, and the common parties in this case demonstrate that the final LFCR rates can be developed with reasonable efforts by all parties.

Q. **Does this conclude your direct testimony?**

A. Yes, it does.

Testimony - Howard Solganick

Arizona Corporation Commission
Case – Tucson Electric Power Company Docket No. E-01933A-12-0291 (December 2012 and January 2013)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Arizona Corporation Commission
Case – Arizona Public Service Company Docket No. E-01345A-11-0224 (November and December 2011)
Client - Staff of the Arizona Corporation Commission
Scope - Testimony covered revenue decoupling, cost of service, revenue allocation, rate design and other related issues.

Public Service Commission of Delaware
Case - Delmarva Power & Light Company Docket No. 10-237 (October 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and miscellaneous charges.

Case - Delmarva Power & Light Company Docket No. 09-414 (February 2010)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization and weather normalization.

Case - Delmarva Power & Light Company Docket No. 09-277T (November 2009)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered an analysis of a straight fixed variable rate design for small gas customers and implementation issues.

Case - Delmarva Power & Light Company Docket No. 06-284 (January 2007)
Client - Staff of the Delaware Public Service Commission
Scope - Testimony covered cost of service, revenue allocation, rate design and other related issues including revenue stabilization or normalization.

Georgia Public Service Commission
Case – Atlanta Gas Light Company Docket No. 31647 (August 2010)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered revenue forecast, cost of service, revenue allocation, rate design and other related issues.

Case – Atmos Energy Corporation Docket No. 27163 (July 2008)
Client – Public Interest Advocacy Staff of the Georgia Public Service Commission
Scope - Testimony covered rate design and other related issues.

Jamaica (West Indies) Office of Utility Regulation
Case - Electricity Appeals Tribunal (August 2007)
Client - Jamaica public Service Company, Ltd.
Scope - "Witness Statement" on behalf of the Jamaica Public Service Company Limited. This Statement covered issues relating to recovery of expenses incurred due to Hurricane Ivan.

Maine Public Utilities Commission
Case - Northern Utilities, Accelerated Cast Iron Replacement Program Docket No. 2005-813 (2005)
Client - Public Advocate of the State of Maine
Scope - Testimony covered an analysis of the program's economics and implementation.

Public Service Commission of Maryland
Case - Chesapeake Utilities Corporation Case No. 9062 (August 2006)
Client - Office of the Maryland People's Counsel
Scope - Testimony covered cost of service, rate design and other related issues.

Case - Baltimore Gas & Electric's (1993)
Client - As president of the Mid Atlantic Independent Power Producers
Scope - Testimony covered BG&E's capacity procurement plans.

Michigan Public Service Commission
Case - Consumers Energy Company Case No. U-15245 (November 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered cost of service, rate design and revenue allocation.

Case - Consumers Energy Company Case No. U-15190 (July 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy's gas revenue decoupling proposal.

Case - Consumers Energy Company Case No. U-15001 (June 2007)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues related to Consumers Energy and the MCV Partnership.

Case - Consumers Energy Company Case No. U-14981 (September 2006)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope - Testimony covered issues relating to the sale of Consumers interest in the Midland Cogeneration Venture.

Case - Consumers Energy Company Case No. U-14347 (June 2005)
Client - Attorney General Michael A. Cox (Don Erickson, Esq.)
Scope – Testimony covered cost of service and revenue allocation.

Missouri Public Service Commission
Case – AmerenUE Storm Adequacy Review (July 2008)

Client – KEMA/AmerenUE
Scope – Oral testimony covered KEMA's review of AmerenUE's system major storm restoration efforts.

Case – Veolia Energy Kansas City, Inc. File No. HR-2011-0241 (September 2011)
Client – City of Kansas City, Missouri
Scope – Testimony covered various aspects of the Company's tariff provisions and the impact on the City of Kansas City.

New Jersey Board of Public Utilities
Case - Cogeneration and Alternate Energy Docket # 8010-687 (1981)
Case - PURPA Rate Design and Lifeline Docket # 8010-687 (1981)
Case - Atlantic Electric Rate Case - Phases I & II Docket # 822-116 (1982)
Case - Power Supply Contract Litigation – Wilmington Thermal Systems Docket # 2755-89 (1989)
Case - NJBPU Atlantic Electric Rate Case - Phase II (1980-81) Docket # 7911-951 (Before the Commissioners of the New Jersey Board of Public Utilities)
Client - Employer was Atlantic City Electric Company.
Scope - The cases listed above covered load forecasting, capacity planning, load research, cost of service, rate design and power procurement.

