# News from the Oklahoma Corporation Commission

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**January 7, 2009**

## MEDIA ADVISORY

**WHO: Corporation Commissioner Dana Murphy**

**WHAT: Republican Dana Murphy will take the oath of office for her first term as an Oklahoma Corporation Commissioner 1/12/09. Former Oklahoma Secretary of Tourism Jane Jayroe Gamble will serve as Mistress of Ceremonies, while Oklahoma Supreme Court Vice-Chief Justice Steven W. Taylor will administer the oath. The Murphy family and honored guests will be present.**

**WHEN: The ceremony will take place Monday January 12, 2009 at 3:00 p.m. Media are advised to arrive early.**

**WHERE: The Commissioners' Courtroom (Room 301) on the third floor of the Jim Thorpe Office Building, State Capitol Complex, 2101 N. Lincoln Blvd, Oklahoma City, OK.**

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**January 14, 2009**

# MEDIA ADVISORY - PSO RATE CASE

**The Oklahoma Corporation Commission today approved* a final order in the Public Service Company of Oklahoma (PSO) rate case. The full final order is attached.**

**In brief:**

- **A legislatively-imposed deadline of 180 days applied to this case. After 180 days from the date the case was filed, the law approved by the legislature allows the utility to impose the full rate hike request if the Commission has not made a decision, subject to refund when a Commission decision is made. The 180 day period ended this month.**
    - **The Commission's handling of the case included two full weeks of public hearings, hundreds of hours and thousands of pages of sworn testimony from dozens of parties to the case, soliciting and receiving comment from the public by telephone, email, mail, and directly before the Commission, and a final public deliberation today.**
- **PSO had initially requested an overall increase (rates and other charges) of $126.6 million**
- **All parties to the case recommended substantial rate increases of varying amounts. This included the Attorney General (who represents consumers before the Commission) at approximately $75 million, to the OIEC (which represents industrial consumers) at approximately $40 million. The referee in the case recommended an overall increase of $92.5 million.**
- **The Commissioners approved an overall increase of $81.4 million. Among other things, this includes a $7.7 million increase in funding for programs (such as line burial) to "harden" the PSO infrastructure against weather. The increase for the average residential consumer is estimated at 7.59% .**

***Note: Commissioner Dana Murphy, who took office on Monday, January 12 did not vote on the case.**

**Witness Testimonies** **Final Order**

**PUD Cause No. 2008001444 – Revenue Distribution**

**PUD Cause No 2008001444 - Revenue Requirement**

**-OCC-**

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**ATTACHMENT "A"**

**Summary of Evidence**

**PSO Witnesses**

**Michael G. Morris**

Mr. Morris received Bachelor's and Master's Degrees in Science from Eastern Michigan University. He also received a law degree from Detroit College of Law. He has spent his entire professional career in the energy industry. Prior to joining the AEP System in January 2004, he was Chairman, President and Chief Executive Officer of the Northeast Utilities system; President and Chief Executive Officer of Consumers Energy; President of Colorado Interstate Gas Company; Executive Vice President of marketing, transportation and gas supply for ANR Pipeline Company; and founder and President of ANR Gathering Company.

He is currently Chairman of the Board and Chief Executive Officer and President of American Electric Power Service Corporation (AEPSC) and American Electric Power Company, Inc. (AEP). He is also Chairman of the Board and Chief Executive Officer of the AEP operating companies, including Public Service Company of Oklahoma (PSO).

His direct testimony emphasized the importance of this case to PSO and its customers. He described the many challenges presented to PSO by the current environment, including continuing growth in demand for electricity, deteriorating returns, continuing significant increases in the costs to operate and maintain its facilities, PSO's substantial new investment, and the requirement for substantial new investment in the future. He emphasized that, in the midst of these challenges, it is PSO's goal to provide the reliable electric service that customers expect while encouraging and educating them about the benefits of using service more efficiently.

He explained that achieving these goals and meeting these challenges requires a substantial commitment of funds from the capital markets, which is more readily available at a reasonable cost if the markets have confidence that their investments will be recovered timely with a competitive return. PSO's testimony and schedules were provided to demonstrate that the needs of customers require a substantial revenue increase to meet these challenges.

His testimony also described the relationship between AEP and PSO, the responsibilities faced by PSO as a member of the AEP system, and the overall direction of AEP and PSO.

His testimony contained and described AEP's Corporate Sustainability Report, which contains AEP's strategy for meeting key stakeholders' needs, including those of customers, regulators, shareholders, employees and communities. The objective is to safely provide reliable, reasonably priced electric power while working to protect people and the environment. The Report identifies seven material issues, states the challenges associated with each issue and specifies goals and progress towards them. The issues include leadership, management and work force issues; the need for a modern, reliable delivery system and adequate, fuel diverse generation that is environmentally compliant and considers the health of AEP's communities; addressing climate change through the development of commercial scale technologies and actively engaging policy makers to ensure that laws and regulations allow AEP to continue to serve its customers and reward shareholders. AEP also recognizes the need to work closely with its numerous stakeholders, being transparent and listening to all points of view, and holding itself accountable for its impacts. Of paramount importance to AEP is the health and safety of its employees and contractors and the communities it serves.

He testified that if PSO is to meet these challenges on behalf of its customers, shareholders, employees and communities, additional rate relief is required. He expressed PSO's appreciation for past Commission support for PSO with rate relief to meet its challenges, and cited examples including approval of a vegetation management rider; allowing PSO to recover major 2007 ice storm operation and maintenance expenses; the approval of a rider to cover the cost of adding new peaking facilities; and the recognition that PSO needs 450 MW of baseload capacity, the hiring of an independent evaluator and initiation of a DSM proceeding that has facilitated a collaborative effort to address future needs.

He reiterated that PSO continues to need a base revenue increase to support its continuing investment and recover the significant increases in operations and maintenance expenses it is incurring. He emphasized that a fair return on PSO's investment is critical to attracting the capital needed to meet the challenges that PSO faces. PSO represents a substantial investment to AEP shareholders. Those shareholders require a reasonable return to make the additional investment in new generation, environmental improvements, and transmission and distribution assets to serve customers. It is important for PSO to provide a reasonable return so that the service customers expect, can continue to be achieved.

Meeting the challenges set forth in the Corporate Sustainability Report will require AEP and PSO to make substantial investments in PSO's distribution, transmission and generation facilities. The capital investments needed to prepare PSO to meet the needs of its customers going forward necessarily comes from cash from operations, capital contributions and securities issuances. PSO's financial performance can be adversely affected by the lag in time between when an investment is made and when it is recognized for ratemaking purposes, an effect that undermines PSO's ability to make these important investments. If PSO is to be successful going forward, it needs the support of its regulators to adopt progressive approaches toward the timely recognition of these costs in rates.

He testified that investors and market analysts look at the ratemaking treatment afforded a company's investments by regulatory commissions when making investment and ratings decisions. If they are confident that a company will be allowed timely recovery of its investments, they will be more inclined to invest in that company or rate it more favorably, which is critical to being able to maintain the credit quality and cost of capital required to be able to fund the investments PSO is planning.

PSO's financial performance therefore depends in part on the policies and practices of its regulators. It is critical to allow PSO the opportunity to earn a reasonable return on the capital PSO invests. These actions by the Commission are essential to meet the growing needs of PSO's customers and are in the best interests of both the company and its customers.

**Stuart Solomon**

Mr. Solomon received a Bachelor of Arts degree in Sociology from Southwestern University; a Masters of Business Administration degree from University of Texas; and a Juris Doctorate from the University of Colorado. He has been President and Chief Operating Officer of PSO since 2004.

Mr. Solomon's direct testimony expressed that significant rate relief through this filing is essential to PSO's financial health and its ongoing provision of reliable service to customers. Adequate rate relief will allow PSO to fully recover the costs of investments the Company has made, support PSO's increased spending levels, and provide an adequate return to ensure ongoing investment on reasonable terms. The investments made by PSO, and the increased O&M costs, provide benefits to PSO's customers through the provision of safe, reliable, and adequate electric power.

Failure to receive adequate rate relief through this case would financially weaken the Company and could adversely impact PSO's ability to continue to provide the service its customers need and expect. If investors cannot be assured of recovering the costs of their investments along with a reasonable return, the costs of financing investments will increase, thereby increasing costs to customers. PSO's current return on equity is far below that of comparable utilities, which if not addressed could have an adverse impact on PSO's ability to raise capital at a reasonable cost.

PSO has worked hard to control costs and provide increasingly reliable service to customers. Despite increases in fuel costs over the past few years, PSO's prices remain below national averages and continue to provide a good value for customers. PSO is concerned about the impacts of price increases on low-income customers and has taken some steps to help these customers better deal with increased energy prices, and continues to investigate other approaches to address this issue.

PSO's commitment to the communities it serves goes beyond the provision of safe and reliable service, and includes economic development assistance, financial assistance to community organizations and events, and employee volunteer efforts and leadership in community organizations.

**David P. Sartin**

Mr. Sartin received a Bachelor of Science degree in Business Administration from Oklahoma State University in 1978. In 1987, he received a master of Business Administration degree in finance from the University of North Texas. He is a Certified Public Accountant in Oklahoma and a member of the American Institute of Certified Public Accountants.

Mr. Sartin has worked in the electric utility industry in the areas of accounting, finance, and regulatory since 1978, and is currently Public Service Company of Oklahoma's Director, Business Operations Support. In this position, he is responsible for coordinating PSO's financial planning with other American Electric Power Corporation, Inc., organizations.

Mr. Sartin's direct testimony provided PSO financial information for the period 2006 through 2009. It described PSO's financial results, including key credit metrics, from the time of PSO's last base rate case filing in 2006 through 2009, the first calendar year when rates from this application are expected to be in effect. PSO's financial results support the need for rate relief in this application by showing PSO has not been earning its allowed return and, even with rate relief in this case, is not expected to earn a reasonable return in 2009 because of the effects of regulatory lag. His direct testimony also summarized additional investments PSO has made since its last base rate case and the higher costs PSO is experiencing, to explain why PSO's current revenues are not adequate. Lastly, Mr. Sartin discussed expectations for PSO capital investment over the next five years, which will require PSO to continue to access capital markets.

Mr. Sartin's rebuttal testimony addressed the pre-filed testimony of Fairo Mitchell of the Oklahoma Corporation Commission's Public Utility Division regarding PSO's access to capital markets given the recent turmoil in the capital markets. It also addressed PSO's sharing of off-system sales and other margins and interim adjustments to PSO's fuel adjustment factor in response to the testimony of Oklahoma Industrial Energy Consumers (OIEC) witness Mark E. Garrett.

Mr. Sartin explained that due to the substantial unsettled state of current financial markets, PSO's short-term borrowing abilities are reduced, and access to long-term debt may be restricted at this time. Even if PSO can issue debt, the interest cost of the borrowings may not be reasonable. PSO witness Dr. Murry addressed in some detail the current state of U.S. and global financial markets and their impact on PSO's cost of equity. Mr. Sartin discussed the effect of these markets on PSO's spending plans during this uncertain time in the marketplace, which are mostly reduced future capital expenditures until the markets return to some normalcy.

The reductions to capital expenditures, or future cash outflows, will come from temporary reductions in PSO's future construction program, and do not affect the current rate case. The rate base included in this Application reflects actual capital expenditures through February 29, 2008. Future reductions in capital spending do not impact the historical rate base, or the rate base included in PSO's rate case. Further, even with reduced spending, the size of PSO's construction program will cause PSO's rate base to continue to increase, just not at the rate previously planned. Further, the operation and maintenance expenses proposed in this Application are representative of the ongoing level of expenses PSO expects to incur.

PSO's sharing of off-system sales margins, stand-by service margins, and real time pricing margins are a result of long-standing Oklahoma Corporation Commission orders, and Mr. Sartin indicated there are no valid reasons to change them at this time.

OIEC's proposal to change the process currently in place and approved by the Oklahoma Corporation Commission regarding the way adjustments are made to PSO's fuel cost adjustment rider is not warranted. Mr. Sartin testified that the current process was recently reviewed and found to be justified by the OCC in Cause No. PUD 200800150.

**David A. Davis**

Mr. Davis has a Bachelors degree in Business Administration from Ohio University and a Masters Degree in Business Administration from the University of Dayton. He is also a Certified Public Accountant (inactive) in Ohio. He has held accounting positions in the utility industry since 1980 and has been employed in various accounting-related positions with AEP since 1986.

In Mr. Davis' testimony in July 2008, he discussed the revised depreciation accrual rates for PSO's electric plant in service.

Depreciation Study Overview

Mr. Davis' testimony included a comparison of PSO's current rates and the study rates, shown below, which are based on December 31, 2007 depreciable plant balances as adjusted for study purposes:

*Composite Rates and Accruals*

| Functional Plant Group | Existing Rates | Accruals | Study Rates | Accruals |
|---|---|---|---|---|
| Steam Production Plant | 1.77% | $18,955,817 | 2.13% | $22,774,532 |
| Other Production Plant | 2.25% | 3,025,931 | 2.15% | 2,889.826 |
| Transmission Plant | 1.97% | 11,173,071 | 2.29% | 12,995,732 |
| Distribution Plant | 3.13% | 41,677,377 | 3.14% | 41,853,477 |
| General Plant | 3.55% | 5,690,204 | 3.73% | $5,985,125 |
| Total | 2.47% | $80,522,400 | 2.65% | $86,498.692 |

Based on the study results, he recommended an increase in the annual depreciation expense of $5,976,292 or 0.18% in the annual accrual rate. The depreciation rate changes are necessary because of changes in the average service lives and the gross salvage and cost of removal estimates that were used to calculate PSO's current depreciation rates.

Definition of Depreciation

In preparing the study, Mr. Davis used the definition of depreciation used by the FERC and the National Association of Regulatory Utility Commissioners.

Study Methods and Procedures

The Depreciation Study Report includes full descriptions of the methods and procedures. All the property included in this report was considered on a group plan, under which, depreciation is accrued upon the basis of the original cost of all property included in each depreciable plant group instead of individual items of property. Upon retirement of any depreciable property, its full cost, less any net salvage realized, is charged to the accumulated provision for depreciation regardless of the age of the particular item retired. The dollars in each primary plant account are considered as a separate group for depreciation accounting purposes and an annual depreciation rate for each account is determined. The plant groups in this study consisted of the individual primary plant accounts for Production, Transmission, Distribution and General Plant property.

For Production Plant, the generating unit retirement dates and the interim retirement history for the individual plant accounts were used to determine the average service lives and the remaining lives of the plants. The net salvage for each property group was determined based on actual historical experience for the Transmission, Distribution and General Plant accounts. For Production Plant, the net salvage was primarily based on a dismantling cost study performed by Sargent & Lundy, an engineering firm retained by PSO. The depreciation rates were calculated by the Average Remaining Life Method.

Study Results

For Steam Production Plant, the composite rate increased from 1.77% to 2.13% and for Other Production Plant the rates decreased from 2.25% to 2.15%. The changes were caused by a combination of the net effects of: (1) Steam Production Plant - changes (both increases and decreases) in interim plant retirements; (2) Steam Production Plant - changes in removal and salvage amounts; and (3) Other Production Plant - decrease primarily due to changes in removal and salvage amounts. For Transmission Plant, the composite rate increased from 1.97% to 2.29%, which was caused by an increase in the negative net salvage ratio for four accounts, partially offset by a decrease in the net salvage ratio for one account and an increase in the average service life for one account. For Distribution Plant, the composite rate increased from 3.13% to 3.14%, which was caused by increases in the net salvage ratio and decreases in average service lives for some accounts mitigated by decreases in the net salvage ratio and increases in the average service lives for other accounts. The General Plant composite rate increased from the current 3.55% to 3.73% and was mainly attributable to the recommended increase in account 397 Communication Equipment's rate from 3.73% to 4.16%.

Rebuttal Testimony

Mr. Davis' rebuttal testimony of November 2008, rebutted depreciation-related testimony from Oklahoma Commission Staff witness Mr. Lains, AG witness Mr. Pous, OIEC witness Mr. Garrett, and Wal-Mart Stores, Inc. witness Mr. Selecky, who propose depreciation adjustments that would reduce the Company's recommended level of depreciation by amounts ranging from $5.9 million to $21.1 million.

Plant Lives

In the depreciation study, a plant's useful life was used to determine a remaining life over which the remaining cost can be allocated to normalize the plant's cost and spread it ratably over future periods.

The Company's current depreciation rates were the product of plant lives established in the Company's last rate case in Cause No. PUD 200600285, net salvage percentages recommended in the last rate case for Production and General property and calculated net salvage percentages for Transmission and Distribution property from a settlement in the Company's rate case in Cause No. PUD 200300076.

For the Transmission and Distribution net salvage percentage calculation, only the rates were specified in the settlement in Cause No. PUD 200300076 and, as a result, it is not possible to specifically determine plant life and net salvage information. If one assumes that any difference between the requested and the settlement depreciation rates are reflected in net salvage values (rather than in asset useful lives), then the lives and net salvage values can be calculated. This is how Mr. Davis determined the net salvage percentage information provided to the Commission for Transmission and Distribution accounts and the net salvage percentages embedded in the Company's current depreciation rates.

The current depreciation rates are reflected on Attachment 2 on the Commission's Order in Cause No. PUD 200600285.

The current depreciation study maintains the useful lives of production plant embedded in current depreciation rates from Cause No. PUD 200600285. The Company's generation department estimated useful lives for new peaking plants at Riverside and Southwestern generating plants. The plant lives used by the current depreciation study are shown below:

| | | | | |
|---|---|---|---|---|
| ***Steam Production Plant*** | | | | |
| ***Northeastern*** | | | | |
| Unit 3 | Coal | 1979 | 2039 | 60 |
| Unit 4 | Coal | 1980 | 2040 | 60 |
| ***Rail Spur*** | | 1995 | 2040 | 45 |
| ***Oklaunion*** | Coal | 1986 | 2046 | 60 |
| ***Comanche*** | Combined Cycle | 1986 | 2024 | 38 |
| ***Northeastern*** | | | | |
| Unit 1 | Combined Cycle | 2001 | 2036 | 35 |
| Unit 2 | Gas | 1970 | 2035 | 65 |
| ***Riverside*** | | | | |
| Unit 1 | Gas | 1974 | 2034 | 60 |
| Unit 2 | Gas | 1976 | 2036 | 60 |
| ***Southwestern*** | | | | |
| Unit 1 | Gas | 1952 | 2017 | 65 |
| Unit 2 | Gas | 1954 | 2019 | 65 |
| Unit 3 | Gas | 1967 | 2032 | 65 |

| | | | | |
|---|---|---|---|---|
| ***Tulsa*** | | | | |
| Unit 2 | Gas | 1963 | 2025 | 62 |
| Unit 3 (re-started in 2006) | Gas | 2006 | 2015 | 9 |
| Unit 4 | Gas | 1964 | 2026 | 62 |
| ***Other Production Plant*** | | | | |
| ***Weleetka 4*** | | 1975 | 2019 | 44 |
| ***Weleetka 5 & 6*** | | 1976 | 2020 | 44 |
| ***Weleetka*** | | 1963 | 2020 | 57 |
| ***Comanche*** | | 1962 | 2024 | 62 |
| ***Northeastern (1&2)*** | | 1968 | 2036 | 68 |
| ***Northeastern (3&4)*** | | 1980 | 2040 | 60 |
| ***Riverside - Diesel*** | | 1976 | 2036 | 60 |
| ***Southwestern - Diesel*** | | 1962 | 2032 | 70 |
| ***Tulsa*** | | 1967 | 2026 | 59 |
| ***Riverside - Gas Peaking*** | | 2008 | 2056 | 48 |
| ***Southwestern - Gas Peaking*** | | 2008 | 2056 | 48 |

None of the interveners take issue with the production plant depreciable lives used in the current depreciation study.

Production Plant Net Salvage Value

Mr. Lains recommends that the depreciation rates and net salvage values outlined in Attachment 2 of the final order from Cause No. PUD 200600285 remain in effect. His criticisms of the Company's recommended depreciation rates in this case are for the usage of an inflation factor for decommissioning costs and the usage of data bases published by R.S. Means for estimation of current construction costs. Mr. Pous criticizes the Company's determination of production plant net salvage value and proposes a sweeping recommendation that all production plant be assigned a negative 3.10% net salvage value. Mr. Pous also suggests an alternate proposal that reflects a positive 10% net salvage value, which he based on his claims that many of the Company's plants could be sold in the future. Mr. Garrett proposes that the Pennsylvania (PA) method (where the prior five years of removal and salvage costs are used to determine the net salvage percentage applied to future plant) be used for the Company's production plant. Mr. Selecky criticized the Company's use of a contingency factor in its determination of production plant net salvage and recommended that the production plant net salvage should recognize the potential value of generation sites. Mr. Davis does not agree with these intervener proposals. Unlike Mr. Davis' analysis of net salvage values, which is based on a dismantling study performed by Sargent & Lundy (S&L) that is specific to each PSO generating plant, the interveners' proposals are not based on actual plant data. Instead, they rely on references to Texas Commission practices, an incorrect assumption that the Company's net salvage percent calculations are mathematically flawed, an inaccurate conclusion that the PA method should be considered for any net salvage calculation and an incorrect assumption that future brown field sites should provide a benefit to current ratepayers. These assumptions are unsound and should be rejected by the Commission.

Net salvage values are the amount received for retired property (salvage) less any costs incurred to sell or remove the property (removal). When salvage exceeds removal (positive net salvage), the net salvage reduces the amount to be depreciated over time. When removal exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated. For production plant in this depreciation study, the negative net salvage amounts were calculated as a percentage of original cost dollars at December 31, 2007.

The production plant net salvage value that Mr. Davis utilized in the depreciation study was the result of an engineering study performed by S&L, a company with more than 100 years of experience with the utility industry.

The engineering study included a site visit to each of the Company's generating sites and incorporated data used from the site visits to determine removal cost and salvage amounts specific to each generating plant.

When conducting his depreciation study in connection with this case, Mr. Davis started with the results of S&L's demolition analysis and included the cost of interim retirements for each generating station. Mr. Davis applied inflation to S&L's terminal demolition cost that was stated in 2008 dollars to determine the cost of the demolition at the time of that activity. The cost of interim retirements were calculated using an average of salvage and removal costs incurred in the prior five years from 2003 to 2005 as compared to the original cost retirements during this time period to calculate an interim retirement percentage. The interim retirement percentage was applied to the projected interim retirements for each generating station to calculate an interim retirement cost. No inflation was added to the interim retirement calculation and the interim retirement cost added approximately 3% to the overall negative net salvage calculation for the generating plants.

Mr. Davis testified that this is a reasonable method to determine production plant net salvage values for a depreciation study. The S&L terminal net salvage estimates were based on site visits and are specific to the amount and type of demolition expected for each individual plant site. Based on the results of the study, the Company has proposed negative net salvage values ranging from 0% for its diesel generating stations to 24% for its Oklaunion coal generating station.

The effect of the Company's request for revised negative production plant net salvage percentages in this rate proceeding would increase the Company's proposed book depreciation expense by approximately $550 thousand.

In his rebuttal testimony, Mr. Davis responded to Mr. Lains' criticism of the 2.5% inflation applied by the Company to the production plant terminal net salvage calculation. Mr. Lains disagreed with Mr. Davis' contentions.

Mr. Lains indicated that the Livingston survey used by the Company to determine the 2.5% inflation rate predicts a downward trend in the consumer price index (CPI) for the year ended 2008 to 2.1%. While he is correct for the "Short-Run Inflation Outlook Worsens" section of the Livingston survey that indicated a rate of 2.1%, he failed to mention that the "Slight Change in the Long-Term

Outlook" section that indicated the CPI will average 2.5% over the next 10 years. The long-term average of 2.5% was the value Mr. Davis used in the depreciation study.

Mr. Bertheau from S&L addressed Mr. Lains' criticism regarding usage of the R.S. Means data bases.

Mr. Pous claimed that the Company's negative net salvage percentage should be reduced to 3.10% based on his calculation of the cost of demolition at the Breed generation station owned by PSO's affiliate company, Indiana Michigan Power Company (I&M). Mr. Bertheau of S&L discussed the fallacy of using the Breed generation demolition as an example for PSO's generating station demolition costs in his rebuttal testimony.

Mr. Pous failed to mention that I&M has a negative net salvage percentage of 21% for its Tanners Creek Generating Station embedded in its approved rates in the state of Indiana.

Mr. Pous claimed the Company incorrectly assumed inflation is the only driving factor affecting future demolition costs. This criticism is unfair and unreasonable; inflation will affect removal costs. However, there is no way to predict accurately how potential new ways to demolish plants in the future may affect costs.

Mr. Pous indicated that the Company is using a short and inappropriate time period of five years to determine an interim net salvage percentage to apply to production interim retirements. Mr. Davis disagreed that five years of data is too short a time period for determining the interim net salvage percentage. The average interim retirement percentage was determined using data for all of PSO's generating stations for 2003 to 2007. Unlike the PA method that makes no connection between removal cost and original cost to be retired on the Company's books, his calculation applied the average percent calculated to the estimated book amount of interim retirements. Also, the addition of interim net salvage added only approximately 3% to the overall negative net salvage amount calculated in this depreciation study.

Mr. Davis disagrees with Mr. Garrett that the Company should use the PA method to determine the net salvage values for its generating stations. Mr. Davis' analysis of generating station net salvage amounts indicated that 97% of the negative net salvage amount is applicable to the terminal demolition activity. There are no terminal demolitions of plants included in the prior five years of data and consequently this data provided a poor indication of future cost. Mr. Garrett's proposal would necessitate that future customers pay for the ultimate demolition of generating stations.

Mr. Davis disagrees with Mr. Selecky's argument that the fact that a generating plant's site may be reused in the future should be considered in determining salvage values. Only if the utility sells the property to another utility or entity would removal costs be offset. Any re-use of an existing plant site for a new generating unit could benefit future customers by lowering the cost of developing the property for generating station use. Benefits from having an existing site would be speculative and the existing plant site cost would be reflected in the cost of the new plant and associated rates.

The Commission should accept the negative net salvage percentages proposed by the Company in this rate case because they are reasonable. The Company has provided support for the values in the form of a comprehensive plant demolition study undertaken by Sargent & Lundy. The negative salvage percentages requested by the Company are lower than many of those reflected in current depreciation rates approved by this Commission in the Company's last rate proceeding (Cause No. PUD 200600285). In addition the overall production net salvage rates recommended in this case are comparable to the current net salvage rates as indicated by a comparison that shows the recommended net salvage rates change annual depreciation expense by only approximately $550 thousand.

<u>Transmission and Distribution (T&D) Property Net Salvage</u>

T&D net salvage values, in terms of a depreciation study, are the amount received for retired property (salvage) less any costs incurred to sell or remove the property (removal). When salvage exceeds removal (positive net salvage), the net salvage reduces the amount to be depreciated over time and when removal exceeds salvage (negative net salvage), the negative net salvage increases the amount to be depreciated.

For the depreciation study, Mr. Davis determined most of the T&D net salvage values using twenty-three years of Company data to calculate, on an account-by-account basis, a mathematical relationship between original cost retirements, salvage and removal costs. The resulting mathematical relationship was then used to either increase or decrease the amount to be depreciated over time. This is a reasonable and commonly-employed method throughout the industry. It is the same methodology that was used in the Company's last rate case and in the preceding case.

A comparison of proposed T&D net salvage rates with those embedded in Cause No. PUD 200600285 is shown in Exhibit DAD-1, page 28 of the Depreciation Study.

The impact the Company's recommended net salvage percentage changes and changes in life estimates would have when compared to existing depreciation rates is as follows: based on original cost investment at December 31, 2007, the recommended changes are an increase of approximately $1.8 million for Transmission accounts and approximately $176 thousand for Distribution accounts. Combine these modest recommended increases with the $3.6 million increase the Company has requested for Production Plant and the $294 thousand increase for General Plant and the total increase requested by the Company is only $5.9 million or 7.4%.

As a revision to Mr. Davis' calculation of T&D net salvage and depreciation rates, Mr. Lains recommended that the depreciation rates as outlined in Attachment 2 of the final order from Cause No. PUD 200600285, remain in effect. His specific criticisms focused on the production plant inflation factor and usage of the R. S. Means data bases for production plant. It does not appear that he has a specific criticism of the T&D net salvage percentage calculations used by the current depreciation study so it is difficult to determine why he recommended the current net salvage percentages in lieu of the recommended percentages.

While Mr. Lains' recommendation is more reasonable than other interveners, using the same rates as approved in our prior rate case ignores the effects on depreciation rates of the update to property balances from December 31, 2005 to December 31, 2007 and the shorter remaining life for generating stations and other property since the current study is two years later.

Mr. Pous criticized Mr. Davis' analysis of T&D property net salvage values and recommended altering the salvage values associated with 10 individual property accounts. These specific property account criticisms are addressed below.

Mr. Pous' criticism that Mr. Davis' determination of net salvage amounts is nothing more than a mathematical calculation and is not a depreciation study is unreasonable. Mr. Davis' depreciation study used traditional methods that are accepted by utility commissions across the country. A T&D depreciation study salvage analysis typically uses a mathematical calculation of an average net salvage percentage. Using a span of time such as 23 years tends to smooth out timing differences between the recording of an original cost retirement and the related salvage and removal amounts and provides an accurate picture of the Company's true salvage collections and removal costs. The application of judgment in order to change the results of removal and salvage costs recorded by the Company is arbitrary and should be used in an infrequent manner and only where trends or large transactions that distort results of the study are indicated. Accordingly, Mr. Davis applied judgment to several accounts such as account 364, Poles when he determined that recent trends in net salvage values should be used in lieu of the 23 year average history amount.

Mr. Pous claimed that the Company failed to recognize the likely cost reduction resulting from economies of scale as it retires a greater amount of plant on an annual basis in the future. The argument is invalid based on the nature of the T&D property. T&D property such as poles and conductor is typically retired when needed and where needed and only in small quantities.

Mr. Davis also responded to Mr. Pous' claim that the Company inappropriately categorized amounts received for retired property as a credit or reduction to the cost of new replacements rather than as gross salvage. Where reimbursements are received for mass property, the Company normally allocates the amounts received from a customer between construction and retirement using an estimate of the total cost of the job.

Mr. Pous is not justified in his criticism of the Company's T&D net salvage data as it related to his allegation that the Company cannot identify contractor costs, overtime costs, or the causes of retirements to analyze a depreciation study. His criticism indicated that the Company should maintain a "cause of retirement" analysis as part of its support for its next case. This criticism is unreasonable and Mr. Pous failed to indicate how a "cause of retirement" analysis would be at all useful in determining net salvage amounts. In addition, the Company issued over 11,000 work orders in 2006 for T&D accounts. Maintaining data for all of these work orders that would indicate retirements were caused by obsolescence or wear and tear would be time consuming, costly and useless in calculating the proper net salvage percentage for a Depreciation Study for T&D accounts.

Mr. Garrett and Mr. Selecky recommended that existing net salvage values be changed to reflect the "Pennsylvania (PA) Method" as detailed in his Appendix A to the Depreciation Study. Mr. Davis does not agree with this intervener proposal. It is unreasonable to use the PA method to determine the Company's T&D net salvage values. The PA method makes no connection between the net salvage percentages calculated and the amount of property that will be required to be retired as represented by the balances at December 31, 2007. Using the PA method therefore creates intergenerational inequities where future customers will pay for property that provided them no benefit.

Mr. Garrett contended that there is little support and virtually no explanation for the amounts that the Company is asking for in regard to negative salvage. Mr. Davis disagrees with this contention. The Company is using data obtained from its accounting records and data from prior Depreciation Studies to calculate the salvage percentages used in this rate filing.

Mr. Davis testified that Mr. Garrett also incorrectly alleges there is a mathematical flaw in the calculation of the net salvage percentages. While Mr. Garrett is correct that the calculation generally compared removal costs that are being incurred today with original installed costs that were sometimes booked 20 to 50 years ago, he failed to understand that the mathematical relationship of current removal cost and older retired property cost is constant and does not add inflation. This comparison explained why in some cases, removal costs can be in excess of 100% of the cost of the property being removed. Property retirements will normally occur after the property has been used for many years. Mr. Davis testified that the Company used a traditional approach to calculating and applying net salvage percentages that does not add inflation and is widely accepted.

Mr. Garrett contended that when a removal cost factor of 100% is added to a depreciation rate, 200% of the invested capital is returned to the utility over the life of the asset. According to Mr. Davis, this is incorrect. The removal cost factor does not provide for any return of invested capital at all. This factor only allows the utility to collect removal costs. This amount is collected over the asset's useful life from the very customers that benefit from the use of the assets. This prevents intergeneration inequities in the collection of removal costs.

Mr. Pous - Specific Property Account Criticisms

For account 354, Towers & Fixtures, Mr. Pous recommended using a 0% net salvage rate instead of the negative 69% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 35% embedded in the Company's current depreciation rates and less than the negative 20% he recommended in Cause No. PUD 200600285.

To respond to his criticisms, Mr. Davis agreed that the retirement history for this account is not as frequent as for other accounts and noted this in his analysis in the depreciation study. His proposal for a negative 69% net salvage rate for account 354 is based on 23 years of the Company's history of costs and reimbursements related to this account. There are retirements in 11 of these 23 years. As a result, the retirement data is sufficiently robust to calculate an accurate net salvage percentage.

Mr. Pous recommended using a negative 57% net salvage rate for transmission account 355, Poles & Fixtures, instead of the negative 93% proposed by the Company. Mr. Pous' proposed negative net salvage rate is equal to the negative 57% embedded in the Company's current depreciation rates.

Mr. Pous stated that the Company's proposed negative net salvage rate is one of the most negative values reported for the industry but only cited examples of two of PSO's utility affiliates to support his claim. His suggestion that the Company does not know if its database reflects proper accounting is incorrect. He has no basis for making this assertion other than his contention that the rate is too high. Mr. Davis' proposal for a negative 93% net salvage rate for account 355 is based on 23 years of the Company's history of costs and reimbursements related to this account.

For transmission account 356, Overhead Conductor & Devices, Mr. Pous recommended using a negative 38% net salvage rate instead of the negative 72% proposed by the Company. Mr. Pous' proposed negative net salvage rate is equal to the negative 38% embedded in the Company's current depreciation rates.

Mr. Pous claimed that there is a lack of knowledge of what is reflected in the Company's database to support the recommended 72% rate. Mr. Pous stated that the negative net salvage rate recommended for account 356 is at the high end of the reasonable mid-range of values for utilities in the industry without providing any backup or source of his industry information. Mr. Davis based his proposal of a negative 72% net salvage rate for account 356 on 23 years of the Company's history of costs and reimbursements related to this account. Mr. Davis therefore argued this negative salvage rate is reasonable.

For distribution account 364, Poles, Towers, & Fixtures, Mr. Pous recommended using a negative 40% net salvage rate instead of the negative 98% proposed by the Company. Mr. Davis pointed out that Mr. Pous' proposed negative net salvage rate is less than the negative 76% embedded in the Company's current depreciation rates.

Mr. Pous criticized the Company for using a recent history for account 364 instead of the 23 year history. He also said that the Company should be ordered to explain and justify its allocation of costs between the cost of replacement investment and the cost of removal when a retirement is associated with replacement activity. On this point, Mr. Pous showed a lack of understanding of accounting and the effects on rate base. Rate base increases in an equal amount whether the Company charges the cost of the replacement activity to construction or removal. There is no incentive or favorable rate treatment gained by charging amounts that should have been charged to construction to removal. Mr. Davis based his proposal of a negative 98% net salvage rate for account 364 on the Company's recent history and trends. The most recent history for this account indicated a trend of lower removal costs and should be accepted.

For distribution account 365, Overhead Conductor & Devices, Mr. Pous recommended using a negative 50% net salvage rate instead of the negative 80% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 74% embedded in the Company's current depreciation rates.

Mr. Pous criticized the Company's use of recent experience of net salvage for this account and Mr. Davis testified the negative 50% recommended by Mr. Pous lacks any support. Mr. Pous' suggestion that since arresters, reclosers and switches account for 37% of the recent retirement activity for account 365 somehow invalidated the Company's recommendation is unexplained. Mr. Davis based his proposal for a negative 80% net salvage rate for this account on the fact that, similar to pole account 364, conductor and other equipment represented in this account are of a low dollar value. As a result, one would expect a high negative net salvage rate when comparing current day removal costs to older original costs. Additionally, there is a large amount of activity in this account that makes the calculated average more reliable.

For distribution account 367, Underground Conductor and Devices, Mr. Pous recommended using a negative 10% net salvage rate instead of the negative 21% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 20% embedded in the Company's current depreciation rates.

Mr. Pous stated that industry averages indicate a negative 0% to 5% for this account and that his recommendation of negative 10% is in favor of the Company. Mr. Davis' proposal for a negative 21% net salvage rate for account 367 is only 1% higher (more negative) than the rate embedded in PSO's current depreciation rates. The negative net salvage rate of 21% is based on 23 years of the Company's history of costs and reimbursements related to this account.

For distribution account 368, Line Transformers, Mr. Pous recommended using a negative 5% net salvage rate instead of the negative 17% proposed by the Company. Mr. Davis pointed out that Mr. Pous' proposed negative net salvage rate is less than the negative 24% embedded in the Company's current depreciation rates and less than the negative 10% he recommended in the last rate case.

Mr. Pous criticized the Company for using a simple arithmetic average for the proposed negative salvage rate. To respond to the criticisms with regard to account 368, Mr. Davis pointed out that the Company is requesting a lower (less negative) negative net salvage rate for this account than the rate embedded in the Company's current depreciation rates. He proposed a negative 17% net salvage rate for this account which is less than (less negative) than the negative 24% rate embedded in PSO's current depreciation rates. The negative net salvage rate of 17% is based on 23 years of the Company's history of costs and reimbursements related to this account.

For distribution account 369, Services, Mr. Pous recommended using a negative 25% net salvage rate instead of the negative 76% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 40% embedded in the Company's current depreciation rates.

Mr. Pous stated that his recommended negative 25% net salvage rate for this account is based on his review of the historical data and his recognition that a significant number of services are underground and will not require removal. To respond to the criticisms, Mr. Davis pointed out that Mr. Pous picks and selects specific years and time periods such as 2003 to attempt to prove his points while ignoring the entire account history. Mr. Davis proposed a negative 76% net salvage rate for this account based on recent activity and trends indicated for this account.

For distribution account 371, Installations on Customers' Premises, Mr. Pous recommended using a negative 10% net salvage rate instead of the negative 56% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 85% embedded in the Company's current depreciation rates and less than the negative 25% he recommended in the Company's prior rate case.

Mr. Pous indicated that the ranges of negative salvage for account 371 are of a high magnitude and require investigation. He again stated that the negative rate proposed by the Company is more negative than any other net salvage value reported by the industry. To respond to criticisms, Mr. Davis pointed out that the Company is recommending a negative net salvage value of 56% instead of the negative 85% rate currently embedded in the Company's current depreciation rates. He proposed a negative 56% net salvage rate for this account based on the Company's total historical activity for this account. While a fluctuation of removal cost between years is expected, the use of a 23 year average tends to smooth out any differences that may result from original cost retirements being recorded in a different year than the related removal cost.

For distribution account 373, Street Lighting and Signal Systems, Mr. Pous recommended using a negative 15% net salvage rate instead of the negative 54% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 81% embedded in the Company's current depreciation rates.

Mr. Pous indicated that the relationship between retirements during the period the Company has maintained categorized data compared to recent experience is skewed, since 61% of the Company's retirements in the past 5 years were associated with wood poles that make up only 10% of the total account investment. He also stated that the industry has experienced substantial numbers of sales of street lighting systems to municipalities. To respond to criticisms, Mr. Davis highlighted that the Company is recommending a negative net salvage value of 54%, which is 27% less negative than the negative 81% rate currently embedded in the Company's current depreciation rates. He proposed a negative 54% net salvage rate for this account based on the Company's total historical activity for this account. While a fluctuation of removal cost between years is expected, the use of a 23 year average tends to smooth out any differences that may result from original cost retirements being recorded in a different year than the related removal cost.

