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Transcript Exhibit(s)

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To: Docket Control

Date: February 25, 2010

Re: UNS Electric, Inc. / Rates
E-04204A-09-0206
February 4 through 11, 2010
Volumes I through V, Concluded

STATUS OF ORIGINAL EXHIBITS

FILED WITH DOCKET CONTROL

Arizona School Boards Association (ASBA Exhibits)

1 and 2

Residential Utility Consumer Office (RUCO Exhibits)

1 through 12

Staff (S Exhibits)

2 through 4,
6 through 9, and
11 through 17

UNS Electric (UNSE Exhibits)

1 through 35

LATE-FILED EXHIBITS

Staff (S Exhibits)

18

UNS Electric (UNSE Exhibits)

36

CONFIDENTIAL EXHIBITS

Staff (S Exhibits)

1, 5, and 10 Delivered this date to CALJ Farmer

Copy to:

Lyn A. Farmer, Chief Administrative Law Judge
Maureen Scott, Esq. – Staff
Daniel Pozefsky, Esq. – RUCO
Michael W. Patten, Esq. – UNS Electric
Philip J. Dion, Esq. – UNS Electric
Timothy M. Hogan, Esq. – AZ School Boards Association

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Electric, Inc.

December 11, 2009

EXHIBIT
UNSE 19
ADMITTED

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. What is the Purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to respond to Arizona Corporation Commission ("Commission") Staff ("Staff") and Residential Utility Consumer's Office ("RUCO") testimony on rate design and cost of service. The key issues are:

CARES:

Both Staff witness Mr. William C. Stewart and RUCO witness Dr. Ben Johnson presented Direct Testimony on the CARES program for low-income customers. Staff has recommended that low-income programs be expanded and that CARES customers be allowed to benefit from downward purchased power and fuel adjustor clause ("PPFAC") adjustments but be shielded from upward PPFAC adjustments. RUCO opposes the expansion of low-income programs because of the detrimental impact on other customers on the system. UNS Electric is not necessarily opposed to offering some type of discounts to customers with household incomes between 150% and 200% of poverty under appropriate circumstances. However, expansion of the program could be costly and UNS Electric stands by its position that its support of expanded low income programs is contingent on program costs being fully recovered from other retail customers on a timely basis. UNS Electric opposes Staff's proposal for CARES customers to be subject only to downward adjustments of the PPFAC rate without also being subject to upward adjustments. UNS Electric maintains its proposal for CARES customers to have a PPFAC rate frozen at $0 per kWh.

Additionally, Dr. Thomas H. Fish, witness for Staff, recommends disallowance of a $61,797 adjustment to operating income, because he believes that it constitutes a double recovery of weather and customer annualization adjustments applicable to CARES. There is no double recovery and the Company's proposed adjustment should be accepted.

Residential Customer Charges and Inverted Block Rates:

Staff is supportive of UNS Electric's proposed residential rate design. UNS Electric disagrees strongly with RUCO's proposed rate design. RUCO proposes that residential customer charges decrease, rather than increase as proposed by UNS Electric. RUCO supports adding a third residential rate tier and making the rate more inverted – that is, making the spread between the lower tier price per kWh and the upper tier price per kWh greater. RUCO does not provide any analysis on the impact of its rate design on revenue when, in fact, its proposed residential rate design deprives UNS Electric of a reasonable opportunity to earn its approved return. RUCO's rate design creates a mismatch between revenue collection and cost incursion. Moreover, RUCO's proposal is counter to the energy efficiency policy objectives of the Commission.

Time of Use ("TOU"):

UNS Electric proposes increasing the rate differentials (between on-peak and off-peak) in its existing TOU rates. UNS Electric also proposes a new Super-Peak option where a single hour is priced at a significantly higher rate. Staff supports the Company's proposals. RUCO, however, believes there is need for more analysis before increasing the rate differentials. The Company believes increasing the differentials will encourage more customers to shift load from peak periods and should result in larger savings for customers who keep their peak usage relatively low. RUCO is also concerned about the Super-Peak option and proposes changes that would bring real-time pricing elements into the TOU program. The Company plan as proposed will be less expensive to implement and easier to understand than real-time pricing, and therefore should be implemented as proposed. Even so, implementation of UNS Electric's proposed Super-Peak option will not preclude future implementation of a real time pricing program because the programs are not mutually exclusive.

II. RESIDENTIAL RATE DESIGN.

Q. Please briefly describe UNS Electric's current residential rate.

A. UNS Electric's residential rate is structured as follows:

- A Monthly Customer Charge at $7.50 per month; and
- An inclining (inverted) block (tier) rate structure with a first, lower-priced tier applicable to consumption up to 400 kWh per month, and a second, higher-priced tier applicable to consumption in excess of 400 kWh per month.

Q. When was the inverted block rate structure implemented?

A. The structure was implemented June 1, 2008, in compliance with Decision No. 70360 (May 27, 2008) in UNS Electric's last general rate case.

Q. What is the purpose of an inclining block rate structure?

A. The tiered structure was implemented to encourage conservation by making the incremental price electricity rise at higher usage levels. Moreover, the structure allows customers to purchase up to 400 kWh - energy for the most basic needs - at a reduced price.

Q. UNS Electric proposes to increase the residential monthly customer charge to $8.00 from $7.50. How does that charge compare to the residential customer charges of other Arizona electric utilities?

A. The $8.00 residential customer charge is in line with the customer charges of other electric utilities, including:

- Arizona Public Service Company ("APS") ($7.50 per month for non-Time of Use rate plans to $15.00 per month for TOU rates. A substantial percentage of APS residential customers are TOU customers);
- Tucson Electric Power Company ("TEP") ($7.00 per month for non-TOU to $8.00 per month for TOU); and
- Salt River Project ("SRP") ($12.00 per month for non-TOU to $15.00 per month for TOU in some months).

UNS Electric is also proposing an $8.00 monthly residential charge for its proposed residential TOU rates.

Considering the number of residential customers – both non-TOU and TOU – and the number of customers served by the three aforementioned companies, the proposed UNSE residential monthly customer charge of $8.00 is actually *less than* the weighted average customer charge paid by residential customers of the three companies listed above.

A. <u>Response to RUCO Witness Dr. Ben Johnson – Residential Rate Design</u>.

Q. Dr. Johnson has proposed that the residential customer charge be decreased from $7.50 per month to $5.00 per month, and has proposed adding a third rate block priced at two cents per kWh over the first rate block. Do you agree with these residential rate design recommendations?

A. No. The Company appreciates Dr. Johnson's acknowledgement that progress has been made in promoting conservation in rates. Dr. Johnson, however, has not adequately considered the adverse potential impact of his proposals on UNS Electric's financial condition. Dr. Johnson's proposals do not align UNS Electric's need to have a reasonable opportunity to recover its revenue requirement with efforts to promote energy efficiency and conservation – including development of enhanced Demand Side Management ("DSM") programs.

The Company incurs fixed costs for establishing and maintaining service. These actual embedded costs include costs of metering, meter-reading, billing and customer service, and customer-specific equipment at the customer's premises. Dr. Johnson is attempting to incorporate marginal costing principles into unbundled rates that instead should reflect the average embedded costs of providing customer-related services. By doing so, his proposed residential customer charge is substantially understated and does not cover the costs of items that are typically classified as customer-related and appropriate for inclusion in the customer charge.

Dr. Johnson's methodology is also inconsistent with methodologies previously used to derive customer charges for UNS Electric. The Company's customer charge methodology is an accepted embedded average cost approach that restrains the size of customer charges. The cost-of-service methodology was not an issue in the last general rate case for UNS Electric or TEP.

Q. What concerns do you have with Dr. Johnson's proposal?

A. Dr. Johnson seeks to radically shift recovery away from the customer charge to the energy charge. In doing so, he significantly understates the residential customer charge. This results in a mismatch between revenue collection and cost causation. Shifting customer-related costs to energy (per kWh) charges leads to the Company under-recovering when sales are relatively low, regardless of whether low sales are attributable to weather, the economy, conservation and energy efficiency or other factors. Likewise, over-recoveries result when sales are relatively high. Maintaining a cost-based residential customer charge – like the one proposed by UNS Electric – helps mitigate periodic swings in revenue because of volatility in usage. In short, it is important that a rate design that promotes conservation also gives some measure of revenue stability for the Company.

Q. Doesn't Dr. Johnson's rate design provide customers a greater incentive to conserve, as he states on pages 18 and 21 of his Direct Testimony?

A. Yes, but the problem is that his rate design proposal will also preclude providing UNS Electric a reasonable opportunity to earn its approved return. UNS Electric's proposed residential rate design provides a balance between the conservation goal and providing the Company a fair opportunity to recover its costs. Dr. Johnson's residential rate design proposal, in contrast, ignores customer-related costs that the Company incurs for every customer that receives service from UNS Electric. I believe Dr. Johnson's rate design is confiscatory in its approach.

Q. Why is Dr. Johnson's proposed residential rate design confiscatory?

A. When recovery of costs is shifted from customer charges to energy charges (*i.e.* volumetric charges), these costs will go unrecovered if kWh sales levels are below the test-year levels used to design rates. Simply put, no sales equals no recovery. Given that the Commission is considering energy efficiency rules that would impose aggressive targets to reduce energy consumption, it would become difficult (if not impossible) for any electric utility to recover its fixed costs through energy charges. What makes Dr. Johnson's proposal especially troubling is how radical a shift in recovery he is proposing from the customer charges to the energy charges.

Dr. Johnson has loaded up cost recovery on kWh sales in excess of 800 kWh per month. In other words, a significant portion of the Company's revenues will be obtained through a third tier. Under Dr. Johnson's approach, sales in this third tier (the highest priced tier) will decline more than lower tier sales. Sales revenue from the third tier will not be collected, as a significant portion of third tier sales will be effectively eliminated; thus, the Company cannot recover its revenue requirement. In short, with Dr. Johnson's proposal, sales of electricity will decline to the point that the Company will have no opportunity to achieve its revenue requirement and earn a reasonable return. Again, no sales equals no recovery.

UNS Electric is further at risk taking into account how leveraged UNS Electric's earnings already are to volumetric (kWh) sales and energy consumption, and how a seemingly small reduction in volumetric sales can greatly reduce those earnings. For example, a reduction in kWh sold of just 3% across all classes (except lighting) can lead to a pre-tax earnings reduction of approximately $1.6 million per year. Dr. Johnson provides no detailed analysis to quantify the potential for substantial loss of earnings within his pre-filed testimony. He also did not propose an adjustment to normalized sales that would reflect the anticipated reduction in load due to conservation resulting from his proposed rate design.

Q. **What is the effect of a rate structure where the vast majority of costs are recovered through volumetric rates as Dr. Johnson suggests?**

A. Under the current rate and regulatory structure, sales reductions for any reason (including conservation and energy efficiency) mean margin loss to UNS Electric. Dr. Johnson's residential rate design recommendations exacerbate the problem. His proposed rate design will drive UNS Electric's need to recover its revenues towards increasing use of power and away from conservation.

Q. **What would you recommend to the Commission in order to align the goal of conservation with the Company's need to have an opportunity to recover its costs of providing service?**

A. UNS Electric needs a rate structure that recognizes it is a provider of electric service, and not simply a seller of a commodity. That rate structure should also align important policy goals (*e.g.*, conservation and efficiency) with a financially-healthy public service corporation. Avoiding artificially low customer charges – and implementing customer charges that more fully recover costs – is consistent with that new business model. Customer charge increases are one of the simplest ways to move profitability away from energy consumption and sales. In other words, the Commission should make the correct level of fixed cost recovery (revenue collected to recover fixed costs) more independent of sales being at a certain level. The Company believes that effective conservation programs occur through DSM and energy efficiency. Dr. Johnson's rate design, however, would create a significant disincentive for the Company to aggressively pursue creative and effective conservation programs.

Q. Do you have comments about other aspects of Dr. Johnson's Direct Testimony?

A. Yes. Dr. Johnson makes a specific recommendation not to classify as customer-related two cost components, Account 904 "Uncollectible Accounts" and Account 431 "Customer Deposit Interest". The calculation of customer-related costs serves as the cost-of-service basis for proposed customer charges.

Q. What is the Company's response?

A. UNS Electric agrees with Dr. Johnson's position on Uncollectible Accounts. The Company is not opposed to Dr. Johnson's proposal regarding Interest on Customer Deposits, so long as the same approach applies to the Customer Deposits themselves, a credit to rate base. However, these are minor issues. These modifications to the class cost of service study result in changing the residential customer charge calculation from \$7.65 to \$7.74 (an increase of nine cents). UNS Electric's proposal to increase the residential customer charge from \$7.50 to \$8.00 per month remains unchanged.

Q. Please comment on Dr. Johnson's testimony regarding the relationship between average total price of electricity and usage.

A. Dr. Johnson, in his Direct Testimony at pages 20-21, discusses and makes calculations regarding average price per residential kWh. He does this to show that he would like to see an increase in the average *total* price (total price includes both customer and energy charges measured as cost per kWh) as usage increases over a greater range of usage – and not just an increase in the volumetric price (energy charges only) as usage increases. But requiring average total price (including only the energy charges) to increase with usage over the entire range of usage is only possible if the customer charge is set to zero. That proposal would be extreme and Dr. Johnson does not go that far in his recommendations.

However, a pro-conservation residential rate design requires only that customers see an increasing volumetric price (energy charges only). UNS Electric's proposed residential inclining block residential rate accomplishes exactly this. Specifically, the incremental price (*i.e.* marginal price) of electricity increase as residential usage increases into the second tier.

Consumption decisions are most influenced by marginal cost – meaning that an additional unit of product is consumed only when marginal utility (benefit) to the consumer is greater than or equal to marginal cost to the consumer. In this case, marginal cost is UNS Electric's energy charge – the incremental price. Dr. Johnson's lengthy discussion of average total price (includes both customer and energy charges) – moves the focus away from the more appropriate incremental volumetric price. UNS Electric proposes a rate design where the volumetric charge (the energy charge) is greater in the second tier; the marginal cost to the consumer increases as usage increases. This makes UNS Electric's rate design pro-conservation - despite Dr. Johnson's testimony about average total price.

B. <u>Summary of Staff Rate Design Recommendations.</u>

Q. Has Staff supported UNS Electric's residential rate design proposals?

A. Yes. Staff witness Mr. William C. Stewart, unlike Dr. Johnson at RUCO, has supported the Company's residential rate design and customer charge proposals. However, Mr. Stewart's Direct Testimony does diverge from the UNS Electric position on the issue of the distribution of the rate increase across classes ("Revenue Spread") and the treatment of the CARES rate. I discuss this issue in more detail in the next section.

III. REVENUE SPREAD.

Q. Please discuss "revenue spread" across classes.

A. UNS Electric proposed that all classes receive an equal percentage increase in adjusted test-year revenue (9.21% based on the Company's request), with the exception of CARES customers, who receive a 9.41% *decrease*. This approach is consistent with what was approved in UNS Electric's last rate case – Decision No. 70360 (May 27, 2008) – and with the recent TEP rate case settlement – approved in Decision No. 70628 (December 1, 2008). However, both Staff and RUCO now express an interest in seeing revenue changes vary by rate class. UNS Electric is not necessarily opposed to varying percentage increases, so long as the maximum percentage increase assigned to any class is no more than 200% of the system average percentage increase. This helps avoid the risk of rate shock.

IV. CARES AND LOW-INCOME.

Q. What are Staff and RUCO positions regarding expanding the low-income program?

A. Staff supports the expansion of the low-income program from 150% to 200% of poverty level, and RUCO opposes the expansion. UNS Electric at this time is not taking a position in favor of or opposed to the expansion of the low-income programs, since no consensus has been reached on the issue. Additionally, UNS Electric is not opposed to some minor changes in the structure of the CARES program, as long as the Company can recover associated revenue shortfalls.

Q. Please discuss UNS Electric's response to Staff's CARES and low-income proposals.

A. At pages 7-8 of his testimony, Staff witness Mr. William C. Stewart agrees with the notion of expanding low-income program eligibility to customers whose income is 200%

of the poverty level. UNS Electric is not necessarily opposed to offering some type of discounts to customers with household incomes between 150% and 200% of poverty under appropriate circumstances. However, expansion of the program could be costly and UNS Electric stands by its position that its support of expanded low income programs is contingent on program costs being fully recovered from other retail customers on a timely basis. This is a prudent approach and eliminates the potential that any expansion of the program is confiscatory. Assuming new low-income discounts averaging $140 per customer per year, and 2,500 new participants, UNS Electric stands to lose $350,000 annually in pretax earnings. I assume that Staff agrees that expanded program costs should be recovered from other retail customers in a timely manner.

Additionally, UNS Electric is not opposed to some minor changes in the structure of the CARES program, as long as the Company can recover associated revenue shortfalls.

Q. Please respond to Staff's recommendation concerning CARES customers and UNS Electric's PPFAC.

A. Mr. Stewart for Staff, at page 7 of his Direct Testimony, proposes that CARES customers be subject to downward PPFAC adjustments, but that upward adjustments be capped. Given that CARES customers already enjoy a discount in base rates, such a proposal seems overly complicated and unfair to regular residential customers. It is unfair that other customers incur the costs for freezing the PPFAC rate at a rate no greater than zero for CARES customers, if the downward adjustments (*i.e.*, "negative rates" as Mr. Stewart puts it) are passed on to CARES customers. CARES customers cannot incur all of the benefit and none of the risk because other customers (mostly middle class customers) bear the entire burden with none of the reward. UNS Electric maintains its proposal to freeze the PPFAC rate at zero for CARES customers when new rates become effective.

Q. Staff Witness Dr. Thomas H. Fish recommends disallowance of a $61,797 adjustment to operating income because he believes that it constitutes a "double recovery" of customer annualization and weather normalization adjustments applicable to CARES. Do you disagree with Dr. Fish?

A. Yes. The Company's customer annualization and weather normalization adjustments for CARES customers were calculated using the regular residential rate RES 01 rather than the lower CARES rates. Consequently, the net customer and weather adjustment for CARES – a positive revenue adjustment - is higher (i.e., more positive) than it would have been had lower CARES rates been used in the calculation. The use of this larger customer and weather adjustment results in adjusted test-year CARES revenue being overstated relative to what it would have been had lower CARES rates been used in the adjustment calculation. In reality CARES customers *will* pay lower CARES rates, *not* the regular residential rate RES 01, and CARES revenue (based on adjusted sales) will be lower than the stated adjusted test-year CARES revenue. Absent any adjustment to recognize the lower CARES rates, UNS Electric will face a revenue shortfall. The $61,797 adjustment is necessary to offset this revenue shortfall. The $61,797 adjustment is the *only* adjustment recognizing that sales to CARES customers will in fact be discounted relative to regular residential rate RES 01. The adjustment is not a "double recovery" – it is a necessary step in the overall adjustment process. The $61,797 adjustment is appropriate and should be approved.

V. COST ALLOCATION.

Q. Has Staff or RUCO raised issues regarding the allocation of production or transmission cost?

A. Staff has not taken issue with the Company's position. Dr. Johnson discusses some of the problems in trying to allocate joint costs. I agree with Dr. Johnson that there is no single correct way to allocate a joint cost. I also agree that the Average and Peak method, as described in my Direct Testimony, is a far better approach for production plant allocation than a purely peak-oriented methodology. Dr. Johnson's discussion of production and transmission cost allocation notwithstanding, he does not appear to be recommending changes in UNS Electric's production and transmission cost allocation approaches. His point appears to be that the Commission has some flexibility to deviate from the results of the cost allocation study in the design of rates. UNS Electric does not disagree with that, but does disagree with what seems to be Dr. Johnson's abandonment of cost of service as a basis to formulate customer charges.

In several places in his testimony, Dr. Johnson notes that UNS Electric purchases the majority of its power requirements from the wholesale market and that the portion that is self-generated is relatively small. In the last rate case, the Commission ordered that purchased power be allocated solely on energy and not on average and peaks. UNS Electric used 100% energy as the basis for purchased power allocation in this proceeding. Staff witness Mr. Stewart acknowledges at page 4, lines 1-9, of his Direct Testimony that the Company did allocate purchase power on an energy basis, as directed. Only a relatively small amount of production capacity costs are allocated based on average and peaks. The Average and Peaks method was accepted for that purpose in UNS Electric's last general rate case, and in TEP's rates cases since the early 1990's.

VI. TIME-OF-USE.

Q. Please comment on the Staff and RUCO position on UNS Electric's time-of-use rate proposals.

A. UNS Electric has proposed increasing the rate differentials (between on-peak and off-peak) in its existing time-of-use rates. This results in larger savings for customers who are able to keep their peak usage relatively low. The Company has also proposed some Super-Peak rates that for summer billing months set a single hour during the day to be the peak hour. Staff has recommended approval of these rates.

On the other hand, Dr. Johnson for RUCO has some concerns, and believes there is the need for more analysis on the size of the on peak / off-peak differential. He also inquired about the terms and conditions of the Super-Peak rates, and questioned whether the Super-Peak Rates should not be designed more as a real-time pricing type program. I will clarify some issues of concern below.

Q. Please discuss the Company's goals and objectives for the Super-Peak rate.

A. In layman's terms, this rate was designed to offer the maximum benefit in our efforts to reduce demand in the most critical periods. By pricing a single summer hour at a very high price, the customer will be motivated to dramatically reduce usage – even air conditioning on a hot summer day – for that one hour. The Super-Peak rate is geared for the hot desert climate in UNS Electric's service territory. Even on the hottest days, customers are motivated to reduce energy consumption in the peak hour with the right price signal. There will be some additional usage in the following hour, of course, but the Super-Peak will likely result in eliminating (and not just shifting) some usage during the on-peak period.

The rate was also designed to be revenue neutral for residential customers. So, if all customers maintained usage at current levels over all hours, even the super-peak hour, residential revenue will remain unchanged. Super-Peak subscribers, however, will likely reduce usage during the super-peak hour. That means that the customer will likely save money. The Super-Peak customer saves money while also reducing usage and easing the burden on UNS Electric's system. At a minimum, load is shifted from peak times, which reduces the need for additional infrastructure.

Q. Please describe why you believe implementing a "Super-Peak" TOU option will advance the goals of reducing demand and implementing demand response.

A. The demand for electricity is very inelastic in the Company's hot desert service territory during peak times (*e.g.*, a hot summer day in the mid to late afternoon). Demands are inelastic when the percentage change in quantity demanded is less than the percentage change in price. In other words, the change in the price will not affect significantly the amount of a product that is bought or consumed. On that hot summer afternoon, consumers will use approximately the same amount of electricity when faced with low to moderate price changes.

The demand for peak-period electricity is especially inelastic. With this inelastic demand, a substantial price jolt is necessary to push consumption away from the peak. Compared with goods with more elastic demand – where sales respond to price changes - a greater percentage change in price is needed to cause a given shift in consumption. The question is how much of a price hike will be necessary to change the customer's usage patterns.

Under UNS Electric's proposed Super-Peak rate, the summer peak price is set high enough to elicit a price-elasticity response from the participating customer. A lower peak price may also be effective in shifting load away from the peak, but the true degree of price inelasticity at the most critical times – and UNS Electric's ability to ascertain the level to which the peak price can be decreased – will remain unknown until the Super-Peak rate is implemented. It is possible that an even higher peak price would be necessary and appropriate to achieve the desired load shift. The implementation of

Super-Peak option will be a very useful experiment to help quantify price elasticity at the most critical peak periods. We can "study" this issue at length, but we ultimately will not have good elasticity estimates for *this* service territory over a wider range of prices until we implement the rate. The only meaningful results will come with the implementation of a Super-Peak option, which can then be adjusted and refined once the Company collects the necessary data. The aggressive conservation and load shifting targets being considered by the Commission may necessitate the consideration of innovative, but heretofore untested new programs that may require some "fine-tuning" in the future. Super-Peak TOU is such a program.

Q. How difficult will it be to implement the Super-Peak option?

A. As proposed by UNS Electric, Super-Peak will be easy to implement and does not require expensive communications equipment installation. It is also incredibly easy for customers to understand and implement. It allows customers with programmable thermostats to, for example, set summer thermostats between 85 and 90 degrees during the peak hour and rely on fans. UNS Electric believes that customers will be willing and able to adjust their lifestyles so as to capitalize on the rate.

Q. Does Dr. Johnson agree with the Company's approach?

A. Dr. Johnson prefers a real-time rate with a price that varies with specific circumstances. At this time, Dr. Johnson's rate will be more costly to implement and harder for the customer to benefit from and to understand. Pre-programming thermostats would not be as effective. Also, we do not believe that residential customers have time to watch monitors telling them how expensive usage will be at a particular time.

Q. Does this mean the Company is forever opposed to a real-time pricing option at some time in the future?

A. No. The Company may consider a real-time pricing rate as part of its DSM programs. UNS Electric does not see a real time pricing rate and the Super-Peak rates as mutually exclusive alternatives. In time, UNS Electric could potentially implement both programs. These rates may appeal to different customer groups.

Q. How will a customer's peak hour be chosen under the Super-Peak rate?

A. A customer's peak hour will be based on the last two digits of his street address, an objective, non-changing metric. A non-changing metric prevents the customer from calling back to get a different peak hour. Having the customer choose his own peak hour creates an "adverse selection" issue that Dr. Johnson recognized and that I discuss below. The "last two digits" peak hour selection criterion is also easy to implement. Exhibit DBE-4 shows the peak hour associated with each of the 100 two-digit address combinations ("00" through "99"). Exhibit DBE-5 shows proposed tariffs with the Exhibit DBE-4 peak hour / address combination information included.

Q. Please explain the adverse selection concern you noted in your previous answer.

A. Dr. Johnson correctly noted that the Company is concerned about the issue of adverse selection that could occur if the customer chose the peak hour. If customers could choose the peak hour, then they would choose the hour in which they were already restricting usage. Consequently, there would be less beneficial load shifting if customers could pick their own hour. Since the Super-Peak rates are optional, a customer assigned an hour he sees as undesirable has the regular TOU rate as an additional rate option.

Q. Will the Company need to close subscription for certain Super-Peak hours, or change the selection criteria if too many customers end up on one or two of the peak hours?

A. The Company does not know the extent that a customer will accept the Super-Peak rate based on the summer peak hour assigned. This may result in certain summer peak hours being over-subscribed or under-subscribed. Under these circumstances, the Company may discuss with Commission Staff changes to the peak-hour selection criterion. As mentioned, the Super-Peak tariffs may require some fine-tuning in the future. The possible need for such fine tuning is referenced in the Super-Peak tariffs attached as Exhibit DBE-5. The resolution to some questions may need to wait until the program has been in place for a year or more. UNS Electric will keep the Staff informed as situations arise or resolve themselves.

Q. Please comment on Dr. Johnson's proposal to study the size of the on-peak to off-peak differential in the regular TOU rate.

A. As in the Super-Peak design, the regular TOU rates are designed to be revenue neutral with the regular Non-TOU rates – assuming usage remains the same. So, the larger differentials proposed offer enhanced saving opportunities for customers who can reduce on-peak consumption. The differential deliberately is not cost-based, but is instead designed to elicit the type of price elasticity response that will contribute to significantly reducing peak demand, which is a rate design goal.

Q. Does this conclude your testimony?

A. Yes.

EXHIBIT

DBE-4

UNS Electric, Inc.

Peak-Hour Selection Criterion for Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:

5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

EXHIBIT

DBE-5

EXHIBIT DBE-5

Clarifying Revisions to Proposed Super-Peak Tariffs

UNS Electric, Inc.
Pricing Plan RES-01 SuperPeak TOU
Residential Service SuperPeak Time-of-Use – Weekends Off-Peak

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service.

This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

Service is restricted to private single family dwellings or individually metered apartments.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE

Single phase, 60 hertz, at one standard voltage.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill $ 8.00 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.

All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
Super-Peak	$0.020070	$0.488770	Varies	$0.508840
Shoulder Peak	$0.020070	$0.074812	Varies	$0.094882
Off-Peak	$0.020070	$0.054158	Varies	$0.074228
All Additional kWhs				
Super-Peak	$0.030084	$0.488770	Varies	$0.518854
Shoulder Peak	$0.030084	$0.074812	Varies	$0.104896
Off-Peak	$0.030084	$0.054158	Varies	$0.084242

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.020070	$0.159138	Varies	$0.179208
Off-Peak	$0.020070	$0.041894	Varies	$0.061964
All Additional kWhs				
On-Peak	$0.030084	$0.159138	Varies	$0.189222
Off-Peak	$0.030084	$0.041894	Varies	$0.071978

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

Summer TOU periods:

Weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

Super-Peak:	Either:	Version A: 2:00 p.m. to 3:00 p.m., or Version B: 3:00 p.m. to 4:00 p.m., or Version C: 4:00 p.m. to 5:00 p.m.; or Version D: 5:00 p.m. to 6:00 p.m.
Shoulder-Peak:	Either:	Version A: 3:00 p.m. to 6:00 p.m., or Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m., or Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m., or Version D: 2:00 p.m. to 5:00 p.m.
Off-Peak:	12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)	

Weekends (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak:	*(There are no On-Peak weekend hours)*
Shoulder-Peak:	*(There are no Shoulder-Peak weekend hours)*
Off-Peak:	All weekend hours.

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of the last two digits of the customer's street address. A matrix of address digits and summer peak hours is found below. The "two-digit" rule helps promote load diversity, a beneficial result of a demand response program. The Company shall evaluate subscription to each Version to determine whether certain peak hours are under-subscribed or over-subscribed. In the event that an optimal mix of peak hours is not developing, the Company will notify the Commission Staff and may seek modifications to the selection criterion.

Winter TOU periods:
Winter weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak:	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak:	There are no shoulder peak periods in the winter.
Off-Peak:	12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight).

WinterWeekend days (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak:	*(There are no On-Peak weekend hours)*
Shoulder-Peak:	*(There are no Shoulder-Peak weekend hours)*
Off-Peak:	All weekend hours.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01 SuperPeak TOU
Residential Service SuperPeak Time-of-Use – Weekends Off-Peak

Criterion for Selecting Summer Peak Hour in Time-of-Use Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:
5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$3.097 per month
Meter Reading	$0.862 per month
Billing & Collection	$3.661 per month
Customer Delivery	$0.380 per month
	$8.00 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Transmission	$0.002299
Sub-Transmission	$0.004813
Local Delivery Energy	$0.012643
Production not included in Power Supply	$0.000315
Delivery Services - Energy All Additional kWhs	
Transmission	$0.002299
Sub-Transmission	$0.004813
Local Delivery Energy	$0.022657
Production not included in Power Supply	$0.000315

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.488770
Shoulder-Peak	$0.074812
Off-Peak	$0.054158
Base Power Supply Winter	
On-Peak	$0.159138
Off-Peak	$0.041894
PPFAC (see Rate Rider-1 for current rate)	Varies

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the monthly usage is not more than 7,500 kWh in any two (2) consecutive months. Customers who use more than 7,500 kWh for two (2) or more consecutive months shall not be eligible for this pricing plan and shall take service under the Large General Service pricing plan. However, service is available for customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single phase, 60 hertz at one standard voltage. Three phase for eligible loads over 5 kW.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ 12.50 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
Super-Peak	$0.032440	$0.423680	Varies	$0.456120
Shoulder Peak	$0.032440	$0.072649	Varies	$0.105089
Off-Peak	$0.032440	$0.046759	Varies	$0.079199
All Additional kWhs				
Super-Peak	$0.042454	$0.423680	Varies	$0.466134
Shoulder Peak	$0.042454	$0.072649	Varies	$0.115103
Off-Peak	$0.042454	$0.046759	Varies	$0.089213

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.032440	$0.136759	Varies	$0.169199
Off-Peak	$0.032440	$0.038539	Varies	$0.070979
All Additional kWhs				
On-Peak	$0.042454	$0.136759	Varies	$0.179213
Off-Peak	$0.042454	$0.038539	Varies	$0.080993

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. .The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

The Summer periods below apply to all summer days:

Super-Peak: Either:
Version A: 2:00 p.m. to 3:00 p.m.;
Version B: 3:00 p.m. to 4:00 p.m.;
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either:
Version A: 3:00 p.m. to 6:00 p.m.;
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.;
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of the last two digits of the customer's street address. A matrix of address digits and summer peak hours is found below. The "two-digit" rule helps promote load diversity, a beneficial result of a demand response program. The Company shall evaluate subscription to each Version to determine whether certain peak hours are under-subscribed or over-subscribed. In the event that an optimal mix of peak hours is not developing, the Company will notify the Commission Staff and may seek modifications to the selection criterion.

The Winter periods below apply to all winter days:

On-Peak	6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak:	There is no shoulder peak periods in the winter.
Off-Peak:	12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight)

Criterion for Selecting Summer Peak Hour in Time-of-Use Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:
5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$4.381 per month
Meter Reading	$1.434 per month
Billing & Collection	$6.061 per month
Customer Delivery	$0.624 per month
	$12.50 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Transmission	$0.001889
Sub-Transmission	$0.003993
Local Delivery Energy	$0.026252
Production not included in Power Supply	$0.000306
Delivery Services - Energy All Additional kWhs	
Transmission	$0.001889
Sub-Transmission	$0.003993
Local Delivery Energy	$0.036266
Production not included in Power Supply	$0.000306

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.423680
Shoulder-Peak	$0.072649
Off-Peak	$0.046759
Base Power Supply Winter	
On-Peak	$0.136759
Off-Peak	$0.038539
PPFAC (see Rate Rider-1 for current rate)	Varies

TERMS AND CONDITIONS

Service under this schedule is for the exclusive use of the Customer and shall not be resold or shared with others.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

Standby, supplemental or breakdown service shall not be rendered under this pricing plan.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the maximum monthly demand is less than 1,000 kW.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises. Customers may choose time-of-use service as well.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ 16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand
Demand Charge $13.353 per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
All kWh				
Super-Peak	$0.004254	$0.363690	Varies	$0.367944
Shoulder Peak	$0.004254	$0.064326	Varies	$0.068580
Off-Peak	$0.004254	$0.046221	Varies	$0.050475

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
All kWh				
On-Peak	$0.004254	$0.121221	Varies	$0.125475
Off-Peak	$0.004254	$0.032503	Varies	$0.036757

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

The Summer periods below apply to all summer days:

Super-Peak: Either:
Version A: 2:00 p.m. to 3:00 p.m.;
Version B: 3:00 p.m. to 4:00 p.m.;
Version C: 4:00 p.m. to 5:00 p.m.; or
Version D: 5:00 p.m. to 6:00 p.m.