Public Utilities Commission of Ohio
Case - The Application of Ohio Edison Company, The Cleveland Electric Illuminating Company, and The Toledo Edison Company Case 07-551-EL-AIR (January 2008)
Client - Ohio Schools Council
Scope - Testimony covers issues related to rate treatment of schools.

Case - The Application of the Columbus Southern Power Company 08-917-EL-SSO and the Ohio Power Company Case 08-918-EL-SSO (October 2008)
Client - Ohio Hospital Association
Scope - Testimony covers issues related to rates for net metering and alternate feed service and related treatment of hospitals.

Pennsylvania Public Utilities Commission
Case - York Water Company Docket No. R-00061322 (July 2006)
Client - Pennsylvania Office of Consumer Advocate
Subject - Testimony covered cost of service, rate design and other related issues, also supported the settlement process.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2010)
Client – Municipal Sewer Group
Subject - Testimony covered capacity planning, construction, treatment of future load and associated revenue, cost of service, rate design, capacity fee and other related issues.

Case – Pennsylvania- American Water Company Docket No. R-2008-232689 (August 2008)
Client – Municipal Sewer Group
Subject - Testimony covered cost of service, rate design, capacity fee and other related issues, also supported the settlement process.

Public Utilities Commission of Texas
Case – Determination of Hurricane Restoration Costs Docket No. 36918 (April 2009)
Client – CenterPoint Energy Houston Electric, LLC
Subject – Testimony covered the reasonableness of the client's Hurricane Ike restoration process for an outage covering over two million customers and a restoration period of 18 days

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA AND FOR RELATED APPROVALS.	DOCKET NO. E-04204A-12-0504

DIRECT

TESTIMONY

OF

JULIE MCNEELY-KIRWAN

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 28, 2013

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EXECUTIVE SUMMARY
UNS ELECTRIC, INC.
DOCKET NO. E-04204A-12-0504

Staff's Direct Testimony will cover the revised Rules and Regulations proposed by UNS Electric, Inc.

Staff's recommendations are listed below:

- Staff recommends that language addressing the automated meter Opt-Out Option not be added to the Rules and Regulations as proposed by UNS Electric in this docket.

- Staff recommends that UNS Electric take any measures required in order to maintain the confidentiality of all private customer information. Maintaining confidentiality of customer information would include taking appropriate security measures for protecting computer databases containing this information.

- Staff recommends that the phrase "due to the action or inaction of the Customer," be inserted into the proposed language for 11.J.3., between "unavailable," and "the".

- Staff recommends that the language of 11.F.2 be clarified as follows: delete the phrase "may correct such an error to recover or refund the difference between the original billing and the correct billing" and replace that wording with "shall correct such an error to refund any overbilling and may correct such an error to recover any underbilling."

- Staff recommends that the construction and revenue true-ups be fully and clearly disclosed to customers requesting line extensions.

INTRODUCTION

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

A. My name is Julie McNeely-Kirwan. I am a Public Utilities Analyst V employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst V.

A. My duties as a Public Utilities Analyst V include reviewing and analyzing applications filed with the Commission and preparing memoranda and proposed orders for Open Meetings. In addition, my duties have included preparing written testimony in multiple rate cases and testifying during the related hearings. I have also acted as lead in several rate cases and have performed evaluations of energy efficiency implementation plans.

Q. Please describe your educational background and professional experience.

A. In 1979, I graduated Magna Cum Laude from Arizona State University, receiving a Bachelor of Arts degree in History. In 1987, I received a Master's Degree in Political Science from the University of Wisconsin, Madison. I have been employed by the Commission since September of 2006. Since that time, I have attended seminars and classes on general regulatory issues, including demand-side management and the gas and electric industries.

Q. What is the scope of your testimony in this case?

A. Staff's testimony will cover the revised Rules and Regulations proposed by UNS Electric, Inc. ("UNS Electric" or "Company") as part of this rate case.

This testimony will not address miscellaneous charges, which have been consolidated and moved into the Company's Statement of Charges. Please review the testimony of Staff Witness Howard Solganick for information regarding miscellaneous charges.

Q. What kind of changes have been proposed by the Company?

A. The Company has indicated that the changes it has proposed are generally intended to (i) eliminate ambiguities and inconsistencies; (ii) address issues that have become evident through the customer inquiry and complaint process; and (iii) bring UNS Electric's Rules and Regulations more closely into alignment with those of Tucson Electric Power Company's ("TEP's") Rules and Regulations.