**Donald J. Clayton**

Since April of 2007, Mr. Clayton, has been employed by Tangibl, LLC as Vice President of Management Consulting. In his current position, he performs depreciation and other rate related studies for all types of utility companies including electric, gas, thermal, water and wastewater companies. During a nearly 30-year career, he has held various executive level and consulting positions in the utility industry. Mr. Clayton has testified on numerous occasions before several utility commissions across the country, and he is a registered professional engineer (PE) in Pennsylvania, a Certified Depreciation Professional (CDP) and a Chartered Financial Analyst (CFA). Mr. Clayton serves as a faculty member of the Society of Depreciation Professionals where he taught basic, intermediate and advanced courses in depreciation and life analysis. He holds a Bachelor of Science and Masters of Business Administration degrees from Rensselaer Polytechnic Institute.

Direct Testimony

Mr. Clayton's direct testimony discussed the defects of the Pennsylvania approach (PA approach) to net salvage, which PSO was required to present in this case as ordered in Cause No. PUD 200600285.

He discussed how the PA approach violates the "matching principle", causes fluctuating revenue requirements, causes "rate base inflation", is not widely used by other regulatory commissions, is not consistent with the FERC Uniform System of Accounts for electric utilities, and is not recognized as a valid method in authoritative texts related to public utility depreciation.

Mr. Clayton also presented the results of his review of the depreciation study prepared by David A. Davis for PSO's electric plant in service as of December 31, 2007, and rendered an opinion regarding that study.

Comparison of the PA Approach with the Traditional Approach to Net Salvage

Mr. Clayton compared and contrasted the PA approach with the traditional approach to net salvage by first defining net salvage as the gross salvage received for the asset upon retirement less the cost to retire the asset. If the cost to retire the asset exceeds the gross salvage value of the asset, then the net salvage is negative.

Under the traditional approach, net salvage (either positive or negative) is a component of the service value of an asset, which is reflected in a utility's cost of service ratably over the service life of the assets as part of depreciation expense. The estimated net salvage percentage is based on judgment which incorporates analysis of historical data, field reviews, and management outlook and plans, as well as estimates of other electric utilities.

The PA approach, on the other hand, is described as a methodology whereby the amount of net salvage included in cost of service is based on a five-year amortization of the actual net salvage experience during the five years immediately prior to the end of the test year.

Mr. Clayton further explained that the primary difference between the PA approach and the traditional approach is that the PA approach results in after-the-fact recognition of net salvage in cost of service while the traditional method recognizes net salvage in cost of service ratably over the service life of the underlying assets.

Defects of the PA Approach

The defects of the PA approach as summarized include the following:

1. Violates the matching principle
2. Can result in unnecessary fluctuation in revenue requirements
3. Results in higher total revenue requirements

Matching Principle

Mr. Clayton described the matching principle for ratemaking purposes as a generally accepted principle that matches the cost of an asset with the payments by customers who benefit from the use of the asset. He discussed how the PA approach violates this principle because customers do not begin to pay for the asset's net removal cost (or negative net salvage) until the assets have been retired and do not completely pay for an asset's net removal costs until five years after it has been removed from service.

Fluctuating Revenue Requirements

Examples of how fluctuating revenue requirements can occur under the PA approach to net salvage were provided by Mr. Clayton. The first example showed how revenue requirements fluctuate simply due to the level of retirement activity. The second example showed how revenue requirements can fluctuate due to year to year variations in net salvage amounts. Mr. Clayton explained that such fluctuations would not occur under the traditional method and that fluctuating revenue requirements are undesirable from a ratemaking perspective, because either frequent rate resets are required; or there is a windfall or a shortfall to either the company or customers.

Higher Total Revenue Requirements

When net salvage is negative, the Company will have higher total revenue requirements due to "rate base inflation" when capital recovery, including provisions for net salvage, is delayed. He explained that the PA approach resulted in "rate base inflation" because the full cost of an asset is not reflected in cost of service until five years after the asset has been removed from service. An example which demonstrated that the revenue requirements are higher under the PA approach than the traditional approach was then presented.[1]

Use of the PA Approach in Other Jurisdictions

In the next section, Mr. Clayton's direct testimony discussed the use of the PA Approach in other jurisdictions. He pointed out that the only jurisdiction where the PA approach is in general use is Pennsylvania. In every other jurisdiction where the method has been used, it has only been applied on a limited basis.

Portions of the NARUC depreciation manual were then referenced to demonstrate that the traditional method of net salvage is the only method that is supported by the NARUC[2]. Mr. Clayton pointed out that The NARUC manual states that net salvage can be positive or negative, and explained that even though net salvage can be a large negative number, when expressed as a percentage of original cost, it is appropriate to include such amounts in revenue requirements so that the customers who benefit from the use of an asset pay their pro rata share of the cost of the asset.

The next section of his testimony discussed the California Standard Practice U-W-W *Determination of Straight Life Remaining Life Depreciation Accruals* (U-4). He then presented the following excerpt from U-4 which supports the traditional approach to net salvage.

> "Future net salvage as included in the accrual equation represents an estimate of the dollars which will be realized from the future retirement of all units now in service. Net salvage is gross salvage realized from resale, re-use or scrap disposal of the retired units less cost of removal. It is customary to arrive at the net salvage in dollars by applying an estimated percentage to gross plant."

In the next section, Mr. Clayton pointed out that he was not aware of any authoritative texts that recognized the PA approach as a valid method for determining net salvage.

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[1] The example in the direct testimony was presented in nominal dollars but it was explained in response to AG 5-1, which was included in the filing as Exhibit DJC R2, that revenue requirements under the PA approach are higher for all discount rates up to 9.29%.

[2] It should be noted that the NARUC manual does reference the fact that some jurisdictions have moved to current-period accounting for net salvage or cost of removal but this should not be misinterpreted as an endorsement of methods other than the traditional method for net salvage and the only method explained in detail in the manual is the traditional method.

Adjustment for Inflation in PSO's Historical Cost of Removal

Mr. Clayton disagreed with OIEC's witness Mark E. Garrett, who in PSO's prior rate case argued that inflation embedded in the Company's historical cost of removal data should be removed, because "it is unlikely that the extreme inflation levels experienced in the 1970s and early 1980s will be seen again in the near future". Mr. Clayton went on to explain that it was inappropriate to ignore the Company's relevant historical data in developing depreciation rates. Mr. Clayton argued that the Company's historical data covered property placed in service from 1926 to 2008 and that this 82 year period was long enough to dampen out fluctuations in year to year inflation levels.

Inconsistency of the PA Approach with the FERC Uniform System of Accounts

Mr. Clayton explained how the FERC Uniform System of Accounts (USOA) specifically requires that the original cost of an asset less any net salvage be allocated to accounting periods through depreciation expense in a systematic and rational manner over the service life of the depreciable property. Further, since the PA approach recognizes net salvage in depreciation expense only after the depreciable property had been removed from service, and not over its service life, the method is inconsistent with the USOA.

Conclusion Regarding the PA Approach

Because the PA approach violates the "matching principle", causes fluctuating revenue requirements, causes "rate base inflation", is not widely used by other regulatory commissions, is not consistent with the FERC Uniform System of Accounts for electric utilities, and is not recognized as a valid method in authoritative texts related to public utility depreciation, Mr. Clayton recommended that the Oklahoma Corporation Commission not adopt the PA approach to net salvage for ratemaking purposes in Oklahoma.

Review of PSO's Depreciation Study

In this section of his testimony, Mr. Clayton presented the results of his review of the PSO depreciation study (Exhibit DAD-1) prepared by David A. Davis. He explained that Mr. Davis followed generally accepted practices in the field of depreciation and described the methods and procedures used in the preparing the study.

Life Analysis

For the life analysis portion of the study, Mr. Davis used aged[3] retirement transactions for the period 1934 to 2007 and Surviving plant balances as of December 31, 2007. Mr. Davis applied the retirement rate method (also known as the annual rate method) to the aged retirement and survivor data to arrive at an original life table for each account or sub-account. Mr. Clayton explained that the retirement rate method is the preferable method when aged retirement data are available and that since the original life tables may not completely describe the survivor characteristics of the group, interpretation is required. Mr. Davis interpreted the original life tables by using the widely recognized "Iowa" family of survivor curves. In those cases where the retirement data were insufficient to form the basis for a service life estimate, the estimates were based on judgment which incorporated information obtained during discussions with management and operating personnel, field reviews and estimates used by other electric companies for similar property.

[3] Aged retirement transactions means that both the installation year and the transaction year are known and that the "age" of each retirement is known by subtracting the installation year from the transaction year.

Iowa Curves

As explained by Mr. Clayton, Mr. Davis then presented a brief discussion of the Iowa family of survivor curves. He explained that the Iowa curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired and that Iowa type curves are used to smooth and extrapolate original survivor curves determined by the retirement rate (or annual rate) method. Further, the estimated survivor curve designations for each depreciable property group indicated the average service life, the family within the Iowa system to which the property group belonged, and the relative position and height of the model.

Net Salvage

It was then discussed how the net salvage estimates were based on judgment, which incorporated analysis of historical data for the period 1985 to 2007, field reviews, operating and management personnel's outlook and plans and estimates of other electric utilities. He explained that the twenty-three year period for the salvage data used in Mr. Davis' study is typical for electric utilities which usually have twenty to thirty years of historical salvage data available for analysis.

Life Span Approach

Next, Mr. Clayton discussed the life span approach which is the preferable approach when coincident retirement of a major facility such as a power plant is expected. He explained that under the life span approach, a probable retirement date and a "life span" was estimated along with interim retirements and net salvage for each major facility. Net salvage was estimated in two parts: interim net salvage and terminal net salvage. Under the life span approach, the life for each vintage of property was truncated at the probable retirement date, and the remaining life developed for each vintage did not extend beyond the probable retirement date.

Terminal Net Salvage for Power Plants

In this section, it is explained that the terminal net salvage was based on demolition studies prepared by Sargent and Lundy for the various generating facilities and that the Sargent and Lundy studies for the various generating facilities are described in witness Bertheau's testimony.

General Plant

The Company has used a scheduled retirements approach for general plant accounts other than Structures and Improvements since 1996. Under the scheduled retirements approach, units of property are capitalized in the same manner as they are for other accounts, but retirements are based on a predetermined schedule as opposed to being made when units of property are actually removed from service.

Depreciation Calculations

Once the service lives and net salvage percentages were estimated, Mr. Davis calculated the annual depreciation accruals for each property group, based on the straight line remaining life method of depreciation and utilizing plant balances as of December 31, 2007.

Conclusion of PSO depreciation Study

Mr. Clayton's conclusion related to the PSO depreciation study (presented in this case as Exhibit DAD-1) is that the study was completed in a professional manner consistent with best practices in the field of public utility depreciation and that the rates from the study are reasonable and should be approved by the Commission.

## REBUTTAL TESTIMONY

The purpose of Mr. Clayton's rebuttal testimony was to rebut certain positions taken by intervener witnesses Garrett, Selecky and Pous on the subjects of depreciation, cost of removal and net salvage. His rebuttal testimony demonstrated how Mr. Garrett's testimony is misleading and should be rejected by the Corporation Commission. Additionally, it demonstrated how Mr. Selecky's positions on net salvage related to T&D are inconsistent and fatally flawed, and how Mr. Pous' arguments on discounting negative net salvage to current dollar levels are erroneous and inconsistent.

### Rebuttal to Garrett Testimony

Mr. Clayton explained that Mr. Garrett is asking the Commission to adopt the PA approach to net salvage and Mr. Garrett makes the claim that the Company has over collected $280 million related to net salvage from its customers and the Commission should monitor the Company's removal cost liability in its next case.

In response to Mr. Garrett's criticism of his accounting credentials, Mr. Clayton summarized his considerable accounting experience related to depreciation and net salvage. Mr. Clayton testified that Financial Accounting Standard Number 143 (SFAS No. 143) is not pertinent to the ratemaking process because there are many differences between accounting and ratemaking. According to Mr. Clayton, Mr. Garrett's testimony was misleading because on the one hand he criticized the Company's net salvage methodology for not being consistent with SFAS No. 143 and on the other hand recommended that the Commission adopt the PA approach which is also not consistent with SFAS No. 143.

Mr. Clayton testified that Mr. Garrett was wrong when he stated that negative net salvage is an increase to the Company's plant balance and wrong again when he stated that the Company's cost of removal calculation are flawed because they are not stated in current dollars. According to Mr. Clayton, the plant balance is unchanged whether net salvage is positive, negative or zero. The Company's net salvage calculations are not flawed because what PSO is trying to estimate is the cost to remove assets at the end of their useful lives and the actual cost of removal will be unchanged regardless of the formula used to develop the depreciation accrual rate. Mr. Clayton testified that Mr. Garrett does not recommend current cost treatment for gross salvage which is inconsistent and unfair to the Company.

Mr. Clayton criticized Mr. Garrett's claim that inflation should not be included in the Company's net salvage estimates because it is not verifiable and it is not reasonable. Although future inflation is unknown, it is much more reasonable to make an estimate based on historical levels than it is to simply ignore it. The only way to achieve intergenerational equity is to include the full cost of removal ratably over the useful lives of the underlying assets. Even if future inflation levels differ from historic levels, the Company's remaining life methodology will true up those differences over the useful lives of the underlying assets.

Mr. Clayton testified Mr. Garrett's statement that there is a basic ratemaking principle which requires that cost of removal be excluded from depreciation rates is misleading. The FERC and NARUC support the inclusion of a cost of removal factor in the depreciation rate and the vast majority of regulatory commissions have included cost of removal, or negative net salvage, in depreciation rates for many years.

Mr. Clayton disputed Mr. Garrett's claim that ratepayers would be harmed if the Company's plants became deregulated and the Company took the provisions for future removal costs to income, as it did in jurisdictions where its generating stations were deregulated. The cost of removal is not somehow changed because of accounting and at the time of dismantlement the company, not its customers, will be responsible for paying the costs. Further, the provision for net salvage that was collected from customers was simply their fair share of the removal costs for the service they received during the time the plants were regulated.

According to Mr. Clayton, the PA approach has not been adopted in "several jurisdictions" as claimed by Mr. Garrett. The only jurisdiction where the PA approach is universally applied is Pennsylvania. Methods similar to the PA approach have been used in selected cases in New Jersey, Delaware, Kansas and Maryland but the PA approach has not been fully adopted. Even though Mr. Garrett included Texas and Georgia in his list of Commissions where the PA approach has been used, the Texas Railroad Commission, who regulates gas utilities in Texas, is only considering the method and Georgia has removed inflation from future cost of removal estimates, but has not adopted anything like the PA approach to net salvage.

Portions of a recent order in California (Order No. D-08-07-046 (Exhibit DJC R1)) where the commission flatly rejected the types of net salvage arguments being proffered by Messrs. Garrett and Selecky, were discussed by Mr. Clayton.

Mr. Clayton testified Mr. Garrett's claim that PSO has over-collected $280 million because they have not yet incurred this amount of cost of removal is a fallacious argument, because the Company's provision for net salvage relates to assets that have not yet been retired. The California order referenced above also addresses this issue.

<u>Rebuttal to Selecky Testimony</u>

According to Mr. Clayton, Mr. Selecky, like Mr. Garrett, would like the Commission to adopt the PA method. If the Commission does not adopt the PA method then he would like the Commission to remove inflation from the Company's estimates. Finally, if the Commission does not remove inflation from the Company's estimates, Mr. Selecky would like the Commission to use a different inflation estimate than the estimate embedded in the Company's net salvage estimates.

Mr. Clayton pointed out that the defects of the PA approach were discussed in rebuttal to Mr. Garrett and in his direct testimony. Mr. Clayton explained his disagreement with the other two options presented by Mr. Selecky. An example (DJC R3) is provided which demonstrated an approach that removes inflation from the estimate is more likely to result in intergenerational inequity than an approach that reflects expected future cost of removal. Frequent rate resets are required and, as with all decelerated methods of capital recovery, revenue requirements are higher than under the traditional approach to net salvage. The method proposed by Mr. Selecky, which removes inflation, results in a 4% higher total revenue requirement on a nominal basis than the traditional approach and the revenue requirement is higher for any discount rate up to 9.29%.

Using a current dollar estimate for a single line item and nominal dollars for everything else is an inconsistent approach to ratemaking. If current dollars are to be used for one item then they should be used for all items and an original cost ratemaking concept should move to a fair value ratemaking concept. It would be inconsistent for the Commission to restate revenue requirements on a current dollar basis for just those items that reduce current revenue requirements, but not for those items that tend to increase revenue requirements.

The current dollar approach to net salvage is actually a decelerated method of depreciation that has the effect of increasing rate base throughout the life of the assets.

According to Mr. Clayton, Mr. Selecky's recommendation to adjust the price level for net salvage on a going forward basis is incorrect. First, the data required to develop the ratio of current net salvage to original cost retired is readily available. Second, there are no current forecasts of inflation that cover periods long enough to be meaningful for the expected retirement dates of the existing assets, which can extend beyond 100 years. The notion that future inflation will be less than past inflation for the next 100 years is simply not a supportable position. Further, given the Company's remaining life methodology any differences in future cost of removal will be trued up, and only the cost actually incurred for removal, no more and no less, will be collected over the life of the underlying assets.

Mr. Clayton testified that Mr. Selecky's analysis, which showed that 2037 ratepayers will pay less than 2007 ratepayers in real terms, is incomplete. As shown in Exhibit DJC R3, on a total revenue requirements basis, and for discount rates up to 9.29%, ratepayers will pay more under Mr. Selecky's approach than under the traditional approach to net salvage. Further, Mr. Selecky's analysis overlooks the fact that depreciable assets are in open-ended accounts with new assets being added each year and, if the entire account is examined, revenue requirements for each vintage of ratepayers actually increase, rather than decrease as suggested by Mr. Selecky. Also, as stated previously, it is not consistent to mismatch costs by singling out one particular line item for current dollar treatment and not reflecting all line items on a current dollar basis.

Mr. Selecky's analysis was flawed when he claimed that ratepayers will not be paying a return on, or income taxes related to assets with a 30 year average service life and 50% net negative salvage after just 20 years. Mr. Clayton testified the Company uses group depreciation and does not depreciate items on an individual basis but rather on a group basis. The mechanics that Mr. Selecky applied are misleading because the cost of the plant is recovered on a straight line basis over its useful life and the future cost of removal is also accrued over the useful life of the underlying assets. The fact that the total accumulated provision for depreciation, including the provision for cost of removal, is a deduction from rate base does not somehow translate to future ratepayers not being properly charged for cost of removal.

Mr. Clayton disputed the claim by Mr. Selecky that the time value of money was ignored by the statement that the traditional method of net salvage results in a lower total revenue requirement than the PA approach. The response to AG interrogatory 5-1 (Exhibit DJC R2) was overlooked by Mr. Selecky; it showed that revenue requirements are higher under the PA approach than the traditional approach for all discount rates up to 9.29%.

According to Mr. Clayton, there are flaws in Mr. Selecky's analysis related to historical inflation rates. Mr. Selecky's analysis of the historical data, that claimed to show the historical inflation rate is too high, assumed that a simple average age of 53 years is representative of the historical data when, in fact, the average age of the Company's retirements to date has been much less than 53 years. The range of the retirement ages has been from 1 to 73 years and the historical inflation rates vary depending on the vintage being retired. There is no reason to believe that cost of removal for T&D equipment will experience inflation similar to the CPI or the GNP price deflator and no current forecasts of future inflation exist that extend long enough into the future to be meaningful for the adjustment of the experienced inflation rates. The historical data is readily available and reflects the actual experience of the Company. It does not rely on another estimate of what future inflation will be for periods of up to more than 100 years and under the Company's remaining life methodology, as discussed previously, the recovery of cost of removal will self correct over the life of the underlying asserts.

Mr. Clayton recommended that if the Commission wants to use a forecasted inflation rate, they should not rely on Mr. Selecky's calculations because his calculations are incorrect. Mr. Selecky simply applied a 2.5% inflation rate for five years to the most recent five-year experience, when he should have projected inflation through the retirement dates of all of the Company's property. Mr. Selecky's approach to net salvage is yet another variation that has all of the defects of the PA approach, with the added complexity of introducing an estimate of future inflation into the mix.

Rebuttal to Pous Testimony

In Mr. Clayton's rebuttal to Mr. Pous, he disagreed that the Commission should discount cost of removal, because the approach increases revenue requirements, violates the matching principle, and is inconsistent with original cost ratemaking.

Mr. Pous' claim that the Company's approach to net salvage "is simply not a logical conclusion and is not an accepted practice in utility ratemaking" is wrong; the Company's position has been previously accepted by this Commission and similar positions have been accepted by the vast majority of Commissions across the country. It would not be logical to single out net salvage for current cost treatment without restating the Company's entire case on a current dollar basis.

Mr. Clayton argued it is not valid to compare the Company's provision for net salvage with a nuclear decommissioning fund. Nuclear decommissioning trust funds are external funds which are not deducted from rate base and the "discount rate" that Mr. Pous referred to is the expected fund earnings between the times when deposits are made and when nuclear decommissioning occurs. Negative net salvage provisions represent internal funds or sources of zero-cost capital and the accumulated provision for negative net salvage is deducted from rate base and customers receive the "time value of money" by enjoying a lower rate base throughout the life of the assets.

Conclusion

Mr. Clayton urged the Commission to reject any modification to the traditional approach to net salvage in setting depreciation rates and revenue requirements because the proposals of Messrs. Garrett, Selecky and Pous raise revenue requirements on both an absolute and present value basis.

**Steven R. Bertheau**

Steven R. Bertheau filed direct testimony and rebuttal testimony in this docket. Mr. Bertheau is a Member, Senior Vice President, and Project Director with Sargent & Lundy LLC (S&L). He joined S&L after obtaining his degree from Michigan State University and has performed a number of various engineering duties in various positions, generally related to electric generation units. His current position is Member, Senior Vice President, and Project Director within the Fossil Power Technologies Group of Sargent & Lundy LLC.

Direct Testimony

Mr. Bertheau's direct testimony sponsored the demolition cost estimate studies prepared by S&L, on behalf of the Public Service Company of Oklahoma (PSO), for the dismantling of PSO's electric power generating facilities at the end of their useful lives. The studies provided in this case were prepared under his direction and supervision to be utilized by David A. Davis in preparing PSO's depreciation study.

In Mr. Bertheau's direct testimony, he provided an overview of the analysis performed for completing the cost of dismantling PSO's electric generation facilities. This process included a kickoff meeting, reviews of general arrangement drawings, specifications, and aerial photographs of each site, detailed review efforts to finalize the scope, and site visits to confirm and collect the additional data required to complete the cost estimates.

He also addressed the prime reasons for dismantling a generating station, which would be to prepare the land for re-use and to mitigate potential safety concerns. The table below was included in his direct testimony and provided the estimated net demolition costs for the individual PSO facilities.

| STATION | ESTIMATED NET DEMOLITION COSTS (2008 DOLLARS) |
|---|---|
| SOUTHWESTERN STATION UNITS 1, 2, 3, AND PEAKERS | $2,077,000 |
| NORTHEASTERN POWER STATION UNITS 1 AND 2 | $3,452,000 |
| NORTHEASTERN POWER STATION UNITS 3 AND 4 | $31,756,000 |
| *OKLAUNION UNIT 1 | $49,773,000 |
| Weleetka Units 4, 5, and 6 | $859,000 |
| RIVERSIDE PLANT UNITS1, 2, AND PEAKERS | $15,216,000 |
| COMANCHE STATION UNITS 1A, 1B, AND 1 | $2,026,240 |
| TULSA UNITS 2, 3, AND 4 | $2,813,000 |

*:Estimated net demolition costs for Oklaunion include entire facility of which PSO owns 15.62%.

<u>Rebuttal Testimony</u>

Mr. Bertheau's rebuttal testimony addressed and responded to statements made by Attorney General Witness Jacob Pous and Wal-Mart Stores East witness James Selecky regarding the cost contingency, cost estimate levels, productivity of resources, scrap valuation, and demolition method used in the preparation of the demolition estimates as prepared by Sargent & Lundy LLC for the generation facilities of Public Service Company of Oklahoma (PSO).

His rebuttal testimony noted that maintaining a positive cost contingency is necessary to develop a meaningful cost estimate for demolition and that he did not agree with the criticisms stated by Mr. Pous that the studies conducted are invalid and should be rejected. It is demonstrated in this testimony that these studies are in fact valid and have been carefully prepared. Mr. Bertheau noted that positive contingencies are required in order to capture increases in plant general arrangement configuration that will occur from the time that the cost estimate was prepared until the end of the useful life of the facility.

In responding to Mr. Pous' claims concerning the Breed Plant demolition, he pointed out that his assertions are incorrect. The IMPC demolition contract only constituted a portion of the full scope of demolition that was detailed in the $28.7 million cost estimate provided by S&L. Additional demolition will be required at the Breed Station prior to developing new facilities. Therefore, the demolition scope of work at the Breed Station has not been completed as detailed in the $28.7 million cost estimate.

Mr. Pous made numerous misleading and incorrect statements in his testimony regarding demolition efficiency, labor rates, and productivity factors, excessive costs, scrap prices, and salvage values. Mr. Bertheau's rebuttal testimony addressed each of these issues and provided facts which show that Mr. Pous' are not correct and/or are taken out of context.

One area of interest discussed in his rebuttal testimony concerns the top down chimney demolition technique in preparing the cost estimate, which is not a brick-by-brick process as depicted by Mr. Pous. The top down approach is one of three commonly used methods in the power plant industry. This approach is used when there is a concern for safety or potential damage to plant infrastructure from dynamic forces created by other demolition techniques. Such concern is necessary, specifically for the demolition of facilities at the Northeastern Station. The estimate provided was based on a recent top down chimney demolition quote from Hamon Custodis, Inc. for Southern California Edison Company's Mohave Generating Station.

In conclusion, his rebuttal testimony provided clarity to the misleading comments and examples made by Mr. Pous regarding the demolition cost estimates prepared by Sargent & Lundy $^{LLC}$ for PSO. He confirmed that the costs provided are not excessively high, productivity factors and labor rates are appropriate, scrap price development is appropriate, and that is it appropriate to maintain positive contingency in the demolition cost estimates prepared by S&L for PSO.

**Donald A. Murry**

Donald A. Murry provided direct and rebuttal testimony in this proceeding. Dr. Murry is Vice President and Economist with C. H. Guernsey & Company, working primarily out of the offices in Oklahoma City and Tallahassee. He is also a Professor Emeritus of Economics on the faculty of the University of Oklahoma.

Dr. Murry has a B. S. in Business Administration and a M.A. and a Ph.D. in Economics from the University of Missouri - Columbia.

From 1964 to 1974, he was an Assistant and Associate Professor and Director of Research on the faculty of the University of Missouri - St. Louis. For the period 1974-98, he was a Professor of Economics at the University of Oklahoma and since 1998 has been Professor Emeritus at the University of Oklahoma. In these positions, he directed and performed academic and applied research projects related to energy and regulatory policy. During this time, he also served on several state and national committees associated with energy policy and regulatory matters and published and presented a number of papers in the field of regulatory economics in the energy industries.

In addition, in 1971-72, he served as Chief of the Economic Studies Division, Office of Economics of the Federal Power Commission.

Dr. Murry has appeared before numerous courts and state utility commissions as an expert witness.

Based on his analysis, he is recommending an allowed return on common equity for PSO in this proceeding in the range of 11.25 percent to 11.75 percent, and a return on total capital of 8.64 percent to 8.86 percent. To reach this recommendation, he studied the recent volatile credit and equities markets, a number of current financial statistics, current electric utilities earnings, and market-based measures of capital costs.

For his analysis of the cost of capital of PSO, he considered the appropriate capital structure for this proceeding to be 55.57 percent long-term debt, 0.33 percent preferred stock and 44.10 percent common stock. He determined that the weighted average cost of long-term debt was 6.60 percent and the cost of preferred stock was 4.02 percent. An important relevant risk factor affecting the allowed cost of common equity of PSO is its extremely low common equity ratio.

Dr. Murry's analysis revealed that AEP has reduced its dividend and experienced a declining book value per share in recent years, and this sets it apart from the comparable electric utilities that he selected for his analysis. Furthermore, a comparison of market valuations confirms that investors have noted this difference. Consequently, he relied primarily on the Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) results of the comparable companies to evaluate the appropriate cost of capital for PSO in this proceeding.

As relevant market information, *Value Line* estimated the 2008 common equity return for AEP to be 11.5 percent and the average common equity return for the comparable electric utilities to be 11.9 percent. The DCF and CAPM measures of the cost of common equity for AEP and the comparable companies ranged both above and below the estimated *Value Line* returns. For example, the AEP CAPM results were 10.43 and 12.74 percent. The most relevant DCF results, using projected earnings growth rates, are 12.07 to 12.50 percent.

He verified that his recommended allowed return was not excessive by comparing the After-Tax Interest Coverage at his recommended range to the coverages for the comparable companies. At the high end of his recommended allowed return level, or 11.75 percent, the After-Tax Interest Coverage would be just 2.42 times. By comparison, the average of the coverage of the comparable companies was a significantly higher 3.11 times. As noted in his testimony, the low coverage ratio for PSO largely reflects its low equity ratio. He concluded that this coverage ratio supported looking to the upper half of his recommended range for an allowed return for PSO in this proceeding.

In his rebuttal testimony he commented on the testimony of the three cost of capital witnesses in this proceeding, Mr. Fairo Mitchell, Mr. David C. Parcell, and Mr. Daniel J. Lawton. Significantly these three witnesses had a common, fundamental flaw in their testimony in as much as none of them adequately adjusted his testimony to compensate for the current financial market turmoil. Costs of common equity have adjusted dramatically from the liquidity crisis, and these testimonies did not reflect this. By ignoring the market changes, these witnesses have ignored the *Hope Natural Gas* principle of determining the alternative, competitive cost of investments of similar risk. Additionally, each of these witnesses independently made methodological errors that resulted in recommending a cost of common equity for PSO in this proceeding that is lower than current, alternative investments. These problems are especially apparent and troublesome in Mr. Lawton's and Mr. Parcell's testimonies.

Mr. Mitchell relied in part on an out-of-date Comparable Earnings analysis; however, without the influence of this flawed calculation, his DCF and CAPM results appeared very reliable. His DCF and CAPM results were also consistent with his estimates. In fact, these calculations averaged 11.95 percent primarily because he used more recent market data than was available at the time of Dr. Murry's direct testimony.

Mr. Parcell so completely disregarded the changed market circumstances that his testimony is not credible and is not useful for setting an allowed return in the current markets. As a predicate to his analysis, Mr. Parcell claimed, contrary to the facts, that the liquidity crisis had reduced capital costs. Furthermore, although the prevailing bond market revealed that the cost of utility debt was approximately 9 percent, he recommended an illogical allowed return of 9.5 percent for PSO in this proceeding. In addition to this misdirected testimony, Mr. Parcell's calculations contained a number of technical flaws.

Mr. Lawton likewise failed to recognize the significance of the changed market conditions and committed a number of technical missteps in his analysis. In general, he used historical data that predated the market turmoil, and his calculations reflect market conditions that no longer exist. These results do not provide useful information for determining the current and future cost of common equity of PSO.

Finally, Dr. Murry updated his DCF and CAPM calculations because of the market changes that had occurred since preparing his direct testimony. Although he noted that many of the calculations were now on the order of 100 basis points higher, given the unsettled markets, he did not recommend a higher allowed return at this time.

**John O. Aaron**

Direct Testimony

I. Introduction

John O. Aaron is employed as a Regulatory Specialist by American Electric Power Service Corporation (AEPSC). AEPSC is a subsidiary of American Electric Power Company, Inc. (AEP) that provides corporate support services to the operating subsidiaries of AEP, including Public Service Company of Oklahoma (PSO or Company). He is responsible for the preparation and coordination of accounting-related schedules and other accounting information for regulatory filings before the various regulatory commissions exercising jurisdiction over the electric operating companies of the western portion of AEP, including PSO. He received a Bachelor of Science in Accounting from Louisiana State University in Shreveport in May 1980. He is a Certified Public Accountant (CPA) in the State of Oklahoma and a member of the American Institute of CPAs and the Oklahoma Society of CPAs.

II. Purpose Of Testimony

In his direct testimony, he presented and supported PSO's rate base and accounting cost of service including certain known and measurable ratemaking adjustments to the test year amounts. PSO's filing is based on the financial results for the test year ending February 29, 2008. He described the adjustments that were made to the test year amounts in PSO's filing. Generally, the adjustments are for known and measurable items adjusted in determining a revenue requirement in order to develop a normal, ongoing level of operations. 17 O.S. Section 284 requires the Commission to "give effect to known and measurable changes occurring or reasonably certain to occur within six (6) months of the end of the test period upon which the rate review is based." In addition to this requirement, Order No. 492407 in PUD 200300076, issued on July 21, 2004, provided for the Commission to look beyond the six-month post test-year period if the Commission deemed it appropriate.

He also requested that the OCC approve PSO's request to defer storm maintenance expenses and generation maintenance expenses, and a conditional deferral of rate case expense that is not approved in this proceeding.

III. PSO's Rate Base and Operating Income

As a summary of the results presented in PSO's application package, Schedule B-1 shows a revenue deficiency of $132,522,265 on a total company pro-forma basis. The following table summarizes the results presented in PSO's application package.

| Description | Schedule Reference | Total Company Pro Forma |
|---|---|---|
| Rate Base | B-2 | $1,545,156,028 |
| Rate of Return | F-1 | 8.64% |

| | | |
|---|---|---|
| Operating Income Requirement | | $133,501,481 |
| Pro Forma Operating Income | B-2 | $53,040,865 |
| Operating Income Deficiency | | $80,460,616 |
| Revenue Conversion Factor | | 1.647045 |
| Revenue Deficiency | | $132,522,265 |

## IV. Rate Base

Application Package (AP) Schedule B-2 provided the components of PSO's rate base for the test year on a book basis, the pro-forma adjustments, and the pro-forma balance. PSO's rate base included the following: plant in service, construction work in progress, plant held for future use, accumulated depreciation, prepayments, materials and supplies, fuel inventories, customer deposits, customer advances for construction, certain regulatory assets, other rate base reductions, accumulated deferred income taxes and pre-1971 investment tax credits. Exhibit JOA-2 listed the adjustments made to rate base in this filing.

His direct testimony described the adjustments to rate base that he identified on EXHIBIT JOA-2. Additionally, Application Package (AP) Schedule B-03 lists each rate base adjustment along with the supporting Supplemental Package (SP) workpaper.

PSO is including a negative $128,320,638 cash working capital (CWC) allowance as shown on AP Schedule E-1, which reduces the Company's rate base and resulting revenue requirement. The lead-lag study used by PSO shown on AP Schedule E-1 in this filing is the study results for the test year ending June 30, 2006, the test year end in PSO's last base rate case (PUD 200600285).

## V. Components of Capital

AP Schedule F-1 showed the components of PSO's capital per books at February 29, 2008, the pro-forma adjustments, and the adjusted capital amounts. After pro-forma adjustments, the Company's capitalization consists of 55.57% long-term debt, 0.33% preferred stock and 44.10% common equity. The overall weighted average cost of capital is 8.64%. Supplemental Package WP F-2 provided the cost of preferred stock and SP WP F-3 provided the calculation of the cost of long-term debt. Adjustments were made to AP Schedule F-1 in calculating the weighted average cost of capital to reflect changes to the balance of common equity.

## VI. Operating Income

AP Schedule H-1 provided the components of PSO's operating income on a book basis, a total company pro-forma basis, and a pro-forma basis after the proposed revenue increase. This schedule contained operating revenues, operating expenses, operating income before taxes, income taxes, and net operating income. The schedule also showed rate base and the earned rate of return on rate base, unadjusted, pro-forma, and after PSO's proposed revenue increase. Schedule H-2 provided each individual adjustment to operating income by the categories listed on Schedule H-1. The Supplemental Package workpapers (marked as WP H-2-1, WP H-2-2, etc.) also provided supporting information on each individual adjustment. Exhibit JOA-2 provided a list of pro-forma adjustments to operating income made in this filing along with the witness who sponsored the adjustment. Additionally, AP Schedule H-3 provided a brief description of each adjustment and the associated amount on a total company basis and an Oklahoma jurisdictional basis. Mr. Aaron's direct testimony described in detail the adjustments to operating income on a Total Company basis.

Rebuttal Testimony

The recommendations of the OCC Staff, the AG and the OIEC that Mr. Aaron addressed in his Rebuttal Testimony, focus for the most part, on PSO's test year and the six-month post-test year update. The OCC Staff adjusted only rate base for the six-month post-test year information. The AG's adjustments, according the Ms. Soltani, reflected the final known and measurable amounts for all adjustments proposed by PSO. The OIEC made similar adjustments with different outcomes, however, and recommended adjustments to revenues and rate base. Some of these adjustments were calculated correctly with the six-month post-test year information. Some of the adjustments proposed by the AG and the OIEC, however, were not calculated correctly. In some cases, the proposed adjustments were not supported by the underlying facts or the underlying facts were ignored.

PSO's test year is the twelve month period ending February 29, 2008. PSO has proposed pro forma adjustments in compliance with Commission rules that only reflect either known and measurable changes or changes that are reasonably certain to occur within six months of the end of the test year. At the time of PSO's filing, all known and measurable adjustments were reflected in PSO's rate base and revenue requirement. All components of rate base, revenues and operating expenses were comprehensively reviewed and adjusted accordingly, if necessary, to reflect the known and measurable adjustments and an on-going level of revenues, operating expenses and rate base at February 29, 2008, the test year end. In PSO's filing, the relationship between revenues, expenses, and rate base described in the OCC's Minimum Filing Requirements is intact.

I. Rate Base

Exhibit JOA-2R provided a summary of the adjustments to rate base proposed by the OCC Staff, the AG, and the OIEC.

A. Electric Plant In Service

PSO's total electric plant in service requested in this filing is approximately $3.475 billion. All of the amounts are the actual balances at February 29, 2008, except for PSO's request to include approximately $800,000 capital expenditures required to complete the Distribution Automation Project. For Construction Work in Progress, PSO included the test year ending amounts for only those projects that would be in service within six months after the end of the test year.

The OCC Staff and the interveners recommended updating plant in service to August 31, 2008, based on 17 O.S. Section 284. The OCC Staff recommended a total electric plant in service balance of $3.505 billion. The AG recommended $3.505 billion and the OIEC recommended a $3.506 billion total electric plant in service balance. The OCC Staff and the AG incorrectly reduce PSO's August 31, 2008, plant in service balance by the Distribution Automation Project capital expenditure that was not made in the six-month post-test year period. As indicated above, PSO's request reflected the known and measurable adjustment to the February 29, 2008, test year consistent with the OCC's Minimum Filing Requirements. The actual plant in service balance at August 31, 2008, is $3,506,142,455.

B. Accumulated Depreciation

The OCC Staff, the AG, and the OIEC recommended increases to PSO's accumulated depreciation, which reduced PSO's rate base by a corresponding amount. All three recommendations rely on the six-month post-test year update statute (17 O. S. Section 284) that Mr. Aaron described earlier as well as information provided by PSO in discovery.

Ms. Soltani's adjustment on behalf of the AG reflected the $1,471,467,436 actual balance of accumulated depreciation and amortization at August 31, 2008. The OCC Staff's adjustment is understated by approximately $3.2 million and the OIEC's adjustment is overstated by approximately $3.3 million.

C. Prepaid Pension Asset

PSO has included $77.7 million in prepaid pension assets, the thirteen month average balance at February 29, 2008, in rate base. This is the proper treatment of this item. The prepaid pension asset produces benefits for PSO's customers. Therefore, like any other asset PSO makes an investment in, the Company should be allowed an opportunity to earn a return on that investment.