Shoulder-Peak: Either:
Version A: 3:00 p.m. to 6:00 p.m.;
Version B: 2:00 p.m. to 3:00 p.m. and 4:00 p.m. to 6:00 p.m.;
Version C: 2:00 p.m. to 4:00 p.m. and 5:00 p.m. to 6:00 p.m.; or
Version D: 2:00 p.m. to 5:00 p.m.

Off-Peak: 12:00 a.m. (midnight) to 2 p.m. and 6:00 p.m. to 12:00 a.m. (midnight)

The Version (i.e., A, B, C, or D) available to a specific customer shall be determined on the basis of the last two digits of the customer's street address. A matrix of address digits and summer peak hours is found below. The "two-digit" rule helps promote load diversity, a beneficial result of a demand response program. The Company shall evaluate subscription to each Version to determine whether certain peak hours are under-subscribed or over-subscribed. In the event that an optimal mix of peak hours is not developing, the Company will notify the Commission Staff and may seek modifications to the selection criterion.

The Winter periods below apply to all winter days:

On-Peak: 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: There is no shoulder peak periods in the winter.
Off-Peak: 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight).

Criterion for Selecting Summer Peak Hour in Time-of-Use Super-Peak Proposals
Last 2 digits of Street Address will Determine Peak Hour for the Address.

Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour	Last 2 Digits	Summer Peak Hour
00	5-6 pm	25	4-5 pm	50	3-4 pm	75	2-3 pm
01	4-5 pm	26	5-6 pm	51	5-6 pm	76	5-6 pm
02	3-4 pm	27	3-4 pm	52	4-5 pm	77	4-5 pm
03	2-3 pm	28	2-3 pm	53	2-3 pm	78	3-4 pm
04	5-6 pm	29	4-5 pm	54	3-4 pm	79	2-3 pm
05	4-5 pm	30	5-6 pm	55	5-6 pm	80	5-6 pm
06	3-4 pm	31	3-4 pm	56	4-5 pm	81	4-5 pm
07	2-3 pm	32	2-3 pm	57	2-3 pm	82	3-4 pm
08	5-6 pm	33	4-5 pm	58	3-4 pm	83	2-3 pm
09	4-5 pm	34	5-6 pm	59	5-6 pm	84	5-6 pm
10	3-4 pm	35	3-4 pm	60	4-5 pm	85	4-5 pm
11	2-3 pm	36	2-3 pm	61	2-3 pm	86	3-4 pm
12	5-6 pm	37	4-5 pm	62	3-4 pm	87	2-3 pm
13	4-5 pm	38	5-6 pm	63	5-6 pm	88	5-6 pm
14	3-4 pm	39	3-4 pm	64	4-5 pm	89	4-5 pm
15	2-3 pm	40	2-3 pm	65	2-3 pm	90	3-4 pm
16	5-6 pm	41	4-5 pm	66	3-4 pm	91	2-3 pm
17	4-5 pm	42	5-6 pm	67	5-6 pm	92	5-6 pm
18	3-4 pm	43	3-4 pm	68	4-5 pm	93	4-5 pm
19	2-3 pm	44	2-3 pm	69	2-3 pm	94	3-4 pm
20	5-6 pm	45	4-5 pm	70	3-4 pm	95	2-3 pm
21	4-5 pm	46	5-6 pm	71	5-6 pm	96	5-6 pm
22	3-4 pm	47	3-4 pm	72	4-5 pm	97	4-5 pm
23	2-3 pm	48	2-3 pm	73	2-3 pm	98	3-4 pm
24	5-6 pm	49	4-5 pm	74	3-4 pm	99	2-3 pm

Examples:
5288 W. Oak's Peak Hour would be 5-6 pm, becase "5288" ends in "88."
1 W. Oak's Peak Hour would be 4-5 pm, becase "1" ends in "01."

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the higher of:
(i) the highest measured fifteen (15) minute integrated reading of the demand meter during the on-peak and shoulder hours of the billing period,
(ii) one-half the highest measured fifteen (15) minute integrated reading of the demand meter during the off-peak hours, or
(iii) the contract capacity.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$8.772 per month
Meter Reading	$1.282 per month
Billing & Collection	$5.394 per month
Customer Delivery	$0.552 per month
	$16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge $13.353 per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy – All kWh	
Transmission	$0.001507
Sub-Transmission	$0.003224
Local Delivery Energy (negative charge)	($0.000768)
Production not included in Power Supply	$0.000291

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.363690
Shoulder-Peak	$0.064326
Off-Peak	$0.046221
Base Power Supply Winter	
On-Peak	$0.121221
Off-Peak	$0.032503
PPFAC (see Rate Rider-1 for current rate)	Varies

TERMS AND CONDITIONS

Standby, supplemental or breakdown service shall not be rendered under this pricing plan except for Qualifying Facilities or Independent Power Producers that have entered into a Service or Purchase Agreement with the Company.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rejoinder Testimony of

D. Bentley Erdwurm

on Behalf of

UNS Electric, Inc.

January 25, 2010

EXHIBIT
UNSE-20
ADMITTED

TABLE OF CONTENTS

Q. Please state your name and business address.

A. My name is D. Bentley Erdwurm. My business address is One South Church Avenue, Tucson, Arizona 85701.

Q. Are you the same D. Bentley Erdwurm who filed Direct and Rebuttal testimony in this case?

A. Yes.

Q. What is the Purpose of your Rejoinder testimony?

A. The purpose of my Rejoinder testimony is to respond to Dr. Ben Johnson's (RUCO) Surrebuttal testimony on residential rate design, including the customer charge and tiered rates. Additionally, I address Dr. Thomas H. Fish's and Mr. William C. Stewart's Surrebuttal testimony on the expansion of the CARES program. Finally, I address Dr. Fish's position regarding a $61,797 adjustment to operating income related to the CARES program.

I. <u>RESIDENTIAL RATE DESIGN.</u>

Q. Please summarize UNS Electric's proposed residential rate design and RUCO's proposed design, as supported by RUCO witness Dr. Ben Johnson.

A. The current residential customer charge is $7.50 per month. UNS Electric has proposed a residential customer charge of $8.00 per month. Staff supports UNS Electric's residential customer charge proposal. However, RUCO continues to propose reducing this charge to $5.00 per month.

The current residential rate has an inclining block structure, with two rate blocks. UNS Electric proposes to continue the current two block structure and Staff has agreed with that proposal. However, RUCO has proposed a three block design. Under an inclining block rate structure, the price of incremental usage rises as usage rises.

Q. **Dr. Johnson claims on pages 8 to 9 of his Surrebuttal testimony that the Company's residential rate design proposal is "based on an embedded cost allocation approach which allocates substantial portions of the Company's distribution investment and operating expenses on the basis of customers, regardless of whether or not these items directly vary in response to decisions by customers to join or leave the system." Please comment.**

A. I disagree. Costs classified by UNS Electric as "customer-related" and recovered through the customer charge are limited to metering, meter-reading, billing and customer service, and customer-specific equipment at the customer's premises. These costs vary with changes in the <u>number</u> of customers, <u>not</u> with kWh sales. UNS Electric has not used any technique that classifies a portion of the upstream distribution system (upstream of the customer) on a customer-related basis.

Q. **Dr. Johnson states on page 9 of his Surrebuttal Testimony that the customer charge primarily should collect the variable costs of metering, billing and collecting the monthly bill. Do you agree that only variable costs should be included?**

A. No. Both fixed and variable costs of customer related costs - metering, meter-reading, billing and customer service, and customer-specific equipment at the customer's premises – should be included in the customer charge. For clarity, consider the costs of billing a customer. Some of these costs are variable (for example, the postage to send the bill and the paper stock on which the bill is printed). Some of the costs are fixed (for example the salaries of the Company employees engaged in the billing function and the cost of the computer billing software). UNS Electric must incur both fixed and variable costs to bill customers, and both are appropriately included in the customer charge calculation.

UNS Electric's proposed customer charges in this case and in previous cases have been supported by average embedded cost analyses that include both fixed and variable costs. In fact, the Commission has approved such analyses as the basis for customer charges (including for Arizona Public Service Company (APS) and Tucson Electric Power Company (TEP)) over the last 20 years. Dr. Johnson's methodology is inconsistent with methodologies previously used to derive customer charges for Arizona utilities. Moreover, Dr. Johnson has not demonstrated why a volumetric recovery of fixed costs would be preferable to a customer-based recovery. Dr. Johnson has provided an example that a store's parking lot is not recovered on a "per-customer" basis, but instead on the basis of customers' purchase volumes. Retail stores like COSTCO, however, impose a per-customer membership fee. Even so, it is questionable how much relevance an unregulated grocery store parking lot has to the recovery of the cost of providing regulated electric service to customers.

Q. Limiting our focus to utility pricing in a regulated environment, can you identify another justification for inclusion of both fixed and variable customer-related costs in the customer charge?

A. Yes. Dr. Johnson's approach of including only variable costs in the customer charge is anti-competitive under the direct access rules that are still "on the books" in Arizona. Under direct access, billing, metering and meter-reading are competitive services that may be provided by third parties. If a utility sets its billing component at just the variable costs of billing, a third party supplier who aims to "meet or beat" the utility's billing component will be unable the fund its billing infrastructure. The variable cost-based billing component provides just enough for the postage and the paper stock, but nothing for the employees or for software and equipment in the billing function. No viable third party competition could develop. While there is currently no residential direct access in Arizona, the Commission should still recognize that acceptance of a "variable cost only" customer charge is inconsistent with parts of Arizona's current regulatory framework.

Q. Do you find any inconsistencies in Dr. Johnson's support of forward-looking, marginal cost principles?

A. Yes. Dr. Johnson supports a forward-looking, marginal approach to rate design that may or may not recover the utility's approved margin; however, he then advocates for a strict historical test year approach with little, if any, adjustments to rate base, revenues and expenses (even those that are known and measureable). This inconsistency is problematic even without addressing the appropriateness of his marginal cost approach of rate design.

Q. Is the utility industry moving toward lower customer charges and higher energy charges?

A. No. There is no consistent movement in this direction across all jurisdictions. Though such a rate design may promote conservation, some jurisdictions such as Indiana, Ohio, and others are gradually increasing the level of the customer charges in order to recover more of the customer-related (non-volumetric) costs in the fixed rate component. In fact, Ohio has even approved a customer charge (reservation charge) designed in a manner commonly used by the FERC called a "straight fixed variable rate design", which places most of the system's fixed costs in the customer charge (reservation charge) and collects only variable costs in the volumetric charge. This demonstrates that some jurisdictions are moving in an opposite direction of what Dr. Johnson is proposing here.

Q. Do you still believe Dr. Johnson's proposed rate design radically shifts cost recovery away from the customer charge to the energy charge?

A. Yes. Dr. Johnson's proposal deviates from past regulatory practice in two very significant ways. First, Dr. Johnson is proposing to reduce the residential customer charge, when customer charges have been consistently increasing over time for other major Arizona electric companies, including TEP APS, and Salt River Project (SRP). Dr. Johnson's abandonment of past trends is perplexing because (i) UNS Electric's proposed $8.00 residential customer charge is in-line with similar charges at other Arizona companies, and (ii) the increasing trend is fully supported by accepted costing methodologies. By contrast, Dr. Johnson's $5.00 customer charge for UNS Electric would make the UNS Electric charge an outlier - lower than comparable customer charges for TEP, APS and SRP.

Second, Dr. Johnson uses a marginal cost approach while the Company uses the average embedded approach. As I stated earlier, UNS Electric, TEP, and APS residential customer charge proposals over the last twenty years have been supported by an average embedded cost study. Dr. Johnson offered no evidence that the Company's average embedded cost method is invalid, and cannot since it is an accepted method of cost allocation in Arizona.

Q. Why does Dr. Johnson's residential rate design proposal put UNS Electric's cost recovery at risk?

A. Under both the UNS Electric residential rate design proposal and Dr. Johnson's proposal, a reduction in sales will lead to margin loss. However, Dr. Johnson's approach leads to greater margin loss than UNS Electric's approach. Dr. Johnson's third residential rate tier assumes cost recovery on kWh sales in excess of 800 kWh per month. Because of conservation efforts, sales in this third tier (the highest priced tier) will likely decline more than lower tier sales. Consequently, sales revenue from the third tier will be reduced. As conservation eats away at third tier usage, the Company's ability to recover its revenue requirement and its opportunity to earn a reasonable rate of return diminish.

Dr. Johnson claims on pages 12 to 13 of his Surrebuttal testimony that the potential impact of his residential rate design on UNS Electric's revenue and net income is "relatively mild." Exhibit DBE-6, however, shows that the margin loss would be over 20% higher – under both a 2% and 5% kWh sales reduction scenario – under Dr. Johnson's rate design. RUCO's rate design will likely increase margin loss by $102,180 and $255,449 under the 2% and 5% sales reduction scenarios respectively – based on a 12-month period. Even so, this margin loss will compound over time. Under the 2% sales reduction scenario, the second year loss would be 4% (from the date of rate inception; i.e., 2 years of 2% losses) and the third year loss would be 6% (from the date of rate inception; i.e., 3 years of 2% losses). So, the total compounded loss will be six times the annual total of $102,180 – or over $600,000. This is a significant impact to the Company.

Exhibit DBE-6 further shows that kWh sales reductions of just 2% to 5% will substantially reduce the net income of UNS Electric under *both* the UNS Electric and RUCO rate design proposals. As indicated, 2% reductions in sales reduce net income by around $500,000 ($445,404 under UNS Electric, $547,584 under RUCO) and 5% reductions in sales reduce net income by around $1,250,000 ($1,113,510 under UNS Electric, $1,368,959 under RUCO). Still, Dr. Johnson proposes to put any revenue stability in greater jeopardy by proposing a decrease in customer charge.

Given UNS Electric's exposure to the risk of cost under-recovery under either rate design proposal, TEP believes that RUCO should work toward finding win-win solutions that will lessen rather than increase recovery risks. Even without the rate design change sponsored by Dr. Johnson, UNS Electric is faced with a dilemma: The Commission is contemplating energy efficiency objectives that may necessitate sales reductions of around 2% per year over the coming decade. A utility cannot fully recover its costs if rates are designed in a manner that redistributes the recovery of fixed costs from a fixed customer charge to a volumetric rate – especially when sales volumes start disappearing by design or by public policy.

Q. Has Dr. Johnson proposed any solutions to help align the goals of conservation with the Company's ability to earn a fair rate of return?

A. No. Dr. Johnson does not acknowledge that a problem exists. UNS Electric does not seek "guarantees" of earnings, just a reasonable opportunity to earn a fair return. The Company, however, needs a rate structure that recognizes it is a provider of electric service, and not simply a seller of a commodity.

Any Commission approved rate structure should align important policy goals (*e.g.*, conservation and efficiency) with a financially-healthy public service corporation. Avoiding artificially low customer charges – and implementing customer charges that more fully recover costs – is consistent with that new business model. The Commission should make the correct level of fixed cost recovery (revenue collected to recover fixed costs) more independent of sales being at a certain level. Dr. Johnson's proposal does the opposite.

II. LOW-INCOME PROGRAM EXPANSION.

Q. Staff witness Mr. William C. Stewart alleges that UNS Electric has changed its position on Low-Income program expansion in Rebuttal testimony. What is your response?

A. In Direct testimony, UNS Electric indicated that it supported expansion of the Low-Income programs from 150% to 200% of poverty. UNS Electric believed that there was consensus among stakeholders to expand the program. However, RUCO does not support this expansion. In light of RUCO's position, UNS Electric is not taking a position at this time on the expansion of the low-income programs. Additionally, UNS Electric is not opposed to some minor changes in the structure of the CARES program, provided the Company can recover associated revenue shortfalls. UNS Electric has always expressed the position that its support of any program is conditioned on full recovery of any revenue shortfall from other system customers.

Q. Does the Company remain opposed to Staff's proposed changes to the manner in which the PPFAC is currently applied to low income customers?

A. Yes. UNS Electric continues to oppose Staff's position that low-income customers be subject only to PPFAC decreases, but not increases. UNS Electric's position is for CARES customers to pay a reduced base power supply rate, and to freeze the PPFAC forward and true-up components at zero upon implementation of new rates. UNS Electric's proposal to reduce the base power supply is in addition to other discounts it has proposed for CARES customers. Staff's proposal could result in significantly increased PPFAC charges to non-low income customers, depending on changes in the wholesale electric rates, although Staff has not addressed this potential impact.

III. CARES –ADJUSTMENT TO OPERATING INCOME.

Q. On page 16 of his rebuttal testimony Dr. Fish again recommends the disallowance of the $61,797 adjustment you indicated was necessary to adjust operating income to reflect the discount Customer Assistance Residential Energy Support ("CARES") customers receive. Will you explain why this adjustment is appropriate and should be approved?

A. Yes. Dr. Fish indicated he would like to see support for the adjustment. I will explain the adjustment in more detail and provide supporting documentation in my attached Exhibit DBE-7. I note that the Company provided Dr. Fish this information in workpapers. This information with my added explanation should clarify our need for the adjustment and why it is appropriate.

Q. Does UNS Electric currently have a separate pricing plan for CARES customers that differs from the regular Residential customer's pricing plan?

A. No. The current tariff is the same for a similarly situated Residential customer regardless of whether he/she is a CARES customer or not. The CARES customers currently receive a discount through a "Rider". This discount is applied to the CARES bill after the monthly consumption and resulting billing components have been determined, and is based on three tiers of discounts that are capped at $8.00 per customer if monthly consumption exceeds 1,000 kwh (2,000 kwh if the customer is on the Medical Life Support Program).

Q. When the Company generates its revenue proof (based on current rates), in order to determine if the billing determinants used in the case achieve the test year revenues, is a separate CARES calculation identified?

A. Yes, but the rates for the class are the same as for a regular Residential Customer and are priced out as such.

Q. How is the CARES discount factored into the calculation?

A. Since there are multiple tiers, the Company had to extract individual discount data from each customer during the test year and then accumulate it for a single line item adjustment to the CARES-related sales on the Revenue Proof. As can be seen on line 15 of Exhibit DBE-7, Page 1 of 1, the total CARES related discount totaled $690,468.

Q. Does this adjustment reflect all of the necessary reductions to the Operating Revenues relating to the CARES Program?

A. No. The $690,468 adjustment does not account for customer annualization or weather normalization. Adjustments to sales were 6,427,785 kWh and -701,841 kWh for customer annualization and weather normalization, respectively. The net of these two adjustments totals 5,725,944 kWh approximately 8.95% of the test year sales of 63,995,155 kWh for the CARES group of residential customers (see line 16 of Exhibit DBE-7).

Since the only dollar adjustment to test year CARES usage was based on actual test year discounts, an additional adjustment of $61,797 had to be made to reflect the discount amounts associated with the adjusted (for customers and weather) sales.

Q. How did you calculate this adjustment?

A. Since the CARES discounts fall into multiple tiers the Company took the test year discount amount of $690,468 and adjusted it by the adjusted increase in sales of 8.95%. The resulting adjustment to Operating Income is $61,797 (the product of $690,468 times 8.95%). This is shown on line 18 of Exhibit DBE-7.

Q. Does this adjustment in any way result in an understatement of Company's Operating Revenues or reflect a "double counting" of the discount amounts as indicated by Dr. Fish?

A. No. This adjustment reflects the dollar discount that will be offered to all CARES customers contributing to the net normalized and annualized increase in sales calculated for this group of customers. This increased sales amount has not been contested and is a reasonable adjustment. UNS Electric will lose revenues based on any increase in sales to this group of customers per the CARES provisions in the tariffs. The Company has calculated this loss of revenues to be $61,797. Unless it is excluded from Operating Income, UNS Electric will be required to absorb the cost of these discounted rates. That is not acceptable to the Company.

Q. Does this conclude your Rejoinder testimony?

A. Yes.

EXHIBIT

DBE-6

UNS Electric, Inc.
Potential Margin Loss Under Various Rate Designs

UNSE Proposed
Higher Customer Charge - Two Tiers

					************ 2% Reduction ************			************ 5% Reduction ************		
		Rate	Billing Determinates	Revenue	Billing Determinates	Revenue	Revenue Change	Billing Determinates	Revenue	Revenue Change
1	Cust Chg	$8.00	847,229	$6,777,836	847,229	$ 6,777,836	$ -	847,229	$ 6,777,836	$ -
2	Block 1	$ 0.020070	344,547,535	$6,915,069	344,547,535	$ 6,915,069	$ -	344,547,535	$ 6,915,069	$ -
3	Block 2	$ 0.030084	395,719,694	$11,904,831	380,914,349	$ 11,459,427	$ (445,404)	358,706,333	$ 10,791,321	$ (1,113,510)
4	Block 3	N/A	N/A	N/A						
5	Base Power	$ 0.074812	740,267,229	$55,380,872	725,461,884	$ 54,273,254	$ (1,107,617)	703,253,868	$ 52,611,828	$ (2,769,044)
6				$80,978,608		$79,425,586	($1,553,021)		$77,096,054	($3,882,554)

	2% Reduction	5% Reduction
7	Margin Loss Under UNSE Design $ 445,404	Margin Loss Under UNSE Design $ 1,113,510

RUCO-Type Design
Lower Customer Charge - Three Tiers

					************ 2% Reduction ************			************ 5% Reduction ************		
		Rate	Billing Determinates	Revenue	Billing Determinates	Revenue	Revenue Change	Billing Determinates	Revenue	Revenue Change
8	Cust Chg	$5.00	847,229	$4,236,147	847,229	$ 4,236,147	$ -	847,229	$ 4,236,147	$ -
9	Block 1	$ 0.021985	344,547,535	$7,574,878	344,547,535	$ 7,574,878	$ -	344,547,535	$ 7,574,878	$ -
10	Block 2	$ 0.031986	282,782,081	$9,044,937	275,379,409	$ 8,808,159	$ (236,778)	264,275,401	$ 8,452,991	$ (591,946)
11	Block 3	$ 0.041986	112,937,613	$4,741,747	105,534,941	$ 4,430,941	$ (310,805)	94,430,933	$ 3,964,734	$ (777,013)
12	Base Power	$ 0.074812	740,267,229	$55,380,872	725,461,884	$ 54,273,254	$ (1,107,617)	703,253,868	$ 52,611,828	$ (2,769,044)
13				$80,978,580		$ 79,323,379	($1,655,201)		$ 76,840,578	($4,138,003)

	2% Reduction	5% Reduction
14	Margin Loss Under RUCO Design $ 547,584	Margin Loss Under RUCO Design $ 1,368,959
15	Line 14 - Line 7: Additional Margin Loss Under RUCO Design **$ 102,180**	Line 14 - Line 7: Additional Margin Loss Under RUCO Design **$ 255,449**

EXHIBIT

DBE-7

UNS Electric, Inc.

**CARES DISCOUNT TEST YEAR ACTIVITY
FOR PERIOD ENDING DECEMBER 31, 2008**

		Cares Discount	Cares Medical Discount	Total
1	January	$48,425.36	$2,840.43	
2	February	$46,463.15	$2,868.59	
3	March	$45,407.37	$2,665.48	
4	April	$48,756.25	$2,934.19	
5	May	$46,549.55	$2,923.69	
6	June	$38,169.29	$2,270.79	
7	**Subtotal**	**$273,770.97**	**$16,503.17**	**$290,274.14**
8	July	$61,555.95	$3,891.48	
9	August	$58,511.19	$4,038.00	
10	September	$60,862.97	$4,116.13	
11	October	$68,060.49	$4,870.99	
12	November	$59,031.54	$6,106.80	
13	December	$64,452.47	$4,695.35	
14	**Subtotal**	**$372,474.61**	**$27,718.75**	**$400,193.36**
15	**TOTAL**	**$646,245.58**	**$44,221.92**	**$690,467.50**

	Test Year Unadjusted Sales	Cares Customer Annualization Sales Adjustment	Weather Normalization Adjustment	Adjustment as a Percent of total TY sales
16	63,995,155	6,427,785	(701,841)	8.95%

17	**Test Year Cares Discount Adjusment to Retail Revenues**	**$752,264.00**
18	**Cares Discount Adjustment**	**$61,796.50**

BEFORE THE ARIZONA CORPORATION COMMISSION

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2009 OCT -2 P 3: 49

AZ CORP COMMISSION
DOCKET CONTROL

EXHIBIT
UNSE-21
ADMITTED

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

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

DOCKET NO. E-04204A-09-0206

NOTICE OF ERRATA

UNS Electric, Inc., through undersigned counsel, filed a Notice of Errata on August 31, 2009 regarding certain redlined versions of tariffs submitted as exhibits to the Direct Testimony of D. Bentley Erdwurm. The attached non-substantive changes to the tariffs include additional redlining in the "Additional Notes" section and the "Availability Section" and replace the proposed versions previously submitted.

RESPECTFULLY SUBMITTED this 2d day of October 2009.

UNS Electric, Inc.

By [signature]

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Original and thirteen copies of the foregoing filed this 2nd day of October 2009, with:

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UniSourceEnergy SERVICES

UNS Electric, Inc. - CLOSED
Pricing Plan CTL
Voluntary Curtailment Rider

AVAILABILITY

~~Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.~~ This pricing plan is no longer available.

APPLICABILITY

To any customer served on existing pricing plans LPS and LGS that have an aggregate minimum peak demand of 250 kW in the previous twelve (12) month period. The customer must be able to curtail a portion of their service, although it is not required to curtail. Participation in this program is entirely voluntary.

MONTHLY BILL

Participating customers' monthly bills shall be calculated using the existing applicable pricing plan plus a monthly program customer charge of $25.00. In addition, the bills shall reflect a credit for the curtailment amounts as determined by the Company, in accordance with the following procedure.

DETERMINATION OF CURTAILMENT CREDIT

The curtailment credit will be based upon the forecasted day ahead prices posted electronically, the Company's actual avoided costs during the curtailment period, and the customers' actual curtailment performance on an event day. The amount of the credit will be computed upon the lower of fifty percent (50%) of the posted price or fifty percent (50%) of actual avoided costs.

TERMS AND CONDITIONS

The Company reserves the right to conduct a voluntary curtailment and to suspend the voluntary curtailment event at any time. The Company's ability to offer this program is contingent upon timely receipt of adequate pricing information from its wholesale power supplier and software, internet, and other communications capabilities. Participating customers will be required to maintain the confidentiality of the prices contained in curtailment offers.

Customers who qualify and elect to participate in this program must agree to allow the Company access to a phone line for the purposes of transmitting meter data. The Company may install recording and modem equipment onto their electric meter.

The Company plans to provide customers a day-ahead notice of voluntary curtailment events. The Company will determine when and how such notice is given, along with determining the amount of curtailment needed from each customer. The customer may choose not to participate in a curtailment event.

The Company shall not be responsible for any loss or damage caused by or resulting from participation in a curtailment event.

Failure of a customer to curtail as agreed upon may result in exclusion from the program.

UniSourceEnergy SERVICES

UNS Electric, Inc. - CLOSED
Pricing Plan FLX
Flexible Contracting

AVAILABILITY

~~Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.~~
This pricing plan is no longer available.

APPLICABILITY

To any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the monthly demand is at least 500 kW, and who otherwise would be eligible for the Large Power Service ("LPS") pricing plan. Customers must demonstrate ability to have all or part of their service requirements provided from a competitive alternative, or require unique pricing for electric service in order to increase or to maintain existing load.

CHARACTER OF SERVICE

Service will be provided under a contract approved by the Arizona Corporation Commission ("ACC"). Contracts will include the following provisions:

a) Customers will be responsible for incremental distribution or transmission investment which is required for service.

b) Pricing shall be commensurate with potential alternatives.

c) Service under this pricing plan will be subject to the Purchased Power and Fuel Adjustment Clause unless, on a case-by-case basis, unless the ACC approves otherwise.

d) Pricing will at least yield revenue exceeding the marginal cost of service to the customer. For contracts with terms extending beyond the date which UNS Electric, Inc. will be required to add capacity, marginal cost means long-run marginal cost.

e) Pricing shall not exceed the prices set forth in the LPS pricing plan.

f) Service Contracts under this pricing plan must be reviewed and approved by the ACC.

TAX CLAUSE

To the charges computed under the above pricing plan, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS
Interruptible Power Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department

To any customer with a minimum demand of 50 ~~kW for any purpose where such service is supplied at one point of delivery and measured through one meter~~ and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE
Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand
Demand Charge $5.237 per kW per month~~3.650~~

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All charges below are for all summer and winter months.

	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
All kWh	$0.019500	$0.048927	Varies	$0.068427

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration

above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~BUNDLED STANDARD OFFER SERVICE~~

~~Customer Charge $15.50 per month~~

~~Demand Charge $3.40 per kW~~

~~Energy Charges:~~
~~Delivery $0.014800 per kWh~~

~~Base Power Supply Charge $0.055491 per kWh~~
~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

PENALTY FOR FAILURE TO INTERRUPT:
In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$9.002 per month
Meter Reading	$1.231 per month
Billing & Collection	$5.225 per month
Customer Delivery	$0.542 per month
	$16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge	$5.237 per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Local Delivery-Energy	
Transmission	$0.008590
Sub-Transmission	$0.005376
Delivery	$0.005213
Production not included in Power Supply	$0.000321

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply	$0.048927
PPFAC (see Rate Rider-1 for current rate)	Varies

~~BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:~~

~~Customer Charges:~~

~~Meter Services~~	~~$ 1.452 per month~~
~~Meter Reading~~	~~$ 0.495 per month~~
~~Billing & Collection~~	~~$ 2.582 per month~~
~~Customer Delivery~~	~~$10.971 per month~~
~~Demand Charge (kW):~~	~~$ 3.400 per kW~~
~~Energy Charges (kWh):~~	
~~Delivery:~~	
~~Transmission~~	~~$0.001859 per kWh~~
~~Sub-transmission~~	~~$0.002256 per kWh~~
~~Delivery~~	~~$0.010436 per kwh~~
~~Production (not included in power supply)~~	~~$0.000249 per kWh~~
~~Base Power Supply~~	~~$0.055491 per kWh~~

TERMS AND CONDITIONS

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

Standby, supplemental or breakdown service shall not be rendered under this pricing plan.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan IPS-TOU
Interruptible Power Service Time-of-Use

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department

To any customer with a minimum demand of 50 and is interruptible within fifteen (15) minutes of verbal notice by the Company. The Customer must be able to interrupt service for up to eight (8) hours per day.

CHARACTER OF SERVICE
Three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ ~~8~~16.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand
Demand Charge $5.237 per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.
~~All energy charges below are on a per kWh basis.~~

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	- Total[3]
~~First 400~~All kWh				
On-Peak	$0.019500	$0.097611	Varies	$0.117111
Shoulder Peak	$0.019500	$0.048927	Varies	$.068427
Off-Peak	$0.019500	$0.037611	Varies	$.057111

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	- Total[3]
~~First 400~~All kWh				
On-Peak	$0.019500	$0.097611	Varies~~Annual~~	$.117111
Off-Peak	$0.019500	$0.022479	Varies~~Annual~~	$.041979

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~BUNDLED STANDARD OFFER SERVICE~~

~~Customer Charge~~ ~~$15.50 per month~~

~~Demand Charge~~ ~~$3.40 per kW~~

~~Energy Charges:~~
~~Delivery~~ ~~$0.014800 per kWh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

	~~Summer (May – October)~~	~~Winter (November – April)~~
~~On-Peak~~	~~$0.079833~~	~~$0.079833~~
~~Shoulder Peak~~	~~$0.055491~~	~~N/A~~
~~Off Peak~~	~~$0.049833~~	~~$0.042267~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

TIME-OF-USE PERIODS
Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m.. The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

PENALTY FOR FAILURE TO INTERRUPT:
In the event that the Customer fails to interrupt its load when requested to do so by the Company, the customer shall pay an additional charge as follows:

Billing Demand Charge per kW @ $10.00
Unbundled $/kWh Charge is entirely a Delivery Charge

For a second failure to interrupt in any twelve (12) month period, the Customer will revert to the otherwise applicable firm pricing plan for a period of at least twelve (12) months.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month. If demand is not metered, the billing demand shall be based on nameplate ratings of connected motors and equipment, or by a test as approved by the Company.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):	
Meter Services	$9.002 per month
Meter Reading	$1.231 per month
Billing & Collection	$5.225 per month
Customer Delivery	$0.542 per month
	$16.00 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy– All kWh	
Transmission ~~Transmission~~	$0.008590
Sub-Transmission ~~Sub-Transmission~~	$0.005376
Local Delivery Energy ~~Delivery~~	$0.005213
Production not included in Power Supply ~~Production not included in Power Supply~~	$0.000321

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.097611
Shoulder-Peak	$0.048927
Off-Peak	$0.037611
Base Power Supply Winter	
On-Peak	$0.097611
Off-Peak	$0.022479
PPFAC (see Rate Rider-1 for current rate)	Varies

~~**BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:**~~

~~Customer Charges:~~

~~Meter Services~~	~~$ 1.452 per month~~
~~Meter Reading~~	~~$ 0.495 per month~~
~~Billing & Collection~~	~~$ 2.582 per month~~
~~Customer Delivery~~	~~$10.971 per month~~

~~Demand Charge (kW):~~ ~~$ 3.400 per kW~~

~~Energy Charges (kWh):~~

~~Delivery:~~

~~Transmission~~	~~$0.001859 per kWh~~
~~Sub-transmission~~	~~$0.002256 per kWh~~
~~Delivery~~	~~$0.010436 per kwh~~
~~Production (not included in power supply)~~	~~$0.000249 per kWh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

~~—~~	~~Summer (May – October)~~	~~Winter (November - April)~~
~~On-Peak~~	~~$0.079833~~	~~$0.079833~~
~~Shoulder Peak~~	~~$0.055491~~	~~N/A~~
~~Off Peak~~	~~$0.049833~~	~~$0.042267~~

TERMS AND CONDITIONS
A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

The Company reserves the right to curtail service to the customer at any time and for such period of time that, in the sole judgment of the Company, the operation of the system requires curtailment by the customer.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach. Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of one (1) year or longer, with a minimum Contract Demand at the Company's option in view of the anticipated demand of the Customer.

The Company will endeavor to provide the customer with as much advance notice as possible of the required interruptions or curtailments. However, the customer shall interrupt or curtail service within fifteen (15) minutes, if so requested.

The Company reserves the right to have automatic equipment installed for immediate interruption of the customer's load. Should the Company's automatic equipment fail to interrupt the load, no penalty will be assessed.