AUTOMATED METER OPT-OUT

Q. Is an Opt-Out Option for automated meters addressed in the Company's proposed Rules and Regulations?

A. No. However, the filing includes testimony, tariff language (in the Residential Electric Service Pricing Plan, R-01) and proposed fees (in the Statement of Charges) related to an opt-out option for customers choosing to have an Automated Meter Reading meter replaced.

Q. Should language addressing the Opt-Out Option be added to the Rules and Regulations for UNS Electric proposed in this docket?

A. No. A generic docket exists for the Commission's inquiry into smart meters (Docket No. E-00000C-11-0328), and it would be premature to address UNS Electric's proposed opt-out charges while investigation into the use of smart meters is pending. If the Commission determines that an opt-out option should be established, the Company should file a tariff conforming to the Commission's decision.

CONFIDENTIALITY OF CUSTOMER INFORMATION

Q. Has the Company proposed to change the type of information it obtains from applicants applying for service?

A. Yes. In the Rules and Regulations, in Section 3 ("Establishment of Service"), UNS Electric is proposing additional language that would allow UNS Electric to obtain the Social Security number or driver's license number and date of birth from an applicant for service.

Q. Is there similar language in the Rules and Regulations for TEP in the Section governing Establishment of Service?

A. Yes. The proposed language would conform UNS Electric's rules to TEP's Rules and Regulations regarding Establishment of Service.

Q. Does the Company maintain this information in a secure environment?

The Company states that this information goes directly into a Microsoft Outlook mailbox and that only UNS Electric Credit and Collections staff have access to that mailbox. UNS Electric also notes that "mailbox security is regulated by protection instituted through Sarbanes-Oxley ("SOX") requirements."

Q. Does Staff have any recommendations regarding the collection of this type of information referenced in the proposed additional language?

A. Yes. Staff recommends that UNS Electric take any measures required in order to maintain the confidentiality of all private customer information. Maintaining confidentiality of customer information would include taking appropriate security measures for protecting computer databases containing this information.

CHANGE OF OCCUPANCY

Q. Does Staff have any issues with the proposed language for Section 11.J.3 ("Change of Occupancy") in the UNS Electric Rules and Regulations?

A. Yes. UNS Electric proposes to add the following sentence: "If access is unavailable, the Outgoing Customer will be responsible for the services consumed until such time as access is provided and services can be turned off." Staff recommends that the phrase "due to the action or inaction of the Customer," be inserted into the proposed language for Section 11.J.3., between "unavailable," and "the".

Q. Does the language proposed by Staff already exist in TEP's proposed Rules and Regulations?

A. Yes. TEP's Rules and Regulations include the phrase "due to the action or inaction of the Customer."

Q. What is the purpose of Staff's proposed language relating to Change of Occupancy?

A. The purpose of Staff's proposed language is to protect outgoing customers from continuing to be responsible for services consumed at former residences where they are unable to provide the access required in order to turn that service off.

Staff notes that, in response to a data request, UNS Electric identified the missing language as an oversight and indicated that it supports this conforming change.

REFUNDS OF OVER-BILLED AMOUNTS

Q. Please describe any issues regarding Section 11, "Billing and Collections."

A. In the Billing and Collections Section of the UNS Electric Rules and Regulations, in Section 11.F.2., the language states that the Company "may" recover or refund the difference between an original and a corrected billing. In discussions with Staff, the Company has clarified this language by stating that any overbillings would be refunded, but that the Company might choose not to recover any under-billed amount in cases where the amount is small.

Staff recommends that the language of Section 11.F.2 be clarified as follows: delete the phrase "may correct such an error to recover or refund the difference between the original billing and the correct billing" and replace that wording with "shall correct such an error to refund any overbilling and may correct such an error to recover any underbilling."

In a response to a data request, the Company has indicated that it is the Company's practice to refund any overbillings by crediting the customer's next bill, or bills, unless the customer specifically requests a refund check. This is reasonable except in cases where a customer has discontinued service with the Company. In such cases, refunds should be addressed in accordance with the requirements of Section 11.N ("Refund of Credit Balance Following Discontinuance of Service.")

IMPACT OF PROPOSED CHANGES TO LINE EXTENSION POLICY

Q. Why did UNS Electric revise its line extension policy?

A. UNS Electric Witness Dallas Dukes states that the Company proposed changes to its line extension policy in order to better align that policy with TEP's. Mr. Dukes states that the revised methodology will be easier for the Company to administer and for customers to understand.

Q. Please describe the changes to UNS Electric's Rules and Regulations with respect to line extensions for Residential customers.

A. Residential applicants for line extensions currently have three options for being evaluated: footage, revenue, and economic feasibility. The proposed revisions would base line extensions only on footage. Mr. Dukes' testimony indicates that there is no change in how Residential customers are treated in terms of collecting or refunding costs.