Mr. Garrett proposed reducing PSO's rate base by the prepaid pension asset and increased operating expense to include a debt return on the prepaid balance. Mr. Garrett claimed that since PSO's contributions were discretionary, PSO should not earn a full weighted average cost of capital return on that contribution. He further claimed that PSO's adjustment to the cost of service proposed in PUD 200600285, and recognized in the Final Order in that proceeding, negated the Referee's adjustment in that case.

The December 2004 contribution of $48.7 million was discretionary in terms of ERISA-required minimum contributions, while the remaining $29.0 million occurring prior to 2004 were almost entirely ERISA-required contributions. Whether the pension contributions were either discretionary or mandatory should have no impact on the proper rate base treatment. The pension contributions produce current and future benefits for PSO's customers. Exhibit JOA-3R showed that cost savings, resulting from the pension contributions represented in the $77.7 million prepaid pension balance, were approximately $2.5 million in 2004, $7.0 million in 2005, $7.4 million in 2006, and $8.0 million in 2007. Therefore, like any other asset PSO makes an investment in, the Company should be allowed an opportunity to earn a return on that investment. EXHIBIT JOA-4R identifies a $2.0 million benefit to PSO's customers even with the prepaid pension asset in rate base.

He disagreed with Mr. Garrett that a cost of money return is the proper return to apply to this prepaid asset. Mr. Garrett claimed that PSO should not be able to earn a return greater than the cost incurred to make the contribution and that the use of a weighted average cost of capital return allowed PSO to earn a profit. As a result, he recommended that the pension asset earn PSO's long-term debt rate.

PSO's assets, including these pension contributions, were funded by PSO's overall capital structure that included a mix of common stock, preferred stock, and long-term debt. There is no way to assign a discrete type of capital funding to this asset without a corresponding adjustment to PSO's capital structure. Without this capital structure adjustment, this direct assigned long-term debt supports two assets, which is not possible. The result is that PSO will not have the opportunity to earn its allowed return as approved. EXHIBIT JOA-5R demonstrated the lower return on equity that PSO would earn using Mr. Garett's recommendation. The adjustment proposed by PSO in PUD 200600285, and recognized in the Final Order in that proceeding, is appropriate if the adjustment proposed by Mr. Garrett in this proceeding is accepted by the Commission. Otherwise, PSO will not have the opportunity to earn its allowed return on equity.

Mr. Garrett also created a mismatch by failing to recognize the accumulated deferred income taxes (ADIT) associated with PSO's prepaid pension asset. ADIT reduced PSO's rate base and resulting revenue requirement when the weighted average cost of capital was applied to the net rate base. Mr. Garrett used a lower return for the prepaid pension asset and a higher return for the related ADIT. Both components should have the same return applied. PSO proposed the weighted average cost of capital. In this proceeding, Mr. Garrett updated ADIT to the August 31, 2008, balance with no corresponding adjustment to reflect the exclusion of the prepaid pension asset from rate base. Mr. Garrett agreed to adjust ADIT in PUD 200600285 to reflect the exclusion of the prepaid pension asset from rate base.

D. Prepayments

Ms. Soltani recommended updating all prepayment balances to August 31, 2008, based on 17 O.S. Section 284. Her adjustment reduced PSO's rate base by $772,665.

E. Fuel Inventories, and Materials and Supplies

PSO included the optimal target tons of coal required at their coal plants and a thirteen month average at February 29, 2008, for the oil and gas inventories. Past Commission treatment has allowed for this level of fuel inventory. For materials and supplies, PSO included the thirteen-month average at February 29, 2008.

Both AG and OIEC have recommended updating the balances to reflect the six month post test year period ending August 31, 2008. Ms. Soltani recommended an $181,018 reduction to PSO's rate base while Mr. Garrett recommended a $20,052 reduction.

He disagreed with Ms. Soltani's adjustment. Her adjustment to inventory completely ignored the target level of tons recommended by PSO and accepted by the Commission in past filings. Her adjustment to materials and supplies inventory is based on a thirteen month average amount at August 31, 2008. When inventory decreases, the corresponding entry is to either capital or expense. Ms. Soltani makes no adjustment to expense to recognize the decrease in inventories.

He also disagreed with Mr. Garrett's recommendation. His adjustment included target tons from August 2007 through February 2008 and the booked amounts from March 2008 through August 2008. The Commission has accepted in past filing the target level of coal inventory adjustment proposed by PSO. Mr. Garrett adjusted materials and supplies inventory in the same manner as Ms. Soltani. He also made no adjustment to expense to recognize the decrease in inventories.

F. Customer Deposits

Ms. Kiran Patel of the OCC Staff and Ms. Soltani on behalf of the AG recommended an $849,401 decrease based on a thirteen month average at August 31, 2008. Mr. Garrett on behalf of OIEC also recommended a thirteen month average amount for the period ending August 31, 2008, with a reduction of $173,904. Mr. Aaron disagreed with these recommendations. PSO has included in its filing the year end balance at February 29, 2008, the end of the test year. PSO has included the proper customer deposit level at the test year end that is consistent with the year end level of customer counts reflected in PSO's cost of service study.

G. Accumulated Deferred Income Taxes

PSO has deducted the February 29, 2008, test year ending net ADIT from rate. All parties recommended increasing ADIT by $47.9 million to reflect the six-month post-test year amount at August 31, 2008. If the Commission agrees with the August 31, 2008 update, ADIT should be increased by the $47.9 million as recommended. However, should Mr. Garrett's recommendation to exclude PSO's prepaid pension asset from rate base be adopted by the Commission, PSO's ADIT balance should be reduced by $30,545,708 as Mr. Aaron discussed above.

H. Cash Working Capital

PSO has reduced its rate base by approximately $128.3 million to reflect the Cash Working Capital (CWC) allowance determined by a lead-lag study based on the twelve month period ending June 30, 2006, the test year period used in PUD 200600285. There has been no major change in PSO's receipt of revenues or payment for goods and services that would justify an update to these results. The OCC Staff has recommended an adjustment to CWC to reflect the changes in the level of expenses proposed by OCC Staff. Although he cannot agree with the absolute amount proposed by the OCC Staff, Mr. Aaron does agree that the CWC amount will need to be recalculated with the level of expenses approved in this proceeding. The AG made no adjustment to the CWC to reflect their level of expenses included in cost of service. The OIEC proposed an adjustment to reflect fuel expense to reflect PSO's fuel factors.

Mr. Garrett's adjustment to PSO's CWC allowance on behalf of the OIEC is not appropriate because he used PSO's fuel factors for the May 2008 through June 2009 period as a proxy for the fuel expense to include in the CWC calculation rather than the actual fuel expense incurred by PSO in the six-month post-test year period. PSO's fuel factors are based on projected costs and also include past under-recovered amounts in its derivation which do not represent a test year cost. If costs are updated in this proceeding to reflect the six-month post-test year period, it would be more accurate to include the actual fuel costs incurred by PSO in this time period rather than the proxy calculation proposed by Mr. Garrett.

Mr. Garrett has also failed to make an offsetting adjustment to PSO's factoring expense to recognize the increased level of fuel revenues PSO has factored in this six-month post-test year period. He made no adjustment to factoring expense to reflect this additional cost PSO has incurred. Based on PSO's test year factoring rate of 0.988261%, an additional $2,082,582 should be added to PSO's cost of service to reflect the factoring expense on Mr. Garrett's $210,731,938 fuel factor adjustment.

I. Capitalized Incentives

Mr. Garrett on behalf of OIEC recommended excluding 50% of all capitalized incentive payments from the year 2000 through December 31, 2006 (approved in the Final Order in PUD 200600285). This appears to be retroactive ratemaking and should be denied. Mr. David Jolley supported the incentive compensation included in PSO's cost of services and further described why Mr. Garrett's proposal should not be accepted.

J. Capital Additions

Mr. Norwood on behalf of the OIEC contended that PSO has not provided sufficient documentation to support the approximately $444 million increase in capital investments that has occurred since December 31, 2006. He stated that PSO has provided documentation supporting approximately $134 million (30% of the new capital investment) and not justified approximately $310 million (70% of the new capital investment). He also claimed that little or no documentation existed supporting capital investments totaling less than $500,000 that are subject to blanket funded capital.

Mr. Norwood recommended reducing PSO's rate base by $47,936,678. He did qualify this by allowing PSO to provide the necessary supporting documentation in its rebuttal testimony. Mr. Norwood also recommended that in future rate filings, PSO should be required to provide capital requisition forms supporting all projects with costs greater than $500,000 and justify all projects with costs greater than $150,000.

In his Rebuttal Testimony, Mr. Aaron described the data requests PSO responded to regarding the capital investments placed in service since December 31, 2006. PSO's response to AG 2-66 identified approximately $218.4 million of projects greater than $1 million placed in service since December 31,

2006. Supporting documents (i.e., capital requisition forms) for approximately $134.2 million was included in this response with the remaining $84.2 million subject to blanket funding. The blanket funded projects consisted of the following:

| | |
|---|---|
| System Reliability ( OH to UG Conversion and ROW Widening) | $ 27,437,676 |
| Storm Restoration | 21,331,715 |
| Line Transformers | 15,335,654 |
| New Customer Services | 8,958,981 |
| Capital Software | 6,040,960 |
| Meters and Installation | 4,070,198 |
| Street Lighting | 1,001,709 |
| Total Blanket Funding included in AG 2-66 | $ 84,176,893 |

PSO's response to OIEC 12-15 identified $164.6 million subject to blanket capital funding and defined blanket capital funding. In response to OIEC 16-16, the follow-up question to OIEC 12-15, PSO provided a summary by blanket funding description of the $164.6 million and a listing of the 11,716 work orders included in total. The narrative response also further explained the blanket funding process and blanket authorization for work orders. OIEC 16-16 was subsequently supplemented twice. First, the approved blanket funding authorizations for 2007 and 2008 were provided in support of the blanket projects requested by PSO in this case. Second, a schedule was provided by blanket funding description that summarized the project detail for each blanket funded category for distribution, transmission, and generation.

PSO's response to OIEC 12-14 referred to the response to AG 2-66 for individual projects greater than $1 million placed in service since December 31, 2006. The response to OIEC 12-14 was subsequently supplemented to include projects greater than $500,000 placed in service since December 31, 2006.

Mr. Aaron's rebuttal testimony also described the purpose of the blanket capital funding process at PSO and provided examples of the work performed by the distribution, transmission and generation business units for capital expenditures subject to blanket funding.

He did not agree with Mr. Norwood's $47.9 million disallowance for blanket funded capital projects. PSO has fully supported these investments. In future rate filings, PSO will provide the capital requisition forms for individual projects greater than $500,000. For capital investments subject to blanket funding, PSO will provide summary information at the project level similar to that provide in the second supplemental response to OIEC 16-16.

## III. Operating Income

Exhibit JOA-2R provided a summary of the adjustments to operating income proposed by the OCC Staff, the AG, and the OIEC. As shown on this exhibit, all three parties recommended adjustments in varying amounts resulting in different amounts of operating income.

### A. Distribution Vegetation Management Expense

Mr. James Jones on behalf of the OCC Staff proposed to remove expenses related to the Distribution Vegetation Management (DVM) program PSO has included in its filing and to establish a new Reliability Vegetation / Underground Rider (RVU). Mr. Aaron can agree to remove these expenses since the RVU addressed the recovery of the overhead conversion capital spending and DVM expense recovery conflict of the existing Reliability Cost Adjustment Rider. My rebuttal testimony also addressed the recovery limit on the overhead to underground conversion proposed by the OCC Staff. The recovery should be based on capital spending up to $40.0 million annually rather than the $6.0 million recommended by the OCC Staff. The $6.0 million proposed by the OCC Staff could be exceeded depending on the capital spending and the timing of future base rate cases.

### B. Ad Valorem Tax Expense

In his rebuttal testimony, Mr. Aaron described generally how ad valorem taxes are determined for PSO. Because of the difficulty in replicating the methods used by the Oklahoma Tax Commission – Ad Valorem Division to determine ad valorem tax expense, he recommended that ad valorem taxes included in PSO's cost of service be based on an effective ad valorem tax rate that was developed using the information supplied by PSO that was required on WP H-19, Ad Valorem Tax Paid. This effective ad valorem tax rate relied on information readily available and verifiable. It reflected the actual taxes paid related to the associated taxable plant investment. The effective ad valorem tax rate, adjusted to reflect the most recent evaluation increase, would be applied to the pro-forma amounts of plant in service, including Account 101 (Plant in Service) and Account 106 (Completed Construction not Classified), fuel inventory, and materials and supplies. The result is ad valorem tax expense synchronized with PSO's investments included in rate base. EXHIBIT JOA-8R provided a calculation of the effective ad valorem tax rate based on information provided in WP H-19. This calculation indicated a $34,767 decrease to PSO's pro-forma ad valorem tax expense based on PSO's requested plant levels. If the Commission adopts the recommendations to plant investments proposed by the other parties, this calculation will need to be updated to reflect the correct plant investments.

Mr. Marvin Vaughn of the OCC Staff recommended a $2.6 million reduction to ad valorem tax expense included in PSO's cost of service. Ms. Soltani on behalf of the AG recommended a $3.3 million reduction and Mr. Garrett of the OIEC recommended a $2.3 million reduction.

Mr. Vaughn's adjustment separated PSO's ad valorem taxes into Oklahoma and Texas portions. The Texas related ad valorem tax was based on an average of taxes estimated for 2008 and actual taxes paid from 2006 and 2007. The 2008 Oklahoma related ad valorem tax was estimated by using Fair Cash Value of year end 2007 plant. Fair Cash Value amounts were estimated for 2009 and 2010 by escalating the 2007 year end amount 2.784% annually. The PSO total company amount proposed is an average of the estimated amounts for 2008 through 2010. His method was inconsistent with the method approved by the OCC in PSO's last rate case. Also, by relying on the Fair Cash Value of year end 2007, his Oklahoma calculation estimated taxes based on an understated value of plant that has been included in this case for both the test year (ending February 29, 2008) and the post test year adjustment period (ending August 31, 2008). This is inconsistent with other staff witnesses who recognize these changes in plant and the impact on expenses, such as depreciation, which are also a consequence of those increased levels of investment.

Ms. Soltani used the ad valorem tax expense recorded for the twelve months ending August 31, 2008, provided in PSO's response OIEC 11-5. This is not correct for two reasons. First, the ad valorem tax expense for the twelve month period ending August 31, 2008, is understated by approximately $777,000 as shown on EXHIBIT JOA-7R. In March 2008, PSO began deferring as a regulatory asset the ad valorem taxes associated with the peaker plants at Riverside Power Station and Southwest Power Station because of the recovery mechanism approved in PUD 200200038. On a going forward basis, these ad valorem taxes should be reflected in PSO's revenue requirement in a manner similar with the associated plant investment. Second, the ad valorem tax recorded for the twelve months ending August 31, 2008, did not reflect the plant in service that will be included in PSO's rate base as recommended by Ms. Soltani. Ad valorem taxes accrued and paid in the twelve month period ending August 2008 reflect the plant values at January 1, 2007 and January 1, 2008. This created a mismatch as the amount of ad valorem tax expense does not reflect the plant in service included in rate base. The adjustment to ad valorem tax should reflect and incorporate the plant in service balances and other taxable investments recommended by the AG which resulted in the proper matching of costs.

Mr. Garrett recommended a $1 million increase over the 2008 calendar year estimated accrual of $34,131,347. When compared to PSO's $37,405,762 pro forma ad valorem tax expense, this resulted in the $2,273,415 decrease proposed by Mr. Garrett. Mr. Garrett has understated PSO's 2008 ad valorem tax on his Exhibit MG-2.13, line 20, for the same reason Mr. Aaron identified above regarding the adjustment proposed by Ms. Soltani. Correcting this understatement increased the 2008 ad valorem tax amount to $35.6 million from the $34.1 million shown on Exhibit MG-2.13, line 27. This represented a $2.4 million increase over 2007 ad valorem taxes compared to his calculated increase of $897,548. His recommendation does not reflect the ad valorem tax PSO is actually accruing and does not reflect an effective rate that is representative of PSO's historical ad valorem tax expense and the level of plant investment recommended by the OIEC. As with Ms. Soltani, Mr. Garrett has not matched his recommended ad valorem tax expense to the plant in service he recommended to include in rate base.

C. Payroll Expense

PSO determined the annualized base payroll in effect at April 15, 2008, for active employees on the payroll at February 29, 2008. The date of April 15, 2008, was used instead of the end of the test year, February 29, 2008, in this proceeding in order to capture the scheduled annual salary increase for the Company's non-union employees. Since all non-union employees were moved to a common April 1 salary adjustment date, this is a known and measurable adjustment that should be reflected in PSO's cost of service. PSO annualized only base payroll, not overtime payroll.

Ms. Soltani on behalf of the AG recommended a $1.9 million reduction to PSO's proforma payroll that includes a $322,000 decrease for PSO's base payroll, a $1.260 million reduction for overtime payroll, and a $274,000 reduction for AEPSC payroll billed to PSO. Mr. Garrett on behalf of OIEC recommended a $1.814 million reduction that includes a $1.464 million reduction for PSO's base payroll and a $350,000 reduction for AEPSC base payroll billed to PSO. Both of these adjustments recognize employment levels at August 31, 2008.

Ms. Soltani's recommendation should be rejected for three reasons. First, her base payroll adjustment reflected payroll costs for the twelve months ended August 31, 2008. It is not an annualized amount that reflected a full year of base payroll for active employees at their August 31, 2008, pay level. If Ms. Soltani's intent is to move the test year end to August 31, 2008, her calculation should be based on the annualized base payroll for employees on the Company's roll as of August 31, 2008, not the annual amount incurred for the twelve month period. The result would be a $1.3 million increase above the amount requested by PSO. Second, her adjustment to overtime payroll is not correct. It incorrectly assumed that all overtime payroll cost was charged to expense and does not reflect the adjustment made by PSO to test year overtime payroll for the expense related to the December 2007 ice storm. Based on the twelve month period ending August 31, 2008, as proposed by Ms. Soltani, PSO's cost of service for overtime payroll should be increased by $618,075. Third, her adjustment for AEPSC base payroll billed to PSO reflected payroll costs for the twelve months ended August 31, 2008. It was not an annualized amount that reflected a full year of base payroll for active employees at their August 31, 2008, pay level. Based on the twelve month period ending August 31, 2008, as proposed by Ms. Soltani, PSO's cost of service for AEPSC base payroll and overtime payroll billed to PSO should be increased by $627,270.

Like the adjustment proposed by Ms. Soltani, Mr. Garrett's PSO and AEPSC base payroll adjustments do not reflect annualized base payroll costs. Instead, his adjustment compared payroll costs for a twelve month period to an annualized payroll cost at a specific time. If he had calculated a payroll adjustment using annualized payroll information instead of historic payroll cost, his adjustments should be similar to Mr. Aaron's discussion concerning the adjustments proposed by Ms. Soltani.

An historic annual level of payroll costs does not reflect a normal, ongoing level. Instead, the historic annual level reflected a mixture of payroll costs some of which could be associated with employees no longer on the payroll and some of which could be associated with employees who joined PSO after the beginning of the test year. The annualized calculation as proposed by PSO corrected this and appropriately adjusted payroll costs to a normalized, ongoing level.

Mr. Garrett's claim that PSO's payroll annualization methodology resulted in overstated payroll costs is not true. PSO's calculation reflected the actual annual base payroll for each employee reported in PSO's payroll system at a specific date. Mr. Garrett would rather annualize the base payroll for the last month or pay period of the test year. Such a calculation would not reflect an employee's base payroll if that employee joined the Company prior to month end but after the processing of the monthly (or bi-weekly) payroll. He supported this claim by referencing the $69.7 million base payroll approved in PUD 200600285 when compared to the subsequent payroll activity. The sources used by Mr. Garrett are not comparable. The payroll schedule from PUD 200600285 (WP H-4-4) reported PSO's total payroll commitment. As the operating partner of the Oklaunion Power Station, PSO is responsible for all labor costs at that facility. For financial reporting and ratemaking purposes, however, PSO is only responsible for 15.62% of the cost of that facility. PSO's cost of service was reduced by the billings to the other partners for labor and other costs associated with that facility. In preparing the schedules for this filing, Oklaunion's payroll and employee count information was reported at PSO's 15.62% share. Mr. Garrett's comparison on his Exhibit MG-2.5 is incorrect because it compared the annualized payroll cost of $69.7 million without a reduction for Oklaunion payroll cost to PSO's share to the payroll cost provided in response to OIEC 3-14. The $69.7 million base payroll amount should be reduced by approximately $4.5 million to reflect only PSO's ownership share in the Oklaunion facility. The amount of $65.2 million would then be comparable to PSO's response to OIEC 3-14 indicating $67.2 million payroll costs. The result is a deficit of $2 million not the overstatement claimed by Mr. Garrett.

### D. Payroll Taxes

The level of payroll taxes included in PSO's filing is consistent with the level of payroll and incentive compensation expense requested by PSO. Ms. Soltani on behalf of the Attorney General recommended a $968,020 reduction to payroll taxes. Mr. Garrett for the OIEC recommended a $571,337 reduction to payroll taxes included in PSO's filing. These payroll tax adjustments reflected the recommendations made by the AG and the OIEC. To the extent the Commission changed the level of payroll expense and incentive compensation requested by PSO, there should be a corresponding change made to payroll tax expense. Mr. Aaron recommended that any adjustment to payroll taxes be consistent with the methodology proposed by PSO in WP H-2-8.

### E. Employee Benefits

Ms. Soltani on behalf of the Attorney General recommended a $387,669 reduction to employee benefits. Mr. Garrett for the OIEC recommended a $1,784,480 reduction to employee benefits included in PSO's filing. While preparing his rebuttal testimony, Mr. Aaron discovered an error related to employee benefits, which resulted in a decrease of $1,672,238 to PSO's request. This was due to the billing of the group insurance benefits costs and the savings plan benefit costs related to PSO's ownership in the Oklaunion Power Plant. PSO's original adjustment did not recognize that a portion of these benefits were charged to the co-owners. The revised calculation provided in EXHIBIT JOA-9R corrects this and results in a $1,672,238 reduction to PSO's request.

He does not agree with Ms. Soltani and Mr. Garrett's recommendations to exclude Supplemental Executive Retirement Plan (SERP) expense from PSO's cost of service. SERP is AEP's non-qualified defined benefit retirement plan that allows AEP the flexibility to attract and retain key employees and provides benefits that cannot be provided under AEP's qualified defined benefit plans. The combined plans, of which SERP is a part, allow employees to accumulate an appropriate level of replacement income upon retirement. SERP plans are a part of a market competitive benefits program for the utility industry and large employers in general. Thus, the cost of any one component cannot be eliminated without a corresponding increase elsewhere if AEP is to maintain a market competitive benefits and total compensation program.

F. Depreciation and Amortization

Mr. David Davis addressed this issue in his rebuttal testimony. It should be noted that the final depreciation expense to include in PSO's cost of service should reflect the plant investment approved by the Commission and the resulting depreciation expense that incorporated the approved depreciation rates.

None of the interveners recommended adjustments to PSO's amortization expense. However, all of the interveners did recommend updating Plant In Service to the August 31, 2008, balance. If the Commission determined that this update to Plant in Service was appropriate, a corresponding increase will also need to be made to PSO's amortization expense to reflect the increased plant balances. As shown on EXHIBIT JOA-10R, amortization expense should increase by $686,198.

G. Legislative Monitoring

Ms. Soltani on behalf of the AG and Mr. Garrett for the OIEC both recommended excluding $450,053 of legislative monitoring expenses included in PSO's cost of service. Ms. Soltani erroneously stated that these charges were recorded "below-the-line" and should be borne by shareholders and do not represent necessary cost of providing utility service. Mr. Garrett stated that the costs requested by PSO are not reasonable even if they are accurate.

The charges included in PSO's cost of service were not recorded "below-the-line" as claimed by Ms. Soltani. The charges recorded "below-the-line" for legislative advocacy was not requested in this filing. The expenses recorded "above-the-line" included activities such as researching bills and pending legislation, disseminating information and data to the appropriate departments to determine the impact of the legislation, and developing responses to legislative inquires.

The costs reported by PSO as legislative monitoring represented approximately 79% of the total payroll costs incurred by PSO employees charging labor to the department ID defined as the Oklahoma City State Office. The remaining 21% of the payroll costs has been charged "below-the-line" and not requested by PSO. Mr. Garrett's disallowance would remove from PSO's cost of service the reasonable and necessary expenses for the support staff at PSO's Oklahoma City State Office and, also, exclude payroll charges for Community.

H. Purchased Power Capacity

Mr. Vaughn with OCC Staff recommended recovering the $14.3 million of purchased power capacity costs through PSO Fuel Cost Adjustment Clause using a demand allocation factor. This is a reasonable alternative to PSO's request to include these costs in base rates.

I. Factoring Expense

Mr. Thompson of the OCC Staff made a recommendation to adjust factoring expense to reflect the return on equity and expense adjustments recommended by the OCC Staff. Ms. Soltani and Mr. Garrett did not propose an adjustment to factoring expense to reflect their adjustments or recommended return on equity. No party disputed the short term interest rate and effective bad debt rate proposed by PSO. The final amount of factoring expense to be included in PSO's cost of services should reflect the final total revenue level approved in this proceeding and incorporate the approved return on common equity.

J. Rate Case Expense

PSO requested recovery of its estimated $782,500 in rate case expense over an eighteen month period. Mr. Seyedoff for the OCC Staff recommended a two year recovery and Ms. Soltani on behalf of the AG recommended a three year recovery. Both of these recommendations result in a decrease to PSO's request in this filing. PSO accepted the OCC Staff's recommendation to recover rate case expenses over a two year period with the amortization beginning in the month the new rates resulting from this procedure are placed into effect.

PSO has incurred approximately $297,591 through October 2008. The remaining $485,000 represented outside legal, consulting, and incremental employee expense that will be incurred in the hearing and briefing phases. If the expense PSO is allowed to recover is less than the expense PSO actually incurs, PSO will defer as a regulatory liability the difference between the actual costs incurred and the estimated amounts included in this filing. This regulatory liability will be reflected in PSO's next base rate filing. Likewise, if the actual costs PSO incurred is greater than the estimated amount included in this filing or if the Commission allowed only recovery of the actual costs incurred through a certain date, PSO will defer the additional costs as a regulatory asset to be recovered in PSO's next base rate filing.

K. Transmission Reliability Expenses

Ms. Soltani on behalf of the AG recommended excluding $5,250,469 transmission reliability expenses from PSO's cost of service. She included only the incremental expenses incurred during the test year and the six-month post-test year period for the Transmission Operations Center. Mr. Garrett of the OIEC reversed PSO's entire request because of the decrease in expenses incurred in the six-month post-test year period when the projects are reviewed in total.

Mr. Aaron does not agree with an adjustment that excluded costs PSO will incur on an on-going basis for the Transmission Operations Center. The adjustment proposed by Ms. Soltani does not recognize the annual amount requested by PSO. The adjustment proposed by Mr. Garrett eliminated the costs PSO is currently incurring. The adjustments for the remaining programs are addressed in the rebuttal testimony of Mr. Charles Matthews.

If the Commission determines that PSO should not recover the transmission reliability program costs discussed in the Direct and Rebuttal Testimonies of Mr. Charles Matthews, the $712,100 expense related to the Transmission Operations Center should be allowed recovery. As described in the Direct

Testimony of Mr. Charles Matthews, the operations center was placed in service in early 2008. The adjustments proposed by Ms. Soltani and Mr. Garrett would eliminate recovery of on-going costs that PSO will incur for this facility.

L. Incentive Compensation Expense

Mr. Wreath of the OCC Staff and Ms. Soltani on behalf of the AG recommended a $7.7 million reduction to incentive compensation. They excluded all long term incentive compensation expense from PSO's request and reduced the remaining amount by 50%. Mr. Garrett for the OIEC recommended a $9.3 million reduction to PSO's cost of service to remove all long term incentive compensation and 70% of the remainder. Mr. David Jolly will address this issue and the disallowances recommended by these parties.

M. $SO_2$ Auction Proceeds

OCC Staff recommended removing the $SO_2$ auction proceeds from PSO's base rate revenue requirement and applied these proceeds to the ice storm regulatory asset. Mr. Aaron agreed that these proceeds can be credited to the ice storm regulatory asset on a prospective basis rather than to PSO's base rates.

N. Dues and Memberships

Ms. Kiran Patel of the OCC Staff recommended a $140,522 reduction to PSO's dues and memberships by excluding one-half of the professional and business dues and memberships. Ms. Soltani on behalf of the AG stated in her testimony that she allowed professional dues and memberships but excluded several dues classified as such resulting in a reduction of $274,061 to PSO's cost of service.

Mr. Aaron recommended excluding $102,895 of civic, educational and miscellaneous dues included in PSO's cost of service. The dues and memberships remaining in PSO's cost of service would be $376,243.

O. Postage Expense

PSO's requested $95,054 increase reflected the increase in postage that occurred in the test year in May 2007 and the increase in postage after the end of the test year that occurred in May 2008. PSO's adjustment is a two step adjustment. The first step adjusted the test year postage expense to annualize the test year expense based on the postage rates that were in effect at the test year end. The second step adjusted the on-going level of postage expense to recognize the increase that was effective in May 2008. The OCC Staff's recommended $13,582 reduction does not reflect the actual postage expense increase that was effective in May 2008.

P. Interest on Customer

Ms. Kiran Patel of the OCC Staff recommended an adjustment to reflect the OCC approved short-term interest rate and long-term interest rate applied to the thirteen month average balance at August 31, 2008. Ms. Soltani on behalf of the AG recommended applying the same interest rates to the August 31, 2008 customer deposit balance.

PSO included in its cost of service the appropriate level of interest expense on customer deposits based on the February 29, 2008, test year ending balance. If the Commission chooses to update the test year to reflect the thirteen month average balance at August 31, 2008, the adjustment proposed by Ms. Patel is accurate.

Q. Debt Return on Pension Asset

Mr. Aaron disagreed with the alternative recovery of prepaid pension asset recommended by Mr. Garrett. Mr. Aaron addressed the issue of the prepaid pension asset earlier in his testimony summary in the rate base section. The alternative recommendation of Mr. Garrett to recover in cost of service a lesser return improperly limited PSO's recovery of the return on an investment that provided benefits to PSO's customers.

R. Income Tax Expense

The OCC Staff, the AG, and the OIEC all made adjustments to PSO's income tax expense to reflect the changes to taxable income as a result of their respective adjustments. The final amount of income tax expense will need to be recalculated to reflect the final cost of service approved in this case.

S. Other Issues

Mr. Garrett's statement regarding cost of removal as excess collections that represent a source of cost free capital does not recognize that PSO included the accumulation of depreciation expense, which included a cost of removal factor, as a reduction to PSO's rate base by way of accumulated depreciation.

Mr. Garrett has a misunderstanding of the accounting treatment of the costs of removal for deregulated power plants. The accounting by AEP when it booked the cost of removal of certain deregulated power plants to income was mandated by GAAP and applies only to plants that have been deregulated. There is no basis for his claim that AEP believed that it would not cost as much to remove the assets as it told customers. On the deregulation of a power plant, the utility's deregulated, competitive generation unit will bear the entire cost of removal of that plant. Customers are no longer responsible for those costs. Under GAAP, for a deregulated power plant, removal costs are expensed when they are incurred and not accrued over the life of the power plant. AEP was required to make these accounting entries as a consequence of deregulation and not because there was a change in AEP's estimate of the amount of the costs of removal.

**Gary C. Knight**

Mr. Knight has a Bachelor of Science degree in mechanical engineering from the University of Tulsa. He is a Professional Engineer registered in the State of Oklahoma and a Commissioned Inspector of the National Board of Boiler and Pressure Vessel Inspectors.

Mr. Knight is responsible for the safe, reliable, efficient and environmentally-compliant performance of PSO's generating assets. More specifically, he oversees and directs the operations and maintenance (O&M) and capital budget expenditures with responsibility for allocation of budget resources to ensure the financial optimization of those generating assets. He works with Operating Company Executive Leadership, Commercial Operations, and American Electric Power Service Corporation (AEPSC) Engineering, etc. to optimize the efficiency of PSO's assets.

Direct Testimony

Mr. Knight's direct testimony stated that the PSO Generation fleet is comprised of a combination of 21 coal- and gas- fired units with a net generating capacity of 4,426 megawatts, which provide reliable, low-cost generation to the customers of PSO. Capital investments of over $73 million have been needed since the last rate case to maintain reliability of PSO's existing units and to add megawatts to the generation base; almost $70 million of construction work in progress will close to plant-in-service by

August 31, 2008. Additional capital investments of over $880 million during 2009-2013 are projected, with $662 million of that total targeted to meet the requirements of the Clean Air Visibility Rule.

Additionally in his direct testimony, he concluded that the annual on-going level of operation and maintenance expenditures required to ensure the reliability of PSO's units has increased by 30% since the last rate case. Mr. Knight pointed out that PSO is subject to the same general market forces faced by its customers and other businesses, especially with respect to global commodities and raw materials used in the manufacturing of power generating equipment. To minimize this impact, PSO utilized AEP's Service Corporation to provide at-cost support to PSO Generation for asset and outage planning as well as engineering, environmental, and business services. PSO also proactively sought to reduce costs through preventative maintenance, financially evaluating replacement equipment on a life-cycle basis, and through its Human Performance Initiative.

His direct testimony also pointed out that in order for PSO to achieve the projected plant lives given in this cause, ongoing capital investment and O&M expenditures are required. Without those expenditures, the safe, economic, and reliable operation of PSO's units will be jeopardized.

Rebuttal Testimony

In Mr. Knight's rebuttal testimony, he addressed and responded to statements made in the direct testimony of Oklahoma Industrial Energy Consumers (OIEC) witness Scott Norwood regarding the proposed adjustment to reduce investments in rate base funded through the Production Plant Blanket (PPB) work order mechanism.

While this issue is addressed in greater detail by Company Witness John Aaron, Mr. Knight noted that he was responsible for reviewing the annual Generation capital budget for PSO prior to its submittal to the American Electric Power Company (AEP) Board of Directors for approval. He attested that the value of blankets was a well-established, efficient funding mechanism for managing projects costing less than $500,000. This ensured that unit operations were not impacted when capital equipment needs to be replaced.

Additionally, Mr. Knight demonstrated that processes are in place for reviewing and approving PPB projects. He personally reviewed these projects for cost, scope, and need or priority. This ensured that projects were prioritized based on justification and criticality. Once approved, they were rolled up under the blanket work order budget.

In conclusion, he presented valid examples demonstrating that the Blanket Requisition Process was a needed and effective tool for funding emergent, higher priority projects that were not included in the budget for a given year. This was achieved through his ability to move forward with a more critical, emergent project costing less than $500,000, by funding it with dollars from another project within PSO plant's budget and deferring a lower priority project to a subsequent year. The end result, was keeping the ultimate cost (of providing energy) to the customer lower than it would otherwise have been, by replacing defective or inefficient equipment on a real-time basis.

**Charles D. Matthews**

Mr. Matthews received a bachelor of General Studies degree in 2002 from Louisiana Tech University and a master of arts degree in Industrial / Organizational Psychology in 2004 from Louisiana Tech University. He has been employed in various positions with CSW and AEP since 1977. Mr. Matthews previously submitted testimony before the Corporation Commission of the State of Oklahoma in PSO's application to defer, amortize and recover storm costs, Cause No. PUD 200700397.

Mr. Matthews' direct testimony described the transmission services provided by PSO to its customers and demonstrated that the costs associated with operating PSO's transmission system were reasonable and necessary. It also addressed the need for the administrative and technical support provided by AEPSC and the need for PSO's recent capital investment in transmission projects.

AEP is committed to providing quality service to our customers at a reasonable cost while making the investment needed to ensure that Oklahoma and PSO have the necessary electric infrastructure to meet future demands in an economic, safe, reliable and environmentally compatible manner. The result is a reasonable level of adjusted transmission O&M expenses of approximately $40.2 million. O&M costs have increased since PSO's last rate case in 2006 due to increases in Regional Transmission Organization (RTO)-related charges as explained by Witness Robert L. Pennybaker; a needed increase in spending for vegetation management and various transmission reliability programs also contributed to this increase in the adjusted O&M expenses. The $40.2 million adjusted O&M expenses are partially offset by the associated transmission service revenues of approximately $20.1 million, as discussed by Witness Pennybaker. This adjusted O&M expenses also include approximately $5.7 million transmission reliability programs pro forma.

PSO has undertaken transmission capital construction programs, investing approximately $80 million of capital beyond that included in the last rate proceeding, to address reliability compliance requirements, increased load growth for loads served by the PSO transmission system, and the evolution of the wholesale power market in SPP. The major capital projects undertaken by PSO since 2006 include the completion of the Tulsa area 345/138 kV project. PSO has also invested approximately $17 million in Construction Work In Progress as of February 29, 2008, for transmission projects scheduled to be placed in service by August 31, 2008. The investments for all of these transmission capital projects are necessary and reasonable.

Mr. Matthews' rebuttal testimony covered the topics of transmission reliability programs pro forma and blanket-funded capital projects. Specifically, he responded to the testimonies of: Roya Z. Soltani, Oklahoma Attorney General (AG); and Mark E. Garrett, Oklahoma Industrial Energy Consumers (OIEC) regarding their recommendations to reduce PSO's transmission reliability programs pro forma. In addition, he addressed the testimony of Scott Norwood, OIEC, regarding his recommendation to reduce PSO's proposed plant in service balance included in rate base by 25% of the total blanket-funded capital projects.

In this proceeding, Mr. Matthews' supported adjustments for six transmission reliability programs: Vegetation Management Program, Transmission Operation Center (TOC) Enhancement, Hiring and Training of Additional Full-time Transmission Employees, Transmission Line Programs, Transmission Station Programs, and Animal Mitigation. As stated in his direct testimony, approval of the inclusion of these adjustments (in the amount of $5.7 million) in O&M expenses will not only enable PSO to complete more reliability projects than it is typically able to complete with its current level of resources, but will accelerate improvement of transmission system reliability in the PSO footprint helping to meet growing customer expectations for increased reliability and power quality. In addition, approval of the incremental costs requested in this filing for the transmission reliability programs will allow PSO to move forward with these programs that directly benefit the customers of PSO. PSO's request for the TOC Enhancement represents known and measurable expenditures that PSO has incurred and will continue to incur since the end of the test year. Therefore, with the exception of the TOC Enhancement program, non-approval by the Commission of these incremental programs means that they will not be implemented.

The Transmission blanket process aligns with AEP's procedures for project authorization. Each business unit has a process for determining the prudency of blanket projects and for prioritization of projects within the amount of budget dollars available. In the case of projects that were capitalized under blanket authority, AEP's policy is to provide the Board a summary level document. The business unit has authorization levels which allowed for routine funding requirements to be achieved through a blanket at the various levels of management and with appropriate checks and balances. The Commission should include and approve 100% of the capital blanket amounts within the PSO cases since these are prudent and justified expenditures for the benefit of PSO customers.

PSO's goals are to provide a transmission system that provides reliable delivery of electric energy to the customers served by its transmission system and does not unreasonably restrict generation output or energy transfers. To further these goals, PSO Transmission proactively developed and implemented plans for transmission infrastructure additions and modifications of its system to meet reasonably anticipated delivery system needs for the electric energy market in SPP. Both O&M and capital investments are needed to ensure that Oklahoma and PSO have the necessary electric infrastructure for the future. These investments also ensure that PSO's customers have the reliable electric supply at reasonable cost that they need and expect. As demands placed on the PSO transmission system increase over time, it will be necessary for PSO to incur even greater levels of transmission service expenses and capital in the future to maintain safe and reliable transmission service.