The Company shall not be responsible for any loss or damage caused by or resulting from interruption or curtailment of service under this pricing plan.

Standby, supplemental or breakdown service shall not be rendered under this pricing plan.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS
A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS
Large General Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the maximum monthly demand is less than 1,000 kW.
~~Standard offer sales service to any customer for any purpose where such service is supplied at one point of delivery and measured through one meter and the maximum monthly demand is less than 1,000 kW.~~

CHARACTER OF SERVICE
Single or three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises. Customers may choose time-of-use service as well.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill	$16.00 per month
Customer Charge, Single Phase service and minimum bill (Optional TOU)	$20.90 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge	$15.055 per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

	Delivery Services-Energy[1]	Power Supply Charges[2]		-
		Base Power	PPFAC[2]	Total[3]
All kWh	$0.004354	$0.059129	Varies	$0.063483

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration

above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~BUNDLED STANDARD OFFER SERVICE~~

~~Customer Charge~~	~~$ per month~~
~~Customer Charge, (optional TOU)~~	~~$ per month~~
~~Demand Charge~~	~~$ per kW~~
~~Energy Charges:~~	
~~Delivery~~	~~$0.0 per kWh~~
~~Base Power Supply Charge~~	~~$0.0 per kWh~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

DETERMINATION OF BILLING DEMAND

Normal service: If the time-of-use option is not chosen, the monthly billing demand shall be the highest measured fifteen (15) minute integrated reading of the demand meter during the billing month.

Time-of-Use: If time-of-use service is chosen, the monthly billing demand shall be the higher of:
–(i) the highest measured fifteen (15) minute integrated reading of the demand meter during the on-peak hours of the billing period,
(ii) one-half the highest measured fifteen (15) minute integrated reading of the demand meter during the off-peak hours, or
(iii) the contract capacity.

ON-PEAK HOURS
During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):	
Meter Services	$9.002 per month
Meter Reading	$1.231 per month
Billing & Collection	$5.225 per month

Customer Delivery	$0.542 per month
	$16.00 per month

Customer Charge (Optional TOU) Components of Delivery Services (Unbundling):

Meter Services	$16.935 per month
Meter Reading	$0.612 per month
Billing & Collection	$3.168 per month
Customer Delivery	$0.185 per month
	$20.90 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge	$15.055 per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Local Delivery-Energy	
Transmission	$0.005701
Sub-Transmission	$0.003759
Delivery	($0.005446)
Production not included in Power Supply	$0.000340

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply	$0.059129
PPFAC (see Rate Rider-1 for current rate)	Varies

~~**BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:**~~

~~Customer Charges:~~

~~Meter Services~~	~~$ per month~~
~~Meter Reading~~	~~$ per month~~
~~Billing & Collection~~	~~$ per month~~
~~Customer Delivery~~	~~$ per month~~

~~Customer Charges, (optional TOU):~~

~~Meter Services~~	~~$ per month~~
~~Meter Reading~~	~~$ per month~~
~~Billing & Collection~~	~~$ per month~~
~~Customer Delivery~~	~~$ per month~~

~~Demand Delivery(kW):~~	~~$ per kW~~

~~Energy Charges (kWh):~~

~~Delivery:~~

~~Transmission~~	~~$0.0 per kWh~~
~~Sub transmission~~	~~$0.0 per kWh~~

~~Delivery~~	~~$0.0 per kwh~~
~~Production (not included in power supply)~~	~~$0.0 per kWh~~
~~Base Power Supply~~	~~$0.0 per kWh~~

TERMS AND CONDITIONS

Standby, supplemental or breakdown service shall not be rendered under this pricing plan except for Qualifying Facilities or Independent Power Producers that have entered into a Service or Purchase Agreement with the Company.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UnisourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LGS-TOU-N
Large General Service Time-of-Use

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the maximum monthly demand is less than 1,000 kW.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE
Single or three phase, 60 hertz, at the Company's standard voltages that are available within the vicinity of the Customer's premises. Customers may choose time-of-use service as well.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill — $16.00 per month
Customer Charge, Single Phase service and minimum bill (Optional TOU) — $20.90 per month

Demand Charge Component is unbundled into Delivery Services-Demand
Demand Charge — $15.055 per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
All kWh				
On-Peak	$0.004354	$0.116024	Varies	$0.120378
Shoulder Peak	$0.004354	$0.059129	Varies	$.063483
Off-Peak	$0.004354	$0.041024	Varies	$.045378

Winter	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
All kWh				
On-Peak	$0.004354	$0.116024	Varies	$.120378
Off-Peak	$0.004354	$0.027306	Varies	$.031660

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m..

The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:
(i) the highest measured fifteen (15) minute integrated reading of the demand meter during the on-peak and shoulder hours of the billing period,
(ii) one-half the highest measured fifteen (15) minute integrated reading of the demand meter during the off-peak hours, or
(iii) the contract capacity.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$9.002 per month
Meter Reading	$1.231 per month
Billing & Collection	$5.225 per month
Customer Delivery	$0.5420 per month
	$16.00 per month

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$16.935 per month
Meter Reading	$0.612 per month
Billing & Collection	$3.168 per month
Customer Delivery	$0.185 per month
	$20.90 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge $15.055 per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy– All kWh	
Transmission	$0.005701
Sub-Transmission	$0.003759
Local Delivery Energy (negative charge)	($0.005446)
Production not included in Power Supply	$0.000340

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.116024
Shoulder-Peak	$0.059129
Off-Peak	$0.041024
Base Power Supply Winter	
On-Peak	$0.116024
Off-Peak	$0.027306
PPFAC (see Rate Rider-1 for current rate)	Varies

TERMS AND CONDITIONS

Standby, supplemental or breakdown service shall not be rendered under this pricing plan except for Qualifying Facilities or Independent Power Producers that have entered into a Service or Purchase Agreement with the Company.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer ~~for any purpose where the service is supplied at one point of delivery and measured through one meter~~ whereen the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE
Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill (<69 kV Service)	$ 372.00 per month
Customer Charge, Single Phase service and minimum bill (>69 kV Service)	$ 407.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge (<69 kV Service)	$23.449 per kW per month
Demand Charge (>69 kV Service)	$17.164 per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

	Delivery Services-Energy[1]	Power Supply Charges[2]		Total[3]
		Base Power	PPFAC[2]	
All kWh	$0.000000	$0.046959	Varies	$0.046959

1. Delivery Services-Energy is a bundled charge that includes: Local Delivery-Energy (Local Delivery and/or Distribution exclusive of Transmission, Sub-transmission and production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the

base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~**BUNDLED STANDARD OFFER SERVICE**~~

~~Customer Charge, (<69 kV Distribution Service)~~	~~$365.00 per month~~
~~Customer Charge, (≥69 kV Transmission Service)~~	~~$400.00 per month~~
~~Demand Charge, (<69 kV Distribution Service)~~	~~$17.895 per kW~~
~~Demand Charge, (≥69 kV Transmisison Service)~~	~~$11.610 per kW~~
~~Energy Charges:~~	
~~Delivery~~	~~$0.000000 per kWh~~
~~Base Power Supply Charge~~	~~$0.053260 per kWh~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

DETERMINATION OF BILLING DEMAND
The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling) (<69 kV Service):

Meter Services	$213.296 per month
Meter Reading	$ 25.789 per month
Billing & Collection	$132.801 per month
Customer Delivery	$ 0.114 per month
	$372.00 per month

Customer Charge Components of Delivery Services (Unbundling) (>69 kV Service):

:

Meter Services	$233.364~~3.314~~ per month
Meter Reading	$ 28.215~~0.626~~ per month
Billing & Collection	$145.296~~3.676~~ per month
Customer Delivery	$ 0.125~~.384~~ per month
	~~$8.004~~407.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge (<69 kV Service)	$23.449~~1.221~~ per kW per month
Demand Charge (>69 kV Service)	$17.164~~4.930~~ per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Local Delivery-Energy	$0.000000

~~25965375(8252)0281~~ **Power Supply Charges (Unbundling) ($/kWh):**

Component	Rate
Base Power Supply	$0.046959~~51087~~
PPFAC (see Rate Rider-1 for current rate)	Varies

~~BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:~~

~~Customer Charges, (<69 kV Distribution Service):~~

~~Meter Services~~	~~$ 1.727 per month~~
~~Meter Reading~~	~~$ 42.623 per month~~
~~Billing & Collection~~	~~$221.737 per month~~
~~Customer Delivery~~	~~$ 98.913 per month~~

~~Customer Charges, (>69 kV Transmisison Service):~~

~~Meter Services~~	~~$ .777 per month~~
~~Meter Reading~~	~~$ 27.730 per month~~
~~Billing & Collection~~	~~$142.797 per month~~
~~Customer Delivery~~	~~$228.696 per month~~

~~Demand Charges, (<69 kV Distribution Service):~~

~~Transmission~~	~~$ .725 per kW~~
~~Sub-transmission~~	~~$ .951 per kW~~
~~Delivery~~	~~$ 16.097per kw~~
~~Production (not included in power supply)~~	~~$ .122 per kW~~

~~Demand Charges, (>69 kV Transmisison Service):~~

~~Transmission~~	~~$ .777 per kW~~
~~Sub-transmission~~	~~$ 1.019 per kW~~
~~Delivery~~	~~$ 9.683 per kw~~
~~Production (not included in power supply)~~	~~$ .131 per kW~~

~~Energy Charges (kWh):~~

~~Delivery~~	~~$0.000000 per kWh~~
~~Base Power Supply Charge~~	~~$0.053260 per kWh~~

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and

Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

UniSource Energy SERVICES

UNS Electric, Inc.
Pricing Plan LPS
Large Power Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer ~~for any purpose where the service is supplied at one point of delivery and measured through one meter~~ whereen the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.

CHARACTER OF SERVICE
Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill (<69 kV Service)	$ 372.00~~8.00~~ per month
Customer Charge, Single Phase service and minimum bill (>69 kV Service)	$ 407.00~~8.00~~ per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge (<69 kV Service)	$21.221~~3.650~~ per kW per month
Demand Charge (>69 kV Service)	$14.930 ~~3.650~~ per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

	Delivery Services-Energy[1]	Power Supply Charges[2]		-
		Base Power	PPFAC[2]	Total[3]
All kWh	$0.000000	$0.051087	Varies	$0.051087

	~~Delivery Services-Energy[1] (kWh)~~	~~Power Supply Charges[2]~~		-
		~~Base Power~~	~~PPFAC[2]~~	~~Total[3]~~
~~All kWhs~~	~~$0.025746~~	~~$0.077993~~	~~Annual~~	~~$0.107921~~

1. Delivery Services-Energy is a bundled charge that includes: ~~Local Delivery-Energy (Local Delivery and/or Distribution exclusive of~~ Transmission, Sub-transmission, Local Delivery Energy and P~~p~~roduction not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~**BUNDLED STANDARD OFFER SERVICE**~~

~~Customer Charge, (<69 kV Distribution Service)~~	~~$365.00 per month~~
~~Customer Charge, (≥69 kV Transmission Service)~~	~~$400.00 per month~~
~~Demand Charge, (<69 kV Distribution Service)~~	~~$17.895 per kW~~
~~Demand Charge, (≥69 kV Transmisison Service)~~	~~$11.610 per kW~~
~~Energy Charges:~~	
~~Delivery~~	~~$0.000000 per kWh~~
~~Base Power Supply Charge~~	~~$0.053260 per kWh~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

ON-PEAK HOURS

During the months of May through October, on-peak hours are those hours between 11:00 a.m. and 10:00 p.m. each day, Monday through Saturday. All other hours shall be considered off-peak hours.

During the months of November through April, on-peak hours are those hours between 7:00 a.m. and 7:00 p.m. each day, Monday through Friday. All other hours shall be considered off-peak hours.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling) (<69 kV Service):

Meter Services	$213.296~~3.314~~ per month
Meter Reading	$ 25.789~~0.626~~ per month
Billing & Collection	~~$3.676~~132.801 per month
Customer Delivery	$ 0.114~~.384~~ per month
	$372.00 ~~8.00~~ per month

Customer Charge Components of Delivery Services (Unbundling) (>69 kV Service):

Meter Services	$233.364~~3.314~~ per month
Meter Reading	$ 28.215~~0.626~~ per month
Billing & Collection	$145.296~~3.676~~ per month
Customer Delivery	$ 0.125~~.384~~ per month
	~~$8.00~~407.00 ~~p~~per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge (<69 kV Service)	$21.221~~3.650~~ per kW per month
Demand Charge (>69 kV Service)	$14.930~~3.650~~ per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Local Delivery-Energy	$0.000000

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply	$0.00510873~~3076~~
PPFAC (see Rate Rider-1 for current rate)	Varies~~Annual Rate~~

~~**BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:**~~

~~Customer Charges, (<69 kV Distribution Service):~~

~~Meter Services~~	~~$ 1.727 per month~~
~~Meter Reading~~	~~$ 42.623 per month~~
~~Billing & Collection~~	~~$221.737 per month~~
~~Customer Delivery~~	~~$ 98.913 per month~~

~~Customer Charges, (>69 kV Transmisison Service):~~

~~Meter Services~~	~~$ .777 per month~~
~~Meter Reading~~	~~$ 27.730 per month~~
~~Billing & Collection~~	~~$142.797 per month~~
~~Customer Delivery~~	~~$228.696 per month~~

~~Demand Charges, (<69 kV Distribution Service):~~

~~Transmission~~	~~$ .725 per kW~~
~~Sub-transmission~~	~~$ .951 per kW~~
~~Delivery~~	~~$ 16.097per kw~~
~~Production (not included in power supply)~~	~~$ .122 per kW~~

~~Demand Charges, (>69 kV Transmisison Service):~~

~~Transmission~~	~~$ .777 per kW~~
~~Sub-transmission~~	~~$ 1.019 per kW~~
~~Delivery~~	~~$ 9.683 per kw~~
~~Production (not included in power supply)~~	~~$ .131 per kW~~

~~Energy Charges (kWh):~~

~~Delivery~~	~~$0.000000 per kWh~~
~~Base Power Supply Charge~~	~~$0.053260 per kWh~~

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS

Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LPS-TOU
Large Power Service Time-of-Use

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.
~~To any customer for any purpose where the service is supplied at one point of delivery and measured through one meter when the maximum monthly demand is 500 kW or greater, but if 10,000 kW or more, a service agreement spelling out minimum conditions must be entered into.~~

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE

Three phase, 60 hertz, at the Company's standard transmission or distribution voltages that are available within the vicinity of the Customer's premises.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER, ENERGY AND DEMAND CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill (<69 kV Service)	$372.00 ~~8.00~~ per month
Customer Charge, Single Phase service and minimum bill (>69 kV Service)	$407.00 ~~8.00~~ per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge (<69 kV Service)	$23.449~~1.221~~ per kW per month
Demand Charge (>69 kV Service)	$17.164~~4.960~~ per kW per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

~~**BUNDLED STANDARD OFFER SERVICE**~~

~~Customer Charge, (<69 kV Distribution Service)~~	~~$365.00 per month~~
~~Customer Charge, (≥69 kV Transmission Service)~~	~~$400.00 per month~~
~~Demand Charge, (<69 kV Distribution Service)~~	~~$17.895 per kW~~
~~Demand Charge, (≥69 kV Transmission Service)~~	~~$11.610 per kW~~

Filed By:	Raymond S. Heyman	Tariff No.:	LPS-TOU
Title:	Senior Vice President, General Counsel	Effective:	~~June 1, 2008~~PENDING
District:	Entire Electric Service Area	Page No.:	1 of 6

UniSource Energy SERVICES

UNS Electric, Inc.
Pricing Plan LPS-TOU
Large Power Service Time-of-Use

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
All kWh				
On-Peak	$0.000000	$0.094919~~99047~~	Varies	$0.094919
Shoulder Peak	$0.000000	$0.046959	Varies	$0.046959
Off-Peak	$0.000000	$0.034919	Varies	$0.034919

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
All kWh				
On-Peak	$0.000000	$0.094919~~$0.099047~~	Varies	$0.094919~~$0.099047~~
Off-Peak	$0.000000	$0.022905~~$0.027033~~	Varies	$0.022905~~$0.027033~~

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~Energy Charges:~~

~~Delivery $0.000000 per kWh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

	~~Summer (May – October)~~	~~Winter (November – April)~~
~~On Peak~~	~~$0.077240~~	~~$0.077240~~
~~Shoulder Peak~~	~~$0.053260~~	~~N/A~~
~~Off Peak~~	~~$0.047240~~	~~$0.041233~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m..

The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

Minimum Charge: The minimum charge shall be the customer charge plus the demand charge.

A credit of three percent (3%) will be applied to the demand charge if the customer receives Distribution Service at primary voltage.

The Customer agrees to maintain, as nearly as practicable, a unity power factor. In the event that the Customer's power factor for any billing month is less than eighty-five (85%), an adjustment shall be applied to the bill as follows:

Power Factor adjustment =
(Maximum Demand / (.15 + PF)) - Maximum Demand) x Demand Charge Where Maximum Demand is the highest measured fifteen (15) minute demand in kilowatts during the billing period.

DETERMINATION OF BILLING DEMAND

The monthly billing demand shall be the higher of:

i. the highest measured fifteen-minute integrated reading of the demand meter during the on-peak hours of the billing period,
ii. one-half the highest measured fifteen-minute integrated reading of the demand meter during the off-peak hours,
iii. the highest demand metered during the preceding eleven (11) months, or
iv. the contract capacity.

In the event a customer achieves permanent, verifiable demand reduction through involvement in UNS Electric, Inc.'s Demand-Side Management programs, such reductions will be applicable to adjusted demands billed during the eleven (11) month period prior to the installation of the DSM measures.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling) (<69 kV Service):	
Meter Services	$213.296 per month
Meter Reading	$ 25.789 per month
Billing & Collection	$132.801 per month
Customer Delivery	$ 0.114 per month
	$372.00 per month

Customer Charge Components of Delivery Services (Unbundling) (>69 kV Service):	
Meter Services	$233.364 per month
Meter Reading	$–28.215 per month

Billing & Collection	$145.296 per month
Customer Delivery	$~~—~~ 0.125 per month
	$407.00 per month

Demand Charge Component is unbundled into Delivery Services-Demand

Demand Charge (<69 kV Service)	$23.449 per kW per month
Demand Charge (>69 kV Service)	$17.164 per kW per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Local Delivery-Energy	$0.000000

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.094919 ~~$0.099047~~
Shoulder-Peak	$0.046959 ~~$0.051087~~
Off-Peak	$0.034919 ~~$0.039047~~
Base Power Supply Winter	
On-Peak	$0.094919~~$0.099047~~
Off-Peak	$0.022905~~$0.027033~~
PPFAC (see Rate Rider-1 for current rate)	Varies

~~**BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:**~~

~~Customer Charges, (<69 kV Distribution Service):~~

~~Meter Services~~	~~$ 1.727 per month~~
~~Meter Reading~~	~~$ 42.623 per month~~
~~Billing & Collection~~	~~$221.737 per month~~
~~Customer Delivery~~	~~$ 98.913 per month~~

~~Customer Charges, (>69 kV Transmisison Service):~~

~~Meter Services~~	~~$ .777 per month~~
~~Meter Reading~~	~~$ 27.730 per month~~
~~Billing & Collection~~	~~$142.797 per month~~
~~Customer Delivery~~	~~$228.696 per month~~

~~Demand Charges, (<69 kV Distribution Service):~~

~~Transmission~~	~~$ .725 per kW~~
~~Sub-transmission~~	~~$ .951 per kW~~
~~Delivery~~	~~$ 16.097per kw~~

~~Production (not included in power supply) $ .122 per kW~~

~~Demand Charges, (>69 kV Transmisison Service):~~

~~Transmission $ .777 per kW~~

~~Sub-transmission $ 1.019 per kW~~

~~Delivery $ 9.683 per kw~~

~~Production (not included in power supply) $ .131 per kW~~

~~Energy Charges (kWh):~~

~~Delivery $0.000000 per kWh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

~~—~~	~~Summer (May – October)~~	~~Winter (November - April)~~
~~On-Peak~~	~~$0.077240~~	~~$0077240~~
~~Shoulder-Peak~~	~~$0.053260~~	~~N/A~~
~~Off-Peak~~	~~$0.047240~~	~~$0.041233~~

TERMS AND CONDITIONS

Standby, supplementary, breakdown, and/or temporary service are available under this rate. At the Company's option, customers may have to enter into a Service or Purchase Agreement with the Company for this service.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

Service under this pricing plan is for the exclusive use of the Customer and shall not be resold or shared with others, unless authorized by the Company.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

OTHER PROVISIONS
Service hereunder shall remain in full force and in effect until terminated by the customer unless otherwise provided for in the Service Agreement. Termination of service requires twelve (12) months advance notice in writing to the Company.

Service hereunder may require the customer to enter into a Service Agreement with the Company for a term of two (2) years or longer, with a minimum contract demand capacity at the Company's option in view of the anticipated demand of the Customer.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan LTG
Dusk-To-Dawn Lighting Service

AVAILABILITY
Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
To any Customer, including public agencies, for the lighting of streets, alleys, thoroughfares, public parks, playgrounds, or other public or private property where such lighting is controlled by a photocell and a contract for service is entered into with the Company.

CHARACTER OF SERVICE
Service is supplied on Company-owned fixtures and poles which are maintained by the Company. The poles, fixtures, and lamps available are the standard items stocked by the Company, and service is rendered at standard available voltages.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE

The monthly bill shall be the sum of the following charges and adjustments for each light:

Service Charge (per month):	Overhead Service	Underground Service
Existing Wood Pole	$0.000	$2.2683
New 30' Wood Pole (Class 6)	$4.5354	$6.8146
New 30' Metal or Fiberglass	$9.0828	$11.350

Lighting Charge:
Based on the rated wattage value of each lamp installed per month: $0.051029 per watt

Base Power Supply Charge: based on the rated wattage value of each lamp installed per month: $0.006893 per watt

The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

CONTRACT PERIOD
All dusk-to-dawn lighting installations for public agencies will require an agreement for service.

All dusk-to-dawn lighting installations for other than public agencies will require a contract for service as follows:
Five (5) years initial term for installations on existing facilities, and
Five (5) years initial term, or longer at the Company's option, for installations requiring new and/or an extension of facilities.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

New 30' Wood Pole (Class 6) - Overhead	
Billing and Collections	$3.0000 per unit
Customer Delivery	$1.5354 per unit
New 30' Metal or Fiberglass - Overhead	
Billing and Collections	$3.0000 per unit
Customer Delivery	$6.0828 per unit
Existing Wood Pole – Underground	
Billing and Collections	$2.2683 per unit
Customer Delivery	$0.0000 per unit
New 30' Wood Pole Class 6 – Underground	
Billing and Collections	$3.0000 per unit
Customer Delivery	$3.8146 per unit
New 30' Metal or Fiberglass – Underground	
Billing and Collections	$3.0000 per unit
Customer Delivery	$8.3500 per unit
Lighting Charge	
Production (not included in Power Supply)	$0.000327 per watt
Delivery	$0.050701 per watt
Base Power Supply	$0.006893 per watt

TERMS AND CONDITIONS

1. Overhead extensions beyond one hundred fifty (150) feet and underground extensions beyond one hundred (100) feet will require specific agreements providing adequate revenue or arrangements for construction financing.
2. The Customer is not authorized to make connections to the lighting circuit or make attachments or alterations to the Company-owned pole.
3. Should a Customer request a relocation of a dusk-to-dawn lighting installation, the costs of such relocation must be borne by the customer.
4. The Customer is expected to notify the Company when lamp outages occur.
5. The Company will use diligence in maintaining service; however, monthly bills will not be reduced because of lamp outages.
6. The Company may require a refundable advance for the installation of new construction for facilities.
7. A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01
Residential Service

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

CHARACTER OF SERVICE
Single phase, 60 hertz, at one standard voltage.

RATE
A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $ 8.00 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

	Delivery Services-Energy[1]	Power Supply Charges[2]		
		Base Power	PPFAC[2]	Total[3]
First 400 kWh	$0.026115	$0.068767	Varies	$0.094882
All Additional kWhs	$0.036129	$0.074812	Varies	$0.104896

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~**BUNDLED STANDARD OFFER SERVICE**~~

~~Customer Charge $7.50 per month~~

~~Energy Charges:~~
~~Delivery Charge, 1st 400 kWhs $0.011255 per kwh~~
~~Delivery Charge, all additional kWhs $0.021269 per kwh~~
~~Base Power Supply Charge $0.077993 per kWh~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$3.201 per month
Meter Reading	$0.659 per month
Billing & Collection	$3.747 per month
Customer Delivery	$0.393 per month
	$8.00 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services- Energy 1st 400 kWhs	
Transmission	$0.008232
Sub-Transmission	$0.005237
Local Delivery Energy	$0.012282
Production not included in Power Supply	$0.000364
Delivery Services - Energy All Additional kWhs	
Transmission	$0.008232
Sub-Transmission	$0.005237
Local Delivery Energy	$0.022296
Production not included in Power Supply	$0.000364

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply	$0.068767
PPFAC (see Rate Rider-1 for current rate)	Varies

~~**BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:**~~

~~Customer Charges:~~

~~Meter Services~~	~~$2.227 per month~~
~~Meter Reading~~	~~$0.688 per month~~
~~Billing & Collection~~	~~$3.601 per month~~
~~Customer Delivery~~	~~$0.984 per month~~
~~Energy Charges (kWh):~~	
~~Delivery Charge, 1st 400 kWhs~~	
~~Transmission~~	~~$0.003322 per kWh~~
~~Sub transmission~~	~~$0.003760 per kWh~~
~~Delivery~~	~~$0.003821 per kwh~~
~~Production (not included in power supply)~~	~~$0.000352 per kWh~~
~~Delivery Charge, all additional kWhs~~	
~~Transmission~~	~~$0.003322 per kWh~~
~~Sub transmission~~	~~$0.003760 per kWh~~
~~Delivery~~	~~$0.013835 per kwh~~
~~Production (not included in power supply)~~	~~$0.000352 per kWh~~
~~Base Power Supply~~	~~$0.077993 per kWh~~

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSource Energy SERVICES

UNS Electric, Inc.
Pricing Plan RES-01 TOU-A
Residential Service Time-of-Use – Weekends Off-Peak

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY

Available as an optional rate to Customers served under the Company's Pricing Plan RS, Residential Service.

This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

-Service is ~~provided at one point of delivery measured through one meter and is~~ restricted to private single family dwellings or individually metered apartments.

Not applicable to three phase service, resale, breakdown, temporary, standby, auxiliary service, or service to individual motors exceeding 40 amperes at a rating of 230 volts or which will cause excessive voltage fluctuations.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE

Single phase, 60 hertz, at one standard voltage.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill $ ~~8~~8.00 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.

All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.026115~~0070~~	$0.153093~~$0.159138~~	Varies	~~$~~0.179208~~0.179208~~
Shoulder Peak	$0.026115 ~~$0.020070~~	$0.068767~~$0.074812~~	Varies	$0.094882~~$0.094882~~
Off-Peak	$0.026115 ~~$0.020070~~	$0.048113~~$0.054158~~	Varies	$0.074228~~$0.074228~~
All Additional kWhs				
On-Peak	$0.036129~~0084~~	$0.153093~~$0.159138~~	Varies	$0.189222~~9222~~
Shoulder Peak	$0.036129~~$0.030084~~	$0.068767~~$0.074812~~	Varies	$0.~~104896~~104896

Off-Peak	$0.036129~~$0.030084~~	$0.048113~~$0.054158~~	Varies	$0.084242~~84242~~

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.026115 ~~$0.020070~~	$0.153093~~$0.159138~~	Varies	$0.~~17~~179208~~9208~~
Off-Peak	$0.026115 ~~$0.020070~~	$0.035849~~$0.041894~~	Varies	$0.~~061964~~ 061964
All Additional kWhs				
On-Peak	$0.036129~~$0.030084~~	$0.153093~~$0.159138~~	Varies	$0.~~179208~~189222
Off-Peak	$0.036129~~$0.030084~~	$0.035849~~$0.041894~~	Varies	$0.071978~~71978~~

1. Delivery Services-Energy is a bundled charge that includes~~: Local Delivery Energy (Local Delivery and/or Distribution exclusive of Transmission, Sub-transmission and production not included in Power Supply),~~ : Transmission, Sub-transmission, Local DeliveryEnergy and Production not included in Power Supply.

~~Delivery Services Energy is a bundled charge that includes: Local Delivery Energy (Local Delivery and/or Distribution exclusive of Transmission, Sub-transmission and production not included in Power Supply.~~

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~**BUNDLED STANDARD OFFER SERVICE**~~

~~Customer Charge — $7.50 per month~~

~~Energy Charges:~~
~~Delivery Charge, 1st 400 kWhs — $0.011255 per kwh~~
~~Delivery Charge, all additional kWhs — $0.021260 per kwh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

—	~~Summer~~	~~Winter~~

	~~(May – October)~~	~~(November – April)~~
~~On Peak~~	~~$0.102086~~	~~$0.102086~~
~~Shoulder Peak~~	~~$0.077093~~	~~N/A~~
~~Off Peak~~	~~$0.072092~~	~~$0.068588~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

TIME-OF-USE PERIODS

Summer TOU periods:
Summer weekdays except Memorial Day, Independence Day (July 4), and Labor Day. If Independence Day falls on Saturday, the Weekend schedule applies on the preceeding Friday, July 3. If Independence Day falls on Sunday, the Weekend schedule applies on the following Monday, July 5.

On-Peak: 2:00 p.m. to 6:00 p.m.
Shoulder-Peak 12:00 p.m. (noon) to 2:00 p.m. and 6:00 p.m. to 8:00 p.m.
Off-Peak: 12:00 a.m. (midnight) to 12 p.m (noon) and 8:00 p.m. to 12:00 a.m. (midnight).

Summer weekend days (Saturday and Sunday), Memorial Day, Independence Day (or July 3 or July 5, under above conditions), and Labor Day.

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak: *(There are no Shoulder-Peak weekend hours)*
Off-Peak: All hours.

Winter TOU periods:
Winter weekdays except Thanksgiving Day, Christmas Day, and New Years Day. If Christmas Day and New Years Day fall on Saturdays, the Weekend schedule applies on the preceeding Fridays, December 24 and December 31. If Christmas Day and New Years Day fall on Sundays, the Weekend schedule applies on the following Mondays, December 26 and January 2.

On-Peak: ~~is~~ 6:00 a.m. to 10:00 a.m. and 5:00 p.m. to 9:00 p.m.
Shoulder-Peak: ~~t~~There are no shoulder peak periods in the winter.
Off-Peak: ~~is~~ 12:00 a.m. (midnight) to 6:00 a.m., 10:00 a.m. to 5:00 p.m., and 9:00 p.m. to 12:00 a.m. (midnight).

WinterWeekend days (Saturday and Sunday), Thanksgiving Day, Christmas Day (or December 24 or December 26, under above conditions), and New Years Day (or December 31 or January 2, under above conditions).

On-Peak: *(There are no On-Peak weekend hours)*
Shoulder-Peak: *(There are no Shoulder-Peak weekend hours)*
Off-Peak: All hours.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$3.~~097~~ 201 per month
Meter Reading	$0.~~86~~592 per month
Billing & Collection	$3.747~~661~~ per month
Customer Delivery	$0.3~~80~~93 per month
	$8.00 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	**Rate**
Delivery Services- Energy 1st 400 kWhs	
Transmission	$0.008232~~2299~~
Sub-Transmission	$0.00~~4813~~5237
Local Delivery Energy	$0.012282~~643~~
Production not included in Power Supply	$0.000364~~15~~
Delivery Services - Energy All Additional kWhs	
Transmission	$0.008232~~$0.002299~~
Sub-Transmission	$0.005237~~$0.004813~~
Local Delivery Energy	$0.022296~~$0.022657~~
Production not included in Power Supply	$0.000364~~$0.000315~~

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.153093
Shoulder-Peak	$0.068767
Off-Peak	$0.048113
Base Power Supply Winter	
On-Peak	$0.153093~~$0.159138~~
Off-Peak	$0.035849~~$0.041894~~
PPFAC (see Rate Rider-1 for current rate)	Varies

~~**BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:**~~

~~Customer Charges:~~

~~Meter Services~~	~~$2.227 per month~~
~~Meter Reading~~	~~$0.688 per month~~
~~Billing & Collection~~	~~$3.601 per month~~
~~Customer Delivery~~	~~$0.984 per month~~

~~Energy Charges (kWh):~~

~~Delivery Charge, 1st 400 kWhs~~

~~Transmission~~	~~$0.003322 per kWh~~
~~Sub transmission~~	~~$0.003760 per kWh~~
~~Delivery~~	~~$0.003821 per kwh~~
~~Production (not included in power supply)~~	~~$0.000352 per kWh~~

~~Delivery Charge, all additional kWhs~~

~~Transmission~~	~~$0.003322 per kWh~~
~~Sub transmission~~	~~$0.003760 per kWh~~
~~Delivery~~	~~$0.013835 per kwh~~
~~Production (not included in power supply)~~	~~$0.000352 per kWh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

—	~~Summer (May – October)~~	~~Winter (November - April)~~
~~On Peak~~	~~$0.102086~~	~~$0.102086~~
~~Shoulder Peak~~	~~$0.077993~~	~~N/A~~
~~Off Peak~~	~~$0.072092~~	~~$0.068588~~

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

AVAILABILITY
Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.

APPLICABILITY
This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer where the monthly usage is not more than 7,500 kWh in any two (2) consecutive months. Customers who use more than 7,500 kWh for two (2) or more consecutive months shall not be eligible for this pricing plan and shall take service under the Large General Service pricing plan. However, service is available for customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW

~~To any customer for any purpose where service is provided at one point of delivery and measured through one meter and where the monthly usage is not more than 7,500 kWh in any two (2) consecutive months. Customers who use more than 7,500 kWh for two (2) or more consecutive months shall not be eligible for this pricing plan and shall take service under the Large General Service pricing plan. However, service is available for customer owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW.~~

CHARACTER OF SERVICE
Single phase, 60 hertz at one standard voltage. Three phase for eligible loads over 5 kW.