Previously, Residential customers were allowed 400 feet of primary facilities for a line extension and an additional 150 feet of service line. The proposed language combines these allowances and clarifies that Residential customers receive a total of 550 feet in free footage.

Q. Please describe the changes to UNS Electric's Rules and Regulations with respect to line extensions for Non-residential customers.

A. Currently, Non-residential applicants for line extensions have three options for being evaluated, depending on the project: footage, revenue, and economic feasibility.

- <u>Footage</u>. Non-residential customers requiring line extensions of less than 550 feet would be provided with extensions at no cost.

- <u>Revenue Option</u>: For line extensions of more than 550 feet, but costing less than $25,000, two years of estimated revenue are applied against the cost of construction, with the customer advancing the difference. (There is no free footage.) Under this option the customer may receive a refund after two years, if its revenue was higher than the estimate.

- <u>Economic Feasibility</u>. For line extensions costing more than $25,000, five years of estimated revenue are applied against the cost of construction, with the customer advancing the difference. (There is no free footage.) Under this option the customer may receive a refund after five years, if its revenue was higher than the estimate. A construction true-up is also performed.

The changes proposed by UNS Electric eliminate the free footage and the $25,000 threshold and uses 50 percent of estimated revenue, instead of 100 percent of estimated revenue, to offset the cost of construction. (In other words, the customer would pay the difference between 50 percent of the estimated two year revenue and the actual cost of the project.) After construction is completed there is a true-up of the construction cost, and after two years there is a true-up comparing the actual revenue to the original construction allowance, with the difference being recovered from, or refunded to, the customer.

Staff recommends that the construction and revenue true-ups be fully and clearly disclosed to customers requesting line extensions. In addition, Staff recommends that in its rebuttal testimony, the Company provide a proposal detailing how it intends to address the issue.

Q. Please provide an example of how the deposit process would work.

A. As an example, if the cost of constructing a line extension was $50,000 and the estimated two year revenue was $80,000, the customer would be credited with 50 percent of that two year revenue (or $40,000) and would advance the difference, which is $10,000. At the two year revenue true up, if 50 percent of the actual revenue was $35,000 ($5,000 less than estimated), then the customer would owe $5,000 to UNS Electric; if, in the alternative, actual revenue was $45,000 ($5,000 more than estimated), UNS Electric would owe $5,000 to the customer.

Q. What are the likely financial impacts of UNS Electric's proposed changes to its line extension policy?

A. With respect to Residential customers, the Company "does not believe that there will be any significant financial impact to Residential customers."

With respect to Non-residential customers, the Company informed Staff that, generally, higher cost projects would pay comparable amounts for line extensions, while lower cost projects are likely to pay less for line extensions than they would under the existing system.

Since 2009, the Company has executed nine line extension requests on an economic feasibility basis (projects costing over $25,000). UNS Electric compared the actual cost of line extensions in three instances against what would be paid under the proposed methodology. In each case, the cost was lower under the revised methodology.

The Company states that the mid-range of line extensions (more than 550 feet, but less than $25,000) would have the same type of results.

Customers requesting line extensions of less than 550 feet would be required to pay a deposit, unless 50 percent of the estimated revenue exceeds the estimated construction cost. If a deposit is required, it would be refunded over time, except in cases where the project failed to generate estimated revenue. The Company states that, in such instances, requiring a deposit protects other customers.

Q. What are the proposed rules with respect to developers?

A. Residential developers are allowed 550 feet in free footage per lot. Anything in excess of an average of 550 feet per lot is treated as a non-refundable contribution.

Non-residential developers would be treated in the same manner to that described for individual Non-residential customers.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

- Staff recommends that language addressing the automated meter Opt-Out Option not be added to the Rules and Regulations as proposed by UNS Electric in this docket.

- Staff recommends that UNS Electric take any measures required in order to maintain the confidentiality of all private customer information. Maintaining confidentiality of customer information would include taking appropriate security measures for protecting computer databases containing this information.

- Staff recommends that the phrase "due to the action or inaction of the Customer," be inserted into the proposed language for 11.J.3., between "unavailable," and "the".

- Staff recommends that the language of 11.F.2 be clarified as follows: delete the phrase "may correct such an error to recover or refund the difference between the original billing and the correct billing" and replace that wording with "shall correct such an error to refund any overbilling and may correct such an error to recover any underbilling."

- Staff recommends that the construction and revenue true-ups be fully and clearly disclosed to customers requesting line extensions.

Q. Does this conclude your direct testimony?

A. Yes, it does.