**Preston S. Kissman**

Mr. Kissman earned a bachelor's degree in Electrical Engineering in 1971 from Texas A&M University in College Station and a master's degree in Business Administration in 1979 from the University of Texas at Pan American. He also completed the Harvard University Program for Management Development and the University of Idaho Program for Public Utility Executives. He is a Registered Professional Engineer in the State of Texas and has been employed in various positions within CSW and AEP since 1971.

In Mr. Kissman's direct testimony demonstrated that the $139.9 million test year level of O&M expenses as adjusted for cost increases of wages and benefits, as well as to remove expenses related to the 2007 ice storms and the Company's Reliability Enhancement Plan, as those expenses were recovered through separate Commission approved riders was reasonable and necessary in order to continue to maintain a reliable and safe distribution system capable of meeting the demands of PSO's customers.

Mr. Kissman also discussed an adjustment to vegetation management expenses to continue the current distribution tree trimming program. With this adjustment, PSO, when funds become available, can double its efforts to convert existing overhead distribution lines to underground service. Through the existing Reliability Enhancement rider (RCA) capped at $23.685 million, distribution reliability program expense were included for both tree trimming and the carrying cost on the overhead to underground conversion. These costs together have decreased the amount of funds available to carry out PSO's current distribution tree trimming program. The $7.7 million requested adjustment will support both programs and set the Company on a course to complete undergrounding from 20 to 25 years to within 10 to 12 years.

Further, Mr. Kissman related PSO's commitment to providing reliable service to its customers on both a daily basis and during adverse weather conditions. PSO's commitment to maintaining and improving the reliability of its distribution system was evidenced by the Asset Management Programs and the PSO Reliability Enhancement Plan. PSO's Distribution Asset Management Programs include 10 ongoing maintenance programs designed to proactively improve the effectiveness of line maintenance and improve the reliable performance of the distribution system. PSO's Reliability Enhancement Plan focused on establishing a four-year tree trimming cycle for the distribution system and replacing old inaccessible overhead rear-lot residential power lines with new front-lot underground facilities. In this conversion program, PSO has installed approximately 95 miles of underground electrical cable through August 2008 at a cost of approximately $55 million.

He also described how PSO's quality of service has been continually improving for its customers. PSO's SAIFI and SAIDI indices for 2006 and 2007 indicate a 23 percent improvement between years. Although many factors influence reliability indices from year-to-year, PSO's Reliability Enhancement Plan has proven to be successful.

Finally, Mr. Kissman's direct testimony discussed Distribution Automation (DA), which has the ability to provide real time control and monitoring of selected electrical components within the distribution system. PSO has selected an area in south Tulsa to serve as the first phase of the Company's DA implementation. The benefits from DA include faster restoration of customers affected by an outage, fewer sustained outages and shorter outage durations.

In Mr. Kissman's rebuttal testimony, he addressed how the national financial challenges were affecting PSO. The Company is not immune to these financial pressures and tightening credit.

He further discussed the recommendations and comments of James L. Jones and Jason Thenmadathil representing the Public Utility Division of the Oklahoma Corporation Commission (OCC). He generally agreed with James L. Jones regarding a separate rider to recover the carrying charges associated with PSO's overhead to underground conversion program and did not support the position of Mark E. Garrett of the Oklahoma Industrial Energy Consumers (OIEC). He also discussed PSO's support of Staff's recommendation regarding system hardening, alternative solution to burying service drop lines, and strategic road crossings. He briefly commented on the recommendations of James M. Twombly of the Quality of Service Coalition (Coalition) regarding street lights. The LED street light assessment and evaluation project by PSO will continue. He also addressed AEP's blanket funding process in rebuttal to the recommendations of Scott Norwood representing OIEC. Lastly, he addressed Roya Z. Soltani on behalf of the Oklahoma Attorney General (AG) and Jason Thenmadathil representing OCC, regarding distribution automation.

**Jeffrey W. Hoersdig**

He received a Bachelor of Business Administration degree with a major in accounting in 1996 from The Ohio State University, in Columbus, Ohio. He is a Certified Public Accountant in the state of Ohio and is a member of the American Institute of Certified Public Accountants, and the Ohio Society of Certified Public Accountants.

He is the manager of Regulated Accounting for American Electric Power Service Corporation (AEPSC), a wholly owned subsidiary of American Electric Power Company, Inc (AEP). He is responsible for maintaining the accounting books and records, and regulatory reporting for AEPSC. He is also responsible for AEPSC's monthly service billings to its affiliates, including Public Service Company of Oklahoma (PSO). His responsibilities for AEPSC also include compliance with the Federal Energy Regulatory Commission's (FERC) Uniform System of Accounts accounting and reporting requirements.

He sponsors several schedules and exhibits in the Rate Filing Package (RFP), including schedules W/P P-3, "*Cost Allocation Basis*", W/P P-7, *"Services/Products from Affiliates/Subsidiaries"*, and W/P P-8, *"Services/Products to Affiliates/Subsidiaries"*, and exhibits JWH-1, *AEPSC Charges to PSO Included In Cost of Service by Functional Organization*, JWH-2, *AEPSC Charges to PSO by Functional Organization, Work Order, and Activity*, JWH-3, *AEPSC Allocation Factor Definitions*, and JWH-4 *Description of AEPSC Billing Controls*.

Affiliate Costs Included in the RFP

As shown on W/P P-7, the PSO cost of service amount requested in this RFP included $76,097,053 of affiliate costs. AEPSC accounted for $74,419,475 of these costs and was summarized on Exhibit JWH-1, with a more detailed view on Exhibit JWH-2. PSO has included $1,677,578 billed from other affiliates in cost of service. These other affiliate costs were detailed on schedule W/P P-7, and were discussed in his testimony.

## Organization of AEPSC

AEPSC is a wholly-owned subsidiary of AEP and is the centralized service company for the AEP System. AEPSC provides services primarily to AEP's utility operating companies (utility affiliates), including PSO, under a Service Agreement between AEPSC and PSO dated June 15, 2000. AEPSC performs, at cost, various professional support services for PSO and the other affiliates. Among the services AEPSC performs for PSO and the other affiliates are management, accounting and financial reporting, tax, legal, engineering, treasury and cash management, regulatory and case management, insurance risk management, customer operations, generation, transmission, distribution, human resources, information technology, and supply chain services. Exhibit JWH-1 summarized these services by functional organization. Of the 20,944 employees of the AEP System, 6,201 were employed by AEPSC at the end of the test year. All services provided by AEPSC to PSO and the other affiliates were provided at cost.

AEPSC is functionally organized into the following five areas of services: 1) Chief Operating Officer, which includes customer and distribution services, commercial operations, environmental and safety services, shared services and regulatory services; 2) Generation, which encompasses fossil services, plant engineering services, field services, fuel and emission services, and business services; 3) Finance, Accounting and Strategic Planning, which includes corporate accounting, corporate planning and budgeting, treasury, finance and risk management services; 4) Transmission Services, which includes transmission engineering and project services, transmission system and region operations, and transmission strategy and business development, and transmission reliability compliance; and 5) Office of the Chairman which includes the AEP Chairman and his staff, audit services, legal, federal/external affairs and corporate communication services.

AEPSC exists to provide centralized services to each of AEP's utility affiliates and other subsidiaries more efficiently and at a lower cost than could be done by each operating company. In many cases, AEPSC employees have worked for an AEP utility company and are highly knowledgeable and experienced in utility operations and processes. AEPSC has evolved over the years to provide centralized services in areas where economies can be produced through a common knowledge and provision of services using shared systems, such as the customer accounting and billing, property, accounting, payroll and other systems. Economies are also provided through standard processes being performed by one System-wide department, such as the payment of invoices, billing of customers or providing engineering studies for new facilities. AEPSC allows its utility affiliates to share the costs for professional support services. For example, three AEPSC tax attorneys can handle the needs of AEP's eleven operating companies in lieu of each company employing a tax attorney. It also enables them to concentrate their efforts on serving the immediate needs of their customers, while common processes are performed by AEPSC in a centralized manner to promote synergies.

The costs incurred by AEPSC and billed to PSO were necessary for PSO'S operations and benefit their customers by enabling PSO to meet service obligations in an efficient, cost effective manner. The performance of many of these functions by AEPSC increased efficiency by eliminating the need for each operating company to maintain staff and resources to perform the services separately. Thus, the relationship that PSO enjoys with AEPSC is of substantial benefit to PSO and its customers.

## Affiliate Services Provided to PSO by AEPSC

During the test year, AEPSC provided services to PSO in the following functional areas: Chief Operating Officer; Generation; Financial, Accounting and Strategic Planning; Transmission Services; and Office of the Chairman, including Legal, Audit Services, Federal/External Affairs, and Corporate Communications Services. The amounts billed to PSO by each of these functional areas can be found in Exhibit EKB-1. Further detail, by work order, can be found on Exhibit JWH-2.

The Chief Operating Officer group provided services in the areas of customer and distribution services, commercial operations, environmental and safety services, shared services, and regulatory services. The Generation Services function at AEPSC provided four main services to PSO: fossil services, engineering services, generation business services, and fuel, emissions and logistics. The AEPSC Finance, Accounting, and Strategic Planning groups provided for the corporate accounting, tax research and consultation, planning and budgeting, risk management, cash management and treasury and investor relations activities for the AEP affiliates. The Transmission Services group provided services in the areas of transmission engineering and project services, transmission system and region operations, transmission strategy and business development, and transmission reliability compliance. The Office of the Chairman consists not only of the AEP Chairman and Chief Executive Officer (CEO), Michael Morris and his administrative staff, but also Legal, Audit Services, Corporate Communications, and Federal/External Affairs. Each of these areas was discussed in detail in Mr. Hoersdig's direct testimony, or can be found in the direct testimony of other witnesses in this case.

<u>Affiliate Services Provided to PSO by Affiliates Other Than AEPSC</u>

PSO had transactions with various affiliate companies as shown on schedule W/P P-7 of the filing package. These transactions total $1,677,578. Test year payments by PSO to affiliate companies (other than AEPSC) generally fall into two categories.

The first category is service payments, where the affiliate provided a service such as storm restoration work. Another example of this type of service billing is where PSO may have a critical maintenance need and another affiliated company has the part or expertise to perform that task. In those cases, PSO purchased the part or service from the affiliate at their cost in order to expedite the repair. This type of cost is simply payment for services rendered, much like the billings PSO receives from AEPSC.

The second category is "convenience payments" of bills from third parties. In these situations, the service to PSO was not provided by an affiliate. The affiliate received an invoice, the cost of which should be borne by more than one company. The affiliate made a payment to the vendor, and billed the other affiliates for their share. For example, an invoice for legal services rendered related to an SPP matter may be addressed to SWEPCO but was incurred on behalf of both AEP companies in the SPP region: PSO and SWEPCO. SWEPCO received the invoice and made the payment, then charged the appropriate percentage of the invoice to PSO and other affiliates. This payment was a joint payment, made by SWEPCO as a "convenience" for both parties on the invoice. PSO would then reimburse SWEPCO for its share of the invoice. Similarly, there are instances where PSO made convenience payments on behalf of other AEP operating companies and billsed the other operating companies for their share of the bill.

In addition, PSO provided services to its affiliates during the test year. PSO has affiliate transactions classified under the same two categories as mentioned above. These amounts were shown on W/P P-8.

<u>Overview of AEPSC Accounting Systems for Directly Charging and Allocating Costs</u>

All AEPSC transactions were accounted for through a work order system. Expenditures for support services were accumulated in work orders and were billed to the company benefiting from the service. Accounting within each work order was in accordance with the FERC Uniform System of Accounts. This helps facilitate a clearer understanding of the specific service provided and facilitates the recording of these charges on the benefiting companies' books.

The costs for services benefiting only one company were directly assigned and were billed 100% to that company. AEPSC employees directly assign costs on time and expense reports to the maximum extent practicable. Certain costs, however, are incurred to perform services that benefit more than one company. When this occurs, the costs for these services were allocated to the benefiting companies using one of 59 active allocation factors. The allocation factor for any given cost was selected for use because it best reflected the cost driver associated with the service provided. Services were billed by AEPSC at cost.

Exhibit JWH-3 detailed the allocation factors that were used to allocate service costs to PSO. The allocation factors used to bill PSO and AEPSC's other utility affiliates for services performed by AEPSC were based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices, and other factors as shown on Exhibit JWH-3. The data upon which these formulae were based was updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility.

A volume-driven formula was used in all cases where the cost driver was volume based and the data was available. For example, in allocating costs for processing accounts payable, the number of vendor invoice payments was used; and for the overall management of the customer call centers described earlier, AEPSC used the number of customer calls received.

If a work order did not have a direct volume-based cost driver, the most representative factor for the service provided was used. For example, for administering the employee benefit plans, number of employees was used; for managing and dispatching the transmission system, number of transmission pole miles was used. The allocation factors were designed to ensure that the charges were in proportion to the benefits received by the benefiting companies.

AEPSC employs many levels of oversight to ensure that its costs were billed accurately. The management oversight controls can be divided into three main categories: 1) accounting system controls, which ensure that the accounting systems were operating correctly and that the mechanical processing was accurate, 2) management oversight, including review of departmental charges to budgets, variance explanations, and approval of the monthly AEPSC bill, and 3) audit and reporting oversight, which included both internal and external audits performed on AEPSC, as well as state and regulatory reporting requirements. Exhibit JWH-4 provided an overview of the controls and management oversight utilized by AEPSC.

<u>Oversight and Regulation of AEPSC</u>

The FERC is responsible for the oversight and regulation of AEPSC under the Public Utility Holding Company Act of 2005. In addition, the Oklahoma Corporation Commission (OCC), in proceedings such as these, reviews charges from AEPSC to PSO.

The FERC has implemented regulations for service companies, such as AEPSC, covering areas of financial accounting, reporting, record retention requirements, cost allocation, and at-cost billing procedures. AEP and AEPSC are in compliance with the various requirements of the Public Utility Holding Company Act of 2005 and subsequent FERC orders.

Rebuttal Testimony

Mr. Hoersdig's rebuttal testimony addressed the positions taken on affiliate billings to Public Service Company of Oklahoma (PSO or Company) by the Oklahoma Industrial Energy Consumers (OIEC). Specifically, he addressed the reasonableness of affiliate charges from AEPSC which were billed to PSO during the test year, as addressed in the testimony of OIEC witness Scott Norwood. He also addressed Mr. Norwood's statements that AEPSC's allocation factors were generic in nature and his recommendation that PSO be required to perform and file a study of AEPSC allocation factors in its next rate case.

OIEC Recommendation Regarding AEPSC Charges to PSO

PSO proposed to include in cost of service $74,419,475 of charges from AEPSC to provide necessary services to PSO. OIEC witness Norwood would disallow $6,873,969 of the AEPSC costs charged to PSO.

Mr. Norwood disallowed AEPSC costs based upon a comparison of PSO's billings in 2005 to the test year and then comparing that percentage increase to other AEP entities. He then recommended that PSO's test year charges by limited to the 2005 level of billings plus a 3.5% increase based on the AEP East affiliates, resulting in the $6,873,969 disallowance. Mr. Norwood made no conclusions that any specific charge by AEPSC to PSO was unreasonable in amount or that any service provided to PSO was unnecessary for the provision of utility service.

Appropriateness of Mr. Norwood's Cost Trend Analysis

Cost comparisons, such as Mr. Norwood's cost trend analysis, were one tool in reviewing the reasonableness of costs, but should not be the sole basis for determining reasonableness. There were multiple valid reasons for variations in costs among utilities. This was just as true for AEPSC service charges as it was for any other type of cost. If there were seeming disparities among those utilities, the next step was to inquire why, rather than simply propose a blanket disallowance based on nothing more than those differences. The analysis performed by Mr. Norwood appeared to have generated questions, but these questions were never asked of PSO during discovery. Rather, a disallowance was proposed because PSO did not anticipate the type of analysis and questions of an intervener party and included the response in Mr. Hoersdig's direct testimony.

PSO'S Burden of Proof

PSO complied with all filing requirements of this commission for affiliate costs. No one, including Mr. Norwood, has suggested otherwise. Instead of just including AEPSC costs as a line item in each of the required schedules and workpapers of the filing package, the Company also provided detailed information regarding AEPSC billings on each applicable workpaper or schedule to provide as much transparency as possible in regard to affiliate transactions.

Mr. Hoersdig's direct testimony and supporting exhibits explained the nature of AEPSC services and charges and justified them in the same manner as other witnesses justified the costs they supported. Exhibit JWH-1R provided a listing and description of each supporting exhibit from his direct testimony and each workpaper required in the filing package that supported AEPSC's billing to PSO. As can be seen, there was a variety of available information, contrary to Mr. Norwood's assertion.

PSO fully answered all discovery requested of it. Only four data requests were submitted by any OIEC witness related to the increase in AEPSC billings to PSO. The responses to these requests are provided as Exhibit JWH-2R, for ease of reference. Mr. Norwood had the opportunity, during the approximately 3-1/2 months of discovery, to better understand his analysis by submitting data requests asking for further detail related to the increases in costs, but chose not to do so.

<u>AEPSC Billings to PSO</u>

The appropriate comparison for AEPSC billings to PSO was the test year request compared to the comparable level of charges approved by the commission in the prior rate case filing (PUD 200600285). The increase since the last case was $9,813,758.

Mr. Norwood's cost trend analysis used a comparison of 2005 to the current test year, even though the last test year end was June 2006. In addition, Mr. Norwood's analysis was on a "per-book" basis and did not include the pro-forma adjustments made by the Company in determining the current test year level of charges from AEPSC to PSO. The Company has removed $5,232,607 of AEPSC charges to PSO from the test year level of expense. Mr. Norwood's analysis was not useful in discussing increases in billings from AEPSC to PSO since the last rate case filing.

The increase in billings from AEPSC to PSO since the prior rate filing was primarily due to increases in services provided by AEPSC Commercial Operations, AEPSC Environmental Services, AEPSC Regulatory Services, AEPSC Generation Services and AEPSC Customer Operations.

Billings from AEPSC's Commercial Operations organization for PSO have increased approximately $1.6 million since the 2006 test year. The increase was primarily due to a change in the allocation methodology used by Commercial Operations employees, which has increased the level of commercial operations services billed to PSO.

Prior to March 2007, Commercial Operations services were billed to affiliates based on 90% being assigned to the AEP East utilities and 10% being assigned to the AEP West utilities, including PSO. When certain margin levels were achieved, the assignment changed to 70% to East and 30% to the West. This assignment of Commercial Operations costs was in-line with the allocation of certain system sales margins under the System Integration Agreement (SIA), an agreement required under the AEP-CSW merger in 2000.

In March 2007, AEPSC began billing affiliates more directly for Commercial Operations services. Costs incurred for services provided to AEP East utilities were billed only to the AEP East utilities. Similarly, costs incurred for services provided to AEP West utilities were billed only to the AEP West utilities with generation, PSO and Southwestern Electric Power Company (SWEPCO). The 90/10 and 70/30 percentages were no longer used in assigning margins (and thus costs) through the SIA, which now also assigns margins directly to the East or West utilities.

The result of this more direct assignment of Commercial Operations services to PSO has been an increase in costs, because the actual level of transactions that Commercial Operations performs for the West utilities was higher than the 10% that was formerly billed to the West utilities. There were also an increasing number of transactions required to comply with SPP RTO operations.

Billings from AEPSC's Environmental Services organization to PSO have increased approximately $1.6M since the prior test year. In fact, the level of environmental support required by all utility affiliates has increased over this period due to a continued corporate emphasis on environmental stewardship and compliance. Environmental Services provides a wide-range of guidance, procedures, recommendations, and training to support compliance with environmental laws, regulations and policies. In addition to routine services, Environmental Services assisted PSO with any projects that may be deemed necessary to ensure environmental compliance. Two such environmental compliance projects for the Comanche plant, not required prior to the test year, included a cooling water intake study and a dissolved minerals criteria study.

An example of programs provided by the Environmental Services organization included the adoption of an Avian Protection Plan. This plan was adopted in conjunction with research by both the Edison Electric Institute and the U.S. Fish & Wildlife Services, which enhanced customer service and regulatory compliance and reduced risk to migratory birds. Bird-caused outages add costs through labor, equipment damage, lost revenue and customer complaints. The Avian Protection Plan, was one example of an environmental program that was not included in PSO's prior rate case filing.

Billings from the AEPSC Regulatory Services organization to PSO have increased by $900,000 since the prior test year. Since the prior test year, PSO, as well as most other utility affiliates, has had an increased need for the services provided by the regulatory services organization. As discussed in Mr. Hoersdig's direct testimony, the AEPSC Regulatory Services organization was responsible for the preparation of cost-of-service studies, rate design studies, special contracts and pricing, and tariff filing support for the AEPSC utility affiliates. This organization was also responsible for the case management, preparation and support of filings before the various state commissions under whose jurisdiction AEP or its subsidiaries provide service. The Oklahoma jurisdiction has increased its level of regulatory activity and this level of activity is expected to continue into the future. For purposes of the current filing, all regulatory activity related to this case and the Red Rock proceeding have been removed. The remaining activity was the expected going-level of costs for AEPSC regulatory support provided to PSO.

Billings from the AEPSC Generation Services organization to PSO have increased $2 million since the last rate filing. This increase was a result of two factors – increased maintenance due to aging infrastructure and increased engineering and environmental compliance costs.

AEPSC has been required to add eight employees to the region maintenance support staff. These employees assist PSO in planning, contracting and managing maintenance projects at the PSO power plants. As discussed by PSO witness Gary Knight, PSO's maintenance requirements continue to increase as its installed capacity ages. This accounts for approximately half of the increase in AEPSC's generation services provided to PSO.

The remainder of the increase was due primarily to increases in the plant engineering and environmental areas. Services that have increased since the prior rate case filing include increased engineering support for unplanned outages at PSO power plants, additional plant water quality and chemical studies, drawing and document control and transformer support services.

Billings from the AEPSC Customer Operations organization to PSO have increased $1.7 million since the last rate filing. These customer operations costs have increased for all affiliates over this timeframe. For PSO, the cost increases were primarily due to increased labor costs and an increase in PSO's relative share of total call center volume. While total headcount for the centralized AEPSC customer call centers has not increased, the base pay for these employees was higher than in the prior test year, since the passage of time results in naturally higher base salaries and because the staff was generally more tenured.

Additionally, there have been increased services required for the support of the customer accounting and billing software systems and meter data systems as well as increased load research and measurement services.

Billings to PSO from other AEPSC departments have increased a total of $2 million since the last rate filing. These departments include corporate accounting and finance due primarily to increased support of Oklahoma regulatory activity, risk management primarily due to the increase in commercial operations activity attributable to PSO, transmission system and region operations, and transmission engineering primarily due to an increase in services in order to address emerging transmission issues related to meeting reliability requirements and the growth in demand for transmission services.

The increase in services provided by AEPSC to PSO in the test year was also impacted by the level of services "directly billed" to PSO. An increase in directly billed services with no corresponding decrease in allocated costs was an indication that more services were directly requested and or required by the utility during that period. The amount of services directly billed to PSO, not offset elsewhere, increased over $5 million from the prior rate filing, meaning that PSO required services that were not required by AEPSC's other affiliates.

The increases in billings from AEPSC to PSO were reasonable and explainable. AEPSC has been structured to provide services to AEP affiliates where and when needed. While some AEPSC services, such as payroll processing, were needed by all affiliates in a similar fashion, other services can vary greatly depending on the unique needs of the particular utility. Imposing the AEP East increase to PSO billings was simply invalid and not supported by a reasoned analysis.

<u>OIEC Recommendation Regarding AEPCS Allocation Factors</u>

Mr. Norwood characterized AEPSC's allocation factors as "generic", but this simply was not the case. AEPSC used any of 59 very different allocation factors to assign costs to the company or companies benefiting from each service provided. These factors, shown on Exhibit JWH-3 of Mr. Hoersig's direct testimony, support a wide range of AEPSC services in order to allocate charges in as accurate a manner as possible. Utility service companies, such as AEPSC, have a great deal of latitude in creating their allocation factors. Some service companies may use a small number of allocation factors, including factors that blend a number of different attributes together, which in Mr. Hoersdig's opinion, limits the accuracy of billings and could be characterized as somewhat "generic." AEPSC, however, has taken the approach of using a large number of allocation factors in order to allocate costs as precisely as possible. AEPSC has very specific allocation factors for each major type of service provided. For example, AEPSC's transmission organization can allocate costs based upon factor #28 – Number of Transmission Pole Miles; AEPSC's accounts payable department can allocate costs upon factor #32 – Number of Vendor Invoice Payments; and AEPSC's management of the customer call centers can allocate costs upon factor #16 – Number of Phone Center Calls. These types of volume-driven allocation factors are, in fact, specific in nature and provide for a very accurate billing to affiliate companies. They are anything but generic.

Exhibits JWH-2 and JWH-3 of Mr. Hoersdig's direct testimony, along with W/P P-03 of the filing package provided the level of detail regarding the application of the AEPSC allocation factors that Mr. Norwood asserted were not provided in the filing package or Mr. Hoersdig's direct testimony.

Mr. Norwood stated that the cost allocation process had not been approved by the FERC or any other regulatory authority. The FERC was not required to approve the specific allocations from a centralized service company, such as AEPSC, to an affiliate such as PSO. The FERC reviews all relevant cost allocation information with the annual filing of the FERC Form No. 60. In addition, all centralized service companies subject to the rules of the Public Utility Holding Company Act of 2005, including AEPSC, are subject to a FERC review of books and records as well as cost allocation processes, at any time.

In light of Mr. Norwood's recommendation that an allocation study be provided with the next rate case, the Company has engaged Mr. Thomas Flaherty, of Booz & Company as a rebuttal witness. Mr. Flaherty performed such an analysis for AEP in late 2006 for two different rate cases. Mr. Flaherty performed an in-depth study of AEPSC, which included a detailed review of the allocation factors used to bill costs to each affiliate company, including PSO. Mr. Flaherty concluded that AEPSC's allocation process was well-structured and designed to result in an appropriate level of costs being allocated to each of the operating companies, consistent with generally accepted cost causation principles. Mr. Hoersdig does not believe that it is necessary for PSO to go through the time and expense of preparing such an extensive study when one has already been performed by a third-party and was currently available for review.

**Thomas J. Flaherty**

Mr. Flaherty is a graduate of the University of Oklahoma with a degree in accounting. He was employed by Deloitte & Touche for more than 30 years until joining Booz Allen Hamilton as a Senior Vice President. In July 2008, a transaction was undertaken that resulted in Booz Allen Hamilton being acquired by the Carlyle Group and Booz & Company being created as an independent entity. As of July 2008, Mr. Flaherty is a Senior Vice President of Booz & Company.

Over the course of his consulting career, Mr. Flaherty has specialized in the public utility industry and has performed a variety of assignments. He has participated in numerous regulatory consulting engagements for gas, electric, water and telephone utilities encompassing rate base, operating income, capital structure, rate of return, revenue requirements, affiliate transactions and cost allocations. Specifically, he has previously testified with respect to affiliated interest issues related to service company formation, service company activity necessity and benefits, service company activity overlap, Service Company budgeting and cost management, service company cost comparability, and service company cost apportionment processes. These engagements have been conducted for AEP, Entergy, PNM Resources, Reliant Resources, Commonwealth Edison, Sempra Energy, Oncor, Southwestern Bell, US West, GTE of the Southwest, GTE South, Centel, and Continental Telephone.

Additionally, Mr. Flaherty has performed organization and operations reviews of utilities or regulatory bodies in the states of Arizona, Georgia, Illinois, Iowa, Kansas, Ohio, Oklahoma, Texas and Wyoming and on behalf of the Interstate Commerce Commission and the Federal Power Commission (currently the Federal Energy Regulatory Commission (FERC).

In addition to his involvement in utility regulatory consulting, Mr. Flaherty has participated in several other consulting engagements in the areas of mergers and acquisitions, strategic planning, performance improvement, competitive analysis, organizational restructuring, marketing, litigation assistance, economic feasibility studies and financial analysis, among other areas. During the course of many of these engagements, he analyzed and became familiar with utility holding and service companies.

Mr. Flaherty has pre-filed direct testimony and appeared for cross-examination in 29 states (including Oklahoma), the District of Columbia and the Federal Energy Regulatory Commission. The testimony he presented was principally directed toward certain regulatory, management, operational, and financial areas regarding the telecommunications, electric or gas industries.

Mr. Flaherty was retained by PSO in this docket to provide rebuttal testimony to OIEC witness Scott Norwood regarding his recommendation that PSO be required to perform a study of the allocation process utilized by AEP Services Corporation (AEPSC) for charges to the AEP service companies. In Mr. Flaherty's testimony he discussed a study he performed for two AEP operating companies in Texas in 2006, in which he reviewed the entire AEPSC allocation process. He concluded in that study that the AEPSC allocation process was fair and reasonable and resulted in equitable assignment of costs to all AEP operating companies. Based on that study and on interviews with AEPSC and PSO personnel, Mr. Flaherty concluded in his rebuttal testimony in this docket that the current AEPSC allocation process reflected a sound and reasonable approach to distribution of service company costs to AEP operating companies, including PSO, and that AEPSC's cost assignment and allocation processes and the selection and application of allocation factors were reasonable and were in line with other similar service companies in the utility industry.

Mr. Flaherty further stated that the mechanisms through which AEPSC costs were charged to operating companies ensure that costs were fully captured and equitably distributed to the operating companies. Further, as Mr. Flaherty discussed, AEPSC directly assigns costs to the operating companies for work that is performed for their benefit. He stated that where costs are allocated, the allocation process is based on allocation factors which are similar, and in fact more expansive, than those used by other companies.

Mr. Flaherty concluded that the allocation process that underlies the distribution of these costs is applied in a manner consistent with its objectives and that the application of this process results in an equitable sharing of costs among the AEP operating companies, including PSO. Based on these conclusions, he opined that an additional study of AEPSC's allocation process as it is applied to PSO is unnecessary.

In reaching these conclusions, Mr. Flaherty discussed the principles of a cost effective allocation process, compared the AEPSC cost allocation process to these principles, reviewed the mechanics of the AEPSC allocation process and billing methodologies, and reviewed the particular allocation factors utilized by AEPSC. He concluded that the AEPSC process is consistent with sound cost allocation principles, that the mechanics of the system are reasonable, that the AEPSC cost allocation factors are granular in nature and that their applicability allows for an equitable and cost causative allocation of service company costs among business units, including PSO.

Mr. Flaherty also performed a comparison of AEPSC's allocation process to nine peer service companies and concluded that AEPSC had more established allocation factors than any of its peers. He stated that this allows AEPSC a greater ability to match services with costs and is a further indication of the overall strength of AEPSC's allocation process and of the individual allocation factors it utilizes.

In summary, Mr. Flaherty's rebuttal testimony makes clear that Mr. Norwood is incorrect in describing AEPSC's allocation factors as "generic" and that there is no need for another study of AEPSC's allocation factors to be presented in the next PSO rate case.

**David A. Jolly**

Direct Testimony

David A. Jolley is employed as a Senior Compensation Consultant for American Electric Power Service Corporation (AEPSC), a subsidiary of American Electric Power Company, Inc. (AEP) that provides corporate support services to the operating subsidiaries of AEP, including Public Service Company of Oklahoma (PSO). He filed direct testimony in this cause.

He received a Bachelor of Science degree in Production and Operations Management from The Ohio State University in 1976, and has been certified as a Compensation Professional by World at Work, the world's leading professional association dedicated to knowledge leadership in the fields of compensation, benefits and total rewards. In 2000 he was awarded a lifetime achievement award by the American Compensation Association. He began working for the compensation section of AEPSC in 1990 as a Senior Compensation Consultant in the compensation section of AEPSC's system human resources department, a position he continues to hold. In his current position, he is responsible for conducting research regarding the compensation market to maintain the effectiveness of AEPSC's employee compensation programs, PSO, and other AEP affiliates.

The compensation section developed and maintained compensation programs for PSO that were market competitive and aligned with AEP's business strategies. It conducted ongoing research and recommended changes to compensation programs as necessary, and developed communications materials in support of compensation programs and monitored compliance with federal and state regulations related to compensation.

The purpose of his testimony was to show that the compensation levels for employees of PSO and AEPSC, were necessary, reasonable, and market competitive. He also supported the reasonableness of the portion of AEPSC affiliate charges to PSO that included base pay and incentives.

Reasonableness of AEP's Compensation Levels

It is the practice of AEP and its operating companies to provide total compensation that targets median wage levels for companies of similar size and scope within the electric utility industry for most positions. Employees were compensated through a combination of base pay and incentive pay programs. All employees were eligible for some level of annual incentive compensation, and approximately 450 senior managers were also eligible for long-term incentives. PSO and AEPSC utilize a merit program for all salaried positions whereby each employee's performance was evaluated on at least an annual basis against pre-determined performance objectives.

Incentive programs were offered to employees to drive behavior and support the Company's strategic objectives and business goals. These programs permit employees to focus on measures that, when met, will benefit all stakeholders – customers, shareholders and employees. Incentive compensation programs support PSO's mission of providing cost efficient, safe and reliable electric service through the attraction, retention and motivation of highly qualified employees.

The AEPSC compensation section annually reviews compensation survey data to determine the competitiveness and cost effectiveness of its compensation programs. This is standard practice in both the utility industry and other industries across the country. A number of third-party compensation consulting companies such as Towers Perrin, Mercer, and Hewitt & Associates provide surveys used by the compensation staff in the review of compensation programs. Compensation surveys typically include a description of the job, the number of companies who have a similar position, the number of incumbents in each position, the level of base and incentive compensation reported by each company, and summaries of the compensation data by company type, company size and geographic location.

It is necessary to use a variety of compensation surveys because some surveys are function specific, covering areas such as legal, accounting, human resources, and information technology, and provide information covering a broad range of positions within the functional area. Other surveys are industry specific such as the energy services industry. Utilizing a large pool of information in establishing salary ranges and pay programs supports better decision making.

Information from these surveys is used to establish salary ranges for each position at AEPSC, PSO, and the other AEP affiliates. The objective is to have the midpoint of the salary range for each position established at the median or 50th percentile of the comparable survey data. The company's process for the review of compensation levels and establishment of salary ranges is consistent with compensation practices at other companies, both within the electric utility industry and general U.S. industry as a whole.

The median survey salary is chosen as the midpoint for the salary range because it is an accepted industry standard to establish compensation levels, minimizes the potential for one company's data to influence that survey sample, and helps to ensure that we are not either an industry leader in pay, or lagging behind the market. The median level of incentive pay reported in compensation surveys is utilized to establish the "target" incentive opportunity assigned to similar positions at PSO, AEPSC, and its affiliates. The target incentive level is expressed as a percentage of base compensation.

Use of the survey median as a target does not mean that employee salaries will invariably fall at the median. The median was used to establish the midpoint of the salary range assigned to each position. The salary range extended approximately 22.5% above and below the midpoint, a common compensation design practice. Individual salaries may fall anywhere within the assigned range depending on such factors as performance, qualifications and time in job.

Base Compensation

The base salary level for new employees of PSO and the other AEP operating companies was determined by the qualifications and experience of the new employee relative to the minimum requirements of the position. For positions with multiple incumbents, the base salaries of existing employees were also taken into consideration.

For existing employees, PSO and AEPSC use a merit program for all salaried positions whereby each employee's performance was evaluated on at least an annual basis. The amount of each employee's base salary increase was based on a combination of their individual performance, their performance relative to their peers, the level of the salary within their current salary range and the size of the merit increase budget. The amount budgeted annually for merit increases was influenced by information reported in salary planning surveys conducted annually by several large compensation consulting firms such as Mercer and World at Work, as well as salary budget dollars available.

For the year 2007, the total merit increase budget for both exempt[4] and nonexempt salaried employees at PSO, AEPSC, and the other AEP Operating Companies was 3.6%. For the year 2008, the total merit increase budget for both exempt and nonexempt salaried employees at PSO, AEPSC, and the other AEP Operating Companies was 3.7%. The Mercer 2007/2008 salary planning survey reported average merit increases granted by all companies at 3.8 percent for 2007, and projected 3.8 percent merit increases for 2008. The 2007/2008 World at Work salary planning survey reported that average merit increases granted by all companies for exempt salaried employees were 3.6 percent for 2007, and projected 3.8 percent increases for 2008.

Base pay increases for hourly/craft employees, such as line mechanics and meter readers, are known as "general increases" and apply across the board to all such employees. The general increase amount was determined on an annual basis by reviewing survey data projections provided by other employers of these types of positions. Hourly/craft employees at PSO were granted a 3.1% general increase in 2007 and 2008, which is less than the average rate of 3.7% reported by the Bureau of National Affairs Daily Labor Reporter for 2007 energy services companies in the "mountains/plains" region of the 2007 EAP Data Solutions Nonexempt Technical, Craft & Clerical Survey reported average negotiated increases of 3.9 percent for 2007.

Based on the above described data, Mr. Jolley believed that PSO's and AEPSC's base compensation by merit increases for salaried employees and general increases for hourly/craft employees were consistent with the practices of other employers in both the energy services industry and industry as a whole. The amounts budgeted for merit and general increases have been consistent with too slightly below the market.

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[4] An "exempt" employee is one who is exempt from the overtime provisions of the Fair Labor Standards Act. A "non-exempt" employee is covered by the Fair labor Standards Act and is eligible for overtime compensation for all hours worked over 40 in a work week.

Incentive Compensation

Incentive compensation plans are formal plans that are fully described in written documents and approved by the Company's senior management. The plans applicable to PSO include the Utilities Group Plan, the Generation Plan, the Information Technology (IT) Plan, and the Business Logistics Plan. The plans applicable to AEPSC include the Utilities Group Plan, Generation Plan, the Shared Services Plan, the Finance Plan, and the Corporate Plan. Copies of all of these plans are included in Exhibits DAJ-5, DAJ-6, DAJ-7, DAJ-8 and DAJ-9 to Mr. Jolley's direct testimony.

The majority of PSO's incentive expenses (approximately 82%) during the test year were incurred through the Utilities Group Plan. The Utilities Group Plan, like the others, is part of an overall compensation package consisting of base compensation and annual compensation commonly referred to as an incentive. The incentive plan contains a number of weighted performance measures, each of which has a minimum, target and maximum performance level that corresponds to a performance factor or score of 0 for minimum performance, 100% for achievement of target performance and 200% for achievement of maximum performance. At the conclusion of the year, the resulting performance scores for each measure are multiplied by their corresponding weight, and summed to arrive at an overall performance score ranging from 0 to 200%. This score may then be adjusted up or down through what is known as the operating unit performance adjustment. The score is then multiplied by the Earnings Per Share (EPS) modifier, also a value of between 0-200% to arrive at the final, overall performance score, a value from 0-200%.

In addition, during the test year approximately 359 PSO employees participated in the Generation Plan, 30 employees participated in the Information Technology Plan and 75 employees participated in the Business Logistics plan.

The monetary award paid to an employee is a function of their final overall performance score times their incentive target times their earnings for the period covered by the incentive plan (the previous calendar year). In addition, all exempt employee awards may be adjusted upward or downward based on individual performance. The target payout percentages vary by employee salary grade level and vary from 5% of earnings for non-exempt employees to 5-15% of earnings for exempt employees, and 25-30% of earnings for exempt management employees. Senior management employees have incentive targets of between 30-100% of earnings, depending on their assigned salary grade. Exhibit DAJ-11 illustrates how a hypothetical incentive award is calculated.

The EPS modifier component of the annual incentive plan can increase the size of the incentive pool of dollars generated by the incentive plan measures, so the company is only requesting that an amount equal to target payout be included in this rate case.

The Utilities Group incentive program is necessary for PSO, AEPSC, and the other AEP operating companies to attract and retain qualified employees and provide quality utility service, as well as to incent the employees to achieve goals which positively affect customer satisfaction, safety, and financial performance. Moreover, each of the performance measures promoted either cost control and fiscal responsibility (Net income, capital budget, O&M budget), service reliability and customer satisfaction (SAIFI, CAIDI, customer satisfaction and commission complaint measures), or operational safety (safety measures). In each instance, these measures were consistent with the provision of quality utility service at reasonable cost.