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:
Customer Charge, Single Phase service and minimum bill $12.50 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

	Delivery Services-Energy[1]	Power Supply Charges[2]		-
		Base Power	PPFAC[2]	Total[3]
First 400 kWh	$0.0383109	$0.0667778	Varies	$0.105089
All Additional kWhs	$0.0483249	$0.0667778	Varies	$0.115103

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~BUNDLED STANDARD OFFER SERVICE~~

~~Customer Charge~~ ~~$12.00 per month~~

~~Energy Charges:~~

~~Delivery Charge, 1st 400 kWhs~~ ~~$0.022449 per kwh~~

~~Delivery Charge, all additional kWhs~~ ~~$0.032463 per kwh~~

~~Base Power Supply Charge~~ ~~$0.075738 per kWh~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$4.911 per month
Meter Reading	$0.221 per month
Billing & Collection	$6.673 per month
Customer Delivery	$0.695 per month
	$12.50 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services - Energy 1st 400 kWhs	
Transmission	$0.006812
Sub-Transmission	$0.004414
Local Delivery Energy	$0.026731
Production not included in Power Supply	$0.000354
Delivery Services - Energy All Additional kWhs	
Transmission	$0.006812
Sub-Transmission	$0.004414
Local Delivery Energy	$0.036745
Production not included in Power Supply	$0.000354

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply	$0.066778
PPFAC (see Rate Rider-1 for current rate)	Varies

~~BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:~~

~~Customer Charges:~~

~~Meter Services~~	~~$3.459 per month~~
~~Meter Reading~~	~~$1.173 per month~~
~~Billing & Collection~~	~~$6.123 per month~~
~~Customer Delivery~~	~~$1.245 per month~~

~~Energy Charges (kWh):~~

~~Delivery Charge, 1st 400 kWhs:~~

~~Transmission~~	~~$0.002568 per kWh~~
~~Sub-transmission~~	~~$0.003105 per kWh~~
~~Delivery~~	~~$0.016436 per kwh~~
~~Production (not included in power supply)~~	~~$0.000340 per kWh~~

~~Delivery Charge, all additional kWhs~~

~~Transmission~~	~~$0.002568 per kWh~~
~~Sub-transmission~~	~~$0.003105 per kWh~~
~~Delivery~~	~~$0.026450 per kwh~~
~~Production (not included in power supply)~~	~~$0.000340 per kWh~~
~~Base Power Supply~~	~~$0.075738 per kWh~~

TERMS AND CONDITIONS

Service under this schedule is for the exclusive use of the Customer and shall not be resold or shared with others.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

Standby, supplemental or breakdown service shall not be rendered under this pricing plan.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE
To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS
The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES
Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

UniSourceEnergy SERVICES

UNS Electric, Inc.
Pricing Plan SGS-10 TOU
Small General Service Time-of-Use

AVAILABILITY

Available throughout the Company's entire electric service area where the facilities of the Company are of adequate capacity and are adjacent to the premises.
~~Throughout the entire area where the facilities of the Company are of adequate capacity and are adjacent to the premises.~~

APPLICABILITY

This service is normally provided at one point of delivery measured through one meter. More than one service and meter may be provided in instances where such is permitted under 230.2 (A) through (D) of the National Electric Code with prior approval of the Unisource Electric Engineering Department.

To any customer for where the monthly usage is not more than 7,500 kWh in any two (2) consecutive months. Customers who use more than 7,500 kWh for two (2) or more consecutive months shall not be eligible for this pricing plan and shall take service under the Large General Service pricing plan. However, service is available for customer-owned, operated, and maintained area, street, or stadium lighting, and for firm irrigation service with a maximum monthly demand less than 25 kW.

Service under this pricing plan will commence when the appropriate meter has been installed.

CHARACTER OF SERVICE

Single phase, 60 hertz at one standard voltage. Three phase for eligible loads over 5 kW.

RATE

A monthly net bill at the following rate plus any adjustments incorporated in this pricing plan:

BUNDLED STANDARD OFFER SERVICE - SUMMARY OF CUSTOMER AND ENERGY CHARGES

Customer Charge Components of Delivery Services:

Customer Charge, Single Phase service and minimum bill $ 12.50 per month

Energy Charge Components are unbundled into Delivery Services-Energy and Power Supply Charges.
All energy charges below are on a per kWh basis for all summer and winter months.

Summer	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.038311 ~~2440~~	$0.130888	Varies	$0.~~169199~~169199
Shoulder Peak	$0.038311~~$0.032440~~	$0.066778	Varies	$0.105089~~105089~~
Off-Peak	$0.038311~~$0.032440~~	$0.040888~~046759~~	Varies	$0.0791999~~199~~
All Additional kWhs				
On-Peak	$0.048325~~2454~~	$0.130888~~$0.136759~~	Varies	$0.179213~~179213~~
Shoulder Peak	$0.048325~~$0.042454~~	$0.066778 ~~$0.072649~~	Varies	$0.115103~~115103~~
Off-Peak	$0.048325~~$0.042454~~	$0.040888~~$0.046759~~	Varies	$0.0892123~~089213~~

Winter	Delivery Services-Energy[1]	Power Supply Charges[2] Base Power	PPFAC[2]	Total[3]
First 400 kWh				
On-Peak	$0.038311~~$0.032440~~	$0.~~136759~~130888	Varies	$0.~~169~~169199~~199~~
Off-Peak	$0.038311~~$0.032440~~	$0.032668~~8539~~	Varies	$0.070979~~070979~~
All Additional kWhs				
On-Peak	$0.048325~~$0.042454~~	$0.130888~~$0.136759~~	Varies	$0.179213~~179213~~
Off-Peak	$0.048325~~$0.042454~~	$0.032668~~$0.038539~~	Varies	$0.080993~~80993~~

1. Delivery Services-Energy is a bundled charge that includes: Transmission, Sub-transmission, Local Delivery Energy and Production not included in Power Supply.

2. The Power Supply Charge shall be comprised of the Base Power Charge and the Purchased Power and Fuel Adjustment Clause ("PPFAC"), a per kWh adjustment in accordance with Rate Rider-1. The PPFAC reflects increases or decreases in the cost to the Company for energy either generated or purchased above or below the base cost per kWh sold. The PPFAC rate changes annually every June 1. Please see Rate Rider-1 for current rate.

3. Total is calculated above for illustrative purposes, and excludes PPFAC, because PPFAC changes annually pursuant to Rider-1 PPFAC. While only non-variable components are included in the illustration above, a Customer's actual bill in any given billing month will reflect the applicable PPFAC for that billing month.

~~**BUNDLED STANDARD OFFER SERVICE**~~

~~Customer Charge~~ ~~$12.00 per month~~

~~Energy Charges:~~
~~Delivery Charge, 1st 400 kWhs~~ ~~$0.022449 per kwh~~
~~Delivery Charge, all additional kWhs~~ ~~$0.032463 per kwh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

	~~Summer (May – October)~~	~~Winter (November - April)~~
~~On Peak~~	~~$0.097108~~	~~$0.097108~~
~~Shoulder Peak~~	~~$0.075738~~	~~N/A~~
~~Off Peak~~	~~$0.067108~~	~~$0.064368~~

~~Purchased Power Fuel Adjuster Clause ("PPFAC"): The Base Power Supply Charge shall be subject to a per kWh adjustment in accordance with the PPFAC Rider No. 1 to reflect any increase or decrease in the cost to the Company of energy either generated or purchased above or below the base cost per kWh sold.~~

TIME-OF-USE PERIODS

Summer Billing Months are May-October; Winter Billing Months are November through April. The summer On-Peak period is 2:00 p.m. to 6:00 p.m.. The summer Shoulder periods are 12:00 p.m. (noon) to 2:00 p.m., and 6:00 p.m. to 8:00 p.m..

The winter On-Peak periods are 6:00 a.m. - 10:00 a.m. and 5:00 p.m. - 9:00 p.m.. All other hours are Off-Peak.

BUNDLED STANDARD OFFER SERVICE CONSISTS OF THE FOLLOWING UNBUNDLED COMPONENTS:

Customer Charge Components of Delivery Services (Unbundling):

Meter Services	$4.911~~381~~ per month
Meter Reading	$0~~1~~.221~~434~~ per month
Billing & Collection	$6.~~0~~673~~1~~ per month
Customer Delivery	$0.695~~24~~ per month
	$12.50 per month

Energy Charge Components of Delivery Services (Unbundling) ($/kWh):

Component	Rate
Delivery Services - Energy 1st 400 kWhs	
Transmission	$0.006812 ~~$0.001889~~
Sub-Transmission	$0.004414 ~~$0.003993~~
Local Delivery Energy	$0.026731 ~~$0.026252~~
Production not included in Power Supply	$0.000354 ~~$0.000306~~
Local Delivery-Energy All Additional kWhs	
Transmission	$0.006812 ~~$0.001889~~
Sub-Transmission	$0.004414 ~~$0.003993~~
Local Delivery Energy	$0.036745 ~~$0.036266~~
Production not included in Power Supply	$0.000354 ~~$0.000306~~

Power Supply Charges (Unbundling) ($/kWh):

Component	Rate
Base Power Supply Summer	
On-Peak	$0.130888~~$0.136759~~
Shoulder-Peak	$0.066778 ~~$0.072649~~
Off-Peak	$0.040888~~$0.046759~~
Base Power Supply Winter	

On-Peak	$0.130888~~$0.136759~~
Off-Peak	$0.032668~~$0.038539~~
PPFAC (see Rate Rider-1 for current rate)	Varies

~~Customer Charges:~~

~~Meter Services~~	~~$3.459 per month~~
~~Meter Reading~~	~~$1.173 per month~~
~~Billing & Collection~~	~~$6.123 per month~~
~~Customer Delivery~~	~~$1.245 per month~~

~~Energy Charges (kWh):~~

~~Delivery Charge, 1st 400 kWhs:~~

~~Transmission~~	~~$0.002568 per kWh~~
~~Sub transmission~~	~~$0.003105 per kWh~~
~~Delivery~~	~~$0.016436 per kwh~~
~~Production (not included in power supply)~~	~~$0.000340 per kWh~~

~~Delivery Charge, all additional kWhs~~

~~Transmission~~	~~$0.002568 per kWh~~
~~Sub transmission~~	~~$0.003105 per kWh~~
~~Delivery~~	~~$0.026450 per kwh~~
~~Production (not included in power supply)~~	~~$0.000340 per kWh~~

~~Base Power Supply Charges (All energy charges below are charged on a per kWh basis):~~

~~—~~	~~Summer (May – October)~~	~~Winter (November - April)~~
~~On Peak~~	~~$0.097108~~	~~$0.097108~~
~~Shoulder Peak~~	~~$0.075738~~	~~N/A~~
~~Off Peak~~	~~$0.067108~~	~~$0.064368~~

TERMS AND CONDITIONS

Service under this schedule is for the exclusive use of the Customer and shall not be resold or shared with others.

Customers who qualify for service under this pricing plan must remain on the pricing plan for a twelve (12) month period, unless, in the judgment of the Company, conditions require a different strategy or approach.

Standby, supplemental or breakdown service shall not be rendered under this pricing plan.

A delayed payment charge as stated in the general rules and regulations will be applied to account balances carried forward from prior billings.

DIRECT ACCESS

A customer's Direct Access bill will include all unbundled components except those services provided by a qualified third party. Those services may include Metering (Installation, Maintenance and/or Equipment), Meter Reading, Billing and Collection, Transmission and Generation. If any of these services are not available from a third party supplier and must be obtained from the Company, the rates for Unbundled Components set forth in this tariff will be applied to the customer's bill.

TAX CLAUSE

To the charges computed under the above rate, including any adjustments, shall be added the applicable proportionate part of any taxes or governmental impositions which are or may in the future be assessed on the basis of gross revenues of the Company and/or the price or revenue from the electric energy or service sold and/or the volume of energy generated or purchased for sale and/or sold hereunder.

RULES AND REGULATIONS

The standard Rules and Regulations of the Company as on file with the Arizona Corporation Commission shall apply where not inconsistent with this pricing plan.

ADDITIONAL NOTES

Additional charges may be directly assigned to a customer based on the type of facilities (e.g., metering) dedicated to the customer or pursuant to the customer's contract, if applicable. Additional or alternate Direct Access charges may be assessed pursuant to any Direct Access fee schedule authorized.

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-____

Direct Testimony of

Martha B. Pritz

on Behalf of

UNS Electric, Inc.

April 30, 2009

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Martha B. Pritz. My business address is One South Church Avenue, Tucson, AZ 85701.

Q. What is your position with UNS Electric, Inc. ("UNS Electric" or the "Company")?

A. I am not employed directly by UNS Electric. I am employed by Tucson Electric Power Company ("TEP") as the Director of Financial Planning. TEP is a subsidiary of UniSource Energy Corporation ("UniSource Energy"). In my position, I provide forecasting and analytical support services to the subsidiaries of UniSource Energy, including TEP, UNS Electric and UNS Gas, Inc. ("UNS Gas").

Q. Please describe your education and experience.

A. I have a Master of Science degree in Finance from the University of Colorado, Denver campus, and a Bachelor of Arts degree in Communication from the University of Colorado, Boulder campus. I am a member of the Chartered Financial Analyst ("CFA") Institute and am a CFA charterholder. I am also a member of the Society of Utility and Regulatory Financial Analysts.

I joined TEP in 1999 as a Senior Financial Analyst. I was promoted to Lead Financial Analyst in 2000, then to Director of Financial Planning in 2002. In these positions, I have gained substantial experience in financial analysis and the preparation of financial forecasts.

Q. What is the purpose of your direct testimony?

A. In my direct testimony, I recommend an appropriate capital structure, a reasonable cost of equity, and a cost of debt for use in determining the Company's weighted average cost of capital. I then show the resulting weighted average cost of capital.

I am sponsoring Schedule A-3, which is the Summary of Capital Structure. I am also sponsoring Schedules D-1 through D-4, which show UNS Electric's Cost of Capital.

Q. Please summarize your recommendations.

A. Based on a capital structure consisting of 45.76% equity and 54.24% long-term debt, an 11.40% return on equity, and a 7.05% cost of long-term debt, I recommend a weighted average cost of capital of 9.04%.

II. FINANCIAL CONDITION OF UNS ELECTRIC.

Q. Please describe UNS Electric's financial condition as of December 31, 2008.

A. As of December 31, 2008, UNS Electric's overall financial condition, while stronger than in the past, is still weak by some measures.

The Company's equity ratio of 43.84% is in line with those of industry peers. Also, the Company realized a lower cost of long-term debt when it refinanced maturing 7.61% notes in August 2008 with new notes carrying an average interest rate of 6.80%.

However, the Company's earned return on equity ("ROE") for 2008 was just 4.6% despite the fact that new rates based on an allowed ROE of 10% were in effect for 7 months of the year, including the summer months when sales were highest. With earnings far below the recommended ROE, it may be difficult for the Company to continue to attract capital at reasonable rates.

Also, while UNS Electric's Purchased Power and Fuel Adjustment Clause ("PPFAC") gives some predictability to regulated cash flows, the operating cash generated by the Company in 2008 fell far short of capital spending. Due to recurring weakness in earnings and cash flow, the Company has been unable to pay a dividend since its inception in August 2003. In contrast, the vast majority of investor-owned electric utilities pay dividends, with Edison Electric Institute Index companies paying out an average of 66.6% of earnings for the 12-month period ending September 30, 2008.[1]

Q. Is UNS Electric's debt rated by rating agencies?

A. Yes, as shown in Exhibit MBP-1, UNS Electric's revolving credit facility (a joint credit facility shared with UNS Gas) and senior unsecured debt are each rated by Moody's Investor Services ("Moody's"). These debt obligations are rated Baa3. The Baa3 rating is an investment-grade rating, although the lowest one possible. The credit facility rating was assigned in July 2008 and the rating on the senior notes was assigned in August 2008.

Q. What outlook has Moody's assigned to the ratings?

A. Moody's has assigned a Stable outlook.

Q. Has Moody's described the factors that could cause them to downgrade the ratings?

A. Moody's issued a Credit Opinion on July 9, 2008, following the rating of the credit facility and in advance of the rating of UNS Electric's August 2008 note issuance. The

[1] Edison Electric Institute, Dividends, Q4 2008 Financial Update: 2.

Credit Opinion states that if deferred regulatory balances at UNS Electric or UNS Gas become higher than expected, or if the time to recovery of costs is significantly extended, the rating or outlook could be lowered. Significant cost increases or regulatory lag could result in weaker financial metrics, causing a downgrade. The complete Credit Opinion is attached as Exhibit MBP-2.

III. CAPITAL STRUCTURE.

Q. Please describe UNS Electric's capital structure as of December 31, 2008.

A. As of December 31, 2008, UNS Electric had common stock equity of $83.8 million and total long-term debt of $108.0 million, consisting of $100.0 million of senior unsecured notes and revolving credit agreement borrowings of $8.0 million. After adjusting the long-term debt for unamortized issuance costs, the long-term debt balance at the end of the year was $107.3 million. Based on these figures, the Company's capital structure is 43.84% equity and 56.16% long-term debt.

Q. Is the capital structure you recommend for purposes of determining a weighted average cost of capital the same as UNS Electric's capital structure as of December 31, 2008?

A. No, there is an adjustment that needs to be made to arrive at the weighted average cost of capital for rate setting purposes.

Q. Please describe the adjustment you recommend be made to the capital structure.

A. The capital structure appropriate for use in determining rates should exclude UNS Electric's revolving credit facility borrowings. The $8.0 million of credit facility borrowings were not used to finance the Company's requested rate base. Instead, as of the end of the test year, UNS Electric had used its credit facility to post cash collateral of $6.7 million in support of forward energy purchases and to fund a portion of construction work in progress ("CWIP") not included in the Company's requested rate base. Additionally, although the credit facility borrowings were classified as long-term debt on the Company's balance sheet at December 31, 2008, these borrowings have since been repaid as of March 2009. Since the revolver borrowings were not used for the purpose of funding plant in service in rate base, the balance should not be included in the capital structure for rate setting purposes.

Q. After making this adjustment to UNS Electric's December 31, 2008 capital structure, what is the resulting capital structure that should be used for purposes of calculating the Company's weighted average cost of capital ("WACC")?

A. The capital structure that should be used includes UNS Electric's common equity balance of $83.8 million and its unsecured senior note balance of $99.3 million. Using these figures, the recommended capital structure consists of 45.76% common equity and 54.24% long-term debt.

IV. COST OF COMMON EQUITY.

Q. Please describe the methods used in determining a fair rate of return on common equity.

A. In determining a fair return on equity, investors are likely to use one or more of the models commonly recommended for analysis of an equity investment. In order to estimate the ROE that equity investors would determine to be reasonable, I have chosen to use three of the most widely-used models: the discounted cash flow model ("DCF"); the capital asset pricing model ("CAPM"); and the bond yield plus risk premium model.

Q. Can the three methods of determining the cost of common equity be applied directly to UNS Electric?

A. No. Since UNS Electric is not a publicly traded company, data from a proxy group of companies was used in the DCF and CAPM models.

A. <u>Proxy Group of Companies.</u>

Q. Please describe the selection process for the proxy group of companies.

A. We started with all companies classified by Value Line Investment Survey ("Value Line") as electric utilities. The list of companies was then narrowed using the following tests:

a) retail electric revenue made up at least 50% of the company's total revenue;

b) purchased energy comprised at least 30% of the company's energy requirements;

c) at least 50% of the company's gross plant balance was electric plant;

d) transmission and distribution plant was at least 40% of total net plant;

e) maximum generation capacity of 4,000 MW;

f) no more than 4,000,000 customers;

g) equity capitalization of at least 30%;

h) market capitalization maximum of $5 billion;

i) no pending mergers or acquisitions.

This gave us a list of 10 companies suitable for use as a proxy group for UNS Electric. A list of the companies is shown in Exhibit MBP-3.

B. Discounted Cash Flow Model.

Q. Please explain the DCF method of determining the cost of equity.

A. The method is based on the premise that the value of an asset is equal to the discounted sum of its future cash flows. By using the current stock price and estimates of expected dividends, an estimate of the return required by shareholders can be made. In its general form, the calculation is:

$$P_0 = \sum_{t=1}^{n} \frac{D^t}{(1 + K)^t}$$

In which:

P_0 = current stock price

D^t = expected dividend for each year

K = one-year return required by the investor

n = time period number, one to infinity

Since it is not practical to estimate a stream of dividends to infinity, a simplifying assumption may be made that the rate of growth of the dividend is constant. With that assumption, the formula for the standard, or constant-growth, DCF model becomes:

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

In which:

D_1 = expected dividend one year out

g = expected dividend growth rate

Rearranging the formula, one can solve for the return required by the investor:

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

For cases in which the expected growth of the dividend isn't constant, another form of the DCF model must be used. The non-constant or multi-stage growth model allows calculation of a required return should the dividend growth rate be expected to change such that it grows at a constant rate only after *n* number of years. The calculation is:

$$P_0 = \frac{D_1}{1 + K} + \frac{D_2}{(1 + K)_2} + \ldots + \frac{D_n}{(1 + K)_n} + \frac{D_n(1 + g)}{K - g} \times \frac{1}{(1 + K)_n}$$

Using the current stock price, the expected dividends for periods 1 through *n*, and the expected growth rate after year *n*, one can solve for the return on equity required by investors.

Q. Which form of the DCF model have you chosen to use?

A. I have chosen to use the non-constant growth form of the DCF model.

Q. Why have you chosen the non-constant growth form of the DCF model?

A. Three- to five-year growth projections for UNS Electric's peer group of companies are published by Value Line, Zacks Investment Research ("Zacks") and SNL Financial ("SNL"). Given that information from these sources is widely available to investors, it's appropriate that it be incorporated into the DCF model in determining near-term dividend growth. Since the growth estimates do not extend beyond five years, another growth rate needs to be used after the first five years. This change in growth rates necessitates use of the non-constant growth DCF model.

Q. How did you determine the near-term growth rate to be used for each company?

A. As shown on Exhibit MBP-4, I have included estimates of dividend and earnings growth rates from Value Line, Zacks and SNL. These forward-looking estimates are more suitable for use in the DCF model than relying only on historical rates. Expectations about earnings growth are a factor in forming expectations about dividend growth, so for each of the peer group companies, the near-term growth rate used in the DCF model is the average of the growth rates shown.

Q. How did you determine the expected dividends for the first five years?

A. The expected first-year dividend was calculated based on the most recent quarterly payments. For companies that did not increase their dividends in the past year, the assumption was made that the dividends would not change in the coming year. For companies that increased their dividends within the past year, the assumption was made that the next increase would be at the same in the coming year. If an increase is anticipated, the near-term growth rate shown on Exhibit MBP-4 was used. The resulting quarterly payments were summed to arrive at an expected first-year dividend (D_1 in the non-constant growth DCF model).

The dividends for years 2 through 5 were calculated by applying the near-term growth rate for each company to its expected first-year dividend. The resulting projected dividends are shown on Exhibit MBP-5.

Q. How was the long-term growth rate for the DCF model chosen?

A. In determining a long-term growth rate, an investor is likely to consider estimates of growth for a proxy group of companies, for the electric utility industry as a whole, and for the U.S. economy as a whole.

Q. Please describe the estimate of growth for peer companies.

A. As discussed above, 5-year growth rates for each of UNS Electric's peer companies were calculated by averaging the published estimates from Value Line, Zacks and SNL. The median value of those rates is 6.5%.

Q. Please describe the estimate of growth for the electric utility industry.

A. As an investor looks for additional indicators of long-term growth, an estimate of industry growth is likely to be considered. Zacks' estimate for the electric utility industry shows a 5-year forecast of stock growth of 8.6%. It would be reasonable for an investor seeking to determine a long-term growth rate to start with this industry-specific growth rate.

Q. Please describe the estimate of growth in the U.S. economy.

A. Given that electric utilities provide a basic service, an investor would be likely to look to long-term overall U.S. economic growth as another indicator of long-term utility growth.

In order to estimate a long-term growth rate for the U.S. economy, one can look to historic gross domestic product ("GDP") growth for guidance. For the period from 1929 to 2008, real GDP growth has been 3.3% per year. In addition to GDP growth averaging 3.3% over a very long period of time, the figure is also representative of GDP growth over a number of shorter periods of time representing a variety of business climates. That being the case, no adjustment is made for the current economic conditions. To real GDP growth, an estimate of inflation must be added to arrive at a nominal growth rate figure suitable for use in the DCF model.

Q. How can an estimate of implied inflation be determined?

A. An estimate of long-term inflation to be added to real GDP growth can be obtained by comparing the yields of constant maturity fixed-rate U.S. treasuries to the yields of constant maturity Treasury Inflation-Protected Securities ("TIPS"). Care must be used in selecting an appropriate timeframe from which to estimate implied inflation. As seen in Exhibit MBP-6, the implied inflation rates at the end of February 2009 were well below the average for the period from January 2007 to August 2008, before the turmoil in the financial markets began.

Exhibit MBP-6 includes the Federal Reserve Bank of Cleveland's adjusted measure of implied inflation based on 10-year U.S. treasury yields. The adjusted implied inflation data from the Federal Reserve Bank of Cleveland includes calculations made to correct for biases in TIPS-derived implied inflation. The lack of liquidity in the TIPS market relative to liquidity in nominal treasuries causes a bias. Also affecting TIPS-derived implied inflation is an inflation risk premium in TIPS returns. In October 2008, the Federal Reserve Bank of Cleveland made the decision to suspend its calculation of adjusted implied inflation because it believed the rush to liquidity was affecting the accuracy of its calculation.

In light of the current uncertainty in the financial markets, I recommend averaging two figures to arrive at an estimate of long-term inflation expectations. The first figure is the average adjusted implied inflation rate for the period from January 2007 through August 2008, representative of expectations prior to the disruption in the financial markets. That figure is 2.68%. The second figure is the February 2009 unadjusted implied inflation based on 20-year treasuries, 1.52%. The average of these two figures is 2.1%. Adding 2.1% to the previously-discussed real GDP growth figure of 3.3% results in a 5.4% long-term nominal growth expectation for the U.S. economy.

Given growth estimates ranging from 5.4% for the U.S. economy to 6.5% for the proxy group of companies and 8.6% for the electric utility industry, 6.5% is a reasonable representation of investor expectations for long-term growth.

Q. Using the selected inputs for the non-constant DCF model, what is the result?

A. Using the inputs identified above, the DCF model shows a cost of equity of 12.1%. A summary of the inputs and the resulting point estimate are shown on Exhibit MBP-7.

C. <u>Capital Asset Pricing Model.</u>

Q. Please explain the CAPM method of determining the cost of equity.

A. The Capital Asset Pricing Model is based on the assumption that by investing in a highly diversified portfolio of assets, an investor can eliminate company-specific risk in that portfolio. Therefore, when evaluating the required return on a single stock, an investor would expect to earn an overall market rate of return, plus or minus an adjustment reflecting the variability in expected returns for the individual stock relative to the overall market. This measure of relative variability or risk is expressed as beta (β). Beta values for publicly traded companies are published by companies such as Value Line and are based on historical observations. A beta value of 1.0 would indicate that a security's returns move in tandem with the market's returns. A value greater than 1.0 would indicate that changes in a security's returns are greater than changes in the market's returns. Under the CAPM, the total rate of return expected by an investor is represented by the sum of a risk-free rate of return (typically measured using U.S. treasury rates) plus a market risk premium for overall market risk, adjusted for the beta value of the individual stock. Mathematically, the CAPM is expressed as follows:

$$K = R_f + \beta(R_m - R_f)$$

in which:

K = required rate of return

R_f = risk free rate of return

β = a security's risk

R_m = required return on market

Q. Please describe the application of the CAPM model in calculating the cost of equity for UNS Electric.

A. Since UNS Electric is not a publicly traded company, the CAPM calculations were made for the previously described peer group of companies.

Q. What risk-free rate is used for the model?

A. For the risk-free rate of return, the average February 2009 rate for 20-year constant-maturity nominal treasuries, 3.83%, was used. Long-term treasury yields are appropriate since investors form expectations of common stock returns based on long-term expected cash flows. This is true even if a particular investor does not intend to hold a stock for the long term.

Q. How were the beta values for each of the proxy companies determined?

A. The beta values for each company are published values, primarily from Value Line.

Q. How was the market risk premium for the CAPM model determined?

A. As discussed above, the market risk premium is equal to the required return on the overall market minus the risk-free rate. It is a fairly common practice to estimate the expected market risk premium using observed differences in historical returns on common stocks and long-term U.S. Treasury bonds. Using historical data for the period

1926-2008 from Morningstar's SBBI 2009 yearbook, a market risk premium of 6.5% was obtained. This estimate represents the arithmetic average of the difference between 20-year treasury returns and average returns on large company stocks.

In order to adequately reflect increased risk premiums required by investors in the current economic environment, I adjusted the 6.5% historical market risk premium upward by an additional 2.29%. This adjustment is based on the observed increase in long-term credit spreads since August 2008, just before the financial markets began to deteriorate. The credit spread selected represents the spread between yields on Baa/BBB rated bonds (a rating representative of the proxy group of companies being used) and 30-year U.S. Treasury bonds. In August 2008, bondholders required a yield on Baa-rated public utility bonds that was 248 basis points above 30-year treasuries. As of January 2009, bondholders were requiring a yield of 477 basis points over 30-year treasuries, an increased premium of 229 basis points. This is shown on Exhibit MBP-10. Since shareholders bear even greater investment risk than bondholders, the risk premium they require should be at least as high as that of bondholders.

The total market risk premium, summing the two components (6.50% and 2.29%), is 8.79%.

Q. What result is obtained from the CAPM model using the inputs described above?

A. As seen in Exhibit MBP-8, the average cost of equity calculated for UNS Electric's peer group is 10.1%.

Q. Why is it appropriate to use the second component of the risk premium?

A. The current extraordinary situation in the capital market results in the unmodified CAPM producing illogical results. If the second component of the risk premium were not included in the calculation, the indicated return on equity would be only 8.4%, far too low to be attractive to rational investors. As of January 2009, the average bond yield for Baa-rated public utility bonds was 7.9%. At an 8.4% return on equity, an investor would be receiving only .5% for the incremental risk of investing in equity instead of debt. Since dividend payments are not contractually required like interest payments are, and since equity investors stand well behind bondholders in the event of bankruptcy or financial restructuring, a substantially higher risk premium is required by equity investors relative to observed bond yields.

It is important to remember that cost of equity "methods cannot be applied in a robotic, mechanistic manner."[2] Rather, such methods must rely on judgment and "objective common-sense economic reasoning."[3] A "robotic" application of the CAPM, under the current extraordinary economic situation, results in a cost of equity barely above average utility bond yields of comparable utilities. Thus, the second component is required to more accurately reflect the cost of equity of UNS Electric.

D. <u>Bond Yield plus Risk Premium Method</u>.

Q. Please explain the bond yield plus risk premium model for determining the cost of equity.

A. The bond yield plus risk premium method of determining the cost of equity is based on the fundamental premise that investors require a higher return for taking on greater investment risk. This relationship of return to risk is often depicted by the Security Market Line which shows the risk and return available on various capital market investments at a given point in time. While an investor's appetite for risk may change

[2] Morin, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) at 443.
[3] Id.

over time, an investor always expects to earn a higher return on corporate debt than on U.S. treasury debt. An even higher rate of return is required on a common stocks since the investor gets only a company's residual returns after all other obligations have been met. The risk premium used in this method of estimating cost of equity is an estimate of difference between the returns required by stockholders and those required by debt holders. The risk premium is added to a required bond yield to arrive at a total cost of equity.

Q. What bond yield have you selected for use in this model?

A. The bond yield selected for use in this model is the yield on Baa-rated utility debt. The average yield on Baa-rated utility bonds for January 2009 was 7.90% based on data from the Mergent Bond Record. This is shown in Exhibit MBP-9.

Q. What method of determining a risk premium have you selected for use in this model?

A. To determine the risk premium, I chose to examine the equity risk premiums implied in the allowed ROEs granted by utility commissions in recent years. By comparing the allowed returns on equity to bond yields, a premium can be calculated for use in this model. Exhibit MBP-11 shows the allowed ROEs for the period from January 2006 through January 2009. As shown in Exhibit MBP-12, the average premium was 4.07% above average utility bond yields.

Q. What return on equity is indicated using the bond yield plus risk premium method?

A. Using the bond yield and risk premium described above, the indicated ROE is 11.97% or 12.0%, rounded.

E. Cost of Equity for Peer Group of Companies.

Q. Please summarize the results of the DCF, CAPM and bond yield plus risk premium methods you chose for determining a return on equity.

A. The returns for UNS Electric's proxy group as indicated by the models are:

DCF	12.1%
CAPM	10.1%
Risk Premium	12.0%

F. Cost of Equity for UNS Electric.

Q. What do you recommend as the appropriate cost of equity for UNS Electric?

A. The average ROE indicated by the three models above is 11.4%. An appropriate cost of equity for UNS Electric would be no lower than the 11.4% calculated for the proxy group of companies because an investment in UNS Electric would be no less risky than investing in the proxy group of companies. In fact, given that it is currently unable to pay a dividend and that its small size makes it more vulnerable to financial stresses, UNS Electric would most likely be viewed by investors as riskier than the proxy group of companies. I recommend 11.4% as a conservative return on equity for UNS Electric.

V. COST OF DEBT.

Q. What cost of debt should be used in determining the Company's weighted average cost of capital?

A. The cost of debt that should be used is 7.05%, which reflects the interest on UNS Electric's $100 million of long-term notes, amortization of debt issuance costs, and half the fees associated with joint revolving credit facility shared with UNS Gas. As explained above, the credit facility balance as of December 31, 2008 is properly excluded from the proposed capital structure because the borrowings were not used to finance the Company's rate base. However, the fees associated with the maintenance of a credit facility are included in the cost of debt as the credit facility provides needed liquidity for the Company's ongoing operations. The fees include commitment fees and amortization of initial fees. This treatment of credit facility fees is consistent with the cost of debt calculations approved by the Arizona Corporation Commission in past rate proceedings for UNS Electric, UNS Gas and TEP.

VI. WEIGHTED AVERAGE COST OF CAPITAL.

Q. What is the Company's weighted average cost of capital?

A. Given the capital structure, cost of debt and cost of equity recommended above, UNS Electric's weighted average cost of capital is 9.04%. The calculation follows.

	Weight of Component	Cost of Component	Weighted Cost of Capital
Common Equity	45.76%	11.40%	5.22%
Long-term Debt	54.24%	7.05%	3.82%
	100.00%		9.04%

VII. SUMMARY OF SCHEDULES.

Q. Please describe the data in Schedule A-3.

A. Schedule A-3 shows the Company's capital structure for the years ending December 31, 2008 (the test year) and December 31, 2007. It also shows the capital structure for the projected year ending December 31, 2009 under both present and proposed rates.