The PSO and AEPSC incentive plans differ from the Utilities Group incentive compensation plan in that the other incentive plans incorporate measures that support the objectives of the business function. For example, the Business Logistics Plan included measures related to controlling the amount and cost of inventory, the Human Resources Plan included measures related to diversity and employment, and the

Information & Technology (IT) Plan included measures related to availability of computer applications and support of computer equipment. All other incentive plans were similar to the Utilities Group plan in regard to the application of the operating unit performance adjustment, the EPS modifier, and the discretion that can be applied to exempt employee awards.

AEP's incentive plan targets for PSO, AEPSC, and the other AEP Operating Companies were very consistent with those reported in surveys of national and western region utilities.

Incentive plans are part of a total compensation package. Incentive compensation plans were not designed as "bonuses" or additions to an already appropriate level of compensation. Instead, the Company designed an overall compensation package that included an incentive compensation portion to reward employees for the achievement of strategic objectives that were both financial and operational in nature. It was the entirety of this compensation package that allowed the Company to provide a competitive salary, and therefore attract and retain qualified, highly motivated employees able to support reliable, cost effective service to customers.

The Company was not requesting that all of the incentive compensation from the test year be included in its revenue requirement in this case. It is only requesting that the target amount of incentive compensation during the test year, $8,078,012, be included in cost of service, rather than the $13,451,337 in expense during the test year. Incentive compensation during the test year exceeded target amounts because the AEP earnings and the earnings per share modifier used in the formula were higher than expected during 2007 and many of the plan measures were met or exceeded. However, this was unusual and the Company is only requesting that target amounts be included in cost of service because this is the amount that is designed to ensure that employee salaries will be competitive. PSO witness John Aaron supported this pro forma adjustment for the PSO rate case and PSO witness Hoersdig supported the adjustment for AEPSC test year charges to PSO.

Incentive compensation plans are common in the electric industry. Incentive compensation plans similar to the ones that AEP employs are widespread in the electric, gas, and similar industries. The 2007 Towers Perrin Energy Services Industry Middle Management and Professional Survey reported that 104 of 109 companies participating in the survey have annual incentive plans similar to those used by PSO and AEPSC. The 2007 Mercer US Compensation Planning Survey reported that 86% of the responding companies and 93% of utilities offer incentive pay programs to all employees. The Mercer survey also reported that key performance measures are, in order of prevalence, financial, operational and customer satisfaction related in nature, similar to the design of AEP's programs. The 2007 World at Work Salary Budget Survey reported that the number of companies using incentive pay programs continues to increase each year and that 80% of 2,426 responding companies were using incentive pay programs in 2007, up from 79% reported in 2006.

As such, these plans are necessary to attract and retain qualified employees. PSO's and AEPSC's ability to attract and retain qualified employees, moreover, has a very real and direct effect on the quality of customer service.

If PSO's and AEPSC's compensation levels were set for ratemaking purposes without inclusion of amounts for incentive plans, PSO's rates would not support payment of total compensation competitive with the total compensation being paid in the market by the employers with whom PSO and AEPSC competes to obtain qualified employees. Absent recognition of incentive pay for rate setting purposes, PSO's rates would only support salaries that would fall below what constituted a competitive, market based total compensation package.

Competitiveness of Total Compensation Levels

Exhibit DAJ-1 compared compensation data from the 2007 Southwest Personnel Group Survey to that of key hourly/craft benchmark positions at PSO. A "benchmark" job is one that is commonly used to make pay comparisons, either within the organization or to comparable jobs outside the organization. Pay data for these jobs are readily available in published surveys. Participants in this survey include Austin Energy, CenterPoint Energy, CPS Energy, CLECO, El Paso Electric, LCRA, OG&E Electric Services, PNM Resources, TXU, and XCEL Energy. This exhibit compares base, target annual incentive and total cash compensation. From an overall perspective, PSO's total average salary for all comparable positions covered by Exhibit DAJ-1 falls within +/- 10% of the total average salary levels of the survey participants. In fact, in some cases PSO's base compensation is below market median and the addition of incentive pay brings the total compensation package to a more competitive level.

Exhibit DAJ-2 compared compensation data from the 2007 EAP Data Solutions Energy Technical, Craft & Clerical (EPSO) Survey to that of key hourly/craft benchmark positions at PSO. This survey was the largest source of compensation data for positions of this type and included data collected from 75 companies representing 99,450 incumbents nationally. The information included in Exhibit DAJ-2 represented data from the Mountains/Plains region. This exhibit also indicated that, with the exception of Meter Readers, PSO's compensation levels were market competitive and within an acceptable range of +/- 10% compared to the average compensation for comparable positions paid by the other survey participants. Similar to Exhibit DAJ-1, in many cases base compensation was below market median and the addition of incentive pay brings the total compensation package to a more competitive level overall.

Exhibit DAJ-3 compared exempt positions at PSO and AEPSC to compensation survey benchmarks covering a broad range of professional, management and supervisory positions for which survey data was available. The survey data was drawn from the Towers Perrin Energy Management and Professional Survey and the Mercer Information Technology Survey, Human Resources Survey, and Accounting/Finance & Legal Survey. This exhibit also indicated that with a few exceptions, PSO and AEPSC fall within a reasonable range in comparison to average survey data.

It is reasonable to expect greater variances between PSO and AEPSC compensation and average survey results in some instances. AEP established salary ranges whose midpoints were approximately +/- 10% of the median base salary for comparable positions in compensation surveys. The entire salary range extended approximately 22.5% above and below the midpoint. Actual employee salaries can fall anywhere within this range depending on the employee's performance, qualifications, and time in job.

Management Compensation Program

AEP used a market-based pay philosophy for senior managers that is similar to that used for other positions. In addition to base pay and annual incentives, the compensation program for senior managers also included long-term incentives. Approximately 450 senior managers participate in this program. The combination of base salary, annual, and long-term incentives balances both the long and short term interests of customers, shareholders, and employees alike. The Human Resources (HR) Committee of the AEP Board of Directors annually reviews AEP's senior management compensation program in the context of performance of management and performance of AEP. In carrying out its responsibilities, the HR Committee has hired a nationally recognized independent consultant (Towers Perrin) to provide recommendations to the HR Committee regarding AEP's senior manager compensation and benefits programs and practices, and to provide information on current trends in senior manager compensation and benefits within the energy services industry and among U.S. industrial companies in general. The HR Committee regularly holds meetings with its independent consultant and without management present to help insure that it receives full and independent advice. In setting compensation levels, the HR

Committee recognizes that AEP's senior management team is charged with managing one of the largest and most geographically diverse electric generation, transmission, and distribution companies in a dynamic business atmosphere that requires high levels of business and management innovation and expertise.

The HR Committee annually reviews AEP's senior management compensation relative to a peer group comprised of companies that represent the talent markets from which AEP must compete to attract and retain senior managers. For 2007, the compensation peer group consisted of 14 large and diversified energy services companies, plus 12 Fortune 500 companies, which, taken as a whole, approximately reflected the company's size, scale, business complexity and diversity.

The HR Committee generally used median compensation information of the compensation peer group as its benchmark but did consider other comparisons, such as alternative percentile benchmarks and industry-specific compensation surveys, when evaluating compensation.

The primary purpose of AEP's long-term incentive program is to motivate senior managers to take a longer, more strategic view of the business. The current long-term incentive program provides grants or awards in the form of performance units (units are similar to shares of AEP common stock but have no voting rights) with a three-year performance and vesting period beginning January 1 of each year. Performance units may be earned subject to two equally weighted performance measures: three-year total shareholder return measured relative to the S&P Utilities, and three-year cumulative earnings per share measured relative to a Board approved target. The scores for these performance measures determine the percentage of the performance units outstanding at the end of the performance period that are earned and can range from zero to 200%. The value of each performance unit that is earned equaled the 20-day average closing price of AEP Common stock for the last 20 days of the performance period. Exhibit DAJ-13 explained this program in more detail.

PSO's share of the long term incentive program that it is requesting to be included in cost of service in this case is $3,660,113. This long term incentive program is reasonable and necessary to support reliable utility service. Companies of AEP's size and complexity offer similar programs; AEP cannot hope to attract the highly qualified professionals needed to manage its utility service unless it offers such a program. Towers Perrin reports that 99 of 102 companies that participated in their 2007 Energy Services Executive Compensation Survey have long term incentive programs for their senior managers. Moreover, the focus of AEP's overall operations is the success of PSO and the other AEP Operating Companies. Senior management ensures that shareholder value is increased, among other things, by working to improve the efficiency and reliability of the utility services provided by PSO and the other AEP Operating Companies, while at the same time adopting measures to maintain their operating costs at reasonable levels. Accordingly, there is no inconsistency between the performance measures in the long term incentive plan and the interests of utility customers.

<u>Rebuttal Testimony</u>

Mr. Jolley filed testimony rebutting the recommendations of the Staff of the Corporation Commission of the State of Oklahoma (Commission) witness Brandy Loyd Wreath, Office of the Oklahoma Attorney General (AG) witness Roya Soltani, and Oklahoma Industrial Energy Consumers (OIEC) witness Mark A. Garrett with regard to their testimony relating to Public Service Company of Oklahoma's (PSO or the Company) and AEPSC's annual incentive compensation plans. Mr. Jolley also offered rebuttal testimony related to these same witnesses' proposals to remove all costs associated with AEPSC's long-term incentive compensation plan for senior employees.

All of these intervener and Staff witnesses would disallow portions of incentive compensation, yet none of them challenge the Company's testimony demonstrating that the requested overall compensation is reasonable. They would disallow the recovery of $7,711,851 to $9,327,453. These criticisms are misplaced because they fail to take into account that:

1. Providing a substantial component of compensation as incentive-based is normal in business today and considered to be good industry practice.

2. Incentive compensation is not a bonus for performance that exceeds targeted expectation. In fact, PSO already eliminated the test year amount of that portion of compensation from its request.

3. Providing an incentive for improved financial performance benefits customers by supporting overall financial health which can have a positive impact on financial costs.

All three witnesses have an outdated understanding of the role incentive compensation plays in today's business environment. They view incentives as simple "bonuses," or put another way, as compensation paid for work over and above what is normally expected. While that view may have been true ten years ago before incentive compensation became the norm, incentive programs, both annual and long-term, are now a key element of total compensation that, by design, are expected to achieve target levels on a regular basis. The "bonus" element has now shifted to those opportunities for performance above target levels which, as explained later, the Company has removed from test year amounts.

There has been no showing at all that these incentive compensation amounts are unreasonable. In fact, if intervener proposals are adopted by this Commission, it will guarantee that *less* than the Company's reasonable and necessary compensation expenses will be included in cost of service. This is improper and should be denied.

<u>Annual Incentive Compensation</u>

Mr. Wreath and Ms. Soltani have both recommended that the company's proposed annual incentive costs be reduced by $4,039,006 (50%). Mr. Garrett has recommended that the company's proposed incentive costs be reduced by $5,654,608 (70%).

Mr. Wreath and Ms. Soltani contend that the Company's and AEPSC's incentive compensation programs benefit ratepayers and shareholders equally and they should each share 50% of the cost. Mr. Garrett considers the extent to which what he refers to as "financial" measures are contained in the various annual incentive compensation plans. He concludes that the Company's requested annual incentive costs are overwhelmingly weighted toward Company, rather than customer, objectives. He also argued that the earnings per share (EPS) modifier, by its very nature, shifts the risks associated with incentive compensation payments to ratepayers since he claims there is no certainty that incentive payments will be made from year to year. As a result, he suggests that 70% of incentive compensation be removed from the cost of service.

However, none of these witnesses contend that PSO's and AEPSC's salary levels are excessive when incentive compensation is taken into account. Their only contention is that PSO should not be permitted to recover any incentive compensation tied to certain financial or non-customer related measures. At no point does any witness suggest that PSO's or AEPSC's salary levels are not in line with industry norms or are otherwise excessive. They simply argued that the Company should not be permitted to recover a portion of its payroll expense despite the fact that they have no criticism of the overall level of that expense. This was significant because it suggested that these witnesses were primarily criticizing the design of AEP's compensation program, and not the reasonableness of the compensation. The consequence is that they recommend the disallowance of costs that are actually reasonable.

In his direct testimony Mr. Jolley explained that AEP's comprehensive compensation package is specifically designed to be market competitive. It pays employees the going market rate for their services. Assume that instead of offering an incentive component, AEP were to replace the targeted level of that compensation with a fixed salary. Interveners and Staff contend that improper incentive compensation would be eliminated, and the requested level of compensation is still at the reasonable amount. This suggests that the criticisms relate to the method of compensation, not the reasonableness of the amount. No part of the evidence that Mr. Jolley presented in his direct testimony showing the reasonableness of PSO's total compensation package, which included both base compensation and annual incentives, is contested by Mr. Wreath, Ms. Soltani or Mr. Garrett.

The Company's overall level of salary expense is reasonable and necessary to attract quality employees, and it is therefore inappropriate for the Commission to disallow a portion of that expense because of the manner in which it is calculated and paid. The Commission should thoroughly review PSO's and AEPSC's overall salary level for reasonableness and consistency with industry norms. However, once that level is determined reasonable, the Commission should not disallow a portion of that level because of how that level is derived or how it is paid to employees. It makes no sense to conclude that a salary level of a certain amount is reasonable and necessary, but whether the company is allowed to recover that expense depends on how it is paid out to employees. Yet that is what Mr. Wreath, Ms. Soltani, and Mr. Garrett seem to be arguing.

The intervener witnesses call into question various aspects of the design of PSO's and AEPSC's incentive compensation plans. Ms. Soltani questioned the measures that she contends focus on corporate-wide financial results. Similarly, Mr. Garrett questioned the inclusion of financial measures, but then ultimately concluded that all annual incentive amounts, including those based on safety-related measures, such as OSHA recordable rate, severity rate, and preventable vehicle accidents, should be removed. He also criticized the EPS modifier. Mr. Wreath also questioned the plans' use of financial measures but ultimately concluded that the cost of the plans should be evenly split between ratepayers and the Company.

Mr. Jolley disagreed with these criticisms. The financial measures contained in the various incentive plans are consistent with ratepayer interests. These measures (*i.e.*, O&M budget, net income, and capital budget) benefit customers by promoting the optimal use of the company's limited financial resources, leading to O&M and capital cost control, encouraging the pursuit of all sources of additional earnings, and contributing to the financial health of the Company, all of which benefits both customers and shareholders alike. Customers directly benefit by company policies designed to ensure fiscal discipline since efficient use of these limited resources will likely result in more work being done for the same cost and ultimately a lower cost of service. When operations are conducted consistently at or under budget, this supports not only the earnings objectives of shareholders, but also the reasonable O&M and capital cost levels that are an objective of Commission rate setting. Higher earnings translate into stronger financial integrity and stability, access to the capital markets on lower cost terms, lower cost of service and lower rates over time. These financial measures benefit both shareholders and customers because their interests are aligned.

Customers' interests are furthered when PSO provides service as effectively and efficiently as possible, and this is often best measured from a financial perspective. In addition, to the extent that financial targets are more consistently met, the need for higher rates is reduced. Mr. Garrett's contention that *all* annual incentive compensation amounts should be removed implicitly means that non-financial measures, such as safety-related measures, only benefit the company and not ratepayers. This is both an extreme position and patently absurd. The safety and well being of Company employees is of value to all constituents, including ratepayers.

The EPS modifier ensured that no incentive awards were paid unless AEP met its targeted level of earnings per share. More importantly, from a customer benefit perspective, the portion of incentive awards above the target level were paid from additional earnings, not by ratepayers. This was the very reason why the amount requested in this case was set at the target payment level. In other words, all test year amounts of incentive compensation payments above the target levels have already been removed by the Company.

Long-Term Incentive Compensation

Mr. Wreath, Ms. Soltani, and Mr. Garrett recommend that all of PSO's test year long-term incentive compensation for senior employees, in the amount of $3,672,845 incentive expense, be denied. They contend that all of the performance measures used in the long-term incentive program were based on achieving financial goals that only benefit shareholders and should not be paid by ratepayers. Mr. Jolley disagreed with the interveners' recommendation and their reasoning for the same reasons he outlined above when discussing annual incentive compensation. No party has suggested that these amounts are part of an overall compensation package that is unreasonable or excessive. Further, as explained above, the use of financial measures in the Company's incentive compensation plan benefits all stakeholders, including customers.

None of the witnesses suggest that the long-term incentive compensation plan is excessive in amount or not necessary to attract high quality senior managers. They simply suggest that this plan was calculated on a basis they disagree with. They do not contend that the plan results in excessive compensation for senior managers or that the Company and AEPSC could attract high quality senior managers if this amount of their compensation was simply eliminated. Senior managers are not over-compensated. Thus, this component of total compensation should be included in rates unless the Commission specifically concluded that the overall level of compensation is excessive. Given all of the testimony on this issue, including the interveners', there is no basis for the Commission to conclude that those managers are excessively compensated.

The managers participating in the long-term incentive program have a responsibility to fulfill earnings goals through successful management of overall company operations, including financial, customer satisfaction, safety and reliability measures. Success in all of these areas ultimately contributes to meeting the long term success of AEP and its subsidiaries. Disallowing 100% of long-term incentive compensation ignores these facts.

**A. Naim Hakimi**

Mr. Hakimi has BS and MS degrees in Electrical Engineering from the University of Texas at Austin. He has been employed in various positions with AEPSC and CSWS since 1980. He has previously testified before this Commission and his qualifications are contained within his prefiled testimony.

His testimony described PSO's resource needs and the capacity procurement process used to meet those needs. He described PSO's capacity purchases and costs and PSO's proposed treatment of capacity purchases as they relate to this current proceeding. There are many factors that influence the resource needs of PSO. These are: forecasted load, generating resource additions and/or changes in unit ratings, Southwest Power Pool Capacity Margin requirements, the availability of firm transmission, and existing capacity purchase contracts. AEPSC prepared Capability, Demand, and Reserves (CDR) forecasts for PSO and acted as agent for PSO in securing capacity purchase contracts from market resources when needed. The capacity purchase process followed by AEPSC assured that the resources needed by PSO will be acquired at a market rate that allowed PSO to provide reliable service to its customers at the lowest reasonable cost.

Because PSO did not recover any portion of its capacity costs through the Fuel Cost Adjustment (FCA) Rider, PSO is seeking recovery of its purchased capacity costs through base rates. PSO's capacity needs will continue beyond calendar year 2008 and the capacity costs of the contracts entered into by PSO for the year 2009 are known and measurable. PSO is seeking a pro-forma adjustment based on 2009 capacity contracts because compared to Test Year capacity expenses, the 2009 contracts are a better indicator of the costs PSO will incur to meet its resource obligation in 2009, around the time when PSO's new rates will go into effect. One of the new capacity purchase contracts in effect in 2009 and 2010 will result in significant fuel cost savings for PSO's customers that will more than off-set the increase in capacity costs reflected in PSO's pro-forma adjustment. PSO is also receptive to recovery of future capacity costs through a cost recovery mechanism other than base rates, provided that all capacity purchase costs are recovered through the proposed mechanism.

Mr. Hakimi also described the anticipated O&M expenses associated with the Clean Air Interstate Rule (CAIR) Annual NOx compliance program for PSO's share of the Oklaunion generating unit. Under CAIR, PSO would need to hold and surrender sufficient NOx allowances each year to generate and receive the output from the low-cost, coal-fired energy from its share of the Oklaunion plant rather than replacing the Oklaunion generation from other higher cost resources. Given that the number of NOx allowances PSO would need will be variable in nature similar to fuel consumption, and vary each month depending on the amount of energy dispatched from its share of the Okalunion plant, PSO is recommending that the associated NOx allowance costs be recovered through the FCA Rider.

**Robert L. Pennybaker**

Mr. Pennybaker earned a Bachelor of Science degree in Electrical Engineering from the University of Oklahoma and a Master's degree in Business Administration from Oklahoma City University. He is a licensed Professional Engineer in the State of Oklahoma. He has been employed in various positions with PSO, CSW and AEP since 1990. He presented testimony to the Federal Energy Regulatory Commission (FERC) relating to the proposed formula rate methodology for the annual updating of the AEP transmission revenue requirement under the SPP OATT in FERC Docket No. ER07-1069. He also presented testimony to FERC relating to the rate treatment of load connection facilities in *Northeast Texas Electric Cooperative, Inc. et al. v. Central and South West Services,* FERC Docket No. EL01-73.

His direct testimony provided an overview of PSO and SPP transmission planning processes and SPP's plans regarding the SPP Transmission Expansion Plan (STEP) and extra high voltage (EHV) Overlay that PSO and other utilities will be building. His testimony also explained and supported the test year level of Regional Transmission Organization (RTO) related O&M costs and the costs associated with the regional transmission services. In addition, his testimony discussed the revenue offsets related to these activities.

The SPP as an RTO affects the transmission planning process by planning and authorizing projects whose costs are allocated among transmission owners and recovered under the provision of SPP OATT. Mr. Pennybaker's testimony provided an overview of SPP projects within the 2008-2017 STEP that are planned in the PSO footprint. Compared to the pre-RTO era, the level, location, and timing of transmission investment is determined more today by the RTO than the individual transmission owner. In addition, under the RTO umbrella, PSO not only has to construct and pay for transmission facilities to serve its own loads, it also has to bear a share of the responsibility for regional transmission facilities (i.e., Base Plan Projects).

PSO seeks to recover adjusted test year transmission O&M expenses related to the RTO activities and regional transmission services of approximately $22 million, of which $5.3 million is non-SPP related Transmission of Electricity by Others (e.g., related to MISO, ERCOT and other entities) and the remaining $16.7 million expenses is related to SPP RTO activities. However, the SPP related costs are offset by approximately $20.1 million of associated transmission service revenues.

As an SPP transmission owner, PSO and other SPP transmission owners now construct and operate transmission facilities to provide wholesale open access transmission service on a non-discriminatory basis to all eligible transmission customers served by SPP. The focus of transmission planning and construction has expanded beyond a primary focus on each company serving its own loads to one where PSO and other companies upgrade and expand transmission facilities to meet local needs and to meet the regional service needs of the RTO. This new paradigm means that PSO is in a better position to benefit from the use of regional transmission service, but it also means that PSO has certain obligations to expand its system to meet regional needs, and to pay a share of the regional transmission costs. Although PSO participates fully in the open and transparent RTO stakeholder processes, RTO membership necessarily means that PSO now has reduced control over the transmission costs it incurs to meet the needs of retail customers. Further, regional transmission costs by others that impact PSO are expected to increase over time through the action of other's FERC-approved transmission rate increases and formula rates.

**Chad M. Burnett**

Mr. Burnett received a Bachelor of Science degree in Business Administration from the University of Tulsa in 1998 with emphasis in Finance and Economics. In 2002, he received a Master of Business Administration degree from the University of Tulsa. He has worked in the utility industry as an economist since 1997 with Central and South West Service Corporation, which later merged with American Electric Power Company (AEP). He has been in his current position as Manager of Economic Forecasting since June 2007.

Mr. Burnett's rebuttal testimony responded to the load growth adjustment provided by Mr. Mark Garrett, who is testifying on behalf on the Oklahoma Industrial Energy Consumers (OIEC). Mr. Garrett recommended a $4.5 million increase to the test year operating revenues filed by Public Service Company of Oklahoma (PSO) to account for known and measurable load growth that occurred during the six-month post-test year period ending August 2008.

Mr. Burnett's testimony clearly showed how Mr. Garrett's adjustment was made in error and not based on the actual data from the six-month post-test year period. This mistake drastically changed his conclusion that an increase in the test year operating revenues was warranted. In fact, had Mr. Garrett used the actual data during the six-month post-test year period, he would have suggested a decrease to the test year operating revenues instead of an increase. Furthermore, Mr. Burnett provided information on two large industrial customers who have recently announced plans to significantly reduce their electric consumption from PSO which were known and measurable adjustments that will certainly affect the load growth for PSO going forward.

**Kathy J. Champion**

Ms. Champion has a Bachelor of Science degree in Business Administration from Bartlesville Wesleyan College. Ms. Champion has been with PSO, American Electric Power Service Corporation (AEPSC) or the predecessor service company for Central and South West Corporation (CSW) since 1983. She has previously testified before this Commission and her qualifications are contained within her rebuttal testimony.

In Ms. Champion's rebuttal testimony, she responded to various statements and recommendations in the prepared Direct Testimony of Joe Robson, President of the Robson Companies, Inc., Paul Kane, Executive Vice President and Chief Executive Officer of the Home Builders Association of Greater Tulsa, and Mark E. Garrett of the Oklahoma Industrial Energy Consumers (OIEC).

Both Mr. Robson and Mr. Kane offered specific programs for PSO to consider for inclusion in future DSM/EE offerings. The programs they suggested include a rehabilitation program for existing homes and a Green Building program for new homes. PSO appreciated the support offered by both Messrs. Robson and Kane for PSO's DSM/EE programs. Both of the programs suggested by Messrs. Kane and Robson are being considered by PSO for inclusion in the new offerings planned for implementation in 2010. However, it would be premature for PSO to agree to include either program at this time.

PSO has just begun implementation of its Quick Start programs. The results of the Quick Start programs, how the programs performed and the implementation processes used, will be important information to consider in developing additional offerings. Further, selecting additional programs will include many steps, none of which have yet been completed. The process for selecting new programs will include: soliciting input from stakeholders; review of best programs in place in other jurisdictions; establishing clear goals for the programs and for the portfolio of programs to be offered; and integration of potential offerings into a portfolio of programs that will best fit the class of customers they are targeted towards and the overall goals and objectives for that portfolio of programs. Again, while the suggested programs offered by Messrs Kane and Robson are worthy of consideration, it would be premature of PSO to commit to their adoption at this time. PSO looks forward to working with Mr. Robson, Mr. Kane, and other stakeholders in developing new DSM/EE offerings for our customers.

Mr. Garrett made one recommendation related to the DSM Rider and that was to add a limitation to the Rider, so that it would be applicable to only the Quick Start programs. Ms. Champion disagreed with Mr. Garrett's recommendation. While the DSM Rider is currently being used to recover the costs and incentives for the Quick Start programs, there is no reason to assume it would or could not be used to recover costs for future DSM/EE programs. As any recovery of costs of additional programs would need to be reviewed and approved by the Commission, the additional limitation is simply unnecessary.

Mr. Garrett also made comments about pricing programs as opposed to DSM/EE programs. Most of Mr. Garrett's comments were simply a text book description of what can be achieved by sending proper price signals to customers. However, Mr. Garrett's conclusion, that by sending price signals, demand response will occur naturally, is not text book, and it has not been proven. PSO's own experience with pricing options has shown that customers typically respond to high price signals by changing their behavior, altering their schedules, or operating practices. However, as can be seen by the participating Real Time Pricing customers, while these changes can be significant, they typically are not permanent and subside over time as customers adjust to the higher costs or respond to higher demand for their own product.

Mr. Garrett's recommendations should be reviewed with caution as sending higher price signals, regardless of their purpose, could result in dramatic shifts in recovery from all customers. Some customers, like those Mr. Garrett represents, may have the ability and the financial resources to respond. While other customers, like the many small commercial or residential customers, may not have the same flexibility to respond. If smaller customers continue to use the same amount of power, even in the face of higher prices, the result may nevertheless be an increased need for resources.

Additionally, Mr. Garrett's characterization of DSM programs as more costly is without merit. PSO, by request from this Commission, has implemented and will pursue DSM programs that by definition are cost effective, which means they cost less than the resources they are targeted to replace. The Quick Start DSM programs are targeted to reduce kilowatt-hour sales by 20 million kilowatt-hours.

The cost of that reduction, including the Lost Revenues and the Net Shared Savings Incentive, was less, or was more cost effective, than the long-term cost of purchasing power or building additional resources.

**Mary E. Williamson**

Ms. Williamson has a Bachelor's degree in Business Administration from Oklahoma City University and an Associates degree in Human Resource Management from Tulsa Community College. Ms. Williamson has been with the Company since 1989 in various positions in departments including Customer Service, Contract Administration, and since 1994, Rates and Regulatory. In April 2008, she was named to the position she holds today, Regulatory Consultant, located in Tulsa. She has filed testimony Public Utility Commission of Texas.

In her direct testimony, Ms. Williamson presented and supported PSO's jurisdictional and class cost-of-service studies and the development of the jurisdictional and class allocations and related schedules as required by the Oklahoma Corporation Commission's (OCC or Commission) OAC 165:70-5-4.

General Overview of Cost-of-Service Studies

In general, cost-of-service studies are used to determine the revenue requirement for the services offered by the utility, and to determine the costs that different classes of customers impose on the utility system. A cost-of-service study is a tool used in traditional utility rate design. When the process of preparing a cost-of-service study is completed and all of the costs are allocated to the various jurisdictions, the result is a fully allocated embedded cost-of-service study that establishes cost responsibility and makes it possible to determine the cost of providing service to each customer class. Embedded cost-of-service studies rely on the utility company's historic accounting records to establish cost levels, and on-peak demands, energy sales and other data to support allocation of the costs. A three-step process is followed to assign costs to the customer classes: functionalization, classification, and finally, allocation.

Functionalization, Classification, and Allocation

Once the relevant data is gathered, the costs are separated by function. Typically, functions in a fully integrated electric utility are: (1) Production and Purchased Power; (2) Transmission; (3) Distribution; (4) Customer Service; and (5) Administrative and General (A&G).

The production function captured the costs associated with production facilities and power purchase agreements. The transmission function captured the costs associated with the high voltage lines and stations that deliver power to the distribution system and connect with other utilities, generators, and some large customers. The distribution function included facilities and costs associated with distribution stations, primary and secondary lines, transformers, service drops and meters that connect most customers to the utility network. The customer service function encompassed the services and costs associated with providing meter reading, billing, collection, customer information and related services such as energy applications, advice, and assistance. The A&G function is a general service category that captured the costs associated with management of the business and general services such as staffing, accounting, legal, regulatory, communications, general purpose buildings, maintenance of such facilities, and other costs that may not be directly assignable to the other functions.

The functionalized costs are then separated into three classifications: (1) demand-related costs (costs associated with the maximum rate of energy use by the customer, also referred to as kW demand), (2) energy costs (costs that vary with the amount of energy used by customers, e.g. kWh consumption), and (3) customer costs (costs that are directly related to the number of customers served).

The functional classified costs are then allocated among the jurisdictions, or classes of customers, based on the factors that most influence cost incurrence for each cost item. PSO's customer classes have been determined and grouped according to the nature of service provided and the load characteristics. PSO's major customer classes are residential, commercial, industrial, and outdoor lighting.

When the process is completed and all of the costs are allocated to the jurisdictions and customer classes, the result is a fully allocated embedded cost-of-service study that established the cost responsibility for each class of service.

Customer Revenue and Sales Data

The source for the customer, revenue, and sales data is the Marketing, Accounting, and Customer Service System (MACSS). MACSS is the mainframe application that houses all of the customer-specific data. Pro-forma adjustments are made to the data to reflect any known and measurable changes that are needed to ensure the data either accurately represents the test year or includes those changes necessary to reflect permanent differences from the data that will occur within six months of the test year as allowed by the OCC. The same method that was employed in PSO's previous rate cases was used to make pro-forma adjustments to the MACSS data in this filing.

The pro forma adjustments fall into five different categories. They are: (1) Annualized number of customers; (2) Customer-specific billing or tariff requirements; (3) Weather normalization; (4) Base revenue change due to PSO's last rate change; and (5) Removing Rider revenues from base revenues.

Jurisdictional Cost-of-Service Study

The jurisdictional cost-of-service study is used to divide costs between the retail and wholesale (FERC jurisdictional) customers. The costs and revenues applicable to PSO's retail jurisdiction are then used in the retail customer class cost-of-service study. The cost-of-service study Ms. Williamson submitted in this proceeding used a four coincident peak (4CP) allocation methodology for the jurisdictional assignment of demand-related transmission and production plant. The 4CP method reflected the system peak demands that were considered in the planning and operation of PSO's generation facilities.

Fuel expense that is not recovered through the fuel cost adjustment, depending on whether it is energy- or capacity-related, varies by either the number of kilowatt-hours consumed or the demand placed on the system and is allocated based on the proportion of total energy used or demands imposed by a jurisdictional class.

Sales Revenue was assigned to the jurisdictions by rate code. Late Payment Charges and Miscellaneous Service Revenues were directly assigned to the retail jurisdiction.

Other Electric Revenue related to firm wholesale transmission service to non-affiliates was directly assigned to the FERC jurisdiction, because these customers' demands were included in the determination of the transmission 4CP allocation factor, thereby accurately matching the allocation of transmission costs and revenues for the service they receive.

All Other Electric Revenue, which could not be directly assigned, was first functionalized based upon analysis of the Company's records and then allocated to the jurisdictions based upon the functional assignment of the asset used to generate the revenue.

Jurisdictional Allocation Factors

Production plant was classified as predominantly demand-related and was allocated to the jurisdictions using the Demand Production Allocator (DEMPROD). This allocator is developed based on the 4CP methodology.

The investment and expenses related to the transmission system are demand-related and were allocated to the jurisdictions based on the 4CP allocator (DEMTRAN). The DEMTRAN allocator is calculated similar to the production allocator DEMPROD, but PSO's transmission system serves additional customers beyond those that buy power from PSO. DEMTRAN captures the demand of all the loads connected to PSO's transmission system, recognizing that the transmission system also serves the demands of customers that take firm wholesale transmission service from the Southwest Power Pool (SPP), but do not buy power from PSO.

The majority of distribution plant was allocated on the basis of customer Maximum Diversified Demands (MDD) during the test year. MDDs can be thought of as a group's maximum demand placed on the system regardless of the relationship of that point in time to the time of the system peak. This allocation was selected because PSO's distribution system is sized and operated to meet the localized load imposed upon it.

Customer-related distribution costs are limited to the costs that vary directly with the number of customers (i.e., are incurred because of the existence of a customer). These costs include meters, service drops, transformers, and associated expenses. The customer-related distribution plant costs and associated expenses are allocated to the customers who require such facilities by using the weighted-number-of-customers methodology.

Customer accounting expenses, customer information expenses, and customer services expenses were allocated to each jurisdiction using a combination of test year end number of customers, manual bill customers, and various other customer-based allocators.

Portions of supervision, other taxes, federal and state income taxes and return are considered to have a customer component. These additional, indirect customer-related costs are generally incurred relative to the cost of facilities operated to serve customers. These costs are incurred, in part, based on the level of peak demand and, in part, based on the number of customers. In recognition of those relationships, such costs are identified as having a demand-related and a customer-related portion.

The investment in general plant was allocated on the basis of the labor allocation factor developed in Workpapers K-6 and K-10. This factor was developed by allocating the labor portion of each O&M expense account on the same basis as the total expense. The resulting labor allocation factor is used to allocate general plant as well as many A&G expense items.

The jurisdictional cost-of-service study identified the embedded cost-of-service for both the Oklahoma retail and FERC jurisdictions. The embedded cost-of-service study was based upon sound cost allocation principles, reflected all of the test year adjustments, and established the cost responsibility for the provision of electric service to each jurisdiction.

Class Cost-of-Service Study

The class cost-of-service study is a fully allocated, embedded cost-based study, consistent with PSO's previous filings before the Commission. An embedded class cost-of-service study assigned the retail jurisdictionally-allocated total Company costs to the individual retail customer classes to evaluate the cost the Company incurs in providing electric service to each individual retail customer class. A number of different allocation factors were employed in the study, consistent with the underlying cost causation for each item of rate base and expense separated into the three basic cost components: demand, energy, and customer. For the most part, the same methodologies for allocating costs were used in both the jurisdictional and class study; however, production and distribution demand-related components are treated differently in the jurisdictional and class cost-of-service studies.

The allocation of production demand-related costs to the various retail customer classes in the class cost-of-service was based on a 4CP A&E methodology. This method was reasonable for individual retail service class allocations because peak demand methods do not allocate production plant-related costs to classes, e.g. the lighting class, whose usage occurs outside of peak hours.

Distribution plant is allocated on the basis of customer class MDD during the test year. Direct assignment of dedicated distribution facilities was made to the individual customer classes, where possible, thereby ensuring that those customers bear the responsibility of the costs for those facilities dedicated to serving only that customer or class. This is the same methodology that was employed in PSO's previous rate cases.

The results of the class cost-of-service submitted in this proceeding are primarily used to: (1) provide embedded cost information that can be used as one tool in developing the pricing structures for each customer class, (2) provide information with which present and proposed relative rates of return by customer class can be compared and reviewed, and (3) comply with OCC filing requirements.

The class cost-of-service study quantified the embedded cost-of-service for the Oklahoma retail individual customer classes that make up the Oklahoma retail jurisdiction.

Rebuttal Testimony

Ms. Williamson's rebuttal testimony responded to and rebutted OIEC witness Mark E. Garrett's specific issues in his responsive testimony. Mr. Garrett's responsive testimony made the assertion that PSO should use billed numbers and should not have used booked revenues in the calculation of a class's revenues. Mr. Garrett's assertion is incorrect. The booked revenues are from the Company's official books and records and tie to the Company's financials and should be the starting point for determining the revenues produced by each class under current rates. It has always been the practice of PSO, and accepted by the Commission, to use the Company's booked revenues adjusted for known and measurable changes in determining revenues produced under current rates.

Mr. Garrett, in his representation of total industrial billing units, attempted to determine industrial class billing units beyond the test year. In that attempt, Mr. Garrett incorrectly imputed revenue and billing determinants to reflect a full 12 months of usage for customers who were actually existing customers that had a name change on their account outside of the test year period. There is no need to "annualize" revenues and billing determinants as Mr. Garrett recommended because the customers in question were already represented in the test year adjusted data.

Mr. Garrett also claimed that PSO's pro forma adjustment for a special contract customer was removed from non-fuel base revenues twice and in effect, the adjustment "double-counted the revenue deduction." A review of the adjustment made to the SL2 customer class revealed that the base revenue amount for the special contract customer was inadvertently removed during the calculation and removal of the embedded fuel amount from the unadjusted, booked test year revenues. PSO will make the correction to the historical test year billing determinants.

Mr. Garrett also stated that the kWh included in the Company's proof of revenue schedules for the SL2 class do not agree with the kWh that are included in the cost-of-service study. In her rebuttal Ms.

Williamson stated that customer's kWh's were properly excluded from the cost-of-service study. However, in the SL2 proof of revenue that was filed in this case, that special contract customer's kWhs were inappropriately subtracted from the kWhs that were input into the cost-of-service study. This caused a mismatch of kWhs in the cost-of-service study and the proof of revenue. Further, after reviewing the kWh billing determinants in more detail another error was discovered. Both special contract customers' kWhs were originally excluded from the SL2 class in the cost-of-service study when only one customer's kWhs should have been excluded. PSO will make corrections to the historical test year billing determinants based on these findings.

**Donald R. Moncrief**

Mr. Moncrief has a Bachelor of Science degree in Accounting from Illinois State University. Mr. Moncrief has been with AEP, or its predecessor Central and South West Corporation (CSW) since joining West Texas Utilities Company (WTU) in 1982. He has previously testified before this Commission and his qualifications are contained in his direct testimony.

Mr. Moncrief's direct testimony presented and supported PSO's proposed revenue requirement by rate class (revenue distribution), changes to the tariff rates based on the proposed revenue distribution, and the corresponding proof of revenue. He also supported the changes to the service fee charges. He is sponsoring Section M (the Proof of Revenue Statement), and Section N (the Tariff manual) of the Company's filing package. He also discussed the results of the requirement from the final order in PSO's last rate case that PSO perform a minimum-system study. He sponsored EXHIBITs DRM-1 through DRM-7.

Revenue Distribution

In previous cases, PSO had the goal of moving class rates of return toward a system average return while limiting impacts on customers. Given the level of base rate increase proposed in this case, along with the recent fuel cost increase, it would be difficult if not impossible to move class rates of return to the system average and still limit the impacts to various customer classes. PSO therefore proposed to limit impacts on customer classes and individual customers by applying the same percentage increase to each rate class and to each individual component of the rates in each rate class.

If rates were designed to produce equalized rates of return as shown in the cost-of-service (COS) study, there would be additional significant increases to certain rate classes. The proposed revenue distribution using an equal percentage increase to each class and each component of the rates mitigates customer impacts that otherwise would have varied widely from the system average return if equalized rates were pursued in this filing.

Rate Design Proposals

Two rate design proposals apply to all PSO rate classes. First, PSO is proposing to apply an equal percentage increase to each rate class and each component within rates. Second, the current amount of embedded fuel is 3.4¢ per kWh. PSO proposes to increase that to 6.1¢, which is the current average fuel cost as shown on EXHIBIT DRM-2. This does not reflect an additional increase in the fuel rate, it simply reflects the movement of the current fuel cost adjustment component of the fuel cost to base rates, increasing the total embedded fuel to reflect the current average fuel cost.

PSO's current rate structure includes seasonal prices, blocked energy rates, and demand ratchets to send reasonable price signals to customers. PSO's proposed rates, to the extent possible, will continue to provide appropriate signals by encouraging efficient use of the generation system and encouraging conservation in the on-peak season by continuing these structures.

For the Residential Class, PSO proposed to eliminate the closed Good Cents residential rates (GCRS and GCLURS) and move those customers to the standard rates. The elimination of the residential Good Cents rates and movement of those customers to the standard rate simplified the residential basic rate structure. The qualification for the Good Cents rates is based on outdated energy efficiency standards and no longer represented the cost savings characteristics of the Good Cents customers. PSO also proposed to close the LURS rate to new customers.

Most of PSO's commercial customers are served from one of three major commercial tariffs: Low Use General Service (LUGS), General Service (GS), and Power & Light (PL). There are also customers served under the closed Good Cents tariffs. PSO also has the following commercial tariffs that are available to either particular end-use customers or to a limited number of customers: Municipal pumping (MP), a closed tariff for municipal pumping customers; Unmetered Service; and Real Time Pricing (RTP) (Secondary). PSO also has a school classification under the LUGS, GCLUGS, GS, and GCGS tariffs. The school rates were offered to all Public Schools grades K-12. Although the school rates use the same structures as the other commercial tariffs, the school charges were reduced pursuant to an agreement of the parties approved by the Commission in a previous rate case, Cause No. PUD 200300076. PSO proposed to maintain a discount for schools. PSO proposed to clarify the school tariffs to specifically define the "Public School Facilities" as K-12.

For the commercial classes, PSO proposed to eliminate the closed Good Cents commercial rates and move those customers to the standard rates as well as apply an equal percentage increase to all components of the commercial rates.

The Industrial class includes Large Power and Light Primary, Primary Substation, and Transmission, which are all ratcheted demand Time of Day tariffs. These tariffs encourage conservation during PSO's highest use hours, 2 p.m. to 9 p.m., during the on-peak months of June through September. PSO is not proposing any structural rate changes for the industrial customer classes. However, as is the case in the other classes of customers, PSO is proposing an equal percentage increase to all components of the industrial rates.

PSO'S lighting schedules consist of flat rates for Security Lighting, Non-Roadway Lighting, Municipal Street Lighting, and Governmental Street Lighting. The municipal and governmental street lighting tariffs also include a rate for customer-owned lights. In addition to these, PSO offers an Outdoor Lighting schedule for metered and non-metered installations as well as a Recreational Lighting offering. These schedules consist of a basic service charge and an energy charge. PSO is not proposing structural changes for any of the lighting classes. However, as is the case in the other classes of customers, PSO is proposing an equal percentage increase to all components of the lighting rates.

<u>Reactive Power Charge</u>

PSO is proposing to revise its reactive power (kVAR) charge for commercial and industrial customers. The purpose of the reactive power charge is to encourage commercial and industrial customers to correct their power factors up to the level PSO requires for optimal system operation and to compensate PSO for the additional cost on its system created by poor power factor customers. A low power factor is expensive and inefficient and can affect PSO's distribution capacity. PSO currently requests that the customer take action to improve its power factor and notifies the customer that PSO will begin charging 31¢ (or 33¢ depending on a customer's service level) for each additional kVAR above 30% of monthly maximum demand.

If a customer declines to correct its poor power factor in favor of paying the extremely low reactive power charge, PSO is forced to install capacitors on its distribution system to correct the situation. This is neither efficient nor in the customer's best interest. The optimal result would be for the customer to correct the poor power factor on its side of the electrical service, thereby having more control over its operations. A customer fix eliminates the need for PSO to install and operate a capacitor to alleviate the problems caused on the distribution system by a specific customer's poor power factor.

PSO's current KVAR pricing has been ineffective in encouraging commercial and industrial customers to correct their power factors. PSO is proposing to increase its reactive power charge to cover the cost of correcting poor power factor problems caused by the customer. The proposed reactive power charge is increasing from the current rate of 31¢ and 33¢ to $3.33 for each kVAR required above 30% of a customer's monthly maximum demand requirements. PSO proposed to implement the revised power factor charge 12 months after the approval of the new reactive power charge, to give those customers who choose to do so time to install the equipment necessary to correct the power factor situation on their side of the delivery point. PSO's goal is not to charge the new fee but to motivate customers to correct their power factor on their side of the electric service meter.

Net Metering Rider

PSO is also adding a Net Metering Rider for residential and commercial customers. PSO has received requests for net metering service from residential and commercial customers. To date the customers are being served on the Net Metering Schedule for qualifying facilities or small power producers. With the resurgence of solar and wind applications to residential and commercial customers, PSO is requesting approval of a Net Metering Schedule that is more appropriate for residential and commercial customer use.

Service Fees

PSO is requesting approval for two changes in its Service Fees. In the Service Connect Fee, PSO is adding language to address seasonal customers who may connect and disconnect service within the same year in order to avoid a demand ratchet. The following language was added:

> When a meter is disconnected or turned off at the direction of the Customer, and the Customer for whom it was disconnected or turned off has it reconnected or turned back on at the same location within 12 billing periods of the time service was interrupted, a charge as follows shall be paid at the time the Customer requests the meter to be reconnected or service is turned back on: "An amount equal to the total minimum monthly billings from the date of interruption to the date of reinstatement, or the applicable reconnect charge, which ever is greater."

In the Radio Frequency Meter Installation Fee, prices are changed to reflect the current cost to install the meters and three-phase service meters were added to the fee schedule.

Minimum System Study

In PSO's last rate case, Cause No. PUD 200600285, the Final Order issued on October 9, 2007 (Page 154) stated that PSO is to prepare a minimum-system study to be filed in PSO's next rate review. A minimum-system study for PSO has been completed and is shown in EXHIBIT DRM-6. A minimum-system study was used to allocate a portion of distribution plant using a customer allocator instead of a demand allocator. However, the Commission has adopted as reasonable PSO's demand-only methodology for classifying distribution system costs in Accounts 364-368 in its COS study. The plant included in those accounts is as follows:

- Account 364 - Poles, Towers and Fixtures;

- Account 365 – Overhead Conductors and Devices;
- Account 366 – Underground Conduit;
- Account 367 – Underground Conductors and Devices; and
- Account 368 – Line Transformers

PSO continues to support the use of the demand-only allocator for distribution plant Accounts 364-368. PSO's distribution system is sized to meet the maximum instantaneous loads placed on it – which is directly related to demands and not how customers are connected. The distribution system includes poles, wires, and conduit sized to meet the maximum local demand imposed on the system. The cost of those facilities does not vary directly with the number of customers, unlike distribution costs such as service drops (Account 369) and meters (Account 370), which are allocated on the basis of customers.

If the minimum-system study had been used in PSO's current COS study, the residential class would be allocated more distribution costs than it was allocated in previous COS studies due to the addition of a customer allocator. For instance, Account 364 (Poles, Towers, and Fixtures) would now have a customer allocation of 48.71% compared to 0% previously, which would shift excessive costs to the residential class.

The demand-only allocator is reasonable and PSO will continue its use until instructed otherwise by the Commission. The demand-only allocation of Accounts 364 through 368 has been accepted by the Commission for PSO rate cases dating back many years and should be approved as filed in this case.

<u>Rebuttal Testimony</u>

Mr. Moncrief's rebuttal testimony responded to criticisms and rebutted certain arguments made by various intervener and Oklahoma Corporation Commission Staff (Staff) witnesses regarding (1) the adjustments to the industrial class billing data, (2) the results of the minimum-system study, (3) the appropriateness of price signals and anticipated demand growth, (4) the across the board rate increase, (5) PSO's proposed kVAR charge, (6) changes to the Customized Contract Tariff, (7) time-differentiated fuel pricing, and (8) the level of embedded fuel in PSO's proposed rates.

<u>Rebuttal Testimony Related To Adjustments to Industrial Class Billing Data</u>

Oklahoma Industrial Energy Consumers (OIEC) witness Mark Garrett in his responsive testimony identified adjustments to the industrial class test year data. Mr. Moncrief does not agree with Mr. Garrett's conclusion that the SL1 and SL3 test year revenues should reflect anything other than test year adjusted booked revenues. He does agree that an adjustment should be made to the SL2 test year adjusted booked revenues and kWh due to the treatment of a special contract customer in the SL2 class as discussed in the rebuttal testimony of PSO witness Mary Williamson. Mr. Garrett also reflected a change in total kVAR billing units for the industrial classes in his analysis that is appropriate based on Mr. Moncrief's response to discovery request OIEC DR 23-1. The adjustments with which Mr. Moncrief agreed will be made in the compliance proof of revenue schedules and rate design.

<u>Rebuttal Testimony Related To The Results of The Minimum System Study</u>

Wal-Mart witness James Selecky asserted that the PSO COS study overstates the portion of distribution plant allocated on demand and that the results of the minimum-system study should be reflected in the PSO cost-of-service study. Mr. Moncrief does not agree with Mr. Selecky's assertion. It is Mr. Moncrief's opinion that using a demand allocator to allocate the distribution costs in Accounts 364-368 is more appropriate than using a combined customer-demand allocator determined from a minimum-system study. Distribution Accounts 364-368 are appropriately allocated using a demand allocator in the PSO COS study. Those accounts consist of distribution poles, wires, and transformers and a demand allocator is an accepted method for allocating those costs, because distribution wires and transformers are sized to meet the local demand imposed on them, and the size and spacing of the poles is driven by the weight of the wire and transformers needed to meet the local demand.

Rebuttal Testimony Related To Pricing Signals and Demand Distortions

Mr. Garrett suggested that demand distortions occur because PSO rates were not cost-based. The fact is that PSO used a fully allocated COS study to determine the costs of serving each class of customers. The final result of the COS study shows that the rates charged to some classes produce a higher rate of return while others produce a lower rate of return than other classes. The study also shows that none of the classes are presently providing the level of return requested in this docket. Mr. Garrett has not provided any evidence to show that historic demands may have been impacted by the price signals inherent in the present rates. Mr. Garrett also suggested that this causes lower levels of production and employment in PSO's service territory, but again he provided no evidence in support of his statement. PSO's past and current rate structure generally reflected the cost to produce and deliver electricity, and thereby provides an average cost-based price signal to help customers in their electricity consumption decisions. Over time PSO has gradually flattened, and even inclined, the prices in rate schedules that used declining block energy charges, increased the demand charges for demand measured classes, and introduced seasonal and time-of-day pricing, so as to more accurately signal customers about the cost of the capacity and energy components of their service. The flat percentage increase to all rate schedules proposed in this case maintains the cost-based price signals of the existing rate structure.

Rebuttal Testimony Related to the Across-the-Board Rate Increase

OIEC witnesses Garrett and Scott Norwood, and Wal-Mart witness Selecky have stated concerns regarding the PSO across-the-board rate increase. As stated in Mr. Moncrief's direct testimony at page 7 and the discussion above, because of the level of base rate increase proposed in this case, PSO proposed to limit impacts on customer classes and individual customers by applying the same percentage increase to each rate class and to each individual component of the rates in each rate class. This strategy limits inter-class impacts to the system average increase, with the exception of those classes that were eliminated. As shown in the filed cost-of-service study, Workpaper L-1, this strategy did move all classes, with the exception of the lighting class, closer to an equalized return and limited impacts to customers. The additional objective of sending appropriate price signals is also achieved by PSO's current rate structure, which includes seasonal prices, blocked energy rates, and demand charges to send reasonable price signals to customers.

Rebuttal Testimony Related to the Proposed kVAR Charge

OIEC, Wal-Mart and OCC Staff witnesses expressed concerns regarding PSO's proposed kVAR charge. As stated in Mr. Moncrief's direct testimony, customers with poor power factors cause the entire system, not just service to them, to operate less efficiently and the cost should be borne by those customers. The cost-causing customer may either install equipment to alleviate the problem or pay the Company the cost of the Company's action to correct the problem caused by the customer. PSO's proposal reasonably charges the customers that cause the poor power factor-related costs. The concept of the proposed kVAR charge is to provide customers encouragement to correct their own power factor problems. Economics must drive the customer to take action. The cost of approximately $3.33/kVAR or approximately $40/kVAR per year was proposed to encourage the customer to take action. PSO understands that this is a substantial investment for the customers and therefore proposes to give them 12 months to correct their power factor prior to charging the new kVAR fee. PSO's hope is that all commercial and industrial customers will do so, thereby creating the most efficient system possible.

Rebuttal Testimony Related to the Customized Contract Tariff

In direct testimony, OIEC's witness Garrett suggested that the Customized Contract Tariff should require Commission approval whenever a customer is offered a contract price and in any situation where other customers are being required to subsidize an individual customer. PSO customers are not required to subsidize the customers served under a CCR contract rate. Further, the CCR tariff, in its current form, including all the provisions of service under the tariff, has been reviewed and approved by the Commission. The final pricing arrangements under the CCR are part of the contract for electric service, which is filed at the Commission. The CCR has been subject to Commission oversight and PSO does not agree that the CCR should be repealed.

Rebuttal Testimony Related to the Time-Differentiated Fuel Charges

OIEC witness Garrett also made recommendations concerning time-differentiated fuel pricing. In his responsive testimony, OIEC witness Garrettt recommended that PSO introduce a fuel cost adjustment that reflects on-peak and off-peak energy costs and consumption or hourly fuel prices. Mr. Garrett overlooked the fact that higher cost base load generation goes along with the lower cost fuel. He was looking at the benefits of that fuel and ignoring the associated base load plant that uses it. To just look at the fuel cost without the corresponding capacity cost would be inappropriate and further departs from average ratemaking.

Rebuttal Testimony Related to the Changes to the FAC Rider

OIEC witness Norwood recommended that PSO'S proposed FAC Rider be revised to reflect the existing $0.034 per kWh embedded in the current base rates. PSO recognized that fuel prices have dropped since PSO filed this case and if current price projections were used the proposed embedded fuel cost would be lower than the $0.061 requested.

## OIEC Witnesses

### Mark E. Garrett

I. Revenue Requirement Issues

In Mr. Garrett's revenue requirement testimony he addressed several issues regarding PSO's revenue requirement. He also sponsored the OIEC Accounting Exhibits where the overall impact of the revenue requirement recommendations of the various OIEC witnesses was set forth. The overall impact of the OIEC adjustments on PSO's requested revenue requirement results in a $103,102,252 decrease in PSO's requested rates:

| | |
|---|---|
| Rate Increase Proposed by PSO | $132,522,262 |
| OIEC Adjustments | – $103,102,252 |

Plant in Service and Accumulated Depreciation

In Oklahoma, the Commission gives effect to known and measurable changes that occur within six months of test year end. In this application, the six month cut-off period for post test year adjustments is August 31, 2008. Mr. Garrett's adjustments to Plant in Service and Accumulated Depreciation update these accounts to their actual balances at August 31, 2008. In other words, all projects actually completed and in service within six months of test year end are included in rate base. Also, all off-setting decreases in the plant investment levels – in effect, all changes in the Accumulated Depreciation accounts – are recognized as well. This approach has been accepted by the Commission in every litigated rate case for a major utility since the 6-month rule was statutorily enacted.[5] With this approach, PSO's adjustment to include CWIP at test year end is not needed. With the 6-month update, all CWIP projects completed by that time are included in the adjustment.

Accumulated Deferred Income Tax

Mr. Garrett's adjustment to Accumulated Deferred Income Tax updates the balance in this account to the August 31, 2008 level. This adjustment gives effect to the known and measurable increase in the deferred taxes that occurred within six months of test year end. When additions to the investment levels in Plant are recognized through the 6-month period, off-setting increases in Accumulated Depreciation and Accumulated Deferred Income Tax must also be recognized. This adjustment has been consistently recognized and accepted by the Commission in recent rate case proceedings.

Customer Deposits, Materials and Supplies and Fuel Inventories

Mr. Garrett's adjustments to Customer Deposits, Materials and Supplies and Fuel Inventories update the balances in these accounts to their August 31, 2008 levels, consistent with the 6-month rule in Oklahoma.

Prepaid Pension Asset

The balance in the Prepaid Pension account represents discretionary contributions made by the Company over the past several years. When these contributions were made, the Company's required contribution levels were zero. Mr. Garrett's adjustment reduces PSO's rate base by the balance in this account and increases operating expense by an amount equivalent to a cost of debt return on the balance. The effect of this adjustment is to provide a cost-of-money return, as opposed to a full rate base return, on these discretionary contributions. This approach is used when regulators want to strip out the profit component embedded in a full rate base return on items where a profit would not be appropriate such as on discretionary investments or accumulated fuel balances. This approach has been used by this Commission before. In PUD 05-151, the Commission removed OG&E's prepaid pensions from rate base and provided a cost of debt return on the balance. In ONG's 1992 rate case, PUD 91-1190, the Commission removed ONG's prepaid pension asset from rate base and allowed a cost of debt return instead on the balance. In PSO's last rate case, PUD 06-285, the Commission allowed a debt return on the Company's prepaid pension balance. In that case, however, the Referee also recommended an adjustment to the debt component in the Company's capital structure equal to the amount of the prepaid pension adjustment. The Referee made this recommendation because the Company's testimony – that a capital structure adjustment was necessary – was un-rebutted in that case. What the Company did not explain to the Referee was that a capital structure adjustment would have the affect of *washing out* the Referee's intended adjustment.[6]

Cash Working Capital

Mr. Garrett did not propose any changes to the Company's CWC methodology. He did, however, adjust the fuel and purchased power expense levels in the lead-lag study to accurately reflect PSO's actual fuel factors at August 31, 2008.

Load Growth Adjustment

[5] ONG Rate Case 04-610, OG&E Rate Case 05-151, and PSO Rate Case 06-285.

[6] In the two previous cases where the Commission dealt with the prepaid pension costs of ONG and OG&E, no adjustment to the capital structure was included.

As with OIEC's adjustments to update the Company's rate base investment levels through August 31,2008, to reflect the known and measurable changes that have occurred during the statutory 6-month post test year period, an adjustment is also needed to reflect changes in the Company's revenue levels over the same period of time. Mr. Garrett's adjustment to recognize revenue growth through August 31, 2008, is based on the testimony of PSO witness Mr. David P. Sartin. On page 13 of his Direct Testimony, Mr. Sartin stated that "PSO's base revenues grow by about $9 million per year on a weather normalized basis due to higher levels of kwh sales as new customers are added and customers' electric consumption increases." On the same page, Mr. Sartin further stated that "the increase in base revenues reduces, but falls short of eliminating the amount of base rate increase required in this Application." OIEC's load growth adjustment recognizes one-half (six months) of the annual revenue increase supported by Mr. Sartin. This recognition of six months of additional revenues is needed to match the updated rate base and expense levels included in OIEC's testimony. There are a couple of independent indications that Mr. Sartin's testimony is accurate. First, PSO's customer count continued to grow during the six-month post test year period. Also, PSO budgets indicate an expected load growth of at least 2% in 2008. OIEC's 1% increase is consistent with PSO's asserted growth.

Large Power and Light SL2 Revenues

PSO made an adjustment to remove $4,270,331 from the revenues of the LPL-SL2 class to reflect the movement of a special contract customer to the basic SL2 rate. However, the special contract amount of $4,270,331 had not been included in the class revenues. Therefore, PSO's adjustment to remove the $4,270,331 from the class revenues was not necessary, since the $4,270,331 had already been excluded. In effect, PSO's adjustment double-counted the revenue reduction. In its rebuttal testimony, PSO agreed with this correction.

Also, the Company's proof of revenues included only 1,355,310,464 kWh as billing determinates for the basic service billing to the class. Even the Company's own calculations, as provided in its workpapers, indicated the appropriate amount should be 2,024,599,464 kWh. This adjustment alone would generate $3,157,625 more revenue than the amount proposed by PSO.

Mr. Garrett also adjusted the on-peak demand and maximum demand billing determinants to reflect the increased summer demand observed for the class during the test year. Mr. Garrett also annualized the usage levels of two customers who came on the system during the test year. These adjustments resulted in an addition of 835,138,752 kWh units, 195,166 on-peak demand units, and 127,422 maximum demand units. Mr. Garrett also added 311,597 kVAR units to reflect the kVAR units actually billed to SL2 customers during the test year.

Large Power and Light SL3 Revenues

Based on actual billed out revenues, the non-fuel revenue for the class should be $29,084,897 instead of the $28,326,517 supported by PSO for this class. OIEC Industrial Revenue Adjustments were made using information through test year end. Total revenues were then updated to 8-31-08 based on Mr. Sartin's load growth assessments.

Payroll Adjustment

Mr. Garrett's payroll adjustment reflects actual payroll costs through the 12-month period ending August 31, 2008, six months after test year end. This adjustment results in a base payroll level increase of $718,794 over test year levels. Mr. Garrett's adjustment decreased the pro forma amount requested by PSO by $1,463,831. Oklahoma, to the extent possible, gives effect to known and measurable changes that occur within the six month period following test year end. Like the adjustments to Plant, Accumulated Depreciation, Deferred Taxes, Inventories, Customers Deposits and Operating Revenues, Mr. Garrett's adjustment to payroll expense reflected the Company's actual payroll costs through August 31, 2008. The Company did not use a typical annualization methodology for payroll, and the methodology it elected to use appears to produce unreliable results. Rather than multiplying the final month by twelve, or the final pay period by 26 (the method used by OG&E), PSO simply used the annual base salary for all employees at a specific date, April 1, 2008. PSO chose this date to include the post test year salary increases for the Company's non-union employees. By picking up the actual payroll expense for the 12-month period ending August 31, 2008, Mr. Garrett's adjustment also included the post test year pay raises granted in April.

AEPSC Payroll

Mr. Garrett's adjustment to AEPSC payroll compared the actual AEPSC payroll cost for the 12-month period ending August 31, 2008, with the adjusted pro forma level included in the Company's application. This adjustment resulted in a decrease to pro forma operating expense of $350,019.

Payroll Tax Adjustment

OIEC's payroll tax adjustment reflected the decrease in payroll tax expense that flows from OIEC's adjustments to payroll expense and incentive compensation. To the extent PSO's pro forma payroll expense and incentive compensation levels are decreased by the Commission, a corresponding decrease in payroll tax should also occur. If OIEC's payroll and incentive adjustments are accepted, the corresponding adjustment to payroll tax would be $571,337.

Annual Incentive Compensation Expense

Mr. Garrett testified that, during the test year, the total cost to PSO for incentive compensation was $26,882,254. Because the amounts paid during the test year were abnormally high, PSO included an adjustment of $8,100,670 in this case to normalize the incentive levels. Of the remaining $18,781,584, PSO capitalized $7,030,727 and included $11,750,857 in its pro forma expense for ratemaking purposes. Of the amount included in pro forma operating expense, $8,078,012 is associated with the Company's annual incentive plans for all employees and $3,672,845 is associated with long-term stock plans for executives.

Mr. Garrett proposed one adjustment to remove the portion of the *Annual Incentive Program* costs related to financial performance measures and a second adjustment to remove the incentive costs related to financial performance measures in the *Equity Ownership Plan* for executives.

Mr. Garrett testified that, in many jurisdictions, the cost of incentive plans tied to financial performance measures are excluded for ratemaking purposes based on one or more of the following reasons:

(1) Payment is uncertain.

(2) Many factors that impact earnings are outside the control of most company employees and have limited value to the customers of the company.

(3) Incentive plans conditioned on earnings can discourage conservation.

(4) The utility and its stockholders assume none of the financial risks associated with incentive payments.

(5) Incentive payments based on financial performance measures should be made out of increased earnings.

(6) Incentives embedded in rates shelter the utility against the risk of earnings erosion.

Mr. Garrett testified that his firm conducted a survey of utility commissions in the western United States regarding the rate treatment of incentive compensation. That survey showed that most states follow guidelines similar to those used in Oklahoma to evaluate the portion of utility incentive compensation plans allowed in rates. Some states disallow incentive pay using other criteria, and a few states have no established policy with respect to incentive compensation. Mr. Garrett testified that the following states closely observe the financial performance distinction: Oklahoma, Texas, Washington, Oregon, Idaho, Utah, North Dakota, South Dakota, Missouri, Kansas, and New Mexico. States that exclude incentive costs using other criteria are: Arizona, Colorado, and Minnesota.

Mr. Garrett further testified that even though regulators generally disallow incentive compensation tied to financial performance, utilities continue to include financial performance as a key component of their plans. By doing so they achieve the primary objective of the incentive plans: to increase corporate earnings and, thereby, earnings per share (EPS). However, since the utility retains the increased earnings these plans help achieve, payments for the plans should be made from a portion of these earnings.

Mr. Garrett analyzed the Company's annual incentive plans and testified that 70% of the incentive compensation weight is given to company concerns while only 30% is devoted to customer satisfaction and reliability. Further, the emphasis on financial performance is even more apparent when the overall compensation payment calculation is subjected to the Company's *Earnings per Share Modifier* which states:

> EPS Modifier
> AEP is committed to achieving its 2007 EPS target for shareholders. ***No award funding or annual incentive awards will be provided from the Plan unless AEP achieves at least its EPS threshold of $2.85 per share for 2007***. . . . The EPS Modifier ensures that the aggregate level of incentive compensation paid is appropriate to AEP's overall EPS performance and ***does not come at the expense of reaching this EPS objective***. This modifier may range from 0% to 200% and applies consistently to the incentive plans for all employees across AEP. (Emphasis added).

This description clearly shows that the overriding goal of each incentive plan is to increase earnings for AEP shareholders. More importantly, though, the EPS modifier ensures that shareholders will be taken care of first, and that employees will be compensated only to the extent additional earnings are available to do so. In other words, incentive payments will be made out of the earnings that result after the EPS targets are achieved. It is also interesting to note that the EPS Modifier allows AEP to make no incentive payment at all if the threshold EPS goals are not met, and instead amounts collected in rates for incentive programs are retained by the shareholders. Further, the AEP Shared Services Incentive Plans are also focused on financial performance measures.[7] The primary stated objective for all of the AEP plans is:

> Foster the creation of sustainable shareholder value through achievement of AEP's earnings per share (EPS) targets.

[7] The AEPSC plans can be seen at DAJ-7 attached to Mr. Jolley's testimony.

Also, all of the AEP plans are limited by the *EPS Modifier* which operates to ensure that incentive payments are not made at the expense of reaching AEP's EPS objectives. Further, the *customer-related* benefits of the AEP plans should be discounted because the *customers* of AEPSC are the other AEP operating companies (utilities) not actual utility customers.

Mr. Garrett testified that all of the cost of the AEP and PSO incentive plans could be excluded, because the EPS Modifier effectively retains the incentive money for shareholders to the extent shareholder value objectives were not met each year. However, if the Commission wanted to include some portion, the Commission could include the 30% weighted toward customer satisfaction and reliability goals.

In PUC Docket No. 28840,[8] the Texas Public Utility Commission disallowed sixty-six percent (66%) of AEP-Texas Central's incentive payments because this was the portion the Texas Commission believed was based on financial performance measures. The AEP-Texas Central incentive plans are the same company-wide plans used at AEP-PSO.

Mr. Garrett testified that the AEP incentive plans were beneficial for the Company financially. According to AEP's 2007 Annual Report, AEP shareholder returns for the year were 13.1%, which was more than double the 5.5% average return for the S&P 500 Index in 2007.

Mr. Garrett testified that the Company proposed an adjustment to reduce the test year level of PSO's incentive payments because incentive payments in the test year were abnormally high. Mr. Garrett accepted the Company's adjustment to normalize test year levels. He then applied the predominant ratemaking standard for including incentive pay in rates discussed above. OIEC's adjustment reduces pro forma operating expense for regular incentives by $5,654,608.

Long-Term Executive Stock Incentive Plan

Mr. Garrett testified that the Company is proposing to recover $3,672,845 for its long-term executive stock plans, which is the amount remaining after PSO's adjustment to normalize the unusually large payments made during the test year. Along with the company-wide incentive plans discussed above, executives are provided additional stock-based incentives. These incentives are financially based.

> The Board of Directors and shareholders adopted the American Electric Power System Long-Term Incentive Plan to provide important members of AEP management and other key employees, such as you, with compensation that further aligns the interest of employees with those of shareholders. The performance units that you have been awarded provide just that by directly tying your compensation to the value of AEP common stock. Performance units encourage you to think and act like a shareholder, since you share in the financial rewards and successes and the consequences of failure with AEP shareholders. Since your compensation is tied over a long period of time to AEP's share price, it is in your best interest to make business decisions from a perspective of long-term shareholders.[9] (Emphasis added).

Mr. Garrett testified that incentive compensation payments to executives are generally excluded because officers of any corporation have a duty of loyalty to the corporation not to the customers, and they typically put the interests of the company first. The natural divergence of interests between company and customer creates a situation where not every cost associated with executive compensation is

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[8] *Application of AEP Texas Central Company for Authority to Change Rates*, Docket No. 28840; SOAH Docket No. 4 73-04-1033, Final Order (August 15, 2005)

[9] *See* AEP Guide to Performance Shares at DAJ-10, page 2, attached to Mr. Jolley's prefiled testimony.

presumed to be a necessary cost of providing utility service. Also, long-term executive incentive plans, such as the stock option plan, are specifically designed to tie executive compensation to the financial performance of the company. This is done to further align the interest of the employee with those of the shareholder. The goal, stated in the AEP incentive plan, is to encourage the employee to *think, and act, like a shareholder*. Since the compensation of the employee is tied over a long period of time to the company's stock price, it becomes in the best interest of the employee to make business decisions from the perspective of long-term shareholders. This intentional alignment of employee and shareholder interests means the costs of these plans should be borne solely by the shareholders. It would be inappropriate to require ratepayers to bear the costs of incentive plans designed to encourage employees to put the interest of the shareholders first. Mr. Garrett testified that the incentive survey of treatment in other states found that most commissions exclude executive stock-based compensation. In Oklahoma, executive incentives tied to corporate earnings are excluded. In PSO's last rate case, 100% of the executive long-term stock-based plans were excluded.

Incentive Payments in Rate Base

Mr. Garrett also testified that the capitalized portion of disallowed incentives should be removed from rate base. If not, the Company will earn a return on, and eventually recover from ratepayers, compensation associated with incentive plans the Commission has disallowed. At test year end, PSO's rate base included $22,493,884 of capitalized incentive compensation. Mr. Garrett recommended that 50% of the capitalized incentive payments be excluded. This was the amount disallowed by the Commission in PSO's last rate case.

Supplemental Executive Retirement Plant

Mr. Garrett testified that the Company provides supplemental retirement benefits to highly compensated executives in excess of the compensation limitations imposed by the Internal Revenue Code. The limitations imposed by the Code allow for the computation of benefits on compensation levels of up to $225,000 for the year. Retirement benefits on compensation levels in excess of the $225,000 limitation are paid through supplemental plans. The amount of Supplemental Executive Retirement Plan costs included in PSO's filed cost-of-service was $698,642. Mr. Garrett recommended that ratepayers pay for all of the executive benefits included in the Company's regular pension plans, and that shareholders pay for the additional executive benefits included in the supplemental plan. As discussed earlier, because officers of any corporation have a duty of loyalty to the corporation, these individuals put the interest of the company first. This creates a situation where not every cost associated with executive compensation is presumed to be a cost appropriately passed on to ratepayers. For example, this Commission excluded SERP costs in PSO's last rate case, PUD 200600285.

Employee Benefits Expense

Mr. Garrett testified that PSO proposed to increase test year employee benefits expense by $1,787,480 based on an annualization of employee benefit levels at test year end. However, Mr. Garrett's analysis of actual employee benefits costs over the 6-month period after test year end revealed that these accounts increased by only an immaterial $5,500 on an annual basis, far less than the $1,787,480 requested by the Company. This analysis showed that the test year level for these accounts was a reasonable level for setting rates. Mr. Garrett's adjustment reversed the Company's requested increase of $1,787,480. In its rebuttal testimony, the Company admitted that it had made an error in its calculations that would reduce the requested increase by $1,672,238.

Transmission Reliability Adjustment

Mr. Garrett testified that PSO proposed to increase its non-RTO transmission O&M expense by $5,658,100 for the following programs:

| | |
|---|---|
| Vegetation Management | $3,100,000 |
| Operation Center Enhancement | $ 712,100 |
| Additional Employees | $ 576,000 |
| Line Programs | $ 630,000 |
| Station Programs | $ 540,000 |
| Animal Mitigation | $ 100,000 |
| | $5,658,100 |

However, a review of the expenditures in these accounts through August 31, 2008, revealed that there has been no measurable increase in these accounts during the 6-month post-test-year period. In Oklahoma, post-test-year increases are limited to those that occur within six month of test year end. In the case of these programs, no increase has occurred. Because the increased spending levels the Company claims will occur in these accounts did not begin within the prescribed 6-month period, Mr. Garrett reversed the Company's proposed increase for these reliability programs.

Legislative Affairs

Mr. Garrett testified that the Company included $450,053 in rates for costs associated with legislative affairs. Traditionally, the costs of legislative activities are excluded for ratemaking purposes because the political interests of a regulated utility with a monopoly franchise can be quite different from the interests of the company's captive customers. It would be unfair to require ratepayers to fund the legislative goals of corporate executives who put the interests of the corporation and its stockholders first. Mr. Garrett also testified that PSO characterized these costs as "legislative monitoring" costs. However, if this characterization were accurate, the costs would be disallowed for reasonableness. Clearly, it does not cost $450,000 per year to *monitor* legislation. In PSO's last rate case, the Commission appropriately excluded PSO's *legislative monitoring* costs.

Ad Valorem Tax Expense

Mr. Garrett testified that the Company proposed to increase test year ad valorem tax expense based on an estimated assessment of its pro forma plant levels. However, ad valorem tax is actually assessed on an agreed-upon appraised market value of the property, using a formula that considers both utility revenues and net plant values. Based on the Company's actual historical tax assessments over the past 5 years, Mr. Garrett recommended an increase of $1 million over the 2008 level, which is an increase of approximately $1.5 million over the test year level. A $1 million increase to tax expense as of August 31, 2008, results in an ad valorem level of $35,131,347. This amount is $2,274,415 less than the $3,789,125 increase requested by PSO.

Fleet Fuel Expense

Mr. Garrett testified that PSO proposed an adjustment to increase test year fleet fuel expense by $583,307, based on the higher gasoline prices that existed at test year end. However, since that time, fuel prices have returned to levels experienced during the test year. As a result, the Company's proposed increase is no longer necessary to reflect the ongoing cost of fuel. Mr. Garrett's adjustment reverses PSO's proposed increase in test year fuel expense for company vehicles.

Vegetation Management Cost Increases in Base Rates

Mr. Garrett testified that PSO proposes to increase base rates by $7.7 million for additional vegetation management costs. PSO is currently authorized to recover $23.685 million per year of vegetation management cost through the Reliability Cost Adjustment (RCA) Rider. The costs PSO seeks to include in base rates are eligible for recovery through the RCA. In Mr. Garrett's opinion, the Company should file a separate application to include these costs in its RCA rider. In that application, the requested increases in vegetation management costs could be reviewed in light of the costs already being recovered through the rider.

Adjustments Proposed by Other OIEC Witnesses

Mr. Garrett quantified the recommendations of the other OIEC witnesses as follows:

| Recommendations of Mr. Scott Norwood | |
|---|---|
| Adjust Plant Balances for Unsupported Additions | $47,936,678 |
| Adjust AEPSC Allocations to PSO | $ 6,873,969 |

| Recommendations of Mr. David Parcell | Cost | Capital Ratio |
|---|---|---|
| Return on Common Equity | 9.50% | 44.10% |
| Cost of Long-Term Debt | 6.60 | 55.57% |
| Cost of Preferred Stock | 4.02% | 0.33% |

Mr. Garrett quantified the overall impact of the OIEC adjustments as follows:

| | |
|---|---|
| Rate Increase Proposed by PSO | $132,522,262 |
| OIEC Adjustments | $103,102,252 |
| | $ 29,420,010 |

Rebuttal Testimony of Mr. Garrett – Revenue Requirement Issues

In his rebuttal testimony, Mr. Garrett addressed an important conceptual flaw in the approach taken by both Staff and the Attorney General in updating the test year for known and measurable changes occurring within the statutory 6-month post-test-year period. Mr. Garrett testified that, specifically, both Staff and the Attorney General failed to update the Company's *revenue* levels for post-test-year increases.

Mr. Garrett testified that this oversight is important because rates are set based upon a synchronized review of (1) the utility's *investment* levels (rate base), (2) the utility's *expense* levels, and (3) the utility's *revenue* levels that exist at a particular point in time, a test year. This synchronized review compares the revenue levels achieved with existing rates with the cost obligations of the utility. From this comparison, the regulator determines if rates should be increased or decreased to provide sufficient revenues to cover the utility's operating costs and a return on capital investment. Some jurisdictions, including Oklahoma, provide a specific additional period of time, after test year end, where known and measurable changes occurring during this period can be incorporated in the rate review. When a post-test-year period is used, all three components of the revenue requirement calculation must be reviewed together to arrive at an accurate rate determination. A synchronized update of these components is important because, although rate base and expenses levels may tend to increase over time, to the disadvantage of ratepayers, these increased cost levels are typically offset, to some extent, with higher revenue levels.

OIEC updated rate base, operating expense, depreciation and tax accounts to the end of the 6-month period. In most cases, the cost levels at the end of the 6-month period were higher than the test year levels (although in some cases they were lower than the pro forma levels <u>requested</u> by PSO). These higher cost levels were reflected in OIEC's case. As an important, partial offset to these higher cost levels, OIEC appropriately recognized the higher revenue levels that also existed at the end of the 6-month period.

<u>Surrebuttal Testimony of Mr. Garrett – Revenue Requirement Issues</u>

Mr. Garrett corrected his Responsive Testimony filed on October 29, 2008 at page 6, line 8, by changing "December" to "August."; by changing "two" to "three" at page 11, line 12; and by adding "be recognized" after the word "and" on page 11, line 18 (166).[10] He further added "of" before "executive" on p. 49, line 18; he struck the last two sentences of the paragraph on page 34, lines 2-4; and he corrected page 33, line 18 to say "I am proposing two adjustments" (167).

Mr. Garrett made changes to Ex. MG-2, which is a summary of all adjustments at end of his testimony (168-169). OIEC is filing Ex. MG-2-SR to adopt several of the Company's recommended changes in its rebuttal testimony. Ex. MG-2-SR was marked as Hearing Exhibit 4. Mr. Garrett made seven changes to the original exhibit (Ex. MG-2), based upon the Company's rebuttal. (169)

In almost all cases he is accepting positions the Company took in its rebuttal (170). The effect of the changes can be seen at the bottom of Columns F and G. Column F shows new surrebuttal revenue requirement increase that is recommended as a result of all of OIEC's adjustments. The bottom of Column G shows the original revenue requirement increase of OIEC, and the bottom of Column H, the last column, shows the difference in OIEC's surrebuttal position compared to its original position (170).