A second version of Schedule A-3 is provided to show, in the projected year columns, the impact of the purchase of the Black Mountain Generating Station ("BMGS"), as described in the Direct Testimony of Mr. Kentton C. Grant.

Q. Please describe the data in Schedules D-1 through D-4.

A. Schedule D-1 shows the Company's actual capital structure and WACC as of December 31, 2008, as well as the proposed capital structure and WACC. Schedule D-1, Page 2 shows the capital structure and WACC for the projected year ending December 13, 2008. Schedule D-2 shows the Company's actual cost of debt as of December 31, 2008, as well as the proposed cost of debt. Schedule D-2, Page 2 shows the projected cost of debt for the year ending December 31, 2009. Schedules D-3 and D-4 show the costs of preferred and common stock, respectively.

Also included are versions of Schedules D-1 through D-4 that show the impact of the proposed purchase of BMGS on proposed test year and projected year costs of capital. The purchase is assumed to be financed with 45.76% common equity and 54.24% long-term debt, consistent with the capital structure recommended above.

Q. Does that conclude your direct testimony?

A. Yes, it does.

EXHIBIT

MBP-1

Because of recent rating actions relating to Syncora Guarantee Inc., MBIA Insurance Corporation and its supported subsidiaries, and MBIA Insurance Corporation of Illinois, ratings appearing on this website may not yet reflect current information. For current information, visit **http://www.moodys.com/guarantors**.

UNS Electric, Inc.

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Research

Page 1 (1 - 2 of 2 records)

Report Type	*Date*	*Title*
Credit Opinion	9 JUL 2008	UNS Electric, Inc.
Rating Action	8 JUL 2008	Moody's assigns Baa3 to UNS Electric/UNS Gas credit facility

Issuer Details

Ticker:
Domicile: UNITED STATES
Previous Name:

Broad Industry: PUBLIC UTILITY
Specific Industry: INTEGRATED ELECTRIC UTILITY

Analyst Information

Analyst: Laura Schumacher
Phone Number: 212-553-3853
Backup Analyst:
Managing Director: William L. Hess
Rating Group: Corporate Finance

Rating Information

Long Term Rating: Baa3, Aug 7 2008 , BACKED Senior Unsecured - Dom Curr
ST Most Recent Rating:
Outlook: Stable, 8 JUL 2008
Watchlist Status: No
Direction:
Date:

Current Rating List

3 records

Important information on Insured ratings

6.5% GTD SR NOTES due 2015

Id	*Class Description*	*Curr*	*Rating*	*Rating Date*	*Rating Action*	*Watch Status*
MDY:831087277	BACKED Senior Unsecured	USD	Baa3	7 AUG 2008	Assign	Not on watch

7.1% GTD SR NOTES due 2023

Id	*Class Description*	*Curr*	*Rating*	*Rating Date*	*Rating Action*	*Watch Status*
MDY:831087280	BACKED Senior Unsecured	USD	Baa3	7 AUG 2008	Assign	Not on watch

GTD REVOLVING CREDIT FACILITY due 2011

Id	*Class Description*	*Curr*	*Rating*	*Rating Date*	*Rating Action*	*Watch Status*
MDY:831045021	BACKED Senior Unsecured Bank Credit Facility	USD	Baa3	8 JUL 2008	Assign	Not on watch

Important information on Insured ratings

Back to Top

EXHIBIT

MBP-2

Credit Opinion: UNS Electric, Inc.

UNS Electric, Inc.

Tucson, Arizona, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Bkd Sr Unsec Bank Credit Facility	Baa3
Ult Parent: UniSource Energy Corporation	
Outlook	Stable
Sr Sec Bank Credit Facility	Ba1

Contacts

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Opinion

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.

On May 27, 2008, the Arizona Corporation Commission (ACC) authorized UNSE a $4 million (2.5%) base rate increase predicated on a 10% ROE and a 48.85% equity ratio. The utility had originally filed for an $8.5 million (5.5%) rate increase based upon on a 11.8% ROE and 48.85% equity ratio. The case was decided in 18 months which is roughly within the time frame of other Arizona rate cases though it is still significantly longer than the one year time frame that states generally attempt to decide rate cases. The test year used in the rate case was year-end June 2006 indicating some regulatory lag will likely continue given additional investments UNSE has already made in its system. Additionally, UNSE was awarded two mechanisms which should help reduce regulatory lag: a Purchased Power and Fuel Adjustment Clause (PPFAC), which has a capped initial factor but allows for a true-up over the subsequent twelve month period; and, the ACC also approved the concept of line extension fees which should result in almost immediate recovery from customers of a portion of the capital costs associated with hooking up new customers.

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. The rating also considers the traditionally challenging regulatory environment in Arizona, but contemplates recent decisions which appear intended to provide more timely recovery of certain costs.

The rating assumes UNSE and UNSG will be reasonably successful in managing their regulatory relationships with an objective of achieving more timely recovery and an opportunity to earn a fair return. The rating also incorporates an expectation that increasing capital expenditures will be financed in a manner consistent with maintaining current financial strength.

The key rating and outlook drivers are as follows:

Regulatory Environment

Virtually all of UNSE's and UNSG's operations are regulated. Moody's generally views a significant percentage of regulated operations as positive for credit quality as regulated cash flows tend to be more stable and predictable than those of unregulated companies. This key factor is tempered somewhat by the regulatory environment of Arizona, which Moody's ranks below average for U.S. regulatory jurisdictions in terms of expectation of timely recovery of costs and predictability of rate decisions.

Fuel and Purchased Power and Gas Recovery

UNSE is essentially a regulated transmission and distribution company. Through May 2008, virtually all of UNSE's power supply needs were met via a fixed-price all requirements contract with Pinnacle West Marketing and Trading (Pinnacle West), a subsidiary of Pinnacle West Capital Corporation (Pinnacle: Baa3 senior unsecured, negative outlook). Recovery of UNSE's cost of purchased power under the Pinnacle West contract had been specifically approved by the ACC and included in UNSE's rates. Going forward, UNSE will procure power primarily from the market via a portfolio of committed long and short-term contracts including a tolling agreement with its affiliated Black Mountain Generating Station, as well as spot purchases. Effective June 1, 2008, UNSE's costs for fuel and purchased power will be recovered via an ACC approved PPFAC with two components: a capped forward component and an uncapped true-up component. Although the initial forward PPFAC component is expected to be capped below the level required to immediately recover UNS Electric's actual cost for fuel and purchased power, the true-up component is uncapped and is intended to recover excess costs over the following twelve month period. Moody's notes that the PPFAC is a new adjustment mechanism for UNSE and we remain cautious regarding the potential for longer deferral periods in the event power costs, and associated deferral balances, should rise significantly above levels anticipated by the ACC.

UNSG recovers the cost of its gas via a purchased gas adjustment (PGA) mechanism that compares the rolling twelve month average actual cost of gas to the cost assumed in base rates. Adjustments for over or under recoveries may be made monthly to the PGA subject to an annual cap. Differences between actual and recovered gas costs accumulate in a "gas bank" and may be recovered or returned via a surcharge or surcredit when the balance in the gas bank exceeds certain limits. These mechanisms have generally limited the level of purchased gas cost deferrals for UNSG.

Regulatory Lag Expected to Continue

While UNSE and UNSG each have fuel recovery mechanisms that are designed to reduce long-term deferrals, the capped PPFAC and growing capital expenditures at UNSE, the significant rate case time frame and use of historic test years are likely to continue to exacerbate UNSE's and UNSG's under-earning situation. While both utilities have an allowed ROE of 10%, it appears unlikely that either will achieve that level in the near-to medium term.

UNSE has a growing capital expenditure plan, increasing its need for further rate relief in the near-term. UNSG has also been attempting more frequent rate relief to support its capital expenditures and its increased operating costs. In UNSG's most recent rate increase, which became effective December 2007, the ACC approved a base rate increase of $5 million (4%) versus a request of $9 million (7%); the request, filed in July 2006, was based on a test year ended December 2005. In February 2008 UNSG filed for a $10 million base rate increase premised on an 11% ROE and a September 2007 test year. The ACC Staff did not accept this filing as it was filed so quickly after UNSG's last rate increase became effective. We anticipate UNSG will file another rate case in the second half of 2008.

Position within UniSource Energy

The rating also recognizes the position of UNSE and UNSG as indirect subsidiaries of UNS through UES. UES is an intermediate holding company with no operations or debt. Debt at UNSE and UNSG is guaranteed by UES, which creates cross-support. UES has not historically received any dividend payments from its utility subsidiaries, and none are anticipated for the foreseeable future. Between 2005 and 2007, UNS contributed approximately $40 million of equity to these subsidiaries in support of their capital programs and to strengthen their balance sheets.

Credit Metrics

UNSE's cash flow credit metrics have historically been strong; generally at or above the upper end of the ranges indicated in Moody's rating methodology for electric utilities rated Baa. For example, the ratio of cash from operations excluding changes in working capital (CFO - Pre WC) to Debt (adjusted in accordance with Moody's standard analytical adjustments), has been above 20% for the past several years. Credit metrics are expected to decline somewhat over the next few years, with CFO - Pre WC / Debt moving into the upper teens. The anticipated weakening in metrics reflects the impact of the termination of UNS Electric's full requirements power supply agreement with Pinnacle as well as its continuing growing capital expenditure program.

UNSG's credit metrics have also historically remained reasonably stable and generally within the ranges indicated for regulated gas distribution utilities rated Baa in Moody's regulated gas distribution methodology. Metrics are expected to improve modestly if reasonable rate relief occurs in the near-term.

Liquidity Profile

UNSE has been incurring significant capital expenditures to service its rapidly growing service territory. In 2007, UNS Electric's cash from operations of approximately $22 million covered approximately half of capital expenditures and payments for services to UniSource. The shortfall was funded via a combination of an equity contribution from UNS and draws on UNSE's and UNSG's shared credit facility.

UNSG has also been investing to provice service in its territory, although in 2006 and 2007 cash from operations of approximately $30 million was sufficient to cover capital expenditures of approximately $23 million and service payments to UNS of approximately $5 million. Capital expenditures are expected to increase slightly in 2008, but then return to historical levels.

Over the last three years, UNS has made $40 million of equity contributions to UNSE and UNSG to help fund capital expenditures. Equity contributions are not expected to be significant over the near-term and capital expenditures are likely to be funded via a combination of internal cash flows and external debt financing.

UNSE has $60 million of senior unsecured notes maturing August 11, 2008. Moody's anticipates UNSE will seek to refinance these notes prior to their maturity. UNS Gas has no debt maturities until 2011.

UNSE's and UNSG's short term liquidity needs are supported by a joint UNS Gas/UNS Electric $60 million credit facility which matures August 2011. Either borrower may borrow up to a maximum of $45 million, so long as the combined amount does not exceed $60 million. As of March 31, 2008, UNSE had $30 million drawn under the facility while UNSG has no short-term borrowings outstanding. The UNS Gas/UNS Electric credit facility contains two financial covenants applicable to each borrower: for UNSE a maximum debt to capital ratio of 65% and a minimum interest coverage ratio of 2.25 times, for UNS Gas a maximum debt to capital ratio of 67%, and a minimum interest coverage of 2.25 times. As of March 31, 2008, UNSG and UNSE were well in compliance with their respective covenants and Moody's anticipates the borrowers will remain comfortably within these limits. The credit facility requires a material adverse change (MAC) representation at each new borrowing. In Moody's opinion, the requirement of a MAC representation significantly increases the risk that the credit facility may not be available when liquidity needs are greatest.

Rating Outlook

The stable outlook reflects the relatively stable cash flows anticipated to be generated by UNSE and UNSG and Moody's assumption that increases in the cost of fuel and purchased power will, in fact, be recovered on a relatively timely basis.

What Could Change the Rating - Up

Given the anticipated decline in credit metrics, the potential for large deferral balances, and the limited liquidity provided by the joint credit facility, due in part to the MAC clause, an upward revision in the rating or outlook is not likely over the near-to-medium term.

What Could Change the Rating - Down

The rating or outlook could be adjusted downward if deferral balances grow to be materially larger than anticipated, or if the time to recovery is significantly extended. Continued regulatory lag at UNSG or UNSE or cost increases which result in a sustained deterioration of financial metrics, for example, a ratio of CFO - Pre WC / Debt falling to below 15% for an extended period, could cause the rating to be adjusted downward.

Rating Factors

UNS Electric, Inc.

821044834

Select Key Ratios for Global Regulated Electric Utilities

Rating	**Aa**	**Aa**	**A**	**A**	**Baa**	**Baa**	**Ba**	**Ba**
Level of Business Risk	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**	**Medium**	**Low**

CFO pre-W/C to Interest (x) [1]	>6	>5	3.5-6.0	3.0-5.7	2.7-5.0	2-4.0	<2.5	<2
CFO pre-W/C to Debt (%) [1]	>30	>22	22-30	12-22	13-25	5-13	<13	<5
CFO pre-W/C - Dividends to Debt (%) [1]	>25	>20	13-25	9-20	8-20	3-10	<10	<3
Total Debt to Book Capitalization (%)	<40	<50	40-60	50-75	50-70	60-75	>60	>70

[1] CFO pre-W/C, which is also referred to as FFO in the Global Regulated Electric Utilities Rating Methodology, is equal to net cash flow from operations less net changes in working capital items

EXHIBIT

MBP-3

UNS Electric, Inc.
Comparable Company Data

	Electric Customers	Common Equity as % of Total Capital	Long-Term Issuer Credit Rating			Market Capitalization ($ Millions)
			S&P	Moody's	Fitch	
ALLETE, Inc. (1)	157,000	58%	BBB+	Baa1	-	$ 1,052
CH Energy Group, Inc. (2)	300,600	52%	A	A2	A-	$ 811
Empire District Electric Company	168,280	42%	BBB-	Baa2	BBB-	$ 598
Hawaiian Electric Industries, Inc. (3)	440,411	45%	BBB	Baa2	-	$ 2,004
MGE Energy, Inc (4)	137,000	55%	AA-	Aa3	-	$ 756
Northeast Utilities	1,902,221	35%	BBB	Baa2	BBB	$ 3,749
NorthWestern Corporation (5)	391,048	46%	BBB	Baa2	BBB-	$ 843
NSTAR	1,169,300	37%	A+	A2	A-	$ 3,897
Portland General Electric Company (6)	811,315	47%	BBB+	Baa2	-	$ 1,218
UIL Holdings Corporation (7)	324,476	39%	-	Baa3	-	$ 756
Median Value	357,762	45.5%	BBB+	Baa2	BBB	$ 948

Notes

(1) No Fitch ratings available for ALLETE, Inc. or its subsidiary companies.

(2) S&P Long-Term Issuer Rating for Central Hudson Gas & Electric Corp. is A. Moody's Long-Term Issuer Rating for Central Hudson Gas & Electric Corp. is A2. Fitch Long-Term Issuer Rating for Central Hudson Gas & Electric Corp. is A-.

(3) Moody's Senior Unsecured Rating for Hawaiian Electric Industries, Inc. is Baa2. No Fitch ratings available for Hawaiian Electric Industries, Inc. or its subsidiary companies.

(4) S&P Long-Term Issuer Rating for Madison Gas and Electric Company is AA-. Moody's Long-Term Issuer Rating for Madison Gas and Electric Company is Aa3. No Fitch ratings available for MGE Energy, Inc. or its subsidiaries.

(5) Moody's Senior Unsecured Rating for NorthWestern Corporation is Baa2.

(6) No Fitch ratings available for Portland General Electric Company.

(7) No S&P or Fitch ratings available for UIL Holdings Corporation or its subsidiaries.

Source: SNL Financial

EXHIBIT

MBP-4

Exhibit MBP-4

UNS Electric, Inc.
Projected Growth Rates for Earnings and Dividends
Comparable Company Group

	Value Line Investment Survey Dividend Growth (3 to 5 Years)	Projected Earnings Growth			
		Value Line Investment Survey (3 to 5 Years)	Zacks Investment Research (5-Year)	SNL Financial (5-Year)	5-Year Growth Rate for DCF
ALLETE, Inc.	2.5%	-0.9%	6.5%	6.5%	3.7%
CH Energy Group, Inc.	0.0%	7.6%	NA	NA	3.8%
Empire District Electric Company	2.3%	12.5%	NA	NA	7.4%
Hawaiian Electric Industries, Inc.	1.2%	8.8%	4.5%	3.0%	4.4%
MGE Energy, Inc	1.2%	2.9%	NA	NA	2.1%
Northeast Utilities	7.3%	5.0%	9.8%	8.5%	7.7%
NorthWestern Corporation	NA	NA	10.0%	10.0%	10.0%
NSTAR	6.6%	7.5%	7.2%	5.5%	6.7%
Portland General Electric Company	5.5%	10.7%	6.3%	5.3%	6.9%
UIL Holdings Corporation	0.0%	3.2%	6.4%	4.8%	3.6%
Median Value for Group	2.3%	7.5%	6.5%	5.5%	5.5%

Notes:

Dividend and earnings growth projections not available from Value Line for NorthWestern Corporation

Earnings growth projections not available from Zacks Investment Research for CH Energy Group, Inc., Empire District Electric Company, and MGE Energy, Inc.

Earnings growth projections not available from SNL Financial for CH Energy Group, Inc., Empire District Electric Company, and MGE Energy, Inc.

Sources: Value Line, Zacks Investment Research, SNL Financial

EXHIBIT

MBP-5

Exhibit MPB-5

UNS Electric, Inc.
Calculation of Expected First-Year Dividend
Comparable Company Group

	Current Quarterly Dividend	Last Change in Dividend Payment	Recent Ex-Dividend Date	5-Year Growth Rate for DCF	Expected Quarterly Dividends (as of 2/28/09) 1Q 2009	2Q 2009	3Q 2009	4Q 2009	1Q 2010	Expected First-Year Dividend
ALLETE, Inc.	$ 0.440	1Q 2009	02/11/09	3.7%		$0.440	$0.440	$0.440	$0.456	$1.776
CH Energy Group, Inc.	$ 0.540	None Recent	01/07/09	3.8%		$0.540	$0.540	$0.540	$0.540	$2.160
Empire District Electric Company	$ 0.320	None Recent	02/25/09	7.4%		$0.320	$0.320	$0.320	$0.320	$1.280
Hawaiian Electric Industries, Inc.	$ 0.310	None Recent	02/26/09	4.4%		$0.310	$0.310	$0.310	$0.310	$1.240
MGE Energy, Inc	$ 0.362	3Q 2008	02/25/09	2.1%		$0.362	$0.369	$0.369	$0.369	$1.469
Northeast Utilities	$ 0.238	1Q 2009	02/25/09	7.7%		$0.238	$0.238	$0.238	$0.256	$0.968
NorthWestern Corporation	$ 0.335	1Q 2009	02/13/09	10.0%		$0.335	$0.335	$0.335	$0.369	$1.374
NSTAR	$ 0.375	1Q 2009	01/07/09	6.7%		$0.375	$0.375	$0.375	$0.400	$1.525
Portland General Electric Company	$ 0.245	2Q 2008	12/23/08	6.9%	$0.245	$0.262	$0.262	$0.262		$1.031
UIL Holdings Corporation	$ 0.432	None Recent	12/10/08	3.6%	$0.432	$0.432	$0.432	$0.432		$1.728

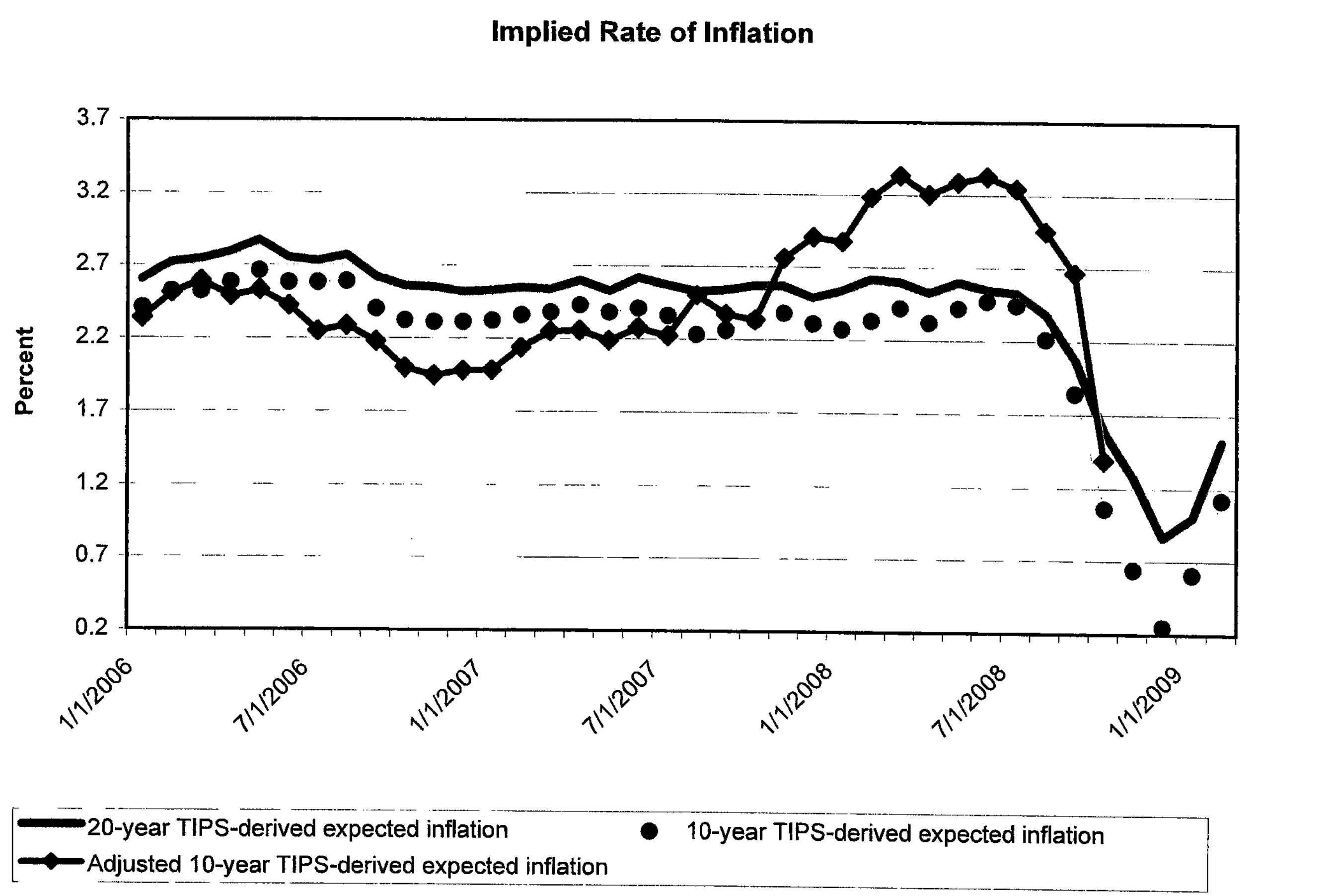
Source: Dividend information is from Yahoo! Finance and SNL Financial

EXHIBIT

MBP-6

Exhibit MBP-6

UNS Electric, Inc.
Implied Rate of Inflation from U.S. Treasury Securities



Sources: Federal Reserve Bank of Cleveland and Federal Reserve Board of Governors

EXHIBIT

MBP-7

Exhibit MBP-7

UNS Electric, Inc.
Non-Constant Growth DCF Analysis
Comparable Company Group

	Recent Avg. Share Price	Projected Dividends					Long-Term Growth	Estimated Cost of Equity
		Year 1	Year 2	Year 3	Year 4	Year 5		
ALLETE, Inc.	$ 29.66	$1.78	$1.84	$1.91	$1.98	$2.05	6.5%	11.9%
CH Energy Group, Inc.	$ 46.94	$2.16	$2.24	$2.33	$2.42	$2.51	6.5%	10.7%
Empire District Electric Company	$ 16.12	$1.28	$1.37	$1.48	$1.58	$1.70	6.5%	14.7%
Hawaiian Electric Industries, Inc.	$ 18.89	$1.24	$1.29	$1.35	$1.41	$1.47	6.5%	12.6%
MGE Energy, Inc	$ 30.94	$1.47	$1.50	$1.53	$1.56	$1.59	6.5%	10.6%
Northeast Utilities	$ 23.15	$0.97	$1.04	$1.12	$1.21	$1.30	6.5%	10.8%
NorthWestern Corporation	$ 22.62	$1.37	$1.51	$1.66	$1.83	$2.01	6.5%	13.3%
NSTAR	$ 33.16	$1.53	$1.63	$1.74	$1.85	$1.98	6.5%	11.1%
Portland General Electric Company	$ 17.74	$1.03	$1.10	$1.18	$1.26	$1.35	6.5%	12.4%
UIL Holdings Corporation	$ 23.99	$1.73	$1.79	$1.85	$1.92	$1.99	6.5%	13.1%
Average Value for Group								12.1%

Source: Share prices are from Yahoo! Finance

EXHIBIT

MBP-8

Exhibit MBP-8

UNS Electric, Inc.
Application of Capital Asset Pricing Model
Comparable Company Group
(Using February 2009 Risk-Free Rate and Adjusted Risk Premium)

	Risk-Free Rate		Beta			Equity Risk Premium		Risk Premium Adjustment			Estimated Cost of Equity
ALLETE, Inc.	3.83%	+	0.75	x	(	6.50%	+	2.29%	)	=	10.4%
CH Energy Group, Inc.	3.83%	+	0.70	x	(	6.50%	+	2.29%	)	=	10.0%
Empire District Electric Company	3.83%	+	0.75	x	(	6.50%	+	2.29%	)	=	10.4%
Hawaiian Electric Industries, Inc.	3.83%	+	0.70	x	(	6.50%	+	2.29%	)	=	10.0%
MGE Energy, Inc	3.83%	+	0.70	x	(	6.50%	+	2.29%	)	=	10.0%
Northeast Utilities	3.83%	+	0.75	x	(	6.50%	+	2.29%	)	=	10.4%
NorthWestern Corporation	3.83%	+	0.68	x	(	6.50%	+	2.29%	)	=	9.8%
NSTAR	3.83%	+	0.70	x	(	6.50%	+	2.29%	)	=	10.0%
Portland General Electric Company	3.83%	+	0.65	x	(	6.50%	+	2.29%	)	=	9.5%
UIL Holdings Corporation	3.83%	+	0.70	x	(	6.50%	+	2.29%	)	=	10.0%
Average Value for Group											10.1%

Notes
Risk-free rate is 20-Year Treasury Constant Maturity Rate (Average for February 2009).

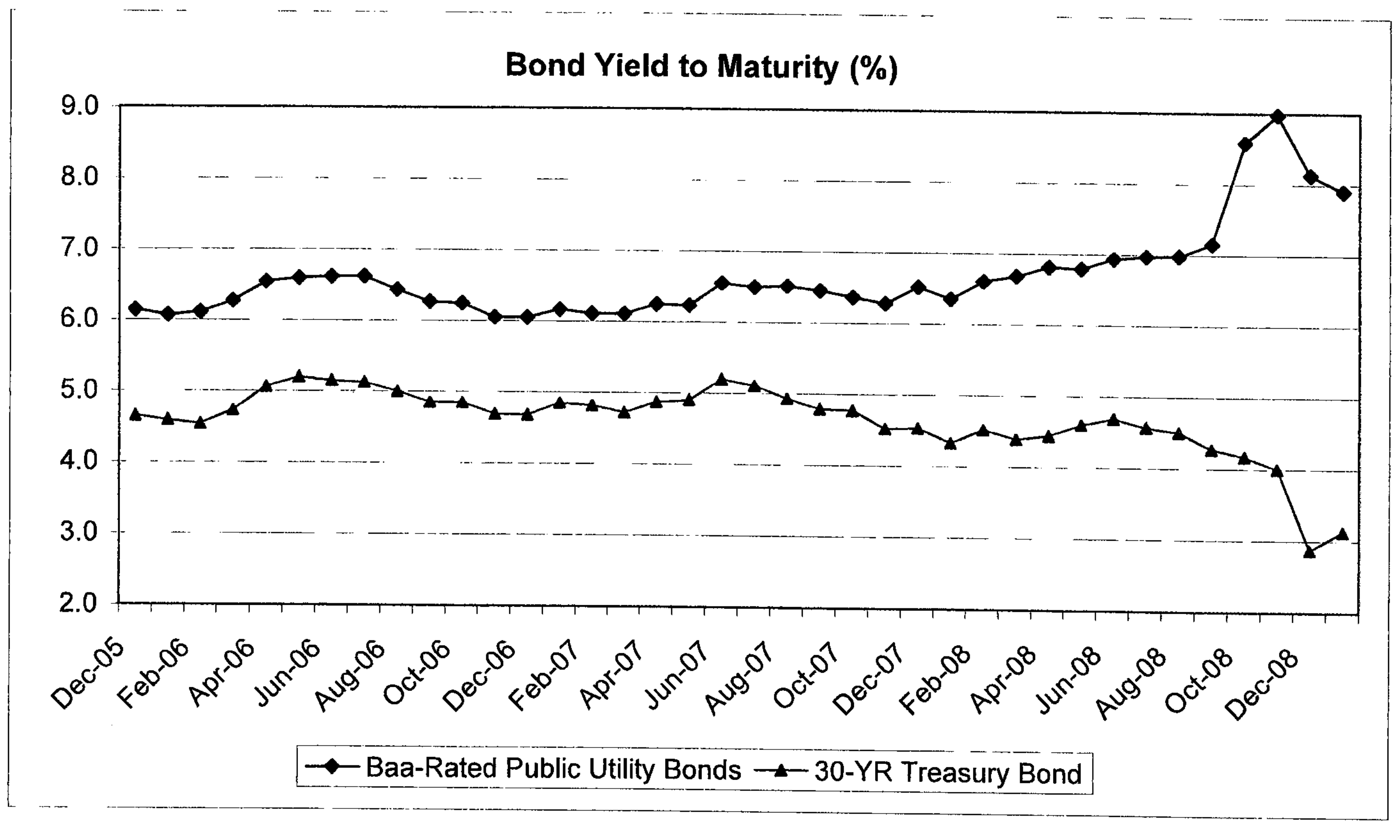
Sources: 20-Year U.S. Treasury Constant Maturity Rate is from the Federal Reserve Board of Governors Web site (www.federalreserve.gov). Beta value for NorthWestern Corporation is from Yahoo! Finance. All other beta values are from Value Line.
Equity Risk Premium is from Morningstar SBBI 2009 Yearbook.
Equity Risk Premium = 6.5% Equity Risk Premium + 2.29% Risk Premium Adjustment

EXHIBIT

MBP-9

Exhibit MBP-9

UNS Electric, Inc.
Yields on Baa Public Utility Bonds and U.S. Treasury Bonds



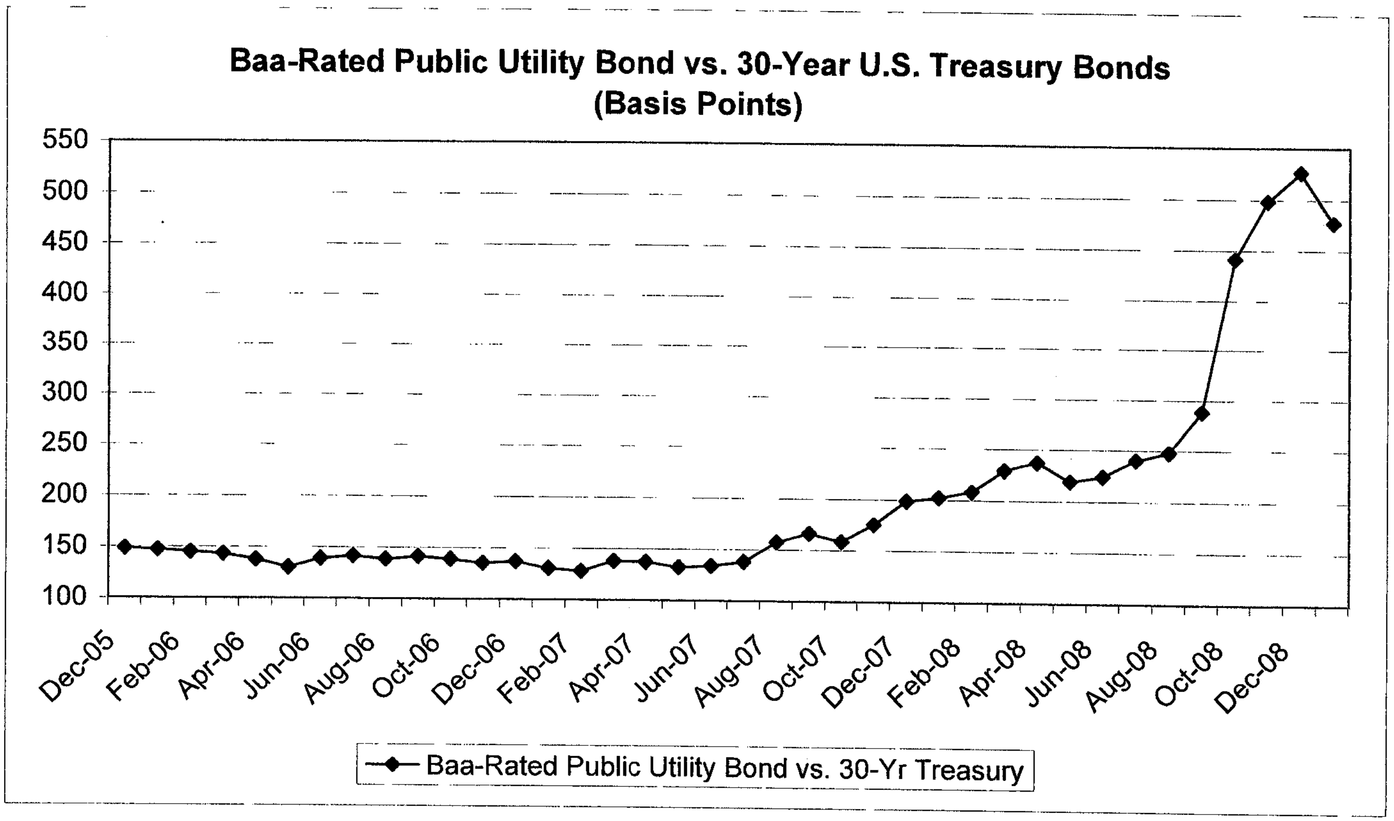
Sources: Public Utility bond yields are from Mergent Bond Record. 30-Yr. U.S. Treasury bond yields are from Mergent Bond Record (Dec 2005 - Jan 2006 data) and the Federal Reserve Board of Governors Web site (www.federalreserve.gov, Feb 2006 - January 2009 data).