The first adjustment decreases OIEC's proposed adjustment to accumulated depreciation based upon Mr. Aaron's testimony that the number OIEC picked up at August 31, 2008, was different than the Company's actual accumulated depreciation at that date. The difference was $3.2 million goes in the Company's favor (170).

The second adjustment was to remove accumulated deferred income tax related to the excluded prepaid pension balance (171). Mr. Garrett agreed that deferred taxes associated with the prepaid balance should be removed. The amount of that adjustment is $27 million (171).

The third adjustment was to remove OIEC's fuel cost adjustment to the lead-lag study. Mr. Garrett had said that the Company's higher fuel costs at August 31, 2000, should be recognized when the Company changed its fuel factors and the fuel expense went up considerably this past summer (171-172). The Company has now lowered its fuel factors to basically the level that was incurred during the test year (172). Therefore, Mr. Garrett removed the adjustment to cash working capital balance, as shown on line 6, adjustment 3 (172).

Adjustment 4 removes incentive costs capitalized prior to December 31, 2006 (172). Mr. Aaron appropriately pointed out in his rebuttal testimony (p. 29) that removing those incentive payments could be viewed as retroactive ratemaking (172). Adjustment 6 adjusted OIEC's employee benefit adjustment to reflect the correction of the error that was presented in Mr. Aaron's rebuttal testimony. The differences between the numbers are now so small that OIEC went ahead and adopted the Company's employee benefit number (172).

The last adjustment is to recognize post test year increases for transmission operation center referenced in Mr. Aaron's rebuttal testimony at p. 64, lines 6-12 (172). The Company points out that transmission operation center costs were being incurred during six months following test-year end, which

[10] Citations are to the transcript of proceedings on December 15, 2008.

is correct (172-173). Therefore, Mr. Garrett changed OIEC's adjustment to reflect those higher cost levels (173).

The net affect of he changes is that OIEC's recommended increase in revenue requirement for PSO has increased from $29,420,010 to $32,326,361 (173).

Mr. Garrett disagrees with Mr. Aaron's rebuttal testimony criticizing Mr. Garrett's interpretation of Okla. Stat. tit. 17, § 284 (174). There is nothing conceptually new in Mr. Aaron's testimony, and Mr. Aaron's arguments were rejected by the Commission in PSO's last rate case (174).

Mr. Garrett testified that OIEC is the only party recognizing changes in PSO's revenue levels (174-175). To the extent rate base and operating expenses are changed to the Company's advantage, revenue levels also need to be synchronized to the advantage of ratepayers (175).

Mr. Aaron incorrectly stated that Mr. Garrett made no adjustment to increase expenses for the post test year period. OIEC made numerous adjustments to raise expense levels to levels at August 31, 2008 (175). OIEC updated PSO's payroll by increasing test year of payroll expense for PSO to the August 31, 2008, level and OIEC updated depreciation expense, taxes, employee benefits, and transmission reliability costs; and OIEC accepted PSO's reduction relating to the production O&M area (175).

Mr. Garrett testified that Mr. Aaron was incorrect when he said that updating plant in service would trigger a 5% or more change in the requested revenue increase of PSO (176). When you look at plant in conjunction with accumulated deprecation and accumulated deferred income tax – the three components of plant balances, there's actually a decrease in actual amounts at August 31, 2008, compared to PSO's requested amounts (176).

Mr. Garrett testified in response to Mr. Aaron's position that if a portion of PSO's long-term debt was assigned directly to the prepaid pension asset, an additional adjustment was required to increase PSO's revenue requirement because long-term debt that was assigned to prepaid pension asset was no longer available to fund remaining assets (177). Mr. Garrett testified that everyone understands that there is no long-term debt assigned to fund the prepaid pension asset (177). Mr. Aaron even testified under cross-examination that the prepaid pension contributions were not funded with long-term debt. Mr. Garrett testified that the capital structure adjustment was inappropriate because it reversed the intended cost of money return that the Commission had ordered on that item. There are numerous Commission orders where the Commission has ordered a cost of money return with no corresponding capital structure adjustment (177). For example, in ONG's 91-1190 case and OG&E's 05-151 rate case, the Commission gave cost of money returns with no capital structure adjustments (177-178). As the Company's deferred fuel balances grow and shrink over time, where actual expenditures are different than rates to recover fuel, a balance will build up and the Commission allows a cost of money return and obviously no capital structure adjustments. Mr. Garrett explained that a capital structure adjustment wipes out the lower return on that investment (178).

The amount recommended by OIEC at August 31, 2008, relating to fuel inventories is based on actual levels and a 13-month level of actual levels. Mr. Garrett testified that it is the best test of what the Company is spending on its fuel inventories and it is also consistent with prior Commission orders that update inventory levels and materials and supplies to balance six months outside of the test year (179).

With respect to capitalized incentives, OIEC changed its adjustment to reflect only the amount of incentives capitalized after December 31, 2006, which was the rate base amount included in the Company's last rate case (180). The Commission updated the rate base to December 31, 2006; so OIEC only adjusted incentive payments going forward from that date. OIEC used 50% of the amount of executive incentives, which is a more conservative adjustment, because the Company does not track executive incentives separately in rate base. (180).

With respect to ad valorem tax expense, Mr. Garrett pointed out that Mr. Aaron had admitted that the Oklahoma Tax Commission actually relies more on an income approach rather than an asset approach, which is what Company's proposed adjustment uses (181) Mr. Aaron also admitted that the tax level is a negotiated level each year. Mr. Garrett testified that the annual increase from 2004 forward has not been greater than $1 million, which makes his $1 million recommended increase reasonable (181).

Mr. Garrett testified that Mr. Aaron is incorrect and OIEC is not recommending a reduction to PSO's payroll expense (181). He further testified that OIEC is recommending an increase over test-year level of $491,00 and an increase of AEPSC's allocation to PSO of $967,000 (181). Mr. Garrett said that OIEC is recommending a decrease in the Company's requested increase, but not to PSO's actual payroll levels (182). The reason that OIEC didn't annualize is because PSO's monthly levels appeared to fluctuate, so OIEC went beyond the test year by six months, picking up 12 month at that point, which is reasonable (182). Mr. Morris and Mr. Solomon testified at the hearing that PSO will actually reduce its payroll costs in 2009, which further demonstrates that the increase OIEC is proposing is reasonable (182).

Mr. Garrett agreed with Mr. Aaron's rebuttal testimony that there must be a corresponding change made to payroll tax expense to the extent the Commission changes the level of payroll expense and incentive compensation (183).

Although they do not agree on methodology, Mr. Garrett and Mr. Aaron agree on a dollar decrease of approximately $1.67 million to the requested employee benefit expense. Because their numbers are so close, Mr. Garrett testified that OIEC would adopt the Company's number (183).

Mr. Aaron, at page 65 of his testimony, lists five transmission reliability programs (184-185). Mr. Garrett testified that OIEC looked at each program and noticed that costs were not being incurred for those programs and that cost levels six months outside the test year were not higher than the test-year level (185). OIEC originally excluded all programs. However, in rebuttal the Company pointed out that $712,000 in expense had actually been incurred during the six-month period following the end of test year with respect to Transmission Operation Center. Therefore, OIEC reversed its position on the transmission reliability expenses to the extent of the Transmission Operation Center (185).

In response to Mr. Jolley's testimony at p. 7, line 10, that Mr. Garrett and other experts for Commission Staff and the AG have an "outdated" understanding of the role incentive compensation plays in today's business environment, Mr. Garrett testified that virtually all commissions currently have the same view of incentive compensation, and OIEC tailored its adjustment to reflect this Commission's understanding of incentive compensation and the understanding of most commissions on this issue (186).

On p. 11, line 17, Mr. Jolley says that the EPS modifier insures that no incentive awards are paid unless AEP meets its target level of earnings per share. Mr. Garrett testified that this admission is grounds for excluding the entire incentive, much like ONEOK's incentive that was entirely disallowed in PUD 2004-610 because there was an earnings per share trigger in that plan as well, so that if an earning's target puts incentive collected from ratepayers at risk, the entire incentive should be disallowed (186).

Mr. Garrett testified that, contrary to Mr. Jolley's testimony, the issue is not whether executives are over compensated but who is responsible for their compensation. Commissions agree that shareholders and ratepayers should share costs of executive compensation and that line is generally drawn at the incentive level so that ratepayers pay the salaries, and shareholders bear the incentives.

Mr. Garrett disagrees with Mr. Jolley's testimony at the hearing that compensation tied to performance factors, such as increased shareholder return, is in the best interest of both the customers and the company (187). This arrangement predominately benefits the Company. For example, PSO has a witness arguing for an 11.75% ROE (187). No Commission has authorized a ROE at that level. The average return in the stock market last year was 5.5% (187). PSO also has a witness supporting transmission reliability programs of $5.7 million, when none of those costs have been spent and the Company has admitted it won't spend that money without refunding for those programs. PSO has a witness supporting depreciation removal rates of negative 95% when those were the highest in the industry (188-189). Mr. Garrett testified that those type of extreme recommendations do not benefit ratepayers (189).

Mr. Garrett testified that the industry norm is that Commissions disallow incentive tied to financial performance (189). If PSO's overall payroll level is comparable with that of other utilities, and other utilities have incentives disallowed, then PSO would have to have its incentives disallowed to remain on an equal footing with those companies (189-190).

Mr. Garrett testified that Matthews' testimony at page 5 line 4 that the Transmission Operation Center enhancement will be the only program implemented unless the Commission approves funding for the programs shows that these are not essential programs; they are not necessary for provision of electric service and should be disallowed (190). Also, those programs are not known and measurable because nothing within six months of test year had been expended on these programs (190). PSO failed to meet known measurable standard and also failed to meet the necessary for provision of electric service standard (191). Therefore, OIEC's recommendation is to exclude all of transmission reliability expenses, except those expenses associated with Transmission Operation Center. The Transmission Operation Center was mandated by EPA, so it is an essential program that had already begun by August 31, 2008.

Regarding future hiring needs for the transmission reliability program, no hirings have been made and the Company testifies that they won't be made in future if Commission does not provide funding now (192). In light of Morris' and Solomon's testimony that payroll costs will actually be cut next year, the question of whether employees would be hired; is too tentative for the Commission to be putting these costs in rates (192).

Mr. Garrett testified that PSO's request for an additional $7.7 million in base rates should be recovered through a rider (Tr. 193). Mr. Garrett testified that he believes that the Company now agrees with staff that the rider is appropriate. Mr. Garrett agrees so long as costs are allocated to customer classes based on cost causation used in the vegetation management rider (193). Hearing Exhibit 4 was admitted (193).

## II. Depreciation Expense Issues

Mr. Garrett testified that PSO is proposing to increase its depreciation expense by $11,121,959 annually. This increase is the result of applying the depreciation rates from PSO's new depreciation study to the *pro forma* plant balances at test year end. The most significant changes in the new depreciation study are proposed increases in estimated future removal costs in PSO's transmission and distribution accounts. These estimated increases in future removal costs are reflected in the increased negative salvage values calculated for these accounts. The removal cost increases in accounts 355, 356, 364, 365 and 369 account for most of the requested increase.

Mr. Garrett testified that net salvage is the amount received upon retirement less any costs incurred to sell or remove the property. In those cases where the cost to remove plant will be greater than the value of the plant removed, net salvage value is negative and is an increase to the plant balance to be depreciated.

PSO's cost of removal calculations embed extreme levels of estimated future inflationary increases in current rates, through a simple, but flawed mathematical approach that can no longer be characterized as just and reasonable for ratemaking purposes. The flaw occurs when the removal cost, stated in current day dollars, is compared with the cost of the asset when it was originally installed, sometimes thirty to forty years ago. This results in a significant mismatch in costs when inflated removal costs are divided into the un-inflated original cost of the asset to arrive at a removal cost percentage. This inflated removal cost percentage is then used in the depreciation rate calculations. The result is an excessive current charge to ratepayers. This excessive charge assumes two things: (1) that past inflation levels will be sustained into the future and (2) that ratepayers should pay <u>now</u> for future inflation that has not yet occurred. The first assumption is not accurate, and the second is not fair. Forcing current ratepayers to pay <u>now</u> for future inflation is unfair because it violates the cost/causation principle of ratemaking: that ratepayers bear the costs they cause. Removal costs should be included at current values and not at inflated future values, as is required by SFAS No. 143 for assets with retirement obligations. Just because the accounting profession has not yet addressed assets without retirement obligations is no excuse for PSO embedding inflation in its removal cost calculations to enhance its cash flows.

PSO's approach also violates the basic ratemaking principle that the purpose of depreciation is for the "recovery of" invested capital. As an asset is depreciated over its useful life, 100% of the invested capital is returned to PSO through depreciation recoveries. However, when a 100% removal cost factor is added to the depreciation rates – as is the case with several of PSO's accounts – then, over the life of the asset, <u>200% of the invested capital</u> is returned to the utility.

These over-collections result in a substantial regulatory liability to ratepayers over time that must be tracked and protected for their benefit. At August 31, 2008, the Company has collected a total of \$281,864,976 in excess removal costs (removal costs collected to date in excess of actual expenditures to date). This balance continues to grow by more than \$20 million per year.

Mr. Garrett testified that, while it might seem astonishing, there are circumstances under which the utility could simply keep the accumulated removal cost balance for itself. In fact, AEP has done just that in the past. In 2003, AEP took the balance collected for removal costs from the ratepayers of its newly deregulated utilities and booked that amount as income to AEP. That is, AEP removed \$472.6 million in accumulated removal costs from the balance sheet and booked that amount as income in 2003.

In response to OIEC Data Request No. 4-10, the Company provided the removal cost levels approved for AEP's other ten electric utility companies. The removal cost rates approved in the other jurisdictions are significantly lower than the rates requested by PSO. The salvage rates of the other AEP electric utilities can be seen at *Exhibit MG-2.12(b)*.

| **PSO's Requested Negative Salvage Rates Compared with Other Utilities** | | | | | | |
|---|---|---|---|---|---|---|
| Acct | Description | Balance | OG&E | AEP Avg | **PSO** Current | **PSO** Requested |
| | **Transmission** | | | | | |
| 350 | Right of Way | $33,369,875 | 0% | 0% | 0% | 0% |
| 352 | Structures | $6,721,532 | -5% | -2% | -10% | -23% |
| 353 | Station Equipment | $242,817,583 | -5% | 4% | -8% | -4% |
| 354 | Tower & Fixtures | $14,056,316 | -20% | -13% | -35% | -69% |
| 355 | Poles & Fixtures | $143,762,216 | -50% | -34% | -57% | -93% |
| 356 | OH Conduits | $126,080,953 | -30% | -10% | -38% | -72% |

| | | | | | | |
|---|---|---|---|---|---|---|
| 358 | UG Conductors | $71,915 | -0% | -7% | 10% | 0% |
| | **Distribution** | | | | | |
| 360 | Right of Way | $1,830,116 | 0% | 0% | 0% | 0% |
| 361 | Structures | $1,871,725 | -10% | -3% | 45% | 42% |
| 362 | Station Equipment | $143,508,854 | -10% | 5% | 10% | 0% |
| 364 | Poles & Fixtures | $235,804,864 | -35% | -50% | -78% | -98% |
| 365 | OH Conduits | $233,214,158 | -25% | -14% | -74% | -80% |
| 366 | UG Conduits | $26,213,066 | -15% | -20% | -32% | -32% |
| 367 | UG Conductors | $168,337,329 | -20% | -8% | -20% | -21% |
| 368 | Line Transformers | $221,789,670 | -10% | -7% | -24% | -17% |
| 369 | Services | $159,622,307 | -20% | -38% | -40% | -76% |
| 370 | Meters | $56,732,178 | -15% | -21% | -17% | -36% |
| 371 | Installations | $32,045,879 | | -15% | -85% | -56% |
| 373 | Street Lighting | $49,916,373 | -20% | -21% | -81% | -54% |

This table shows that PSO's requested net salvage rates are much higher than the average rates of the other AEP operating companies. It also shows that PSO's <u>current</u> rates are much higher as well. The table further shows that both PSO's current and requested net salvage rates are much higher than OG&E's net salvage rates. It does not seem plausible that it would cost PSO three times as much to remove Poles and Fixtures (364) as it costs OG&E, or three times as much to remove Overhead Conduits (365), or twice as much to remove Underground Conduits (366), etc. What is apparent from the table, however, is that PSO's negative salvage rates appear to be grossly inflated.

Mr. Garrett testified that it would be easy to manipulate removal cost factors. When an asset is *replaced*, the costs of removing the old asset can either be charged to the cost of the new asset or to the cost of removal. Since there is a certain amount of discretion involved in the coding of these charges, it is easy to charge more of the costs to the cost of removal. This would increase the numerator in the formula (removal cost / original cost = removal cost factor) and thereby increase the removal cost factor which is then applied to the plant in service balances. One of the things a *salvage study* would check is the accounting decisions made when assets are replaced.

Mr. Garrett recommended that, at a minimum, the Commission reject PSO's proposed increases in its removal cost factors, and order instead, that the existing removal cost factors and related negative salvage rates remain in effect. However, PSO's existing removal rates are already excessive. If the Commission orders the Company to continue using these rates, ratepayers will continue to overpay for removal costs and the current accumulated liability, now at $282 million.

Mr. Garrett testified that the better approach would be for the Commission to adopt the approach used in Pennsylvania, and other states, where a normalized level of <u>actual</u> removal cost expenditures is included in the depreciation rate calculations rather than an estimated level of future expenditures.

In PSO's last rate case, the Commission ordered PSO to provide calculations in this case for the Pennsylvania approach for transmission and distribution assets. These calculations were provided in the exhibits attached to Mr. Davis's testimony at Appendix A. Mr. Davis provided the calculations for the Pennsylvania approach at test year end for distribution and transmission assets. Mr. Garrett updated Mr. Davis's calculations to August 31, 2008, and also performed the calculations for PSO's production plant assets. If the Commission were to adopt the Pennsylvania approach in this proceeding, the calculations would reduce the Company's requested depreciation expense by $16,488,045 for transmission and distribution assets and by $5,446,219 for production plant assets.

PSO will not be harmed by using this approach. If, going forward, PSO actually spends more than the amount embedded in rates for removal costs, the difference will reduce the $280 million liability. In other words, since the debit goes to the balance sheet rather than the income statement, net income is not impacted by over or under recoveries of removal costs.

| | |
|---|---|
| Adjustment to Apply PSO's Proposed Rates to Plant at 8-31-08 | ($ 781,581) |
| Adjustment to Reflect Actual Removal Costs for T&D Assets | $16,488,045 |
| Adjustment to Reflect Actual Removal Costs for Production Plant | $ 5,446,219 |

Surrebuttal on Depreciation

Mr. Garrett, after being recognized as an expert on depreciation, offered sur-rebuttal in response to the rebuttal and oral testimony of PSO witnesses Davis and Clayton. As to Mr. Davis, Mr. Garrett explained that the table at p. 72 of his own responsive testimony reflects an average of net salvage values using a denominator only the number of those AEP operating companies which actually provided data (176/1-22).[11] The fact that the values for other AEP companies may have been established in rate cases in the 1990's is irrelevant since AEP has not filed a rate case to correct those values (177/3-9). Contrary to Mr. Davis' claim that the OG&E negative net salvage rates are irrelevant, OG&E's negative net salvage is relevant, since they have not been an issue in OG&E rate cases, are much lower than PSO's request here, are in line with other AEP companies on average and are fairly consistent with Mr. Pous' recommendation here (177/2; 178/5). As to Mr. Davis' testimony that his (Davis') method does not assume past inflation will be sustained in the future, Mr. Garrett stated that Mr. Davis is not correct. Mr. Davis' mathematical calculation does so assume, as PSO witness Clayton confirmed at p. 7, line 15 of his pre-filed testimony (178/12-179/2).

As to Mr. Clayton, Mr. Garrett indicated that Mr. Clayton's six hours of accounting will not qualify him to take the CPA exam in Oklahoma (179/3-21). Mr. Garrett testified that it takes 30 hours of accounting to take the CPA exam (179). As to Mr. Clayton's testimony that SFAS 143 moved the cost of removal from the left to the right side of the ledger, Mr. Garrett explained that SFAS 143 did not move the costs from being characterized as an asset to a liability (180/3-12). Mr. Clayton was wrong in claiming that the Pennsylvania approach violates the matching principle. The matching principle is an accounting principle that requires costs be reflected in the same period as the revenues those costs produce. It is not a cost causation principle. Since the FASB allows no accrual of removal costs, the matching principle does not control (180/17-181/7).

Mr. Clayton's statement that the Pennsylvania approach is more costly to ratepayers is without support since he failed to point to anything to indicate that would be the case (181/11-19). Mr. Garrett did not say in his pre-filed testimony that it was more or less costly. Mr. Garrett noted that over time the Pennsylvania approach should equal an accurately accounted accrual method (181/19-21).

In response to Mr. Clayton's statement that SFAS 143 is not pertinent since it is an accounting, rather than a ratemaking standard, Mr. Garrett explained that in promulgating SFAS 143 the standard utility methodology for accruing removal costs was addressed and rejected, with a methodology implemented instead that would discount the inflation embedded in the calculation to present value (182/1-15). SFAS 143 is also important because it requires that non-regulated assets don't accrue any removal costs, a result that is similar to the Pennsylvania approach (182/16-24). Also SFAS 143 requires a pay as you go approach similar to the Pennsylvania approach (183/3-7).

Mr. Garrett further testified that, contrary to Mr. Clayton's statement about his testimony, Mr. Garrett, consistent with Mr. Davis' Exhibit DAD-1, did inform the OCC that when there is a negative

[11] Citations are to the transcript of proceedings December 9, 2008, page/line.

salvage calculation that amount is added to the plant balance to get a total amount to be depreciated (184/10-185/8).

Mr. Garrett further rebutted Mr. Clayton by stating that at p. 66, lines 13-19 of his own testimony, Mr. Garrett did not state that the Pennsylvania approach will cost less. Rather, the approach is more accurate and fair for ratepayers and will currently yield lower rates for ratepayers than PSO accrual method (185/16-25).

Finally, on sur-rebuttal Mr. Garrett addressed Mr. Clayton's testimony on the accounting effect of a future deregulation of PSO by explaining that when AEP deregulated power plants in the east, $470 million of accumulated removal costs paid in by the ratepayers were simply retained by AEP and taken into income as a gain that year.

In response to inquiry by the Referee about deregulation, Mr. Garrett explained that the negative net salvage value is getting higher all the time and there's a greater risk to ratepayers that the liability would never be returned in the event it was excessive (188/9-189/17).

The OCC staff did not cross examine Mr. Garrett on December 9, 2008 (190/1).

Cross Examination on Depreciation

On cross examination by PSO, Mr. Garrett explained that the Pennsylvania approach is a pay as you go approach in which the utility collects its actual costs to remove assets (191/14-24).[12] Under the Pennsylvania approach the assumption is the same that's made for all operating accounts of the utility -- that the level in the test year is the appropriate level for selling rates, except for adjustments for known and measurable changes (192/21-183/5). There is no reason why traditional ratemaking approach to setting rates for other costs is not appropriate for removal costs as well (193/10-16). Removal costs can be treated differently than recovering the costs of an asset over its life, and are treated differently for accounting purposes (194/9-12). For non-regulated assets, companies are not allowed to accrue removal costs but must expense those costs in the year they're incurred (194/21-25).

Mr. Garrett testified that today's ratepayers should not pay for future inflation, which they do not cause (203/11-25). An assumption that the inflation experienced over the last 20 years will be experienced over the next 20 years is not verifiable (204/16-18). Because we don't know what inflation will be over the next 20, 30, 40 years, the accounting profession rejected the formula presented by the utilities and instead decided that future inflation should be stripped out of the [negative net salvage value] calculation by discounting back to present value (204/21-205/4). Since the cost causation principle can't burden customers with causing future inflation, and because PSO's formula does so, it's inappropriate and inconsistent with that principle (206/12-16).

Mr. Garrett stated that PSO's rates of 75 to 100 percent for negative net salvage seem to be extremely excessive when you compare those rates to the rates of other utilities (219/21-25). They are 3 to 4 times higher than OG&E. Mr. Garrett didn't see how that can be justified (220/6-10).

## III. Rate Design Issues

Class Cost of Service Allocations

Mr. Garrett testified that utility rate design consists of two broad phases: cost allocation and rate design. In the cost allocation phase, each customer class is allocated its proportional share of the total

[12] Citations are to the Transcript of the proceedings on December 9, 2008.

costs based on the costs incurred to provide service to that class. Then, the revenues produced by each class are compared with the class cost levels to determine which classes are under-paying and which classes are over-paying their respective costs. From this comparison we learn which classes need rate increases and which classes need rate decreases to bring all the classes to the same rate of return, or to *equalized rates of return*. When the revenues collected from each class fully cover the costs caused by that class then rates are said to be set at *cost-of-service*. When rates are not set at cost-of-service, then some customers are paying costs caused by other customers. We describe these over- and under-payments among the classes as *inter-class subsidies*.

When costs are correctly allocated to the individual classes, rates can be developed to recover the actual cost of providing service to each class. These cost-based rates are equitable because customers pay only the costs incurred to serve them. Cost-based rates are also more efficient in that they ultimately tend to reduce the overall cost to the electric provider. This efficiency occurs because cost-based rates send better economic price signals to customers who then make better choices in rationing their use of electricity. Conversely, rates that are not cost-based tend to promote inefficiencies. These inefficiencies occur when prices are set below cost for certain customers. These artificially lower rates tend to cause the subsidized customers to increase consumption of energy based on incorrect price signals. Ultimately, the increased consumption brought about from artificially lower rates causes the utility to increase its overall cost over time to meet the increase in demand to serve subsidized customers. For many utilities, such as PSO, the problem is exacerbated when the subsidized customers are already the utility's most inefficient users of electricity, the residential class, and the subsidy providers are the utility's most efficient users of electricity, the industrial class. This creates a situation where distorted price signals cause inefficient users to use more electricity and efficient users to use less. Over time, this creates a more costly system for all users when additional capacity is continually being added to keep up with the artificially created increased demand during peak hours. The only party that actually benefits from the artificially higher demand brought about from the distorted price signals is the utility, since the utility gets to earn a return on the additional capital investment needed to meet the higher demand levels.

Mr. Garrett testified the most effective demand side management tool available to any utility is <u>pricing</u>. When prices reflect the actual cost to produce electricity, and when those prices are communicated at different times of the day or even on an hourly basis, consumers will begin to make more informed decisions about their usage and ultimately use power more efficiently during those periods when prices are higher. Over time, these consumer choices will result in customers using less electricity on-peak or moving load off-peak and toward those hours when prices are lower. These decisions in turn will help the utility level system load and ultimately reduce overall system costs. With proper price signals, demand side management improvements occur naturally over time without costly payments to the utility for DSM program costs, incentive payments and lost revenues.

Mr. Garrett testified that PSO's filed cost of service study (W/P L-1 through L-13) contained a material error in the revenue assigned to the SL2 class.[13] Although, PSO's cost allocation methodologies appropriately assigned costs to the various customer classes, the revenue assignment error in the SL2 class caused the study to provide a flawed rate of return for that class. When the error is corrected, the study shows that the SL1, SL2 and SL5 classes are providing substantial subsidies to the other customers, as shown in the table below.

**<u>PSO's Current Rates of Return</u>**

| Customer Class | Current ROR |
|---|---|
| | |
| Residential | 4.68 % |

[13] In its rebuttal testimony, PSO agreed with Mr. Garrett's correction.

| | |
|---|---|
| Lighting | 4.77 % |
| SL-5 | 9.76 % |
| SL-4 | 0.79 % |
| SL-3 | 6.47 % |
| SL-2 | 8.40 % |
| SL-1 | 10.78 % |
| PSO Average ROR | 6.55 % |

Rate Design and Allocation of Rate Change

Mr. Garrett testified that PSO listed only two rate design objectives. PSO witness Moncrief stateed that the Company's rate design in this filing reflects the objectives of: (1) limiting rate impacts to as close to the system average as possible, and (2) providing rate information to customers and sending appropriate price signals to encourage the efficient use of resources.

The problem with these two objectives is that they are each mutually exclusive of the other. That is, both objectives cannot be pursued at the same time. One objective must be sacrificed to achieve the other. However, only one of the stated goals is actually a valid ratemaking goal. The Company's second stated goal – of sending appropriate price signals to encourage the efficient use of resources – is a valid goal and is consistent with the fundamental ratemaking principle that customers pay the costs they cause on the system. The Company's first objective – of giving all customers the same percentage increase – is not a valid ratemaking goal because it contradicts and is in conflict with the second stated goal which is a fundamental goal of ratemaking.

Unfortunately, the Company's proposed rate design achieves only the invalid goal of providing an equal percentage increase for all customers. Specifically, PSO has recommended a 30.34% rate increase for all customers.

In Order No. 545168 entered in Cause No. PUD 200600285, the Commission specifically adopted PSO's proposal to move customer classes "towards equalized rates of return."[14] In this case, however, PSO is moving in the opposite direction, away from equalized rates of return and away from the Commission's goal of eliminating the class subsidies currently embedded in rates. Mr. Garrett recommended that the revenue requirement ultimately ordered by the Commission be allocated to the customer classes in a manner that brings the classes to equalized rates of return.

Time-differentiated Fuel Rates

Although fuel and purchased power costs vary substantially depending on the time of day the fuel and power is consumed, the utility is allowed to recover these costs from customers on an average basis, i.e. in proportion to the average amount of energy a customer may consume, regardless of when the customer consumes the energy. In general, energy costs tend to increase at times of higher demand. In other words, energy tends to cost more during on-peak hours. These higher costs, however, are not assigned to the customers causing the increase in demand – in effect, those customers adding load during peak hours – the costs are instead assigned to all customers on an averaged basis. This averaging of fuel costs penalizes customers with usage patterns that are less costly to serve, limits customers' incentive to conserve energy in periods of high demand, and provides no incentive for customers to shift usage to periods of low demand and lower cost. In short, the distorted price signal that results from fuel cost

[14] *See* page 154.

averaging encourages customers to use more power on peak than they would otherwise use. This results in overall higher system costs for all customers, including both higher energy and capacity costs.

Mr. Garrett testified that the solution is to introduce an FCA that reflects peak and off-peak energy costs and consumption. Hourly energy rates would be even more helpful. When prices reflect the actual cost to produce electricity, consumers will begin to make more informed decisions about their usage and ultimately use power more efficiently during those periods of higher cost.

Mr. Garrett recommends that the Commission require PSO to work with interested parties to develop hourly fuel and purchased power costs. OIEC and OG&E are currently working together to develop hourly fuel rates on OG&E's system. The Commission should direct PSO to also work toward this important goal.

<u>Other Tariff Provisions</u>

Mr. Garrett made recommendations concerning the following tariffs:

(1) The Customized Contract Tariffs, Tariff Sheets No. 76 and 77
(2) The Fuel Cost Adjustment Rider, Tariff Sheet No. 70
(3) The DSM Cost Recovery Rider, Tariff Sheet No. 85
(4) The Reactive Power Charge, Tariff Sheet No. 49

<u>(1) The Customized Contract Tariffs, Tariff Sheets No. 76 and 77</u>

Mr. Garrett testified that PSO's *Customized Contract Rate* tariff, Sheet No. 76, currently allows the Company to enter into special contracts with customers at rates below the Company's filed tariff rates, without Commission approval. This arrangement is unacceptable. Commission approval is necessary in any situation where other ratepayers may be required to subsidize another customer. Moreover, this tariff appears to violate the spirit and intent of rule OAC 165:35-5-1(c) which requires Commission approval (after notice and hearing) of a special contract for electric service. Mr. Garrett recommends that the Commission either repeal the *Customized Contract* tariff or amend the tariff to require Commission approval. The same recommendation also applies to Sheet No. 77, PSO's *Customized Contract Pilot Program* tariff.

<u>(2) The Fuel Cost Adjustment Rider, Tariff Sheet No. 70</u>

Mr. Garrett testified that, currently, the Company believes that it may change its fuel rates without Commission approval. Such unauthorized changes are unacceptable, especially in light of the fact that fuel costs now represent about 70% of a customer's electric bill, on average. Mr. Garrett proposed specific changes to the FCA Rider language at Exhibit MG-RD-2. These changes provide for Commission approval for fuel factor rate changes in the future.

Mr. Garrett also testified that PSO is currently allowed to retain 75% of the proceeds from off-system sales. In light of the significant recent increase in PSO's fuel rates and the current significant increase in base rates proposed in this case, Mr. Garrett recommends that 100% of the off-system sales revenues flow to customers through the FCA. If the Commission believes that a sharing arrangement of off-system sales revenues is necessary, then he proposes that a 90/10 sharing be used. Also, the amount of fuel in base rates should remain unchanged as recommended by OIEC witness Scott Norwood.

(3) The DSM Cost Recovery Rider, Tariff Sheet No. 85

Mr. Garrett's only recommendation with respect to the proposed DSM Rider is that language be added to the rider to limit application of the tariff to PSO's Quick Start Programs. This rider was intended to apply only to the Quick Start Programs that came out of Cause No. PUD 200700449. As such, the tariff language should limit the application of the rider to the Quick Start Programs.

(4) The Reactive Power Charge, Tariff Sheet No. 49

Mr. Garrett testified that PSO is proposing to increase the reactive power (kVAR) charge by 900%. The magnitude of the increase alone should be reason enough for the Commission to reject the proposed charge. However, a second important reason for the Commission to reject the proposed increase is that PSO has not recognized the additional revenue that would be produced from this charge. Revenue to PSO will increase by several million dollars and this additional revenue is not reflected in rates. Mr. Garrett also testified that the Company's proposed solution amounts to a *big stick* approach to reducing kVAR losses. The better approach would be a *carrot* approach where customers are rewarded with kVAR credits for reducing their reactive power losses.

Rebuttal Testimony of Mr. Garrett – Rate Design Issues

Mr. Garrett testified that he reviewed the rate design testimony filed by Mr. James Selecky on behalf of Wal-Mart. In his testimony, Mr. Selecky identified the customer classes that are *above cost of service* – in effect, those classes that are currently providing a subsidy to the other classes – and recommends that "any reduction in the revenue requirement from the amount requested should be allocated to the classes above cost of service to bring rates more in line with the actual cost to serve."

Mr. Garrett notes that Mr. Selecky did not incorporate the $4.2 million revenue correction to the SL2 class identified in Mr. Garrett's responsive testimony. In his responsive testimony, Mr. Garrett explained that PSO had inadvertently removed $4.2 million from the SL2 class revenues *twice*. This error resulted in a material under-allocation of revenues to the SL2 Class. Mr. Garrett also points our that, in its rebuttal testimony, PSO agreed with this correction. If the revenue allocation correction had been incorporated into Mr. Selecky's exhibits, his exhibits would have shown that the SL2 class, along with the SL1 and SL5 classes, is providing a subsidy to other customer classes.

Surrebuttal Testimony of Mark Garrett – Rate Design Issues

There was an increase on Line 18 of Hearing Ex. 4 to increase revenues by $1,928,777 for a total revenue increase at August 31, 2008, of $7,672,167 (102).[15] This change was based on PSO rebuttal testimony in which PSO stated that OIEC should have used actual numbers at August 31, 2008, rather than the estimated numbers provided by Mr. Sartin (102).

In surrebuttal to the rebuttal testimony of Mr. Moncrief at page 16, lines 5-9 that Mr. Garrett purportedly did not provide evidence to show that historic demands may have been impacted by price signals inherent in present rates and that Mr. Garrett provided no evidence for his suggestions that this causes lower levels of production in employment in PSO's service territory, Mr. Garrett testified that such evidence was provided and that it was undisputed (103-104). The evidence shows that SL1, SL2 and SL5 pay rates are above cost of service while the residential and lighting classes pay rates that are below cost of service (104). These subsidized rates result in distorted price signals, which result in inefficient use of electricity, and inefficient use of electricity results in excess capacity needs, which ultimate benefits PSO.

[15] Citations are to the transcript of proceedings on December 17, 2008.

Mr. Garrett pointed out that Ms. Champion refers to this as textbook economic analysis and she is right (104).

Mr. Garrett testified that in his rebuttal testimony that PSO's rates reflect cost causation through its pricing policy, Mr. Moncrief is talking about on-season and off-season block structures in the rates and these are same structures that PSO has always offered (104). Those rate structures do not fix the subsidy problem. Current subsidies are material and materially impact distortion in price signals which causes the inefficient use of power (104)

Mr. Garrett testified that, as admitted by Mr. Moncrief, there was a material error in Mr. Moncrief's cost of service study in the SL2 class, where the revenues assigned to that class were understated by $4.2 million (104-105). An analysis shows that the Company's proposed rate design with the 30% increase to all parties does not improve the subsidy in the SL2 class with that error correction. Mr. Garrett testified that the Company has not made any real movement towards eliminating the subsidy (105-106). Mr. Garrett testified that Arkansas requires cost-of-service based rates (106). OG&E just filed a rate case in Arkansas and OG&E's cost-of-service study and its proposed rates equal cost-of-service (106). Oklahoma's proximity to Arkansas can put Oklahoma industries at a disadvantage when competing with companies that pay cost of service based rates instead of rates burdened with subsidies (106-107).

In response to Mr. Moncrief's testimony of the cost to PSO per month of eliminating the kVAR problem, Mr. Garrett testified that what Mr. Moncrief's analysis does not show is that the charge to customers, which is about $3700 month (107-108). Mr. Garrett also testified that Mr. Moncrief admitted that the proposed increase in kVAR charge was a 900% increase from the current charge, which is a penalty (108). It is meant to punish customers who are experiencing kVAR losses. Mr. Garrett testified that a penalty is not appropriate (108). Mr. Garrett further testified that a tariff is a contract and penalties in contracts for liquidated damages clauses are not allowed (108). Further, the tariff would generate millions dollars and none of that revenue would be recognized in this rate case, so the Company would keep that money (108-109).

In response to questions from the ALJ, Mr. Garrett testified that either the Company or the customer can put equipment in place to avoid causing imbalance on PSO's system of this kVAR voltage (110). However, the proposed tariff is directed towards industrials because the company expects the industrial customers to pay for the investment to correct the situation. (110-111). Mr. Garrett suggested that the Company compensate customers for making the change out of savings that the change creates for all customers, which is an approach used in other jurisdictions. There are losses on other classes, but the Company makes the correction for those other classes (110-111). The losses are caused by the transmission distribution system of utility and its connection with customers (112).

In response to Mr. Sartin's criticism of OIEC's proposal to change the sharing of off-system sales between the customer and the utility, Mr. Garrett testified that Mr. Sartin did not provide any support in his testimony that 25% retention by the Company provides an incentive for the Company to make these sales or that it is an appropriate number (112-114).

In response to Ms. Williamson's criticism, Mr. Garrett testified that he used the actual book revenues of the Company in adjusting OIEC's surrebuttal position on Hearing Ex. 4 for revenues updated to August 31, 2008 levels (117-118).

Mr. Garrett updated Hearing Ex. 7, Ex. MG-3SR (129). That exhibit references data request 23-8 at bottom (129). The actual source is PSO's response to OIEC data request 23-5 (129-130). In line one, OIEC started with PSO's actual 12-month book revenues at August 31, 2008. Using bill summaries that the Company uses to calculate its revenue adjustment at test year end, Mr. Garrett updated the revenues for the six month period after test year end (130). To those total book revenues Mr. Garrett made the following adjustments: first, he removed the 3.4 cents that is imbedded in base rates for fuel; second, he removed FAC billed revenues. The first two adjustments were to back out fuel so that we are talking about base revenues (130). Next, Mr. Garrett backed out merger savings credit, Commission regulatory fees, the vegetation rider and the Lawton Cogeneration rider revenue. Two other riders were also backed out, so that all rider revenue was removed (130-131). After making those adjustments, all on line one, the total billed revenue is $455 million (131).