EXHIBIT

MBP-10

Exhibit MPB-10

UNS Electric, Inc.
Public Utility Bond Credit Spreads



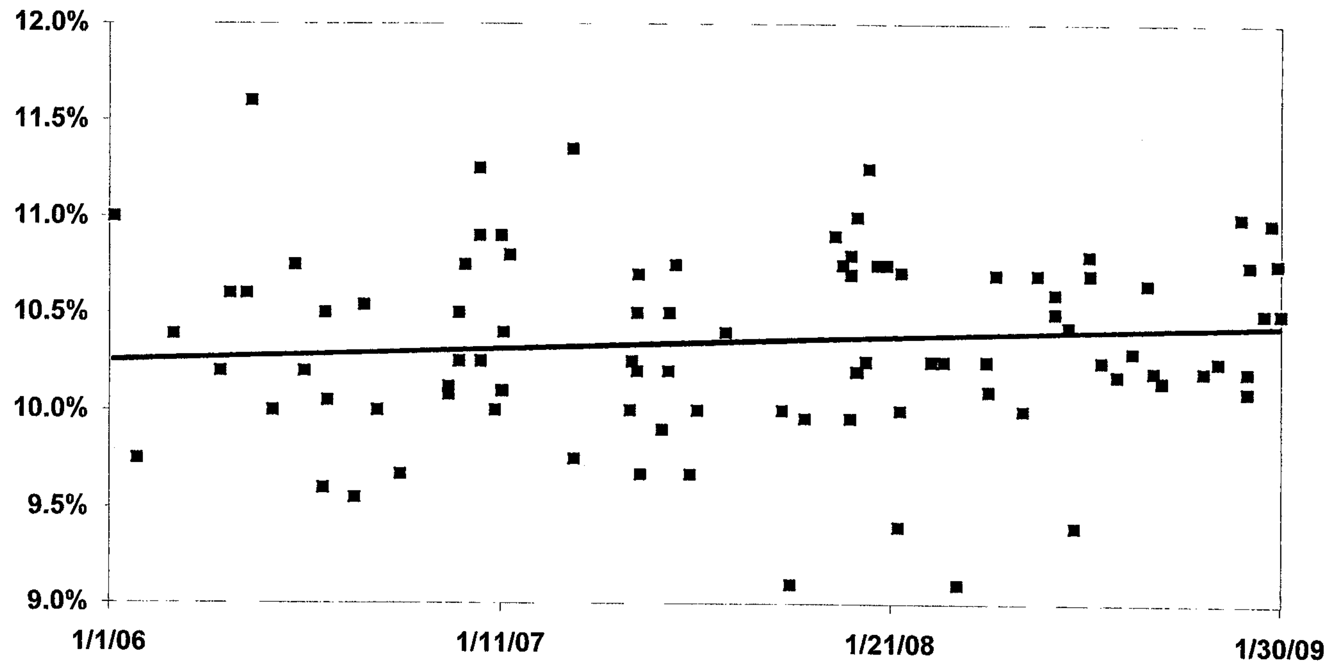
Sources: Public Utility bond yields are from Mergent Bond Record. 30-Yr. U.S. Treasury bond yields are from Mergent Bond Record (Dec 2005 - Jan 2006 data) and the Federal Reserve Board of Governors Web site (www.federalreserve.gov, Feb 2006 - January 2009 data).

EXHIBIT

MBP-11

Exhibit MBP-11

UNS Electric, Inc.
Allowed ROEs for Electric Utilities



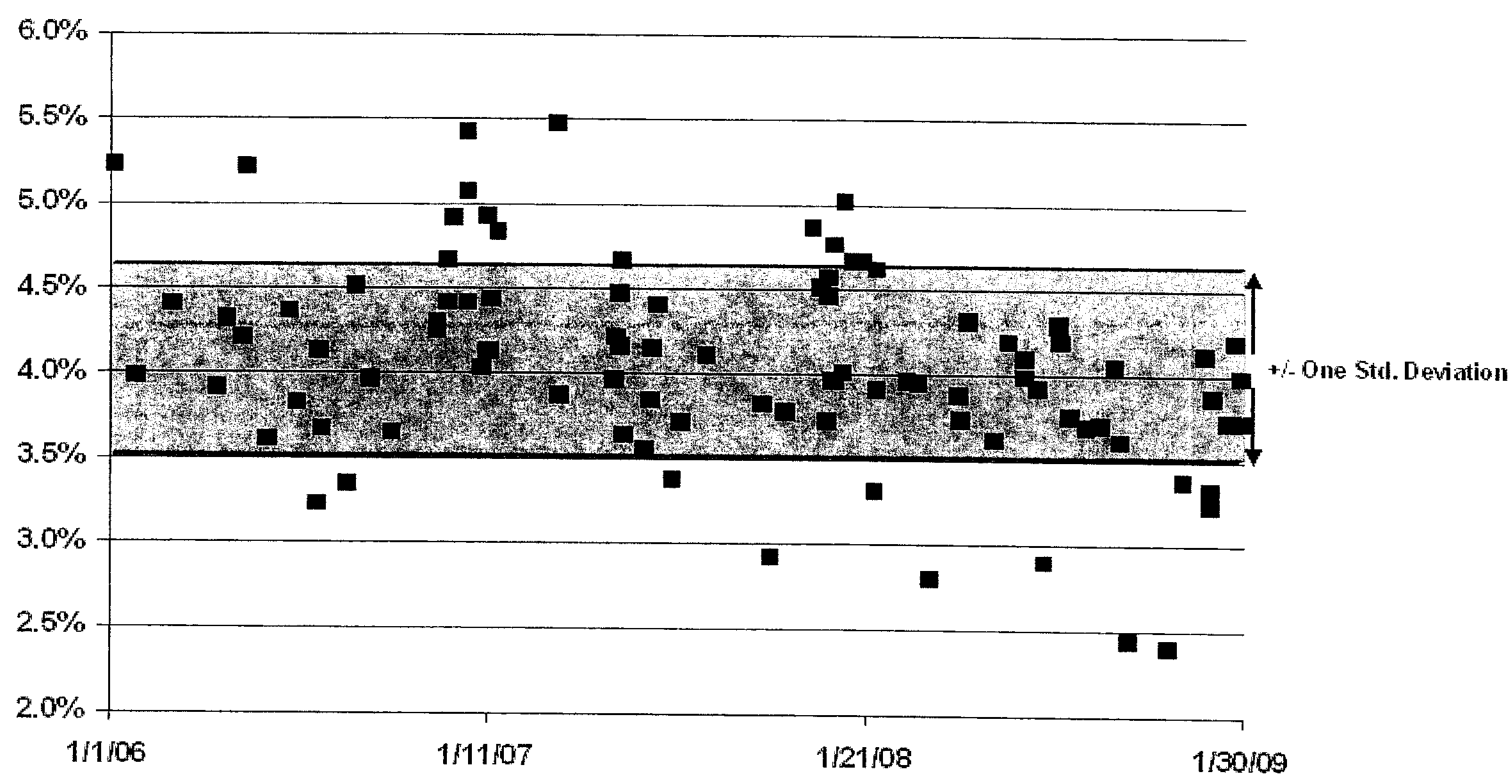
Note: Trend line shown derived from least-squares linear regression.
Source: SNL Financial.

EXHIBIT

MBP-12

Exhibit MBP - 12

UNS Electric, Inc.
Allowed ROE Risk Premium over Avg. Public Utility Bond Yield



Sources: Allowed ROE risk premiums from SNL Financial; Average Public Utility bond yields from Mergent Bond Record.

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

EXHIBIT
tabbies
UNSE-23
ADMITTED

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rebuttal Testimony of

Martha B. Pritz

on Behalf of

UNS Electric, Inc.

December 11, 2009

TABLE OF CONTENTS

I. INTRODUCTION.

Q. Please state your name and business address.

A. My name is Martha B. Pritz. My business address is One South Church Avenue, Tucson, AZ 85701.

Q. What is the Purpose of your Rebuttal Testimony?

A. The purpose of my Rebuttal Testimony is to rebut portions of the Direct Testimony of Mr. David C. Parcell filed by the Arizona Corporation Commission ("Commission") Staff ("Staff"), as well as portions of the Direct Testimony of Mr. William A. Rigsby filed by the Residential Utility Consumers Office ("RUCO"). The main topic addressed in my Rebuttal Testimony is the cost of common equity capital used in calculating the weighted average cost of capital ("WACC") of UNS Electric, Inc. ("UNS Electric" or the "Company").

II. COST OF COMMON EQUITY CAPITAL.

A. Rebuttal of Staff Witness Mr. David C. Parcell.

Q. Please summarize your assessment of Mr. Parcell's Direct Testimony.

A. While Mr. Parcell agrees with the Company's recommendations regarding the cost of debt and capital structure, he recommends a lower cost of common equity resulting in a lower weighted average cost of capital. He suggests a cost of equity of just 10.0%, 140 basis points below the 11.4% recommended by the Company. Because Mr. Parcell uses a cost of equity of just 10.0%, his recommended WACC is only 8.4%, 64 basis points below that determined by the Company. The cost of equity recommended by Mr. Parcell is low due to the use of inappropriate inputs in several of the methods upon which he relies. In addition, one of the methods he uses, the Comparable Earnings method, does not provide relevant information for reasons discussed below.

Q. **Please comment on Mr. Parcell's use of the discounted cash flow ("DCF") method of estimating the cost of equity for UNS Electric.**

A. Mr. Parcell has chosen to use the constant growth form of the DCF model for which dividend yield and expected rate of dividend growth are the inputs. Mr. Parcell presents several weak sets of data as indicators of dividend growth in his DCF calculation, resulting in too low an estimate of the Company's cost of equity.

Q. **Why do you consider some of the sets of data "weak"?**

A. To calculate the growth rate, Mr. Parcell used an average of five growth rates, including two based solely on historical data. One historical data set shows historical retention growth and another shows historical growth in earnings, dividends and book value. Both sets of figures are taken from the Value Line Investment Survey ("Value Line"). Mr. Parcell also includes Value Line's forward-looking estimates of the same measures. Since Value Line's analysts would have taken historical data into account in preparing the forward-looking estimates, the inclusion of historical data again as a separate data source is redundant and produces a downward-biased estimate of growth for the groups of companies he examined.

Q. **Had Mr. Parcell not included the historical data in his estimates of average growth rates, would his calculated range of DCF rates have been closer to the rate calculated by the Company?**

A. Yes, by excluding the historical data, Mr. Parcell's range of DCF outcomes would have been closer to that of the Company. The range would have been 9.9% to 10.7% instead of the 9.4% to 10.1% shown in his Direct Testimony.

Q. Is there anything else about the various growth rates included in Mr. Parcell's calculation of average growth that concerns you?

A. Yes, in the case of the retention growth figures used, the median and mean values for the proxy groups are very low – ranging from 2.8% down to only 1.8%. Since Mr. Parcell has chosen to use a single-stage DCF model, he's asserting that these rates are valid indicators of growth for an infinite number of periods into the future. Furthermore, the retention growth figures are stated in nominal terms. If expected inflation were subtracted from these amounts to get indicated real growth, the rates would be lower still, even negative in some cases. When one considers that real gross domestic product ("GDP") growth has been 3.3% per year for the period from 1929 to 2008, the growth figures presented by Mr. Parcell are unreasonable.

Q. Had Mr. Parcell not included the retention growth data in his estimates of average growth rates, would his calculated range of DCF rates have been closer to the rate calculated by the Company?

A. Yes, by excluding the earnings retention data, Mr. Parcell's range of DCF outcomes would have been closer to that of the Company. The range would have been 10.3% to 11.1% instead of the 9.4% to 10.1% shown in his Direct Testimony.

Q. Please respond to Mr. Parcell's comments on your application of the DCF model.

A. Mr. Parcell is concerned that I did not use historical growth along with forward-looking estimates of growth in arriving at a short-term growth rate for my multi-stage DCF model. As stated above, it is safe to say that analysts providing forward-looking growth estimates will have already considered historical growth in determining the outlook for a company. To average forward-looking growth estimates with historical growth overemphasizes the impact of historical growth. Furthermore, Dr. Roger Morin, in his textbook, *New Regulatory Finance,* explains, "Past growth rates in earnings or dividends may be misleading, since past growth rates may reflect changes in the underlying relevant variables that cannot reasonably be expected to continue in the future, or may fail to capture known future changes."[1]

In short, while companies' historical growth rates (dividend per share growth, earnings growth, and book value per share growth) contain information that should be considered in forming forward-looking projections, blindly plugging unadjusted historical growth rates into a DCF model does not lead to a meaningful estimate of future dividend growth.

Q. Please address Mr. Parcell's concern that analysts' forecasts of growth rates might be biased, subject to conflicts of interest, or optimistic.

A. I used data from three sources. The first, Value Line, is an independent firm. The other two, Zacks Investment Research ("Zacks") and SNL Financial ("SNL"), compile data from a number of analysts in order to avoid bias. By giving weight to all three of these sources in determining a short-term growth rate, the likelihood of any material bias was avoided.

In addition, regulation that became effective in the early 2000s has reduced the likelihood of analysts' projections reflecting conflicts of interest. In a recent paper, *Conflicts of interest and analysts behavior: Evidence from recent changes in regulation*, the authors conclude, "...the recent efforts of regulators have helped neutralize analysts' conflicts of interest."[2]

Also, regardless of whether some analysts' forecasts of growth may have been high (or low) in the past, there is an abundance of academic research that has shown analysts'

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[1] Morin, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) at 292.

[2] Hovakimian (Baruch College) and Saenyasiri (Arizona State University), *Conflicts of interest and analyst behavior: Evidence from recent changes in regulation* (2009) at 24. Paper is available at http://ssrn.com/abstract=1133102.

forecasts of earnings growth to be superior to estimates based on historical growth. Cragg and Malkiel, in *Expectations and the Structure of Share Prices*, compared analysts' growth forecasts to forecasts based on historical growth and found that, "... on balance the security analysts tended to produce stronger predictions."[3]

A study by Brown and Rozeff published in *The Journal of Finance* concludes, "Given rational market expectations, our evidence of analyst superiority over time series models means that analysts' forecasts should be used in studies of firm valuation, cost of capital and stock price changes until forecasts superior to those of the analysts are found."[4]

Finally, it is unlikely that any optimism that has been shown in analysts' estimates of growth would be a significant factor in a relatively stable industry such as regulated utilities.

Q. Mr. Parcell suggests that rather than using historical GDP growth as a one of the data points in determining a long-term growth rate for your DCF model, one could also consider projections of GDP growth. Would that greatly change the cost of equity indicated by the DCF model?

A. No, it would not. I arrived at a 6.5% long-term growth figure by considering the 5-year earnings growth projections for the proxy group of companies (6.5%), the outlook for the electric utility industry (8.6%), and an estimate of GDP growth (5.4%). These three figures average approximately 6.8%, but I selected the slightly lower estimate of 6.5%. If I were to replace my estimate of GDP growth with the average of the projections proposed by Mr. Parcell, this would still produce an average growth rate slightly above 6.5%.

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[3] Cragg and Malkiel, *Expectations and the Structure of Share Prices* (University of Chicago Press 1982) at 85.
[4] Brown and Rozeff, "The Superiority of Analyst Forecasts as Measures of Expectations: Evidence From Earnings," *The Journal of Finance* Vol. XXXIII (1978): 13.

Q. Please summarize any concerns you have regarding Mr. Parcell's use of the Comparable Earnings ("CE") method of estimating cost of equity.

A. The comparable earnings method suffers from a shortcoming that makes it inappropriate for determining forward-looking cost of equity expectations. Also, Mr. Parcell apparently has no qualms about restricting UNS Electric's return on equity in order to produce a market to book value ratio much lower than that of its peers.

Q. Why are CE-based returns inappropriate for determining forward-looking cost of equity expectations?

A. One of the problematic aspects of the CE approach is that it attempts to identify investors' opportunity cost, which Mr. Parcell explains is "the prospective return available to investors from alternative investments of similar risk", but it tries to do so using historical accounting returns. Accounting returns do not reflect the always-changing, market-based returns sought by investors based on alternative investments opportunities. Likewise, comparing the market value of stock to an accounting-based book value is of limited value in a cost of capital analysis. Mr. Parcell includes prospective as well as historical returns in his calculations, but the problem associated with using accounting-based returns on equity ("ROE") persists.

In his recommendation, Mr. Parcell states, "An earned return of 9.5 percent to 10.5 percent should thus result in market-to-book ratios of over 100 percent."Apparently Mr. Parcell believes that a market-to-book ratio that is more than a few percentage points over 100% is excessive. He also states clearly that anything over 150% is "indicative of earnings that exceed the utility's reasonable cost of capital", yet 3 of the 4 average market-to-book ratios he cites (using his two proxy groups and two time periods) are above 150%.

Q. Please address Mr. Parcell's capital asset pricing model ("CAPM") analysis.

A. Mr. Parcell arrives at a CAPM-indicated range of 7.6 to 8.3% using a risk-free rate of 4.28%, Value Line betas for companies in the proxy groups, and a risk premium that was determined by averaging three estimates. While the risk-free rate and the beta values do not cause concern, the risk premium calculation does.

Q. Before discussing your concern about the risk premium calculation, are there any errors in the CAPM estimate that should be noted?

A. Yes. In Schedule 9 of Mr. Parcell's testimony, the beta value for NorthWestern Corp. is shown as zero. Based on Yahoo! Finance, the value should be shown as 0.65. Once that change is made, the mean CAPM rate for the Pritz Comparable Company Group is 8.0% instead of the 7.6% shown on the schedule, which would bring the CAPM range from 7.6- 8.3% to 8.0-8.3%.

Q. Now, please explain why the risk premium used by Mr. Parcell causes concern.

A. Of the three estimates Mr. Parcell averaged to arrive at a risk premium, two incorrectly rely on a comparison of S&P 500 returns to *total* returns for long-term government bonds. A more appropriate comparison would be of S&P 500 returns to long-term government bond *income* returns. In its 2009 Ibbotson SBBI Valuation Yearbook, Morningstar states:

> "Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation... Price changes in bonds due to unanticipated changes in yields introduce price risk into the total return. Therefore, the total return on the bond series does not represent the riskless rate of return. The income return better represents the unbiased estimate of the purely riskless rate of return, since an investor can hold a bond to maturity and be entitled to the income return with no capital loss."

Of the two estimates of the risk premium that incorrectly use total bond returns, one of the estimates suffers from a second problem in that it is calculated using geometric means of historical returns. It is inappropriate to use the geometric mean of an historical data series if the result is to be used as a forward-looking estimate.

Q. Why is it wrong to use a geometric mean of historical return data in estimating forward looking returns or risk premia?

A. While a geometric mean is useful in describing returns for historical periods, it is well-accepted in financial theory that the arithmetic mean of an historical data series is a stronger estimate of future returns. For example, in the textbook *Investments*, by Bodie, Kane and Marcus, the authors state, "There is a general property: geometric averages never exceed arithmetic averages, and the difference between the two becomes greater as the variability of period-by-period returns becomes greater."[5]

They also state, "The geometric average has considerable appeal because it represents exactly the constant rate of return we would have needed to earn in each year to match actual performance over some past investment period. It is an excellent measure of *past* performance. However, if our focus is on future performance, then the arithmetic average is the statistic of interest because it is an unbiased estimate of the portfolio's expected future return (assuming of course, that the expected return does not change over time.) In contrast, because the geometric return over a sample period is always less than the arithmetic mean, it constitutes a downward-biased estimator of the stock's expected return in any future year."[6]

Furthermore, Morningstar, Inc. ("Morningstar"), which Mr. Parcell uses as his source of data for calculations of arithmetic and geometric means, provides its own Long-Horizon

[5] Bodie, Kane, Marcus, *Investments* (Richard D. Irwin, Inc. 1989) at 721.
[6] Bodie, Kane, Marcus, *Investments* (Richard D. Irwin, Inc. 1989) at 721-722.

Expected Equity Risk Premium (Historical) based solely on arithmetic mean returns. In the documentation provided in Morningstar's *Ibbotson SBBI 2009 Valuation Yearbook*, it clearly states that only arithmetic mean returns are appropriate in determining risk premia: "The equity risk premium data presented in this book are arithmetic average risk premia as opposed to geometric average risk premia. The arithmetic average equity risk premium can be demonstrated to be most appropriate when discounting future cash flows. For use as the expected equity risk premium in either the CAPM or the building block approach, the arithmetic mean or the simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number."[7]

While I agree with Mr. Parcell that investors have access to both geometric and arithmetic means for returns over various timeframes, I would also point out that investors have access to financial literature, like that shown above, that would lead them to use the arithmetic averages to form forward expectations.

Q. Is the Long-Horizon Expected Equity Risk Premium (Historical) provided by Morningstar the 6.5% used in the Company's CAPM?

A. Yes, it is.

Q. Had Mr. Parcell calculated the risk premium without including the geometric mean -- in other words by averaging the other two risk premiums he presented -- what would the impact be on the CAPM results for the two proxy groups used?

A. The CAPM results would have indicated a range of 8.4-8.8% instead of 8.0-8.3% (as corrected).

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[7] *2009 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook* (Morningstar, Inc. 2009) at 59.

Q. Had Mr. Parcell used the one risk premium that he calculated that had neither the total return problem nor the geometric mean problem, what total CAPM rate of equity would result?

A. A range of 8.7 to 9.1% would have been indicated, using the two proxy groups (as corrected).

Q. Can you comment on the relationship of the CAPM range recommended by Mr. Parcell and the average yield on public utility bonds?

A. The average yield on public utility bonds as of September 2009 was 5.6%. The CAPM range recommended, 8.0-8.3% (as corrected), is only 2.4-2.7% above that. At first glance, it appears that investors would be compensated for the additional risk of an equity investment relative to the risk of a debt instrument. However, an examination of historical relationships between allowed ROEs and utility bond yields proves that wrong. As shown in my Direct Testimony, the average premium for the period from January 2006 through January 2009 was 4.0%, well above the 2.4-2.7% based on Mr. Parcell's CAPM analysis.

Q. Based on the fact that the CAPM-based rates are so very low (so low as to fail to represent investor expectations) with respect to other cost of equity estimates provided by parties to the rate case, should they be given much, if any, weight in the final determination of a return on equity?

A. No, they should not. As calculated, and without any adjustments, the CAPM-indicated rates should not be given weight in the determination of a return on equity. This is consistent with the approach taken by Mr. Parcell. While he states that the results from his CAPM analysis should not be disregarded, his ROE recommendation appears to be based only on the results of the other methods he used. The entire return range Mr. Parcell calculated using CAPM is well below the ranges indicated by his other methods.

Q. Would you please address the questions Mr. Parcell raised about the assumptions and inputs you used for CAPM.

A. Yes. His first concern is the use of the arithmetic average, rather than geometric average, of historical differences between large company stock returns and long-term Treasury bonds. I addressed the topic at length above in stating my own concerns about Staff's CAPM calculation.

Q. What about his concern with your use of "income returns" rather than "total returns" for Treasury bonds?

A. As discussed in my review of Mr. Parcell's CAPM equity risk premium, total returns are not an estimate of a riskless rate of return. Income returns show returns that are not distorted by price risk. Therefore, Treasury bond income returns are the appropriate data for use in estimating risk premia.

Q. Please respond to Mr. Parcell's concern about the use of a risk premium adjustment.

A. As stated in my Direct Testimony, the CAPM-indicated cost of equity at that time (before any risk premium adjustment) was 8.4%. As that was only 50 basis points above the average bond yields for Baa-rated (low investment grade) public utility bonds as of January 2009, it was clear that 8.4% would not be an equity return acceptable to investors. Since investors take on more risk as they move from Treasury bonds to utility bonds and then to utility stocks, it was clearly necessary to adjust the risk premium applicable to equity investment. In doing so, I used the spreads between 30-year Treasury yields and Baa-rated public utility bond yields as a conservative estimate of the additional amount that would be required by an equity investor at the time my analysis was performed.

Since that time, spreads between 30-year Treasury yields and Baa-rated public utility bond yields have narrowed to a more normal level. The problem remains, however, that an updated CAPM-based estimate of the cost of equity is still too low with respect to Baa-rated utility bond yields to be acceptable to investors.

Q. If the Company had ignored CAPM and simply based its final recommendation of ROE on the other methods it employed, as Mr. Parcell did, would the indicated return have been higher or lower?

A. Had the company based its recommendation for allowed ROE only on the results of the DCF and bond yield plus risk premium methods, the indicated return would have been approximately 60 basis points higher – about 12.0%.

Q. By adjusting the CAPM return initially calculated and including this result in its determination of the cost of equity, did the Company actually recommend a lower return than it would have without adjusting CAPM?

A. Yes.

Q. Did Mr. Parcell comment on the Company's use of the bond yield plus premium method?

A. Yes. Mr. Parcell notes that in my Direct Testimony, I compared average allowed ROEs and yields on public utility bonds for the period 2006 – January 2009 to determine a premium that was then added to the yield for appropriately-rated utility bonds, which in this case is Baa. He observes that yields on Baa public utility bonds are now about 6.1%, down from the 7.9% rate seen at the time my Direct Testimony was prepared. Using this lower bond yield, the cost of equity indicated is 10.2%.

Q. How would a 10.2% ROE compare to the actual allowed ROEs from the last several years?

A. Using data from SNL, the average allowed ROEs for electric utilities are as follows:

2006 – August 2009 - 10.4%

January – August 2009 - 10.5%

Given that UNS Electric is a smaller, riskier company than many of the companies included in the allowed ROE data above, and given that UNS Electric's debt rating is the lowest possible investment grade rating, one would expect that investors would require a return higher than the averages observed.

Q. The average Baa public utility bond yield was 7.9% for January 2009 and 6.1% for September 2009. What was the average Baa public utility bond yield for the period from January 2006 through January 2009 (the same period for which the risk premium was calculated)?

A. 6.7%.

Q. What cost of equity would result if the January 2006 to January 2009 average Baa public utility bond yield were used in the bond yield plus risk premium calculation along with the 4.07% risk premium for the same time-frame?

A. 10.8%.

Q. Is your original recommendation still reasonable in light of risks faced by UNS Electric relative to larger, publicly traded companies?

A. Yes, it is.

B. <u>Rebuttal of RUCO Witness Mr. William A. Rigsby.</u>

Q. Please summarize your assessment of Mr. Rigsby's Direct Testimony.

A. Mr. Rigsby's determinations of the appropriate cost of debt and capital structure for UNS Electric were the same as those proposed by the Company. On the other hand, his recommendation of 9.25% for the cost of equity is far below that proposed by the Company. Mr. Rigsby uses both a CAPM analysis and a single-stage DCF model in reaching his recommendation. In each case, inappropriate inputs to the models result in greatly understated ROEs.

Q. Please discuss Mr. Rigsby's use of the CAPM, starting with the risk-free rate of return he used.

A. Mr. Rigsby determined a risk-free rate using an average of yields on a 5-year Treasury instrument on the basis that the 5-year timeframe approximates the timeframe for a company's filing of rate cases. The average yield he used was 2.41%.

Q. Is that consistent with recommendations made in financial literature regarding an appropriate Treasury instrument?

A. No. As Roger Morin explains in his textbook, *New Regulatory Finance*, "As a proxy for the risk-free rate, long-term rates are the relevant benchmarks when determining the cost of common equity rather than short-term or intermediate-term interest rates." Mr. Morin goes on to explain that "The expected common stock return is based on long-term cash flows, regardless of an individual's holding time period."

Q. Had Mr. Rigsby used a long-term Treasury yield in his CAPM model, would the range of returns he estimated have been higher or lower?

A. The range would have been higher. As can be seen from the information provided by Mr. Rigsby on his Attachment C, the average 30-year Treasury rate for the period from August 12, 2009 through September 20, 2009, the same period he used, was 4.25%, 184 basis points higher than the average yield on 5-year Treasuries. Using the correct risk-free rate in his model would have added 184 basis points to the indicated ROE.

Q. Do you agree with Mr. Rigsby's calculation of the market risk premium?

A. No, I strongly disagree with his calculation for several reasons. First, he has chosen to compare S&P 500 returns to *intermediate-term* Treasury *total* returns rather than *long-term* Treasury *income* returns. Both the use of intermediate-term Treasury returns and the use of total returns are inappropriate. Second, in determining the equity risk premium, Mr. Rigsby included geometric means of historical data series, which is also inappropriate.

The data Mr. Rigsby used in his equity risk premium analysis came from Morningstar's Ibbotson SBBI 2009 Yearbook. That very publication, while it includes tables of short-, intermediate-, and long-term risk premia, states that, "Although the equity risk premia of several horizons are available, the long-horizon equity risk premium is preferable for use in most business-valuation settings, even if an investor has a shorter time horizon. Companies are entities that generally have no defined life span; when determining a company's value, it is important to use a long-term discount rate because the life of the company is assumed to be infinite."[8]

[8] *2009 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook* (Morningstar, Inc. 2009) at 57.

The same publication specifies, "Another point to keep in mind when calculating the equity risk premium is that the income return on the appropriate-horizon Treasury security, rather than the total return, is used in the calculation. ...The income return is thus used in the estimation of the equity risk premium because it represents the truly riskless portion of the return."[9] While the publication provides widely-used tables of risk premia, in none of the tables is the premia calculated based on *total* Treasury returns, only Treasury *income* returns.

My biggest disagreement with Mr. Rigsby's method is that he uses *both* arithmetic and geometric means of historical S&P 500 and government bond returns. Only arithmetic means are appropriate in determining a forward-looking rate of return on equity. In addition to the information I provided in rebutting Mr. Parcell's use of geometric means, I add the following from Roger Morin's *New Regulatory Finance* textbook. "The best estimate of expected returns over a given future holding period is the arithmetic average. ...only arithmetic means are correct for forecasting purposes and for estimating the cost of capital."[10]

Q. If the risk-free rate and equity risk premium were corrected as explained above, would the indicated return on equity have been higher or lower?

A. It would have been significantly higher. The low end of the range determined by Mr. Rigsby would have to be excluded because it was based on geometric means of historical data. Starting with the 6.83% return on equity that was calculated using arithmetic averages, one would have to correct the risk-free rate, which would add 184 basis points. Correcting the selection of Treasury instruments and the measure of returns on Treasuries would add another 40 basis points. The resulting return on equity would be 9.07%, not 6.83%.

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[9] *2009 Ibbotson Stocks, Bonds, Bills, and Inflation Valuation Yearbook* (Morningstar, Inc. 2009) at 58.
[10] Morin, *New Regulatory Finance* (Public Utilities Reports, Inc. 2006) at 116-117.

Q. How much weight did Mr. Rigsby give his CAPM-based estimate of return on equity in making his final recommendation?

A. While Mr. Rigsby presents the results of both his DCF and CAPM models, his final recommendation appears to give very little weight to the CAPM model because his recommendation is well above even the high end of the CAPM-indicated range.

Q. In his comments on your CAPM methodology, Mr. Rigsby notes the use of an upward adjustment to the equity risk premium. His concern is that the adjustment was based on a spread between 30-year Treasuries and Baa/BBB rated debt that occurred over a brief period of time. Would you please comment on that?

A. Of course. At the time I was preparing my Direct Testimony, the turmoil in the financial markets had created the abnormally wide spreads. The spreads have since returned to more normal levels, but that could not have been assumed at the time.

Q. He also questions the need for an adjustment to CAPM.

A. Without an adjustment, the CAPM-indicated cost of equity at that time was 8.4%. It was clear that an 8.4% equity return would not be acceptable to investors as that was only 50 basis points above the average bond yields for Baa-rated public utility bonds as of January 2009. Rather than give the CAPM results little or no weight in my final recommendation of a cost of equity, I chose to make an adjustment based on the unusually high credit spreads seen at that point. As stated above, adjusting and including the CAPM results resulted in my recommending a return that was lower than it would have been had I just averaged the results from the other two methods I used to establish the Company's cost of equity.

Q. What else does Mr. Rigsby point out about the differences between your CAPM analysis and his?

A. He notes significant differences that result from my use of only arithmetic means versus his use of both geometric and arithmetic. He also notes the difference in the Treasury instruments used to estimate a risk-free rate. In addressing Mr. Rigsby's CAPM analysis, I've explained that my choices of inputs for the model were sound.

Q. Please summarize your view of RUCO's DCF analysis.

A. In RUCO's DCF analysis, a dividend yield of 5.4% was used along with a growth rate of 4.15%. While I do not have concerns about the calculation of the dividend yield, I do have several concerns about the calculation of the growth rate.

Q. What are your concerns regarding the growth rate?

A. First, I note that Mr. Rigsby calculated a growth rate that includes an external stock financing component. He cites Dr. Myron J. Gordon's textbook, *The Cost of Capital to a Public Utility*, as the source of the growth rate formula and states that Dr. Gordon is "the individual responsible for the development of the DCF or constant growth model". Then, instead of using the formula as presented by Dr. Gordon, he makes an adjustment based on an assumption that utilities' market-to-book ratios will tend to move toward 1.0. The market-to-book ratios shown in Mr. Parcell's Schedule 10, covering 18 years worth of data for a number of utilities, clearly demonstrate this is not the case. Had Mr. Rigsby stayed with the accepted form of the calculation, his average growth rate would have been 31 basis points higher. A bigger concern, however, is that his work papers show a comparison of the growth rate he calculated to published growth estimates from Value Line and Zacks for his proxy group of companies. These estimates were 4.04% and 6.44%, respectively. Had Mr. Rigsby given these widely-available estimates weight by averaging them with the rate he calculated, his average growth rate would have been 73 basis points higher, even without any correction to the rate he calculated. He offers no explanation as to why he did not use the data he had gone to the trouble to compile.

Q. Do you have any other comments on Mr. Rigsby's testimony?

A. Yes. Mr. Rigsby points out that UNS Electric's capital structure includes more debt that the average of those companies included in his proxy group. He states that the higher level of debt would cause investors to view UNS Electric as a riskier investment and notes that investors would require a higher return than that recommended based on the proxy group. I would note, however, that he fails to mention UNS Electric's inability to pay a dividend which would also drive investors to require a higher return. He goes on to say that he made no upward adjustment in his recommended rate, instead preferring to believe that the fair value rate of return ("FVROR") recommended by another RUCO witness, Dr. Johnson, would be adequate. He offers no analysis to support this statement.

Q. What comments did Mr. Rigsby have regarding your DCF analysis?

A. Mr. Rigsby mistakenly states that the 6.5% long-term growth rate in my model is based on the five-year growth rate estimates from Value Line, Zacks and SNL. In fact, in determining a long-term growth rate, I considered estimates of growth for my proxy group of companies, the electric utility industry, and the United States economy as a whole.

He also suggests that more emphasis should be placed on the near-term growth than the longer-term rate "that is carried out into perpetuity." He seems to be overlooking the fact that perpetual dividend growth is a fundamental assumption for both the single-stage version of the DCF model he used and the multi-stage model I used.

Q. Does that conclude your testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

EXHIBIT
UNSE-24
~~ADMITTED~~

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206

Rejoinder Testimony of

Martha B. Pritz

on Behalf of

UNS Electric, Inc.

January 25, 2010

TABLE OF CONTENTS

Q. Please state your name and business address.

A. My name is Martha B. Pritz. My business address is One South Church Avenue, Tucson, Arizona.

Q. What is the purpose of your Rejoinder Testimony in this proceeding?

A. The purpose of my Rejoinder Testimony is to respond to portions of the Surrebuttal Testimony filed by David C. Parcell on behalf of the Arizona Corporation Commission Staff ("Staff") and by William A. Rigsby on behalf of the Residential Utility Consumer Office ("RUCO").

I. RESPONSE TO STAFF WITNESS DAVID C. PARCELL.

Q. Does Mr. Parcell offer updated Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM") and Comparable Earnings ("CE") calculations in his Surrebuttal Testimony?

A. Yes. He presents the updated figures only for his DCF and CAPM analyses in the body of his testimony, however updated analyses for all three methods are shown in his attached exhibits.

Q. Do his updates lead him to revise his original cost of equity recommendation of 10.0%?

A. No, assuming that in his statement on page 11 that "the cost of capital for UNS Electric remains at 10.0 percent…," he really intended to say the cost of *equity* remains at 10.0 percent.

Q. Please assess the reasonableness of the 10.0% return on equity ("ROE") recommended for UNS Electric.

A. An investor would view UNS Electric as riskier than most other utilities since the Company's earnings and cash flow do not enable it to pay a dividend. In exchange for taking on greater risk in investing in UNS Electric, an investor would require a higher rate of return. Therefore, a 10.0% return would not be adequate to attract investors.

Q. What evidence can you offer that investors would require more than a 10.0% return on equity for UNS Electric?

A. First, I would refer to Mr. Parcell's Exhibit DCP-1 (Schedule 10) showing the historical and prospective rates of return on average common equity for two groups of comparable utilities. Looking at the prospective figures shown for the periods 2010 and 2012 – 2014, roughly the window before the Company could file and settle another rate case, one sees a range of average values from 8.6% to 10.4%. At first glance, the recommended 10.0% return on equity seems in line with these returns. In fact, it is not because the returns shown on Schedule 10 are projections of *earned* returns. Given the impact of regulatory lag on returns, an *allowed* ROE of just 10.0% would almost certainly result in much lower earned returns.

As Mr. Grant notes in his Rejoinder Testimony, UNS Electric had an *earned* return on equity of just 6.9% for the first twelve months under new rates resulting from its last rate case even though the *allowed* ROE was 10.0%.

Q. How else might one assess the recommended 10.0% return on equity?

A. One could compare the recommended return resulting from detailed analyses to the allowed returns on equity granted in rate cases for other utilities to ascertain whether the recommendation is reasonable.

Q. What have been the allowed ROEs in other recent rate cases?

A. For the thirty-nine rate orders issued in 2009, the average ROE was 10.52%. With the exception of one outlier, the allowed ROEs ranged from 10.0% to 11.5%. As of this writing, there have been five rate orders issued in 2010 with an average allowed ROE of 10.54%. The 2010 allowed ROEs range from 10.0% to 11.0%.

Q. What do you conclude from your review of recently ordered returns on equity?

A. While Mr. Parcell put considerable effort into the analyses that led to his recommended return on equity, the resulting 10.0% figure appears unreasonably low when compared to recent allowed ROEs. When one considers that investors would view UNS Electric as riskier than other utilities, the inadequacy of the recommendation becomes even more pronounced.

II. RESPONSE TO RUCO WITNESS WILLIAM A. RIGSBY.

Q. What concerns do you have about Mr. Rigsby's use of the Capital Asset Pricing Model ("CAPM") as discussed in his Surrebuttal Testimony?

A. While I have reservations about both the risk-free rate of return and the risk premium selected for use by Mr. Rigsby, I will focus on the resulting return on equity ("ROE") ranges presented in his Direct Testimony and his Rebuttal Testimony.

Q. What ROE ranges are indicated by Mr. Rigsby's CAPM calculations?

A. In his Direct Testimony, Mr. Rigsby's model indicated a range of 5.46% to 6.83%. In his Surrebuttal Testimony, he noted that with a slightly different range of risk premiums, his model indicated an even lower range, 5.33% to 6.79%.

Q. Are these ranges reasonable, given that the Company has a cost of debt of 7.05%?

A. No, even the upper ends of the ranges are *below* the Company's cost of debt, but equity investors would require a return on equity *higher* than that on debt as compensation for the incremental risk they bear. This risk-return relationship is fundamental in financial theory. As I noted in my Direct Testimony, a comparison of allowed ROEs to average utility bond yields for the period from January 2006 through January 2009 shows an average premium of 4.07%.

Q. Given that RUCO's CAPM-indicated return on equity is below the Company's cost of debt, should it be considered in the final determination of a fair rate of return on equity?

A. No, it should not.

Q. Please comment on Mr. Rigsby's defense of his DCF analysis.

A. Yes. I note that Mr. Rigsby discusses at length his calculation of the growth rate estimate, which is a departure from more commonly-used methods of determining an appropriate growth rate estimate. His calculation includes an adjustment based on his assumption that investors will expect a company's market-to-book ratio to move toward a ratio of 1.0. He bases this on the theory that if regulators set a utility's rate of return at a level equal to the cost of capital of firms with similar risk, the utility's market-to-book ratio will move toward a value of 1.0. He goes on to say that while fluctuations in earnings may cause a utility's market-to-book ratio to vary, the average earnings over time will result in a ratio of 1.0.

Q. Is it indeed the case that utilities' market-to-book ratios average 1.0 over time?

A. No. As seen in Staff witness David Parcell's Exhibit 10 to his Direct Testimony, the market-to-book ratios for two groups of comparable utilities have averaged well-above

1.0. Restating the percentages shown on Mr. Parcell's schedule as ratios, the market-to-book averages shown are 1.52, 1.29, 1.54 and 1.57 for the two groups of companies each examined over two time periods.

Q. If the adjustment, which appears to be unjustified, were removed, would the growth rate estimate and indicated ROE be higher or lower than those calculated by Mr. Rigsby?

A. The growth rate and ROE would be higher. The ROE would be higher by 47 basis points, 10.02% vs. the 9.55% from Mr. Rigsby's Direct Testimony.

Q. Please discuss Mr. Rigsby's assessment of his final recommendation of 9.25% as an appropriate cost of equity for UNS Electric.

A. Mr. Rigsby says it has been suggested that if regulators set a utility's rate of return slightly higher than that of firms with similar risk, it will send a message to investors that average long-term earnings will not fall below expectations. He also says that because his recommendation of 9.25% ROE is above the CAPM range he derived in his Surrebuttal Testimony (5.33% to 6.79%), his recommendation is consistent with the theory presented.

Q. Is that conclusion reasonable?

A. No, it is not. As I explained above, the CAPM-indicated ROE range is meaningless because it is below the Company's cost of debt. Declaring a recommended rate of return to be consistent with theory just because it is higher than an unusable range is similarly meaningless.

Q. Does Mr. Rigsby raise the question of whether you have prepared updates to the cost of equity analyses presented in your Direct Testimony?

A. Yes, he notes that I had not updated the analyses at the time I filed Rebuttal Testimony.

Q. Have you since updated your analyses for the comparable company group you examined?

A. Yes, I have.

Q. What are the results of your updated comparable company analyses?

A. My updated DCF analysis indicates an 11.2% return on equity, my bond yield plus risk premium ("BYRP) calculation shows 10.3%, and my CAPM analysis shows 8.9%. Based on a comparison to typical risk premiums for equity relative to debt, the result of the CAPM analysis appears too low to be meaningful. The average cost of equity indicated by the other two methods, as updated, is 10.8%.

Q. Have you revised your original recommendation of an 11.4% return on equity for UNS Electric?

A. No, based on a review of my original analyses, my updated analyses and current developments affecting the outlook for financial markets, I am still comfortable that 11.4% is an appropriate ROE for the Company. Additionally, as noted above and in my Direct and Rebuttal Testimony, UNS Electric is riskier from an equity investor's perspective that the group of comparable companies I examined.

Q. What factors in the outlook for financial markets play a role in your decision to maintain your original ROE recommendation?

A. There are two key factors, each likely to put upward pressure on the return on equity required by investors. First, taxes on dividends and capital gains are expected to increase. To offset this increase in taxes, investors will look for higher pre-tax returns on their investments. Second, economic indicators show inflation may be increasing. An increase in inflation will increase companies' cost of capital.

I'll address the impact of income tax rates first. In 2003, the Jobs Growth and Tax Relief Reconciliation Act ("JGTRRA") was enacted, reducing capital gains tax rates from 20% to 15% and reducing the tax rate on qualified dividends from a taxpayer's ordinary marginal tax rate to 15%. (For taxpayers in lower tax brackets, the capital gains and dividend tax rates are lower still.) The rate decreases were originally set to expire in 2008, but were extended through December 31, 2010 by the Tax Increase Prevention and Reconciliation Act of 2005. Barring another extension, taxes will revert to 2002 rates in 2011.

To gauge the potential impact of this increase in income tax rates on the cost of equity, one can look to the impact on the cost of equity that the decrease in rates had when it was put into effect. The Federal Reserve Bank of Boston estimated that the tax cuts reduced the economy-wide cost of equity by 50 to 100 basis points.[1]

Of course, the impact of an increase in the dividend tax rate is even more pronounced for higher-yielding stocks like utility stocks. The *Journal of Financial Planning* addressed this in general terms, saying, "What will happen to high dividend-yielding equities if the special tax rate on qualified dividends sunsets or is repealed…? Evidence would suggest that dividend-heavy stocks and indices won't do well."[2]

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[1] Richard W. Kopcke, "The Taxation of Equity, Dividends, and Stock Prices", *Public Policy Discussion Papers*, (Federal Reserve Bank of Boston, January 2005),18.
[2] Michael Finke, Ph.D., CFP and Tom Langdon, JD, CFP, "Capital Gains and Dividend Tax Rates Will Likely Increase in 2009; Will You Be Prepared?" *Journal of Financial Planning* (August 2008): 2.

Another reason to anticipate an increase in the cost of equity is the possibility of increasing inflation due to unprecedented U.S. budget deficits coupled with the recent easing in monetary policy. Increasing inflation would increase risk-free rates and, therefore, companies' cost of capital. Indeed, implied inflation as measured by the difference between nominal constant maturity Treasuries and TIPS constant maturity treasuries increased by approximately 50 basis points in just the period from September to December 2009.

In addition, in November 2009, James Bullard, president of the Federal Reserve Bank of St. Louis, told the *Financial Times* that while the U.S. central bank still had to contend with the threat of deflation at that point, it might have to "pivot quickly once this danger passed to face the threat of excess inflation."[3]

Q. Does this conclude your Rejoinder Testimony?

A. Yes, it does.

[3] Guha, Krishna. "Uncertainty "high" over inflation outlook", *Financial* Times (FT.com), November 8, 2009.

BEFORE THE ARIZONA CORPORATION COMMISSION

<u>COMMISSIONERS</u>
KRISTIN K. MAYES - CHAIRMAN
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)))))))))))	DOCKET NO. E-04204A-09-____

Direct Testimony of

Dr. Ronald E. White

on Behalf of

UNS Electric, Inc.

April 30, 2009

EXHIBIT
UNSE-25
ADMITTED

Table of Contents

BEFORE THE
ARIZONA CORPORATION COMMISSION

PREPARED DIRECT TESTIMONY OF
DR. RONALD E. WHITE
IN DOCKET NO. E–___

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is Ronald E. White. My business address is 17595 S. Tamiami Trail, Suite 212, Fort Myers, Florida 33908.

Q. WHAT IS YOUR OCCUPATION?

A. I am Chairman and a Senior Consultant of Foster Associates, Inc.

I. QUALIFICATIONS

Q. WOULD YOU BRIEFLY DESCRIBE YOUR EDUCATIONAL TRAINING AND PROFESSIONAL BACKGROUND?

A. I received a B.S. degree in Engineering Operations and an M.S. degree and Ph.D. (1977) in Engineering Valuation from Iowa State University. I have taught graduate and undergraduate courses in industrial engineering, engineering economics, and engineering valuation at Iowa State University and previously served on the faculty for Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. I also conduct courses in depreciation and public utility economics for clients of the firm.

I have prepared and presented a number of papers to professional organizations, committees, and conferences and have published several articles on matters relating to depreciation, valuation and economics. I am a past member of the Board of Directors of the Iowa State Regulatory Conference and an affiliate member of the joint American Gas Association (A.G.A.) – Edison Electric Institute (EEI) Depreciation Accounting Committee, where I previously served as chairman of a standing committee on capital recovery and its effect on corporate economics. I am also a member of the American Economic Association, the Financial Management Association, the

Midwest Finance Association, the Electric Cooperatives Accounting Association (ECAA), and a founding member of the Society of Depreciation Professionals.

Q. WHAT IS YOUR PROFESSIONAL EXPERIENCE?

A. I joined the firm of Foster Associates in 1979, as a specialist in depreciation, the economics of capital investment decisions, and cost of capital studies for ratemaking applications. Prior to joining Foster Associates, I was employed by Northern States Power Company (1968–1979) in various assignments related to finance and treasury activities. As Manager of the Corporate Economics Department, I was responsible for book depreciation studies, studies involving staff assistance from the Corporate Economics Department in evaluating the economics of capital investment decisions, and the development and execution of innovative forms of project financing. As Assistant Treasurer at Northern States, I was responsible for bank relations, cash requirements planning, and short–term borrowings and investments.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE A REGULATORY BODY?

A. Yes. I have testified in numerous proceedings before administrative and judicial bodies in over thirty jurisdictions, including several appearances before the Arizona Corporation Commission. I have also testified before the Federal Energy Regulatory Commission, the Federal Power Commission, the Alberta Energy Board, the Ontario Energy Board, and the Securities and Exchange Commission. I have sponsored position statements before the Federal Communication Commission and numerous local franchising authorities in matters relating to the regulation of telephone and cable television. A more detailed description of my professional qualifications is provided in Attachment REW–1.

II. PURPOSE OF TESTIMONY

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

A. Foster Associates was engaged by UNS Electric, Inc. (UNS Electric), an operating subsidiary of UniSource Energy Services, to conduct 2009 technical updates of depreciation rates for the Company.

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 1, 2008. The second update includes Black Mountain using an estimated year of final retirement provided by Tucson Electric Power engineers. The purpose of my testimony is to sponsor and describe the studies conducted by Foster Associates. Depreciation rates currently used by UNS Electric were approved by the Arizona Corporation Commission (ACC) in Docket No. E–04204A–06–0783 (Decision No. 70360, dated May 27, 2008).

III. DEVELOPMENT OF DEPRECIATION RATES

Q. WHY ARE DEPRECIATION STUDIES NEEDED FOR ACCOUNTING AND RATEMAKING PURPOSES?

A. The goal of depreciation accounting is to charge to operations a reasonable estimate of the cost of the service potential of an asset (or group of assets) consumed during an accounting interval. A number of depreciation systems have been developed to achieve this objective, most of which employ time as the apportionment base.

Implementation of a time–based (or age–life) system of depreciation accounting requires the estimation of several parameters or statistics related to a plant account. The average service life of a vintage, for example, is a statistic that will not be known with certainty until all units from the original placement have been retired from service. A vintage average service life, therefore, must be estimated initially and periodically revised as indications of the eventual average service life become more certain. Future net salvage rates and projection curves, which describe the expected distribution of retirements over time, are also estimated parameters of a depreciation system that are subject to future revisions. Depreciation studies should be conducted periodically to assess the continuing reasonableness of parameters and accrual rates derived from prior estimates.

The need for periodic depreciation studies is also a derivative of the ratemaking process that establishes prices for utility services based on costs. Absent regulation, deficient or excessive depreciation rates will produce no adverse consequence other than a systematic over or understatement of the accounting measurement of earnings. While a continuance of such practices may not comport with the goals of depreciation accounting, the achievement of capital recovery is not dependent upon either the amount or the timing of depreciation expense for an unregulated firm. In the case of a regulated utility, however, recovery of investor–supplied capital is dependent upon allowed revenues, which are in turn dependent upon approved levels of depreciation expense. Periodic reviews of depreciation rates are, therefore, essential to the achievement of timely capital recovery for a regulated utility.

Q. WHAT ARE THE PRINCIPAL ACTIVITIES UNDERTAKEN IN CONDUCTING A FULL DEPRECIATION STUDY?

A. The first step in conducting a depreciation study is the collection of plant accounting data needed to conduct a statistical analysis of past retirement experience. Data are also collected to permit an analysis of the relationship between retirements and realized gross salvage and removal expense. The data collection phase should include a verification of the accuracy of the plant accounting records and a reconciliation of the assembled data to the official plant records of the company.

The next step in a depreciation study is the estimation of service life statistics from an analysis of past retirement experience. The term *life analysis* is used to describe the activities undertaken in this step to obtain a mathematical description of the forces of retirement acting upon a plant category. The mathematical expressions used to describe these forces are known as survival functions or survivor curves.

Life indications obtained from an analysis of past retirement experience are blended with expectations about the future to obtain an appropriate projection life curve. This step, called *life estimation*, is concerned with predicting the expected remaining life of property units still exposed to the forces of retirement. The amount of weight given to the analysis of historical data will depend upon the extent to which past retirement experience is considered descriptive of the future.

An estimate of the net salvage rate applicable to future retirements is usually obtained from an analysis of the gross salvage and removal expense realized in the past. An analysis of past experience (including an examination of trends over time) provides a baseline for estimating future salvage and cost of removal. Consideration, however, should be given to events that may cause deviations from the net salvage realized in the past. Among the factors that should be considered are the age of plant retirements, the portion of retirements that will be reused, changes in the method of removing plant, the type of plant to be retired in the future, inflation expectations, the shape of the projection life curve, and economic conditions that may warrant greater or lesser weight to be given to the net salvage observed in the past.

A comprehensive depreciation study will also include an analysis of the adequacy of the recorded depreciation reserve. The purpose of such an analysis is to compare the current balance in the recorded reserve with the balance required to achieve the goals and objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized exactly as predicted. The difference between the required (or theoretical) reserve and the recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to extinguish the reserve imbalance.

Although reserve records are typically maintained by various account classifications, the total reserve for a company is the most important reflection of the company's depreciation practices. Differences between the theoretical reserve and the recorded reserve will arise as a normal occurrence when service lives, dispersion patterns and salvage estimates are adjusted in the course of depreciation reviews. Differences will also arise due to plant accounting activity such as transfers and adjustments, which require an identification of reserves at a different level from that maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory, to periodically redistribute recorded reserves among primary accounts based on the most recent estimates of retirement dispersion and salvage. A redistribution of the recorded reserve will provide an initial reserve balance for each primary account consistent with the estimates of retirement dispersion selected to describe mortality characteristics of the accounts and establish a baseline against which future comparisons can be made.

Finally, parameters estimated from service life and net salvage studies are integrated into an appropriate formulation of an accrual rate based upon a selected depreciation system. Three elements are needed to describe a depreciation system. These elements (*i.e.*, method, procedure and technique) can be visualized as three dimensions of a cube in which each face describes a variety of sub–elements that can be combined to form a system. A depreciation system is therefore formed by selecting a sub–element from each face such that the system contains one method, one procedure and one technique. The sub–elements most widely used in constructing a depreciation system are shown in Table 1.

Methods	Procedures	Techniques
Retirement	Total Company	Whole-Life
Compound-Interest	Broad Group	Remaining-Life
Sinking-Fund	Vintage Group	Probable-Life
Straight-Line	Equal-Life Group	
Declining Balance	Unit Summation	
Sum-of-Years'-Digits	Item	
Expensing		
Unit-of-Production		
Net Revenue		

Table 1. Elements of a Depreciation System

IV. 2009 TECHNICAL UPDATES

Q. WOULD YOU PLEASE DESCRIBE THE SCOPE OF A TECHNICAL UPDATE?

A. 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 or proposed 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, therefore, is intended to align depreciation rates with the accounting year the rates will become effective. The steps involved in preparing a technical update generally include a) data collection; b) calculation of service life statistics; c) computation of average net salvage rates; d) rebalancing of depreciation reserves; and e) development of accrual rates.

Q. DID UNS ELECTRIC PROVIDE FOSTER ASSOCIATES PLANT ACCOUNTING DATA FOR CONDUCTING THE 2009 TECHNICAL UPDATES?

A. Yes, they did. 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.

Q. DID FOSTER ASSOCIATES CALCULATE SERVICE LIFE STATISTICS IN THE 2009 TECHNICAL UPDATES?

A. Yes, we did. The scope of the updates and calculations performed by Foster Associates are described in the Study Procedures section of Attachment REW–2.

Q. DID FOSTER ASSOCIATES DERIVE AVERAGE NET SALVAGE RATES IN THE 2009 UPDATES?

A. Yes, we did. 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.

Q. DID FOSTER ASSOCIATES REBALANCE DEPRECIATION RESERVES IN THE 2009 UPDATES?

A. Yes, we did. 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.

Q. HOW DO THE DEPRECIATION RATES AND ACCRUALS DERIVED IN THE UPDATES COMPARE WITH CURRENTLY APPROVED RATES AND ACCRUALS?

A. Table 2 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.

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	2.44%	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 2. 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 3 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 3. 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.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

EXHIBIT

REW-1

Attachment REW–1

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Education

1961 - 1964 Valparaiso University
Major: Electrical Engineering

1965 Iowa State University
B.S., Engineering Operations

1968 Iowa State University
M.S., Engineering Valuation
Thesis: The Multivariate Normal Distribution and the Simulated Plant Record Method of Life Analysis

1977 Iowa State University
Ph.D., Engineering Valuation
Minor: Economics
Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate Associated With the Service Life of Industrial Property

Employment

2007 - Present Foster Associates, Inc.
Chairman

1996 - 2007 Foster Associates, Inc.
Executive Vice President

1988 - 1996 Foster Associates, Inc.
Senior Vice President

1979 - 1988 Foster Associates, Inc.
Vice President

1978 - 1979 Northern States Power Company
Assistant Treasurer

1974 - 1978 Northern States Power Company
Manager, Corporate Economics

1972 - 1974 Northern States Power Company
Corporate Economist

1970 - 1972 Iowa State University
Graduate Student and Instructor

1968 - 1970 Northern States Power Company
Valuation Engineer

1965 - 1968 Iowa State University
Graduate Student and Teaching Assistant

Publications

A New Set of Generalized Survivor Tables, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

Standards for Depreciation Accounting Under Regulated Competition, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

The Economics of Price-Level Depreciation, paper presented at the Iowa State University Regulatory Conference, May, 1981.

Depreciation and the Discount Rate for Capital Investment Decisions, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

The Problem With AFDC is ..., paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

The Simulated Plant-Record Method of Life Analysis, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

Simulated Plant-Record Survivor Analysis Program (User's Manual), special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

Modeling the Behavior of Property Records, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

How Dependable are Simulated Plant-Record Estimates?, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

Testifying Witness

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–01345A–08–0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–0135A–03–0437, Arizona Public

Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E–01345A–05–0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G–04204A–06–0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E–04204A–06–0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05–12–002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06–12–009/A.06–12–010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 05–03–17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06–12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04–0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications;

testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 04–AQLE–1065–RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03–KGSG–602–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06–KGSG–1209–RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06–55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2004–0024, Aquila Inc. d/b/a/ Aquila Networks–L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2004–0034, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR–2004–0072, Aquila Inc. d/b/a/ Aquila Networks–L & P and Aquila Networks–MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR–2009–0092, KCP&L Greater Missouri Operations Company, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER–2009–0090, KCP&L Greater Missouri Operations Company, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG–0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone

Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony concerning depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony concerning depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest;

testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General

Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

Other Consulting Activities

Moran Towing Corporation. In Re: Barge TEXAS-97 CIV. 2272 (ADS) and Tug HEIDE MORAN – 97 CIV. 1947 (ADS), United States District Court, Southern District of New York.

John Reigle, et al. v. Baltimore Gas & Electric Co., et al., Case No. C-2001-73230-CN, Circuit Court for Anne Arundel County, Maryland.

SR International Business Insurance Co. vs. WTC Properties et. al., 01,CV–9291 (JSM) and other related cases.

BellSouth Telecommunications, Inc. v. Citizens Utilities Company d/b/a/ Louisiana Gas Service Company, CA No. 95-2207, United States District Court, Eastern District of Louisiana.

Affidavit on behalf of Continental Cablevision, Inc. and its operating cable television systems regarding basic broadcast tier and equipment and installation cost-of-service rate justification.

Office of Chief Counsel, Internal Revenue Service. In Re: Kansas City Southern Railway Co., et. al. Docket Nos. 971-72, 974-72, and 4788-73.

Office of Chief Counsel, Internal Revenue Service. In Re: Northern Pacific Railway Co., Docket No. 4489-69.

United States Department of Justice. In Re: Burlington Northern Inc. v. United States, Ct. Cl. No. 30-72.

Minnesota District Court. In Re: Northern States Power Company v. Ronald G. Blank, *et. al.* File No. 394126; testimony concerning depreciation and engineering economics.

Faculty

Depreciation Programs for public utility commissions, companies, and consultants, sponsored by Depreciation Programs, Inc., in cooperation with Western Michigan University. (1980 - 1999)

United States Telephone Association (USTA), Depreciation Training Seminar, November 1999.

Depreciation Advocacy Workshop, a three-day team-training workshop on preparation, presentation, and defense of contested depreciation issues, sponsored by Gilbert Associates, Inc., October, 1979.

Corporate Economics Course, Employee Education Program, Northern States Power Company. (1968 - 1979)

Perspectives of Top Financial Executives, Course No. 5-300, University of Minnesota, September, 1978.

Depreciation Programs for public utility commissions, companies, and consultants, jointly sponsored by Western Michigan University and Michigan Technological University, 1973.

Professional Associations

Advisory Committee to the Institute for Study of Regulation, sponsored by the American University and The University of Missouri-Columbia.

American Economic Association.

American Gas Association - Edison Electric Institute Depreciation Accounting Committee.

Board of Directors, Iowa State Regulatory Conference.

Edison Electric Institute, Energy Analysis Division, Economic Advisory Committee, 1976-1980.

Financial Management Association.

The Institute of Electrical and Electronics Engineers, Inc., Power Engineering Society, Engineering and Planning Economics Working Group.

Midwest Finance Association.

Society of Depreciation Professionals (Founding Member and Chairman, Policy Committee.

Moderator

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

Speaker

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the "D" in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric

Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998.

Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National

Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

Honors and Awards

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

EXHIBIT

REW-2

Attachment REW–2

2009 Technical Update

UNS Electric, Inc.

Prepared by
Foster Associates, Inc.

CONTENTS

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 1, 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	Net Salvage	Total	Proposed Rates (at 12/31/2008) 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	2.07%		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)			Proposed Rates (at 12/31/2008)		
	Investment	Net Salvage	Total	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%

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			Proposed 2009 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
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)

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
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)

Statement C

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
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			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
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%

UNS ELECTRIC, INC. (Excluding Black Mountain)

Average Net Salvage

Statement D

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	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	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	

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

Statement E

Account Description	Current P-Life/ AYFR	Current Curve Shape	Current BG ASL	Current Rem. Life	Current Avg. Sal.	Current Fut. Sal.	Proposed P-Life/ AYFR	Proposed Curve Shape	Proposed BG ASL	Proposed Rem. Life	Proposed Avg. Sal.	Proposed 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

Statements A through E

Including Black Mountain

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
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			Proposed 2009 Annualized Accrual			Difference
		Investment	Net Salvage	Total	Investment	Net Salvage	Total	
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)

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
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)

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	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
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

UNS ELECTRIC, INC. (Including Black Mountain)

Statement C

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%

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
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			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
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%

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

Statement D

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
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						

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

Statement E

	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
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

	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
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						Proposed Parameters					
	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
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.
Average Summer Residential Bill - UNS Electric Proposed Rates
Without BMGS and with BMGS

	Rate Without BMGS	Billing Units	Bill Calculation	Rate With BMGS	Billing Units	Bill Calculation
Proposed Residential Rate						
Customer Charge	$8.00	1	$8.00	$8.00	1	$8.00
Non-Fuel Base Rates						
Energy Charge 1st 400 kWhs	$0.020070	400	$8.03	$0.026115	400	**$10.45**
Energy Charge, all additional kWhs	$0.030084	683	$20.55	$0.036129	683	**$24.68**
Base Power Supply Charge, all kWhs	$0.074812	1083	**$81.02**	$0.068767	1083	$74.47
PPFAC	$0.004100	1083	$4.44	$0.004100	1083	$4.44
			$122.04			**$122.04**

Portion of the $122.04 attributable to BMGS: **$6.55** **$6.55**

In Base Power Supply
Flows to UED

In Non-Fuel Base Rates
Flows to UNSE

EXHIBIT
UNSE-27
ADMITTED

COMMISSION STAFF RESPONSES TO UNS ELECTRIC'S DATA REQUESTS
DOCKET NO. E-04204A-09-0206

3.5
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ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.5 Please indicate where in the following decisions, that the percentage of post test year plant to be included in rate base is listed as a factor in determining whether post-test year plant should be included.

a. Rio Rico Utilities, Inc, Decision No. 67279 (October 5, 2004);

b. Arizona Water Company, Decision No. 66849 (March 19, 2004);

c. Bella Vista Water Company, Inc., Decision No. 65350 (November 1, 2002);

d. Arizona-American Water Company, Decision No. 68864 (July 28, 2006); and

e. Chaparral City Water Company, Decision No. 68176 (Sept. 30, 2005).

RESPONSE:

a. Percentage of post test-year plant to be included in rate base was not listed as a factor in determining whether post-year plant should be included.

b. See response to 3.5 a.

c. See response to 3.5 a.

d. See response to 3.5 a.

e. See response to 3.5 a.

RESPONDENT: **Thomas H. Fish, Ph.D.**

WITNESS: **Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.6 Please indicate where, in the following decisions, the fact that capital items consisting of projects that were not normal and ongoing constituted a deciding factor in allowing post-test year plant.

a. Rio Rico Utilities, Inc, Decision No. 67279 (October 5, 2004);

b. Arizona Water Company, Decision No. 66849 (March 19, 2004);

c. Bella Vista Water Company, Inc., Decision No. 65350 (November 1, 2002);

d. Arizona-American Water Company, Decision No. 68864 (July 28, 2006); and

e. Chaparral City Water Company, Decision No. 68176 (Sept. 30, 2005).

RESPONSE:

a. Capital items consisting of projects that were not normal and ongoing was not identified by the Commission as deciding factor in rendering its decision.

b. See response to 3.6 a.

c. See response to 3.6 a.

d. See response to 3.6 a.

e. See response to 3.6 a.

RESPONDENT: **Thomas H. Fish, Ph.D.**

WITNESS: **Thomas H. Fish, Ph.D.**

UNSE 3.7 Refer to the Direct Testimony of Thomas H. Fish, Ph.D., page 16, lines 3-5, where Dr. Fish states "Presumably, the investment was made in order to increase the Company's efficiency/productivity and hence reduce the costs of providing service such as maintenance cost."

a. Please provide the basis and supporting information for this statement.

b. Did Dr. Fish review the purposes of the specific items of plant included within UNS Electric' request for Post Test Year Non-Revenue Producing Plant?

c. Does Dr. Fish contend that the only reason a utility would invest in Non-Revenue Producing Plant is to increase efficiency/productivity?

d. Does Dr. Fish acknowledge that a utility might invest in Non-Revenue Producing Plant in order to maintain or improve quality of service?

e. Does Dr. Fish acknowledge that a utility might invest in Non-Revenue Producing Plant in order to meet regulatory requirements?

f. Does Dr. Fish acknowledge that a utility might invest in Non-Revenue Producing Plant in order to maintain or improve safety?

g. Please provide Dr. Fish's calculations of the estimated reduced costs of providing service in connection with the Post Test Year Non-Revenue Producing Plant.

h. Is Dr. Fish's statement regarding "reduc[ed]... costs of providing service" net of incremental depreciation expense associated with the Non-Revenue Producing Plant? If the answer is yes, please explain why Dr. Fish believes the efficiency gains exceed the incremental depreciation expense.

i. Does Dr. Fish dispute that the Post Test Year Plant requested to be included in rate base was Non-Revenue Producing? If so, please set forth each and every basis for that position and include all workpapers that provide support for Staff's belief.

j. Does Dr. Fish dispute that the Post Test Year Plant requested to be included in rate base was not related to customer growth? If so, please set forth each and every basis for that position and include all workpapers that provide support for Staff's belief.

RESPONSE:

a. **Dr. Fish has no reason to believe that the Company does not consider economic efficiency and potential productivity gains in making investment decisions.**

b. **This information was not provided.**

c. **No.**

d. **Yes.**

e. **Yes.**

f. **Yes.**

g. **Dr. Fish did not conduct such a study.**

h. **See response to UNSE 3.7 g.**

i. **Dr. Fish does not know which, if any, of the capital investments are non –revenue producing.**

j. **Dr. Fish has no basis to dispute or agree with which, if any, of the capital investments are related to customer growth.**

RESPONDENT: **Thomas H. Fish, Ph.D.**

WITNESS: **Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO
UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
NOVEMBER 30, 2009

UNSE 3.8	Please provide a list of all of the post-test year plant Dr. Fish believes is not prudently invested as defined in R14-2-103.A.3.l.
RESPONSE:	**Dr. Fish did not conduct a prudence analysis of the Company's proposed post test-year capital investment adjustment. Therefore, he has no reason to believe that the investments were not prudent.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.14	Does Staff dispute that UNS Electric experienced an average fuel price of \$3.32/gallon for gasoline and \$3.82/gallon for diesel during the test year?
RESPONSE:	**No.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO
UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
NOVEMBER 30, 2009

UNSE 3.15	Does Staff believe that the future fuel costs are "known and measurable?" If so, please provide all support for that belief?
RESPONSE:	**Dr. Fish believes that future costs may be associated with some uncertainty.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.17	Does Staff dispute that the Call Center expense during the test year was \$880,553 for UNS Electric?
RESPONSE:	**No.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.18	Does Staff contend that the costs related to the call center are not reasonably related to providing service to customers? If so, please provide any and all justification for Staff's contention
RESPONSE:	**Staff does not take issue with the allocation factors.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.19	Is it Staff's position that the cost of Call Center operations, such as labor expense, did not increase from the previous rate case test year? If so, what is the basis of that position? Provide all support to justify Staff's position.
RESPONSE:	**Staff accepts that the Company spent 47% more for Call Center expenses during the test year compared to the test year in the last rate case.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.20	Does Staff believe the only consideration to consider, when analyzing call center expenses, is that "call volume has decreased." If so, please explain why that should be the case.
RESPONSE:	**No.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO
UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
NOVEMBER 30, 2009

UNSE 3.23	Provide any evidence that SERP is an atypical cost for an electric utility.
RESPONSE:	**Staff is not contending that SERP is an atypical cost and has not conducted a study of other utility's retirement expenses in this proceeding.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.24	Provide any evidence that UNS Electric' overall executive compensation costs are unreasonable or out of line with industry practice.
RESPONSE:	**See response to UNSE 3.23.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.26	Please provide any and all support for Dr. Fish's statement on page 47, line 25 through page 48 line 2 that "a higher interest rate could provide a disincentive to reduce bank balances and become less inclined to take all possible measures to reduce the cost of purchased power and fuel to its customers." Please provide any evidence of where a higher interest rate has provided a disincentive to any utility to reduce bank balances.
RESPONSE:	**Dr. Fish did not allege a causal, but a possible, relationship and conducted no study or survey regarding this matter.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.27	Does Dr. Fish believe that UNS Electric will profit from its proposed change in the interest rate applied to the PPFAC? If so, provide any and all support for that belief.
RESPONSE:	**No.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.28	Does Dr. Fish believe that 3-month LIBOR rate plus 1 percent is not the actual rate incurred by UNS Electric on the PPFAC balance? If so, provide any and all support for that belief.
RESPONSE:	**Dr. Fish believes that under the joint revolving credit facility shared with UNS Gas, UNS Electric may borrow at LIBOR plus 1.0%**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.30 Does Dr. Fish deny that UNS Electric had between $7 million and $12 million of outstanding letters of credit? And $12 million to $21 million of cash collateral outstanding since August 2008? Does Dr. Fish believe these costs are known and measurable. Please explain why or why not.

RESPONSE: **No. Dr. Fish has no basis to believe that this information provided by the Company is not correct.**

RESPONDENT: **Thomas H. Fish, Ph.D.**

WITNESS: **Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.34 What analysis did Dr. Fish undertake to determine whether UNS Electric could acquire BMGS under the authorizations approved in Decision No. 70360. Please include the following:

a. Any materials Dr. Fish reviewed in undertaking his analysis.

b. Interviews with financial professionals, including any notes or recordings from those interviews.

c. Confirmations from entities that they would have provided the necessary financing to UNS Electric to acquire BMGS.

d. Any and all other data reviewed when Dr. Fish performed this analysis.

RESPONSE:

a. The materials reviewed by Dr. Fish were provided by the Company in response to Staff data requests.

b. Dr. Fish did not interview financial professionals.

c. See response to UNSE 3.34 b.

d. See response to UNSE 3.34 a.

RESPONDENT: **Thomas H. Fish, Ph.D.**

WITNESS: **Thomas H. Fish, Ph.D.**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.35	Does Dr. Fish now dispute the $62 million figure as not known and measurable at this time? If so, please explain what exactly Dr. Fish is contending is not known and measurable about the total cost for BMGS net depreciation that equals $62 million as of December 31, 2008.
RESPONSE:	**No.**
RESPONDENT:	**Thomas H. Fish, Ph.D.**
WITNESS:	**Thomas H. Fish, Ph.D.**

EXHIBIT
UNSE-28
ADMITTED

UNS Electric, Inc.'s Response to Request for Investment Recovery Mechanism Proposals

During the hearings in ACC Docket No. E-04204A-09-0206, (the "UNS Electric Rate Case"), UNS Electric, Inc. ("UNS Electric" or the "Company") was requested to investigate and propose mechanisms for the recovery of utility investment in (i) renewable energy projects; and (ii) demand side management and energy efficiency projects. The Company hereby submits its proposals in response to that request. These proposals will be addressed by Mr. David G. Hutchens, Vice President of Energy Efficiency and Resource Planning for UniSource Energy Corporation, the parent company of UNS Electric. The Company reserves the right to provide additional information in connection with these proposals or in further response to questions raised during the UNS Electric Rate Case hearing. UNS Electric requests that the Commission approve the proposals in the order to be issued in the UNS Electric Rate Case and will propose requisite ordering language in its post-hearing brief.

I. Renewable Generation Ownership Plan.

UNS Electric proposes the "Renewable Generation Ownership Plan" (the "Plan") which will allow the Company to invest up to $5 million of capital each year to develop Renewable Technologies (as defined in the Renewable Energy Standard Tariff ("REST")). This Plan will aid the Company in its efforts to diversify its renewable portfolio and meet the REST requirements of 15% retail sales from renewable resources by 2025. The Company will also integrate the Plan projects with its "Community Renewable Program" to be submitted in the UNS Electric 2011 REST Implementation Plan.

The Company requests that the revenue requirement resulting from the Renewable Generation Ownership Plan be recovered through the REST adjustor mechanism. The revenue requirement includes depreciation, property taxes, income taxes, operating and maintenance expense and carrying costs using the authorized weighted average cost of capital, and would be recovered through the REST adjustor mechanism until the investment is included in base rates. The Company is not requesting funding for Plan projects in this case. Specific projects pursuant to this Plan will be identified and presented in the UNS Electric 2011 REST Implementation Plan.

The Company will utilize a competitive bid process for the Plan projects to ensure a fair and unbiased procedure that will efficiently incorporate a full range of renewable resource alternatives from the marketplace. The Company anticipates that projects constructed and owned pursuant the Plan will be located in UNS Electric's service territory.

The following Table illustrates estimated annual Plan revenue requirements that would be recovered through the REST adjustor mechanism:

($ in thousands)	2011	2012	2013	2014	Capital Spending
2011 REST ($5M of investment)	$619	$581	$562	$574	$5,000
2012 REST ($5M of additional investment)		$619	$581	$562	$10,000
2013 REST ($5M of additional investment)			$619	$581	$15,000
2014 REST ($5M of additional investment)				$619	$20,000
Total included in the REST adjustor	**$619**	**$1,200**	**$1,762**	**$2,336**	

Notes:

- Amount included in the REST adjustor until included in rate base.
- Numbers assume customers benefit from a 30% investment tax credit in accordance with Federal tax laws
- Numbers assume existing cost of capital.

II. Demand Side Management and Energy Efficiency Ownership Plan.

UNS Electric commits to submit a plan whereby the Company's demand side management and energy efficiency investments will be recovered in a form similar to its Renewable Generation Ownership Plan. The Company is currently exploring mechanisms and ownership options for the tangible and intangible elements of such programs. The Company has communicated with Ralph Cavanagh in connection with these issues and will work with Commission Staff and other interested parties to develop the components for its proposal. The Company will file its Demand Side Management and Energy Efficiency Ownership Plan as part of its Energy Efficiency Implementation Plan which will be filed in connection with the Commission's Energy Efficiency Rules.

RUCO'S RESPONSES TO UNS ELECTRIC'S DATA REQUESTS
DOCKET NO. E-04204A-09-0206

EXHIBIT
UNSE-29
ADMITTED

2.10
2.12
2.17

UNSE 2.10 Has Dr. Johnson's residential customer charge methodology ever been approved at the Arizona Corporation Commission? If so, please provide the case.

RESPONSE:

(Dr. Johnson)

Dr. Johnson is not aware of any prior proceeding in which the ACC approved or rejected the residential customer charge methodology he has proposed in this proceeding.

RUCO'S RESPONSES TO
UNS ELECTRIC, INC.'s
SECOND SET OF DATA REQUESTS
RE: DOCKET NO. E-04204A-09-0206
NOVEMBER 24, 2009

UNSE 2.12 Has Dr. Johnson studied any data on the housing stock in the UNS Electric service territory, specifically housing occupied by low income customers?

RESPONSE:

(Dr. Johnson)

No.

UNSE 2.17 Are there any aspects of RUCO's accounting adjustments and revenue requirement claim which represents a conscious deviation from the principles and policies established in the prior UNS Electric rate case (Docket No. E-04204A-06-0783), in the recent UNS Gas rate case (Docket No. G-04204A-08-0571), and in prior Commission Orders? If so, identify each area of deviation, and for each deviation explain RUCO's perception of the principle established in the prior Commission orders, how RUCO's proposed treatment in this rate case deviates from the principles established in the prior Commission orders, and the dollar impact resulting from such deviation. Show which accounts are affected and the dollar impact on each account for each such deviation.

RESPONSE:

(Dr. Johnson)

Dr. Johnson has not reviewed the referenced orders in exhaustive detail. However, he is aware that the Commission sometimes allows post test year plant and equipment in rate base. To that extent, Dr. Johnson's recommended end-of-test-year cutoff for rate base items is intended to be a deviation from Commission precedent.

EXHIBIT
UNSE-30
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF UNS ELECTRIC, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS ELECTRIC, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. E-04204A-09-0206 **NOTICE OF FILING LATE-FILED EXHIBIT**

UNS Electric, Inc., (the "Company") through undersigned counsel, hereby files the attached late-filed exhibit incorporating changes to the Company's proposed rules and regulation that were set forth in its Rejoinder filing. These pages replace the corresponding pages in the revised Exhibit TAM-5 to Mr. McKenna's testimony.

RESPECTFULLY SUBMITTED this 9th day of February 2010.

UNS Electric, Inc.

By ______________________
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Jason D. Gellman
ROSHKA DEWULF & PATTEN, PLC.
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and

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Tucson, Arizona 85702

Attorneys for UNS Electric, Inc.

Original and thirteen copies of the foregoing filed this 9th day of February 2010, with:

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

Copy of the foregoing hand-delivered/mailed this 9th day of February 2010, to:

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Steve Olea
Director, Utilities Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

By Mary Ippolito

CLEAN

VERSION

SECTION 9
LINE EXTENSIONS
(continued)

B. Minimum Written Agreement Requirements

1. Each line extension agreement must, at a minimum, include the following information:

    a. Name and address of applicant(s);

    b. Proposed service address(es) or location(s);

    c. Description of requested service;

    d. Description and sketch of the requested line extension;

    e. A cost estimate to include itemized material costs, labor, and other itemized costs as necessary;

    f. The Company's estimated start date and completion date for construction of the line extension.

2. Each Applicant will be provided with a copy of the written line extension agreement.

C. Line Extension Costs

1. Calculations of estimated line extension costs will include the following:

    a. Material cost;

    b. Direct labor cost; and

    c. Overhead cost.

        (i) Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs including but not limited to:

        Indirect labor
        Engineering
        Transportation
        Taxes (e.g. FICA, State & Federal Unemployment which are properly allocated to construction)
        Insurance
        Stores expense

SECTION 9
LINE EXTENSIONS
(continued)

General office expenses allocated to costs of construction
Power operated equipment
Employee Pension and Benefits
Vacations and Holidays
Miscellaneous expenses properly chargeable to construction

D. Conditions Governing Extensions of Electric Distribution Lines and Services

Line extension measurements will be along the route of construction required. This measurement will include primary, secondary and service lines.

1. Prior to the installation of facilities, the Customer will be required to pay the estimated cost of the construction of the distribution facilities. Upon completion of construction the Company will compare actual cost to the estimated cost and any difference will be either billed or refunded to the Customer.

2. Overhead Extensions

   Except as otherwise provided herein, overhead extensions will be made as follows:

   a. The Company will install, own, and maintain the distribution facilities necessary to provide permanent service to the Customer. Prior to the installation of facilities, the Customer will be required to pay the estimated cost of the construction of the distribution facilities.

   b. The Company will extend its overhead distribution facilities to any Customer, or group of Customers, whom the Company considers permanent. Extensions for Irrigation customers, however, will be governed under Subsection 9.D.5.a. of these Rules and Regulations.

REDLINED

VERSION

SECTION 9
LINE EXTENSIONS

Introduction

A request for electric service often requires the construction of new distribution lines of varying distances. The distances and cost vary widely depending upon Customer's location and load size. With such a wide variation in extension requirements, it is necessary to establish conditions under which the Company will extend its electric facilities.

All extensions are subject to the availability of adequate capacity, voltage and Company facilities at the beginning point of an extension, as determined by the Company.

A. General Requirements

1. Upon request by an Applicant for a line extension, the Company will prepare without charge, a preliminary electric design and a rough estimate of the cost of installation to be paid by said Applicant.

2. Any Applicant for a line extension requesting the Company to prepare detailed plans, specifications, or cost estimates will be required to deposit with the Company an amount equal to the estimated cost of preparation. The Company will, upon request, make available within ninety (90) days after receipt of the deposit referred to above, those plans, specifications, or cost estimates of the proposed line extension. Where the applicant authorizes the Company to proceed with construction of the extension, the deposit will be credited to the cost of construction, the deposit will be non-refundable. If the extension is to include over sizing of facilities to be done at the Customer's expense, appropriate details will be set forth in the plans, specifications and cost estimates. Subdividers providing the Company with approved plats will be provided with plans, specifications, or cost estimates within ninety (90) days after receipt of the deposit referred to above.

3. The Company will provide the Applicant with the estimated costs of extending service prior to the Applicant's acceptance of the Company's line extension agreement. The estimated costs provided to the Applicant will be itemized.

4. All line extension agreements requiring payment by the Applicant will be in writing and signed by each party.

5. All charges are due and payable at the time the line extension agreement is executed.

6. The provisions of this rule apply only to those Applicants who, in the Company's judgment, will be permanent Customers. Extension of facilities will not begin until the satisfactory completion of required site improvements, as determined by the Company, and an approved service entrance to accept electric service has been installed.

SECTION 9
LINE EXTENSIONS
(continued)

B. Minimum Written Agreement Requirements

1. Each line extension agreement must, at a minimum, include the following information:

   a. Name and address of applicant(s);

   b. Proposed service address(es) or location(s);

   c. Description of requested service;

   d. Description and sketch of the requested line extension;

   e. A cost estimate to include itemized materials~~s~~ costs, labor, and other itemized costs as necessary;

   f. The Company's estimated start date and completion date for construction of the line extension.

2. Each Applicant will be provided with a copy of the written line extension agreement.

C. Line Extension Costs

1. Calculations of estimated line extension costs will include the following:

   a. Material cost;

   b. Direct labor cost; and

   c. Overhead cost.~~;~~

      (i) Overhead costs are represented by all the costs which are proper capital charges in connection with construction, other than direct material and labor costs including but not limited to:

      Indirect labor
      Engineering
      Transportation
      Taxes (e.g. FICA, State & Federal Unemployment which are properly allocated to construction)
      Insurance
      Stores expense

SECTION 9
LINE EXTENSIONS
(continued)

General office expenses allocated to costs of construction
Power operated equipment
Employee Pension and Benefits
Vacations and Holidays
Miscellaneous expenses properly chargeable to construction

D. Conditions Governing Extensions of Electric Distribution Lines and Services

Line extension measurements will be along the route of construction required. This measurement will include primary, secondary and service lines.

1. Prior to the installation of facilities, the Customer will be required to pay the estimated cost of the construction of the distribution facilities. Upon completion of construction the Company will compare actual cost to the estimated cost and any difference will be either billed or refunded to the Customer~~-~~.

~~b.~~

UNS Electric Base Power Supply & PPFAC Component Comparisons
2009 Rate Case
in Cents per kWh

	A	B	C	D
	Present Rates thru May 31, 2010	Proposed Rates if Effective Prior to June 1, 2010	Present Rates With Est. PPFAC Chg. @ June 1, 2010	Proposed Rates if Effective After June 1, 2010
Average Base Power Supply Rate	7.12	6.77	7.12	6.77
PPFAC - Forward Component	-0.30	0.34	-0.006	0.34
Est. Avg. Cost For PPFAC Cycle	6.82	7.11	7.11	7.11
PPFAC - True-up Component	-0.75	0.07	0.07	0.07
Total of Base Cost and PPFAC	6.07	7.18	7.18	7.18

A: Column A reflects the system wide average base power supply rate within present rates and the PPFAC rate presently in effect for the period June 1, 2009 - May 31, 2010.

B: The Company proposes that if the new rates go into effect prior to June 1, 2010 the PPFAC process be accelerated and the new rates and the new PPFAC rates go into effect simultaneously. Column B reflects the Company's present estimate of the average system cost and the associated PPFAC components based on the reduced base power supply rate.

C: The Company proposes that if the new rates go into effect after June 1, 2010 the PPFAC process be allowed to go through its normal process. Column C reflects the Company's present estimate of the average system cost and the associated PPFAC components based on the base power supply rate presently in effect.

D: The Company proposes that if the new rates go into effect after June 1, 2010 the PPFAC process be allowed to go through its normal process at June 1. Then when the new rates are approved and put into effect the PPFAC rate be reset to synchronize with the estimated average system cost. Column D reflects that reclass and the resulting anticipated changes.

tabbies EXHIBIT UNSE-31 ADMITTED

UNS ELECTRIC BILL IMPACTS

Test Year Ended 12/31/2008; Filed 4/30/2009
DSM & REST NOT Included

Residential Bill Impacts

Average Monthly Usage (kWh)	Small 444	Median 681	Average 874	Large 1,058
Excludes DSM & REST				
April 30, 2009 (Filing)	$54.35	$81.13	$103.14	$124.11
June 1, 2009 (PPFAC Chg)	$43.13	$63.90	$81.02	$97.34
June 1, 2010 (PPFAC Chg)	$48.09	$71.51	$90.79	$109.17
Proposed Rates (with PPFAC est.)	$52.63	$78.22	$99.26	$119.31
% Change - 4/30/09 to 6/1/09	-20.7%	-21.2%	-21.4%	-21.6%
% Change - 6/1/09 to 6/1/10	11.5%	11.9%	12.1%	12.2%
% Change - 6/1/10 to Proposed Rates	9.4%	9.4%	9.3%	9.3%
% Change - 4/30/09 to Proposed Rates	-3.2%	-3.6%	-3.8%	-3.9%

Residential Rates

Charge	30-Apr-09	1-Jun-09
Customer Charge	$7.50	$7.50
Energy Charge 1st 400 kWhs	$0.011255	$0.011255
Energy Charge, all additional kWhs	$0.021269	$0.021269
Base Power Supply Charge, all kWhs	$0.077993	$0.077993
PPFAC	$0.014746	($0.010564)

Charge	1-Jun-10	Proposed
Customer Charge	$7.50	$8.00
Energy Charge 1st 400 kWhs	$0.011255	$0.020070
Energy Charge, all additional kWhs	$0.021269	$0.030084
Base Power Supply Charge, all kWhs	$0.077993	$0.074812
PPFAC	$0.000621	$0.004101

CARES Bill Impacts

Average Monthly Usage (kWh)	Small 411	Median 621	Average 772	Large 899
Excludes DSM & REST				
April 30, 2009 (Filing)	$40.62	$63.92	$78.84	$98.02
June 1, 2009 (PPFAC Chg)	$32.30	$50.39	$61.99	$76.11
June 1, 2010 (PPFAC Chg)	$35.97	$56.37	$69.44	$85.79
Proposed Rates (with PPFAC est.)	$30.49	$49.25	$61.41	$75.97
% Change - 4/30/09 to 6/1/09	-20.5%	-21.2%	-21.4%	-22.4%
% Change - 6/1/09 to 6/1/10	11.4%	11.9%	12.0%	12.7%
% Change - 6/1/10 to Proposed Rates	-15.3%	-12.6%	-11.6%	-11.4%
% Change - 4/30/09 to Proposed Rates	-24.9%	-22.9%	-22.1%	-22.5%

Note: Includes CARES discounts of 30% (0-300 kWh/mo.), 20% (301-600 kWh/mo.), 10% (601-1000 kWh), or $8.00 (for over 1000 kWh/mo.)

CARES Rates

Charge	30-Apr-09	1-Jun-09
Customer Charge	$7.50	$7.50
Energy Charge 1st 400 kWhs	$0.011255	$0.011255
Energy Charge, all additional kWhs	$0.021269	$0.021269
Base Power Supply Charge, all kWhs	$0.077993	$0.077993
PPFAC	$0.014746	($0.010564)

Charge	1-Jun-10	Proposed
Customer Charge	$7.50	$3.50
Energy Charge 1st 400 kWhs	$0.011255	$0.011255
Energy Charge, all additional kWhs	$0.021269	$0.021269
Base Power Supply Charge, all kWhs	$0.077993	$0.071660
PPFAC	$0.000621	$0.000000

Small Comm Bill Impacts

Average Monthly Usage (kWh)	Small 500	Median 600	Average 1,001	Large 5,000
Excludes DSM & REST				
April 30, 2009 (Filing)	$69.47	$81.76	$131.06	$622.73
June 1, 2009 (PPFAC Chg)	$56.81	$66.58	$105.73	$496.18
June 1, 2010 (PPFAC Chg)	$62.41	$73.29	$116.93	$552.10
Proposed Rates (with PPFAC est.)	$68.10	$80.02	$127.82	$604.51
% Change - 4/30/09 to 6/1/09	-18.2%	-18.6%	-19.3%	-20.3%
% Change - 6/1/09 to 6/1/10	9.8%	10.1%	10.6%	11.3%
% Change - 6/1/10 to Proposed Rates	9.1%	9.2%	9.3%	9.5%
% Change - 4/30/09 to Proposed Rates	-2.0%	-2.1%	-2.5%	-2.9%

Small Comm Rates

Charge	30-Apr-09	1-Jun-09
Customer Charge	$12.00	$12.00
Energy Charge 1st 400 kWhs	$0.022449	$0.022449
Energy Charge, all additional kWhs	$0.032463	$0.032463
Base Power Supply Charge, all kWhs	$0.075738	$0.075738
PPFAC	$0.014746	($0.010564)

Charge	1-Jun-10	Proposed
Customer Charge	$12.00	$12.50
Energy Charge 1st 400 kWhs	$0.022449	$0.032440
Energy Charge, all additional kWhs	$0.032463	$0.042454
Base Power Supply Charge, all kWhs	$0.075738	$0.072649
PPFAC	$0.000621	$0.004101

EXHIBIT
tabbies
UNSE-32
ADMITTED

COMMISSION STAFF RESPONSES TO UNS ELECTRIC'S DATA REQUESTS
DOCKET NO. E-04204A-09-0206

EXHIBIT
UNSE-33
ADMITTED

3.36
3.37
3.40
3.52
3.53
3.57
3.61
3.66
3.71
3.72

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO
UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
NOVEMBER 30, 2009

Data Requests for Witness Mr. David C. Parcell

UNSE 3.36 Does Mr. Parcell believe the method used to determine the fair rate of return on fair value rate base ("FVRB") in Decision No. 70441 (July 28, 2008) was reasonable? Please explain why or why not.

RESPONSE: **Yes, Mr. Parcell believes the method used was reasonable. Mr. Parcell also believes the method he is proposing in this case is reasonable.**

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO
UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS
DOCKET NO. E-04204A-09-0206
NOVEMBER 30, 2009

UNSE 3.37	Does Mr. Parcell believe the method used to determine fair rate of return on FVRB in Decision No. 71308 (October 21, 2009) was reasonable? Please explain why or why not.
RESPONSE:	**Yes, Mr. Parcell believes the method used was reasonable. Mr. Parcell also believes the method he is proposing in this case is reasonable.**
RESPONDENT:	**David C. Parcell**
WITNESS:	**David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.40 Please provide any and all analysis Staff (including any witnesses or consultants) conducted to determine whether UNS Electric will be able to achieve its return on common equity recommended in this case. This includes:

a. Analysis to determine how Staff's recommendations affect the Company's earnings comparable to other similarly-situated entities.

b. Analysis to determine how Staff's recommendations affect the Company's financial integrity.

c. Analysis to determine how Staff's recommendations affect the Company's ability to attract capital.

d. Analysis to determine how Staff's recommendations affect the Company's ability to operate in an efficient manner.

e. Analysis to determine how Staff's recommendations affect the financial soundness of UNS Electric.

f. Quantitative analysis to determine how Staff's recommendations affect UNS Electric's ability to finance interest expense.

g. Quantitative analysis of Staff's recommendations as it affects the Company's Cash Flows from Operating Activities.

h. Quantitative analysis of Staff's recommendations as it affects UNS Electric's overall creditworthiness.

RESPONSE:

a. Mr. Parcell's testimony does not address whether UNS Electric will or will not earn the return he is recommending.

b. Mr. Parcell's testimony addresses this on page 41 and Schedule 13.

c. Please see response to b. above.

d. Mr. Parcell has not addressed the efficiency of UNS Electric in his testimony.

e. See response to UNSE 3.40b. above.

f. See response to UNSE 3.40b. above.

g. Mr. Parcell has not addressed the cash flow of UNS Electric.

h. See response to UNSE 3.40b. above.

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.52 Regarding Mr. Parcell's Direct Testimony at page 38, what does Mr. Parcell believe the relationship to be between access to credit and the cost of common equity? Specifically:

a. Does Mr. Parcell believe there is a relationship between cost of common equity and access to credit? If the answer is no, then please explain why not. If the answer is yes, then please explain what Mr. Parcell believes the relationship to be.

b. Does Mr. Parcell agree that access to credit was compromised during the time when, as he puts it, "the United States and global financial markets have been in turmoil"?

c. Does Mr. Parcell agree that entities both regulated and unregulated were seeking access to credit at a time when, as he puts it, "global credit markets [were] virtually coming to a standstill"?

d. Does Mr. Parcell agree that UNS Electric had the responsibility to ensure safe, reliable and adequate service regardless of the credit turmoil and to provide, as he puts it, "a product with no real substitutes"?

e. Does Mr. Parcell believe that Demand-Side Management programs for UNS Electric are non-productive since "consumers can do little to control the amount [of electricity] they use"?

RESPONSE:

a. No such "relationship" is cited on page 38.

b. Please see pages 14-15 of Mr. Parcell's testimony.

c. Mr. Parcell agrees with this, but does not agree that it would have necessarily have been prudent to raise long-term capital during this period.

d. Yes.

e. Mr. Parcell has not addressed this in his testimony.

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.53	What, in Mr. Parcell's view, does UNS Electric need to show in order to demonstrate that UNS Electric' risks have increased to justify a higher cost of equity, referencing page 39 of his Direct Testimony?
RESPONSE:	**Mr. Parcell has not addressed this in his testimony.**
RESPONDENT:	**David C. Parcell**
WITNESS:	**David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.57 Please provide Mr. Parcell's understanding of the purpose of UNS Electric's revolving credit facility. Please reference all documentation that supports Mr. Parcell's understanding of that credit facility. Does Mr. Parcell believe those funds can be used for the purchase of providing "bridge financing" of generation facilities? Please explain why or why not.

RESPONSE: **Mr. Parcell has not addressed the "purpose" of UNS Electric's revolving credit facility in his testimony.**

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.61 Would Mr. Parcell agree that the collapse of the financial markets since 2007 due in part to the "sub-prime" mortgage crisis has been unusual and more extreme than the typical contractions from the previous three business cycles? Please explain why or why not.

RESPONSE: **Yes. Please see financial data in Schedule 2.**

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.66 Does Mr. Parcell believe that projections 25 to 70 years into the future are more or less reliable than projected earnings growth only five years through 2014? Please explain why or why not.

RESPONSE: **Yes. This is why he has not used such projections.**

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.71	Do investors expect real (i.e., non-inflation) growth in their investment? If not, explain why not.
RESPONSE:	**As a general rule, yes.**
RESPONDENT:	**David C. Parcell**
WITNESS:	**David C. Parcell**

ARIZONA CORPORATION COMMISSION STAFF'S RESPONSES TO UNS ELECTRIC INC.'S THIRD SET OF DATA REQUESTS DOCKET NO. E-04204A-09-0206 NOVEMBER 30, 2009

UNSE 3.72 Understanding that Mr. Parcell believes his return on equity recommendation is sufficient; please indicate whether Staff disagrees with the following statements:

a. It is critical that UNS Electric has the financial resources necessary to meet the infrastructure and energy supply needs of its customers;

b. UNS Electric competes with other electric service providers for the necessary financial resources;

c. UNS Electric funded ongoing capital expenditures through increased equity from UniSource Energy Corporation;

d. UNS Electric, while an affiliate, is an entity separate and apart from UniSource Energy Corporation;

e. UniSource Energy Corporation, as a separate entity, must consider the value and risk of infusing additional equity into UNS Electric; and

f. To get other sources of equity financing, UNS Electric must offer a return on equity commensurate with its risk as compared to other electric service providers.

RESPONSE:

a. Yes

b. If this request refers to capital attraction, the answer is yes.

c. Mr. Parcell is aware that this has been maintained by UNS Electric.

d. Yes, because this is the manner in which UniSource has chosen to structure UNS Electric.

e. Yes, along with other factors.

f. Mr. Parcell does not understand the meaning of "to get other sources of equity financing."

RESPONDENT: **David C. Parcell**

WITNESS: **David C. Parcell**

EXHIBIT
UNSE-34
ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF ARIZONA PUBLIC SERVICE COMPANY FOR A HEARING TO DETERMINE THE FAIR VALUE OF THE UTILITY PROPERTY OF THE COMPANY FOR RATEMAKING PURPOSES, TO FIX A JUST AND RESONABLE RATE OF RETURN THEREON, AND TO APPROVE RATE SCHEDULES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01345A-08-0172

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

DECEMBER 19, 2008

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 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for APS. 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:

Discounted Cash Flow	9.5-11.0%
Capital Asset Pricing Model	8.8-9.1%
Comparable Earnings	9.5-10.5%

Q. What is your Cost of Equity recommendation for APS?

A. I recommend a cost of equity of 9.0 percent to 11.0 percent for APS. This reflects each of my three cost of equity model results. Within this range, I recommend an 11.0 percent level, or slightly above the return on equity approved for APS in the Company's last rate proceeding. Even though a lower cost of equity (e.g., the mid-point of my 9.0 percent to 11.0 percent range) could be justified, my 11.0 percent recommendation reflects Staff's desire to aid APS in its efforts to attract captitol investment, as cited in the testimony of Staff witness Johnson.

Q. Please explain how the recent and current economic and financial crisis impacts the Cost of Equity for APS.

A. It is well chronicled that, over the past year and especially over the past few months, the United States and global financial markets have been in turmoil. The impacts of this have been far-reaching and extreme, with global credit markets virtually coming to a standstill. This crisis and its impact, however, do not imply that the cost of equity for electric utilities such as APS has increased. I say this for the following reasons.

First, it must be emphasized that depressed economic conditions and the financial crisis affects virtually all sectors of the economy – households, small businesses, larger commercial and industrials – and, in most cases, the impact is greater than is the case for APS. APS is a regulated utility that sells a product that has no real substitutes and is a product that consumers can do little to control the amount they use. As such, APS and utilities are partially, if not largely, insulated from the impacts of depressed economic conditions.

Second, if a recession is a significant one, the major impact will be to depress the profits of most enterprises. As a result, it is to be expected that capital costs will decrease if a significant recession occurs. There is no justification for increasing the profit level of a regulated utility such as APS at the same time that other enterprises are experiencing lower profits.

Third, even if APS were to incur higher costs of debt and/or other capital costs, these costs can be passed along to ratepayers at the next rate proceeding. Unregulated firms cannot do this.

Fourth, there is no indication that APS' risks have increased since its last rate proceeding. The Company's debt ratings have remained the same, indicating an objective assessment by the rating agencies that there is no significant change in APS' credit quality. Absent a demonstration that APS' risks have increased, there is no justification for increasing its cost of equity.

Fifth, the United States and global governments have and are taking extraordinary measures to avoid a further worsening of the current market turmoil. Most of these measures are designed to put liquidity into the credit markets and make credit more accessible again and, in the process, restore more confidence to the financial markets. All of these measures are clearly designed to lower the cost of capital. In this environment, it would be counter-productive to make any claim that APS should have a higher return at this time due to the above-cited market turmoil.

XII. TOTAL COST OF CAPITAL

Q. What is the total Cost of Capital for APS?

A. Schedule 1 reflects the total cost of capital for the Company using APS's proposed capital structure and cost of debt along with the range of common equity costs my analyses support. The resulting total cost of capital is a range of 7.51 percent to 8.58 percent. I recommend that a 8.58 percent total cost of capital be established for APS.

EXHIBIT

UNSE-85

ADMITTED

BEFORE THE ARIZONA CORPORATION COMMISSION

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

IN THE MATTER OF THE APPLICATION OF TUCSON ELECTRIC POWER COMPANY FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	DOCKET NO. E-01933A-07-0402
IN THE MATTER OF THE FILING BY TUSCON ELECTRIC POWER COMPANY TO AMEND DECISION NO. 62103.	DOCKET NO. E-01933A-05-0650

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

FEBRUARY 29, 2008

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-10.5%
Capital Asset Pricing Model	9.5-9.8%
Comparable Earnings	10.0-10.5%

My overall conclusion from these results is a reasonable range of 9.5 percent to 10.5 percent, which focuses on the respective individual model findings.

The mid-point of this range is 10.0 percent, which is applicable to the proxy companies. However, this 10.0 percent mid-point is not applicable to TEP, which has higher risk and thus a lower cost of capital than the proxy group companies. This higher risk is due to the following:

- Lower bond ratings of TEP versus the bond ratings of the proxy companies; and,
- Lower equity ratio, and thus higher financial risk, for TEP versus the proxy companies.

I recommend a cost of equity at the upper end of this range, or 10.25 percent for TEP, to recognize these differences.