Line 2 is a weather adjustment to weather normalize the kilowatt hours (131). Mr. Garrett used the Company's weather adjusted kWh for each of the 12 months. On Line 3 he then, in the third column, backed out the rate change that occurred in September, 2007, for the rate increase. Mr. Garrett testified that this is exactly what the Company did for that month in its test year end revenues when it backed out the rate change affect (131). For lines two and three, he used the Company's adjustments for weather and the September, 2007 rate change. Line 4 shows OIEC's adjusted actual book revenues, non-fuel revenues at August 31, 2008 (131). Line 5 shows the amount of revenues OIEC spread in its responsive testimony, using Mr. Sartin's analysis. Line 6 shows the difference. In Line 7, OIEC took the revenues assigned of the special contract that is assigned to SL2, and spread them as a credit to all classes, which is what PSO did with those revenues as well, so all classes get benefit of that special contract (131-132).

The compared total on line 9 is OIEC's updated August 31, 2008 actual booked revenues for PSO (132). PSO made similar adjustments to test year revenues. OIEC's supported adjustment of $7.6 million was necessary to bring PSO's test year end revenues up to August 31, 2008 (132).

The other two adjustments needed to fully update revenues were to back out peak rider revenues that started in June, with small amounts of revenues in June, July, and August totaling $684,654 (132). OIEC also backed out the DSM rider revenues to get to actual base revenues (132). One month of DSM rider revenues, in the amount of $434,000, was backed out (132).

The total revenue adjustment is $6,553,513 (as compared to Mr. Garrett's $4.5 million original recommendation for revenue adjustments.) (132). The information upon which OIEC based Hearing Ex. 7 was provided in response to OIEC data request 23-5, in part (133). PSO also provided revenue information through the end of test year in a different data request. In the test year schedule PSO provided, it provided rider revenues for the Lawton Cogeneration rider, vegetation rider, Commission regulatory fees, and merger saving credit. PSO also provided FAC revenues and fuel revenues. The August 31, 2008 information requested did not have that rider information for the peaker plant rider and the DSM rider and that is why Mr. Garrett had to supplement during his testimony on the stand (133).

OIEC has used actual numbers, which responds to Williamson, Moncrief, and Burnett, who criticized OIEC for using Mr. Sartin's numbers instead of actual numbers (135). The use of actual numbers is more accurate and it is consistent with Okla. Stat. tit. 17, § 284. If plant and expenses are updated, which benefits the Company, the revenues, which benefit ratepayers, must also be updated (135-136). The $4.5 million formerly used by OIEC was based on information provided by Mr. Sartin (136). Mr. Garrett has now used actual numbers, rather than the numbers Mr. Sartin used, which were based on an accurate historical representation of actual increases the Company experienced over the last 10 years (136). Contrary to Burnett's statement, OIEC did issue data request for the actual six month post test year load growth (revenue) (137).

Mr. Garrett stated that Mr. Burnett, in his budget forecast for 2009, went way beyond six months, adding 2009 and beyond, and his testimony shows that his entire discussion is based on assumptions (138). Mr. Garrett disagreed with Mr. Burnett's revenue growth schedule and the decrease in base revenues (138-139). The Company provided OIEC, in response to data request OIEC 23-5, with all revenues through August 31, 2008, and in response to OIEC 4-13, with the same data for the test year.

For the six months of March, 2008 through August, 2008, the total of all actual revenues is $238,507,832, after subtracting fuel, vegetation, the Lawton cogeneration and regulatory fees, and all riders that were embedded in those schedules (139) In the second column, if you look at revenues from OIEC 4-13, the total in that column should be $224,581,708. There is an increase in revenues of $13,926,124. This is consistent with a comparison with all riders included, which shows a $20 million increase in 2008 (139). The Lawton cogeneration rider didn't start until November 2007, so it would not be imbedded in the 2007 numbers as it is in 2008 (140). Six months of the Lawton rider resulted in about $6 million, which would bring the $20 million increase down to $14 million, which is consistent with the $13.9 that Mr. Garrett calculated when all riders are removed (140).

The decrease testified to by Mr. Burnett also is not consistent with the Company's 10-Q filing for same period. On page F-2 of the Company's 10-Q filing of September 30, 2008, the Company compares financial net income to the same months of 2007 (January through September) (140). It says that there was an increase in revenues and that major components of the increase is in gross margins, defined as revenues less the related direct cost of fuel, including consumption of chemical sand emission's allowances, and also purchase power, both retail and off-system sales margins (140). The 10-Q filing shows an increase of $16 million for the nine months ending September 30, primarily due to an increase in retail sales margins resulting from base rate adjustments during the year (140).

Mr. Garrett testified that all data provided shows PSO's revenues in 2008 are higher than in 2007 for that six month period after the test year end. The $6.5 million is the total after the actual numbers are adjusted to take out riders and fuel, weather normalization and rate change (140).

**David C. Parcell**

Mr. Parcell filed Direct Testimony and Rebuttal Testimony in this proceeding on the subject of the fair cost of capital for Public Service Company of Oklahoma (PSO). These testimonies have been prepared on behalf of the Oklahoma Industrial Energy Consumers (OIEC).

Direct Testimony

Mr. Parcell's Direct Testimony first addressed the cost of capital for PSO. The overall cost of capital recommendation for PSO can be summarized as follows:

| Capital Item | Percent | Cost | Wgt. Cost |
|---|---|---|---|
| Long-Term Debt | 55.57% | 6.60% | 3.67% |
| Preferred Stock | 0.73% | 4.02% | 0.01% |
| Common Equity | 44.10% | 9.50% | 4.19% |
| Total Cost of Capital | 100.00% | | 7.87% |

There are three steps involved in estimating the cost of capital for a utility. These are:

Capital Structure Determination,
Measurement of costs of fixed-cost components – long-term debt and preferred stock,
Estimation of cost of common equity.

Capital Structure Determination

The capital structure proposed by PSO in this proceeding is the Company's proforma capital structure as of February 29, 2008. Mr. Parcell also used this capital structure in his cost of capital analyses.

Cost Rates of Long-Term Debt and Preferred Stock

The costs of long-term debt and preferred stock proposed by PSO represent its actual cost rates as of February 29, 2008. Mr. Parcell also employed these cost rates in his cost of capital analyses.

Cost of Common Equity

The cost of common equity represents the primary issue in the determination of a company cost of capital. There are four aspects of Mr. Parcell's estimation of the cost of common equity for PSO. These are:

Selection of proxy groups
Discounted Cash Flow Analysis
Capital Asset Pricing Model Analysis
Comparable Earnings Analysis

Proxy Groups

It is customary to employ a "proxy group" of companies in order to apply the financial models used to estimate the cost of common equity. Mr. Parcell selected two proxy groups for this purpose in his testimony. First, he utilized a group of companies that were selected based on several criteria designed to approximate the operational, size and risk characteristics of PSO and/or its parent American Electric Power Company (AEP). In addition, he performed a cost of equity analyses to the group of proxy companies used by PSO witness Murry.

Discounted Cash Flow Analysis

The first cost of equity model Mr. Parcell employed was the Discounted Cash Flow (DCF) model. There are two components to the DCF model – the dividend yield and the expected growth rate.

Mr. Parcell calculated dividend yields for each company in the proxy groups by dividing the current annualized dividend rate (adjusted for one-half the expected growth rate in order to reflect the actual dividend rate over the next year) by the average stock price over the three-month period July - September, 2008. He used a three-month average stock price in order to avoid reliance of a "spot" price, which may not be representative of current investor expectations. This is particularly evident in connection with the recent volatility in stock prices.

Mr. Parcell used five sets of individual proxy company data to estimate the growth rate component of the DCF model. It is appropriate to consider multiple measures expected growth since investors consider alternative factors in making their investment decisions. The measures of growth I consider are:

Five-year historic growth in earnings retention, or "fundamental" growth,
Five-year historic growth in dividends per share (DPS), earnings per share (EPS) and book value per share (BVPS),
Five-year growth projections of earnings retention,

Five-year growth projection of DPS, EPS and BVPS, and
Analysts' estimates of EPS growth over the next five years.

In Mr. Parcell's DCF analyses, he performed individual cost rates for each proxy company and for the composite of each proxy group using all of the growth rate measures, as well as each individual growth measure. Based upon his DCF analyses, Mr. Parcell believeed the DCF cost rate for PSO is within a range of 9.5 percent to 10.5 percent.

Capital Asset Pricing Model Analysis

The second cost of equity model he utilized was the Capital Asset Pricing Model (CAPM). There are three components of the CAPM model – the risk-free rate, beta and the risk premium.

For the risk-free rate, he used a three-month average of 20-year (i.e., long-term) U.S. Treasury bonds for the period July – September, 2008. He used Value Line betas for each proxy company. In order to estimate the risk premium, Mr. Parcell considered three historic measures of the return differentials between common stocks (as measured by the S&P 500) and 20-year U.S. Treasury bonds. My CAPM conclusions for PSO are within a range of 8.9 percent to 9.3 percent.

Comparable Earnings Analysis

Mr. Parcell's third cost of capital model was the comparable earnings model (CE). This model considers the experienced and estimated returns on equity (ROE) and the corresponding market-to-book ratios (M/B) for both the proxy groups and the S&P 500. In evaluating the cost of equity for a utility, it is necessary to evaluate the actual ROEs in connection with their M/Bs in order to ascertain the extent to which earnings are accepted by investors as evidenced by the existence of M/Bs of over 100 percent. My CE conclusion for PSO is a range of 9.0 percent to 10.0 percent.

Cost of Common Equity Summary

Mr. Parcell recommended cost of equity for PSO is a range of 8.9 percent to 10.5 percent. This range reflected the results of his DCF, CAPM, and CE analyses. Within this range, he recommended a point estimate of 9.5 percent.

Impact of Current Economic/Financial Conditions

Mr. Parcell also demonstrated that the recent economic and financial crisis should not be used as a reason to increase PSO's cost of capital. The current credit and related situation affects all of PSO's ratepayers, perhaps more so than the Company since it has regulated rates and a captive market. PSO also has several regulatory mechanisms, or tariffs, that help protect it from many economic/financial conditions.

Response to PSO Cost of Equity Request

Mr. Parcell's Direct Testimony also responded to the cost of equity analyses of PSO witness Murry. In this Direct Testimony, he demonstrated that his 11.25 percent recommendation for PSO substantially over-stated the Company's cost of common equity.

Dr. Murry's DCF analyses relied exclusively on analysts' projections of EPS, which is improper. It is unrealistic to maintain that all investors rely exclusively on a single growth statistic, yet this is what Dr. Murry has done. In addition, his risk premium analyses also produced excessive results since it appears to rely exclusively on the arithmetic growth rates and excluded geometric growth rates. Mr.

Parcell demonstrated in his Direct Testimony that investors use both types of growth rates in making investment decisions and thus these should be considered in a CAPM analysis.

Rebuttal Testimony

Mr. Parcell's Rebuttal Testimony addressed the cost of capital methods of Staff Witness Fairo Mitchell, as well as his 10.72 percent to 11.05 percent recommendation for PSO.

Mr. Mitchell's DCF analyses over-stated the cost of equity because he relied exclusively on analysts' forecasts of EPS. As Mr. Parcell indicated in his Direct Testimony in response to Dr. Murry's DCF analyses, it is improper to rely exclusively on a single measure of expected growth.

Mr. Mitchell's CAPM analyses also over-stated the cost of equity because he relied exclusively on a single measure of historic growth – arithmetic returns. Mr. Parcell demonstrated in his Direct Testimony that it is proper to consider alternative historic growth measures – arithmetic returns, compound returns, and returns on equity vs. bond yields.

Finally, Mr. Mitchell over-stated PSO's cost of equity by applying a "size adjustment" to PSO to reflect his perception that PSO is smaller than the companies in his proxy group. This adjustment ignored the fact that PSO is part of a very large organization (AEP) that raises all of its external common equity capital at the consolidated level. As a result, it is the consolidated entity that investors consider when making investment decisions.

Testimony at the Hearing

David C. Parcell, an economist and president of Technical Associates, Inc., has provided expert testimony on cost of capital before public utility commissions in the U.S., including on behalf of seven state PUC staffs in 2007-08 (57/21-58/11).[16] He has authored a cost of capital manual which is a study guide for the professional designation Certified Rate of Return Analyst sponsored by the Society of Utility and Financial Regulatory Analysis (58/12-17). The Referee recognized him as an expert before this Commission on cost of capital (57/21-22).

Sur-Rebuttal

On sur-rebuttal to Dr. Murry's rebuttal testimony (p. 3, lines 8-12) that Mr. Parcell did not sufficiently adjust his testimony for the current market turmoil, Mr. Parcell explained that since he used data through September 2008 when the turmoil was on and 3 months of data for both the DCF and CAPM, he did use current data when his testimony was filed, which was more current than Dr. Murry's initial testimony (58/19-59/1). Further, PSO did not adjust its initially requested rate of return of 11.25% because of market turmoil (59/5-9).

In response to Dr. Murry's claim (p. 7, lines 1-4) that credit problems add to the operating costs of utilities, Mr. Parcell testified that there is no indication that PSO has been impacted in a quantifiable way. PSO still has solid BBB ratings. Its embedded cost of debt is 6.60%. If PSO were to issue debt at higher rates, it would be the impact on its embedded cost of capital for all its debt which it could recover over the life of that debt from ratepayers (60/20-25).

As to Dr. Murry's claim (p. 15, lines 21-23) that Mr. Parcell's recommended ROE is not reasonable, Mr. Parcell stated that in the past year he has testified in a number of cases where his

[16] Citation is to the December 11, 2008 transcript, page/line.

recommended ROE as well as the authorized ROE has been 10% or less. In no case has it been above 11% (62/2-6).

In response to Dr. Murry's criticism of Mr. Parcell's testimony that capital costs have declined during the current cycle, Mr. Parcell explained that the case in point is that fact that PSO asked for 11.75% ROE in its last case and is seeking 11.25% here, showing that from PSO's perspective its cost of equity capital has come down 50 basis points since the last case. Additionally, earnings on equity will be lower for 2008 and market returns to investors will be negative for 2008, with Warren Buffett losing 25% this year (62/15-20).

In response to Dr. Murry's suggestion (p.17, lines 3-13) that capital costs cannot decline during a recession, Mr. Parcell testified that alternative investment opportunities, a *Bluefields* case factor, will be down and that currently profit margin will be down, if not negative, showing that cost of capital can and does decline during a recession (62/25-63/6).

The retention growth rates used by Mr. Parcell were published in Value Line for the benefit of its clients (64/15-17). In response to Dr. Murry's criticism of using risk premium data back to 1978, Mr. Parcell explained 1978 is as far back as S&P 500 goes (64/18-24). Contrary to Dr. Murry's criticism concerning coverage ratios, Mr. Parcell testified he provided testimony showing the implicit coverage associated with the recommendation, calculated the same way as used by Dr. Murry (65/3-7). As to arithmetic and geometric growth rates, the arithmetic rate used by Dr. Murry is not published by Value Line. The geometric growth rate (not used by Dr. Murry) is published by Value Line (65/11-15).

Cross Examination

Mr. Parcell stated that because of fairness, there is no justification for increasing PSO's profit level at the same time that virtually all of its customers are suffering lower income profits. The impact of a recession should not be used by PSO as an excuse to increase its cost of capital (66/17-67/3).

When asked, Mr. Parcell explained that he real difference between Dr. Murry and him is not the interpretation of the true cost of capital, but the implementation of the models to calculate the current cost of capital. His recommendations in recent years have been at or much closer to authorized returns than are Dr. Murry's (69/5-13).

Mr. Parcell observed that Dr. Murry's position, by recommending a decline to 11.25% from his 11.75% recommendation last time, is that the cost of capital has declined as a result of the recession (69/21-25).

Mr. Parcell testified that the sell off of stocks recently reflects the riskiness of the economy, not riskiness of equity and/or a particular company. It is a macro institutional thing (72/15-22). It makes no sense to use worldwide government efforts of increasing liquidity to single out one industry, utilities, and say that they should make more profits because everyone else is hurting (73/10-13).

Mr. Parcell testified that since PSO's current cost of debt is 6.60%, Mr. Parcell's ROE is almost 300 basis points higher (74/25-75/2). If PSO were to issue new debt at 9% tomorrow, its total debt cost would be somewhere much closer to 6.6%, its total embedded cost of all debt, which is the proper cost for ratemaking purposes (75/6-10).

Mr. Parcell stated that a downgrade by Moody's or S&P would not reduce PSO to junk bond status (77/19).

Redirect

Mr. Parcell testified that PSO is not on a watch list for possible downgrade to junk status by Moody's or S&P (79/20). Mr. Parcell was not aware of any filing by AEP or PSO with the SEC stating that if his proposed ROE is implemented PSO is likely to suffer a downgrade in its credit rating to junk (80/18).

**Mr. Scott Norwood**

Mr. Norwood is an electrical engineer with 28 years of electric utility industry experience in the areas of energy regulation, planning and procurement. He prepared and filed direct and rebuttal testimony addressing various issues in this proceeding on behalf of Oklahoma Industrial Energy Consumers. His testimony addressed five issues underlying PSO's base rate increase request in this proceeding.

First, Mr. Norwood's testimony addressed the potential rate impacts of AEP's plan for investment and operations over the next five years, as presented in the Company's 2008 Corporate Sustainability Strategy Report. Many of the initiatives presented by AEP in its Corporate Sustainability Strategy Report are likely to be very costly and are not necessary to provide reasonable electric service to Oklahoma ratepayers. Given this, and in light of the significant economic challenges presently faced by Oklahoma citizens and industry, Mr. Norwood recommended that the Commission disregard AEP's claim that exceptional rate relief is justified and required to implement this corporate strategy, and that the Commission continue to closely scrutinize PSO's proposed expenditures to ensure that only reasonable, necessary and prudently incurred costs are recovered from Oklahoma ratepayers.

Second, Mr. Norwood's testimony addressed PSO's failure to provide documentation to justify approximately $310 million (69.8%) of the total capital investment which it is seeking to place in rate base in this case. In light of this failure, he recommend that PSO's plant in service balance in this case be reduced by $47,936,678 million, which is equivalent to 25% of the total expenditures for capital projects subject to blanket funding, for which the Company has no detailed supporting documentation. Moreover, Mr. Norwood recommended that the Commission order PSO to file capital project requisition forms for all capital projects whose cost is $500,000 or more, along with summary information documenting the nature, cost and justification for all projects having a budget of more than $150,000, along with its direct testimony in all future base rate cases.

Third, Mr. Norwood's testimony addressed PSO's affiliate charges from AEPSC, which totaled $79,652,082 during the test year. The amount of these charges was 22.1% higher than the affiliate charges to PSO during 2005, and approximately six times the level of increase in AEPSC's charges to AEP East operating companies during the same period. Approximately $522 million (65.8%) of AEPSC's total charges to PSO and other AEP operating organizations during the test year were distributed among the companies based on generic allocation factors which are not defined in the Service Agreement between AEPSC and PSO, and whose reasonableness has not been approved by the FERC or addressed by the Company in this case. The Company has not provided information to demonstrate that the test year charges from AEPSC are reasonable and properly assigned to PSO or to explain why specifically the increase in its charges was six times the rate of increase experienced by AEP East operating companies during the same period. Accordingly, Mr. Norwood recommended that the Company's recovery of such charges be limited to $67,546,506, which is equivalent to PSO's 2005 level of AEPSC charges, adjusted by the 3.5% annual average increase in AEPSC's charges to the AEP East operating companies from 2005 to the test year period in this case. His recommendation reduces PSO's test year AEPSC affiliate expenses by $6,873,969 on a total company basis. He further recommended that the Commission order the Company to file a study which supports the calculation and reasonableness of allocation factors used to assign AEPSC's affiliate charges to PSO and other AEP organizations along with its direct testimony in the PSO's next base rate case.

Fourth, Mr. Norwood's testimony addressed PSO's proposal to recover $0.061 per kWh for fuel in its base rates. This proposal was based on an outdated fuel forecast prepared by the Company in May of this year which overstated the most recent actual fuel costs on the Company's system by nearly 100%. Mr. Norwood recommended that the Company's existing base rate fuel charge of $0.034 per kWh be maintained since it more reasonably reflects the most recent actual fuel costs on PSO's system. He further recommended that PSO's proposed FAC Rider be revised to reflect the existing $0.034 per kWh embedded base rate fuel charge so that future adjustments for differences between fuel expenses incurred and fuel revenues collected each month will be appropriately calculated. OIEC witness Mark Garrett addressed this rider change in his direct testimony.

Finally, Mr. Norwood's testimony addressed PSO's unreasonable proposal to increase its existing reactive power charge by 900%. This proposal is not reasonable or cost-based; it was derived from an estimate of the cost its customers would incur to achieve a 95% power factor, assuming a two-year payback period. The proposed charge also is more than 16 times PSO's existing reactive power charge to wholesale full requirements customers. The cost for PSO to make such improvements would be much lower than assumed by the Company's proposed charge. Accordingly, he recommended that the Commission disallow PSO's reactive power charge proposal and maintain the Company's existing reactive power charge. OIEC witness Mark Garrett addressed the necessary revenue adjustments to PSO's cost of service that would be required if the Commission approved the Company's reactive power charge proposal.

<u>Mr. Norwood Surrebuttal</u>

Contrary to the testimony of Mr. Kissman and Mr. Matthews at the hearing, PSO has still not produced information to support its capital additions (205-208).[17] PSO provided a supplement to OIEC 2-14, which included fairly detailed capital requisition acquisition approval forms, which amounted to approximately $8.5 million (211-212). With the exception of those requisition forms, which is what OIEC is suggesting the Company should provide going forward and which dealt with non-blanket capital additions, no other additional detail with regard to the scope of a project, justification of the project, or alternatives considered, was included in supplemental responses (212).

Mr. Norwood disagreed with Mr. Kissman that it would be burdensome and costly to develop documentation to support blanket additions (212-213). Mr. Norwood testified that he believes that Mr. Kissman ultimately recanted this testimony (213). Mr. Kissman, Mr. Matthews, and Mr. Knight all said the information has already been developed to support the budget (213-214). The number of projects to be documented is relatively small under Mr. Kissman's testimony at this hearing (214). Ex. SN4 of Mr. Norwood's testimony is an example of a capital project requisition form that the Company currently prepares for non-blanket capital additions with budgets above $500,000. This is the type of information Mr. Norwood is recommending be provided for all projects that are above $500,000 in cost, including blanket projects (214).

PSO's second supplemental response no. 16-16, Hearing Ex. 5, is not sufficient to describe work, cost and justification for inclusion of a project in the rate base (215). It has high level summary information, with no details on justification of individual projects or the cost of individual projects (215). Hearing Ex. 6, PSO's original supplement to OIEC 12-14, provided some additional numbers consisting of approximately ten requisition forms, which are attached as Ex. SN4 (215-216). It shows information

[17] Citations are to the transcript of proceedings on December 15, 2008.

for approximately $8.5 million, but information has not been provided supporting the $191 million of blanket additions (216).

For projects above 500,000, he would expect to see detail along the lines of SN4 (216-217). For projects below $500,000 down to $150,000, the Company should provide some summary of scope and reason for doing work (217).

Mr. Norwood testified that although Mr. Hoersdig was critical of Mr. Norwood's testimony relating to the reasonableness of the AEPSC allocation, Mr. Hoersdig admitted that he had not studied or addressed the issue of the 22% increase relative to charges in 2005, or the difference between charges to PSO and the overall increase in charges to other AEP operating companies (217-219). Mr. Hoersdig testified that there had been an overall increase of about 1.5%, but he did not address why PSO's charges increased by 22.5% (219).

With respect to Mr. Moncrief's rate design testimony on reactive power, PSO, instead of a cost based rate, has come up with what it would cost customers to address the issue, assuming a two-year payback on its investment, which is unreasonable in designing rates (219-220).

Mr. Norwood recommended that PSO not recover 6.1 centers per kWh for fuel in base rates (220-221). Mr. Norwood's recommendation is to maintain existing fuel costs in base rates at 3.4 cents (221).

## Wal-Mart Witness

**James T. Selecky**

James T. Selecky filed direct testimony on behalf of Wal-Mart Stores East, LP, (Wal-Mart) on the issues of depreciation and cost-of-service (COS).

I. Depreciation

Mr. Selecky's testimony addressed the proposed book depreciation rates for Public Service Company of Oklahoma (PSO). Specifically, Mr. Selecky addressed the net salvage ratios for the production plant accounts and the net salvage ratios associated with the transmission and distribution plant accounts. These net salvage parameters, together with the average service lives are used to develop PSO's proposed depreciation rates and expense.

Mr. Selecky's conclusions and recommendations are summarized as follows:

1. PSO has overstated the net salvage value associated with production plants. Specifically, the terminal net salvage components of the production net salvage ratios are overstated.

2. The contingency factor should be excluded from the terminal net salvage estimate since it does not represent a real cost.

3. The terminal net salvage utilized to develop the production depreciation rates should reflect or consider the potential value of the generation sites. Ignoring the value of these sites results in today's ratepayers passing on significant benefits to future ratepayers without receiving any compensation. This distorts price signals and violates cost-causation principles.

4. Mr. Selecky's changes to PSO's proposed production net salvage ratios reduce PSO's proposed production depreciation expense by $1.873 million based on December 31, 2007 plant balances.

5. The transmission and distribution (T&D) component of PSO's proposed depreciation rates reflects estimates of future inflation, which unnecessarily raises rates for today's ratepayers, and can produce intergenerational inequities.

6. The Commission should use net salvage ratios to calculate the T&D depreciation rates that are more reflective of actual net salvage cost.

7. Mr. Selecky's proposed changes to the T&D depreciation rates reduce PSO's proposed depreciation expense by $14.123 million based on December 31, 2007 plant balances.

8. Mr. Selecky's changes to PSO's proposed depreciation rates reduce PSO's depreciation expense based on plant balances at December 31, 2007 by $15.996 million.

II. <u>Cost-Of-Service</u>

Mr. Selecky also addressed PSO's cost-of-service (COS) and revenue allocation. His conclusions and recommendations are summarized as follows:

1. PSO's COS study comports with generally accepted COS methods. However, the classification and allocation of certain distribution plant accounts in PSO's COS should be modified to classify a portion of distribution line cost as customer-related.

2. Per the Commission's Order in PSO's last rate case, PSO filed the results of a minimum distribution study. This study is referred to in this case as a minimum-system study.

3. The Commission should utilize the results of PSO's COS study for allocation of any approved increase in this case. However, PSO did not include the minimum-system study in the COS study filed in this case. PSO should be instructed to file a COS incorporating the results of the minimum-system study.

4. The results of the COS study presented by PSO indicates the existence of a rate revenue shortfall for certain customer classes. That is, certain rate classes are paying rates that are in excess of the cost to serve those classes, while other classes are paying rates that are below the cost to serve those classes. Steps should be taken to reduce these disparities between rate revenue and cost of service.

4. If the Commission determines that PSO's overall revenue requirement is less than the amount requested, any reduction should be allocated to the classes above COS to bring rates more in line with the actual cost to serve. Any remaining reduction to the revenue requirement should be spread among the rate classes on the basis of each class' respective rate base.

## QSC Witnesses

**<u>Joe Robson</u>**

Mr. Robson addresses the concerns of the Quality of Service Coalition and its members. A rate review allows the Commission the opportunity to examine a wide variety of issues and the Coalition's involvement is designed to provide the Commission a perspective from the business and community point of view.

The Coalition will present three other witnesses, Mr. Paul Kane, Executive Vice President and Chief Executive Officer of the Home Builders Association of Greater Tulsa, Mr. Rodney Ray, city Manager of the City of Owasso, Oklahoma and Mr. James Twombly, City Manager of the City of Broken Arrow, Oklahoma. Their testimony will provide the Commission information on energy efficiency and demand side programs and community related issues arising out of the filing by Public Service Company of Oklahoma.

The reduction of consumption by residential, commercial and industrial customers is of particular interest to the Coalition and its members. Reduced usage and demand for electricity will have a positive impact on the need for additions of additional generation in the future. The Commission has authorized the implementation of Quick Start programs which is a positive step. From light bulb programs to the selection of more efficient appliance and heating and air conditioning equipment, the Quick Start programs offer consumers the opportunity to have a significant impact on the amount of energy needed to service PSO's more than 500,000 customers.

One area of concern, however, is the need to have energy efficiency and demand side management programs that address existing housing. Existing residential housing is the largest component of buildings served by PSO and other Oklahoma utilities. Programs must be designed to address the variety of needs in this area. Attic insulation and more efficient windows are good examples of retrofits that existing homeowners can make to achieve significant benefits to individual customers while also contributing to the reduction in demand for electricity. A number of existing resource guides for retrofitting homes and businesses already exist that describe in detail energy efficiency technologies for remodeling existing homes and businesses.

The Coalition is also concerned about the impact of PSO's rate case because the economic conditions facing both PSO and its customers are something that will impact both for months and possibly years. An economically sound electric utility serving our members is vitally important because it allows existing businesses to keep people at work while providing the opportunity to attract new business ventures to our cities and to our state. While the economic downturn experienced in many parts of the country has had less of an effect on Oklahoma, we have to be aware that these events have impacted our communities and our state in the past and we are already feeling some symptoms with slowdowns in production and some lay-offs of employees.

Examining proposals offered in this case is an important step in ensuring that the proposals made by PSO allow safe and reliable electric service while recognizing the need to consider the ultimate impact a proposal might have on PSO's customers. PSO's vegetation management program is an example of where the Commission might apply this kind of scrutiny. This is an important program which has accomplished much of its mission to trim trees and to begin to install so of PSO's distribution underground rather than overhead. Determining the extent that the 5 year to 4 year tree trimming cycle has been completed and the cost effectiveness of placing more overhead lines underground is an important topic. We encourage this practice but wonder if some of the resources previously devoted to overhead tree trimming might now be directed to this program.

Finally, we continue to support movement of PSO's rate design toward equalize rates of return among the various customer classes. This was issue before the Commission in the previous rate case, Cause No. PUD 200600285. The Commission adopted "PSO's proposal that customer classes be moved towards equalized rates of return while considering the impacts on all customers" but used a different approach in the determination of how rates would be spread in this case. We support more equalized rates of return that will give customers more appropriate price signals and help in the management of the usage of electricity by each customer class.

**Paul Kane**

Mr Kane is the Executive Vice President and Chief Executive Office of the Home Builders Association of Greater Tulsa. Home Builders Association of Greater Tulsa was among the founding members of the Quality of Service Coalition. The Association participates in educational, philanthropic and community development activities in Tulsa and surrounding communities and has a vested interest in making the community a better place for Oklahoma citizens to live and work.

Home construction and retrofitting are complicated processes that require a variety of tasks. Most of these elements are governed by local, state and national building codes, standards and even best practices to ensure the customer is receiving a quality product. In recent years energy efficiency has become a driving force in the building and retrofitting process.

GREEN BUILDING for BUILDING PROFESSIONALS is a training program developed by the National Association of Home Builders. This program provides builders, sub-contractors, product suppliers and realtors a guide to incorporate environmental consideration into every phase of the home building process. Minimizing the total environmental impact is the objective of this program.

While builders already incorporate many of the elements of green building into their current practices. In fact, most new homes incorporate these principles in today's construction. The GREEN BUILDING training is a valuable resource that should be considered by PSO as it undertakes development of program design for future energy efficiency and demand side management offerings.

Retrofitting existing homes is an additional area where the Home Builders Association of Greater Tulsa has a keen interest. From improving attic insulation to properly sizing heating and air conditioning equipment, our members are aware of the growing need to be more energy efficient. Training is a key element of this process.

Finally, current economic conditions make this rate review an extremely important undertaking. Striking a balance between the impact on customers and the need to have safe, reliable and affordable electricity is critically important.

**James M. Twombly**

Mr. Twombly is the City Manager, City of Broken Arrow, Oklahoma. Broken Arrow voter renewed a franchise with PSO in 1997. The city of Broken Arrow is among the fastest growing cities in Oklahoma. The latest Census report indicated that it is now the 4$^{th}$ largest city in the state with a population of almost 98,000 citizens. Since Broken Arrow voters approved PSO's franchise the population has increased by about 47 % and the boundaries of the city have expanded greatly.

Our franchise is not unlike the franchises adopted in PSO's other communities. It has a length of 25 years. It is not an exclusive franchise but PSO is the dominate supplier of electricity to Broken Arrow electric customers. The franchise grants PSO the right to use the city's public ways. They install their distribution, transmission and other related facilities on these public ways to provide electric service to Broken Arrow customers. In return for the use of the city's public ways, PSO collects a franchise fee of 2% of gross receipts of sales of electricity from residential and commercial customers and remits that franchise fee to the City.

In 2007, the franchise fee receipts remitted to Broken Arrow by PSO totaled $1,315,049.29 which was placed in the general revenue fund of the City. It is interesting to note that during that same period, Broken Arrow paid PSO $1,343,350.96 for electric service to its public facilities and for street lighting. The disparity between franchise fees collected for the use of the City's public ways and the amount paid for electric service is not unusual but the PSO franchise provides the utility a valuable resource that would otherwise require the company to expend significant sums to acquire rights of way for their facilities.

It is important to point out that PSO has no direct cost associated with a franchise granted by voters. A rate case is an appropriate venue to examine how an electric utility like PSO might address issues facing the financial viability of a community where they provide service. Street lighting costs in this case provide an excellent example. Annual costs for the major street lighting categories used in Broken Arrow will double under the current proposal. Current franchise fees do not pay current costs and the increase in street lighting rates and other rates charged for municipal electric use will make that disparity even larger. The only recourse we have in the short term and in the long term are to reduce essential services in other areas to fund the increase proposed by PSO.

Street lighting costs might be reduced significantly if new technological advancements in street lighting bulbs were installed. A Broken Arrow company, DATRAN, manufactures LED lighting bulbs for street lights. Three DATRAN lights were installed on one of Broken Arrow's major streets and two lights were installed in Centennial Park.

That test, in my opinion, has not provided enough information to adequately determine that LED replacement luminaries could operate more efficiently than the existing lighting fixtures and do so at a lower cost. I would suggest a more extensive street lighting assessment project to study the applicabilit6y of LED luminaries in street lighting application in PSO's service area. Quality of Service Coalition members like Broken Arrow, Owasso, and Tulsa offer a variety of testing opportunities to assess this new technology. We would work with PSO to test DATRAN or other LED luminaries to provide reliable date on their performance in Oklahoma weather and to determine how the citizens of these communities perceive this new lighting system. LED lighting uses less electricity and appears to have a longer bulb life. It could become a viable substitute for existing Metal Halide and High Pressure Sodium Vapor bulbs used by PSO and in the process reduce costs for both cities like Broken Arrow and for PSO.

**Rodney Ray**

Mr. Ray is the City Manager, City of Owasso, Oklahoma. Owasso voters approved a PSO franchise in 1966 and renewed that franchise in 1990. The most recent population estimate is about 37,500. More than 8,000 homes and businesses are served by PSO. The City of Owasso has been a member of the Quality of Service Coalition since its formation in 2004.

Budgeting issues are a key concern for Owasso. PSO's rate requests will dramatically increase the cost for our community. PSO has provided electric service to Owasso and its citizens for many years. Since I became City Manager, the population of the City has tripled and its municipal boundaries have drastically increased. New citizens and new businesses provide health care and essential goods and services that can now be obtained in Owasso rather than going to other communities for this support.

Our membership in the Coalition has helped establish a better relationship with PSO. Relocation of services is just one example. We now meet and discuss these situations and the results provide a resolution of outstanding issues with little or no delay.

One concern of a community like Owasso is the need for bill consolidation. While we now receive one bill, which details each individual meter, we still see areas for improvement. Each account listed has charges for energy used during the billing period but also has a basic service charge and demand or reactive energy charges when applicable. Consolidation to one bill is an improvement but other billing consolidation or aggregation issues still exist.

Perhaps the solution is as simple as agreeing on an overall monthly "basic service charge" for public buildings. Another solution might be to have a single "basic service charge" for each location. We think it is important to institute better management of costs for local governments. We want the opportunity to sit down with PSO and discuss billing for municipal services that result in savings for our citizens and for PSO.

Another alternative might be to look at establishing a rate code for public facilities, similar to PSO's rate code that applies to Public School Facilities, General Service Secondary Public School Facilities (Rate Code 304 and 305) and the Limited Usage General Services Secondary Public School Facilities (Rate Code 314, 315, and 317) Little difference in the definition or availability of these rates between the rate code charged to municipalities but the Public School Facilities GS and Limited Usage GS Secondary Public Schools Facilities provide a lower basic service charge and a lower energy charge for each kilowatt hour of energy. Municipal facilities, county facilities, state facilities and public school facilities could included in this new rate code. Owasso and other communities would benefit. The facilities are operated for the benefit of all Oklahoma citizens living in cities, counties and attending public schools.

Finally, government must adhere to a budget. It has to be balanced. A city like Owasso has to make adjustments to it budget when increases like the rate increases proposed in this case occur. The Commission must recognize the impact proposed changes in rates will have on PSO customers. Rate increases like those proposed in this case will require reduction in other community service to meet these increased costs. We do not oppose rates that provide the utility an opportunity to earn a reasonable return on their investment.

We must work together to retain existing businesses and to attract new business opportunities to our city and to our state. The current economic situation will certainly impact our community and its ability to provide parks and other opportunities for our citizens. Working with PSO and AEP, we hope we they can be more involved in community projects in the future.

**AG Witnesses**

**Jacob Pous**

The Company initially requested an annual level of depreciation expense in the amount of $86,498,691 based on plant as of December 31, 2007. This amount increased to $90,323,192 based on plant as of August 31, 2008. Mr. Pous received and analyzed PSO's request and underlying support. Based on his analysis, he recommended various adjustments as summarized below. These recommendations result in an annual level of depreciation expense of $70,022,851, or a reduction of $16,475,840 based on plant as of December 31, 2007. These amounts increase to $73,216,172 and $17,107,020 for total depreciation expense and reduction to depreciation expense, respectively, based on plant as of August 31, 2008. The following is a brief synopsis of each recommended adjustment.

- **Production Plant Net Salvage** – The Company proposes various negative net salvage values for its steam production generating units. These values are based on demolition cost studies recently performed by Sargent & Lundy (S&L) which were then inflated far into the future by PSO. In addition, PSO also estimated net salvage amounts for interim retirements and added those amounts in order to arrive at a net overall net salvage result for total production plant of a negative 14.1%. An example of the Company's process for the Northeast coal units is set forth in the following table.

**Demolition Cost Levels**

| | S&L Amount | PSO Inflated | PSO Request |
|---|---|---|---|
| Northeast Coal | $31,756,060 | $69,982,505 | $83,345,570 |
| Ratio to S&L | 1.00 | 2.20 | 2.62 |
| $/KW | $33.57 | $73.98 | $88.10 |

It is recommended that a negative net salvage level of 3.10% is a more appropriate value for production plant. This recommendation is more in line with the negative 5% level of net salvage previously utilized by some of PSO's sister-operating companies in Texas. Use of an overall 3.10% negative net salvage results in a $5,062,578 reduction to the proposed depreciation expense based on production plant as of December 31, 2007.

One major and fatal flaw to PSO's request, and there are others, is that it is inconsistent. The majority of the proposed S&L costs are attributable to the restoration of the various sites, not the removal of the equipment that rests upon the sites. Inconsistently, the Company fails to recognize any value for the restored sites. If the value of the restored site is not recognized, then projected costs to restore and improve the site cannot be assigned to current customers. It is future customers that will receive the benefit of the restored or improved sites either through the sale of the sites or through reuse of the site for future generation. In either instance, the matching principle requires consistency between costs and benefits, which is missing from the Company's proposal.

In addition, an alternative recommendation reflecting a positive 10% net salvage is also provided as a first step towards the recognition that many, if not all, of the Company's generating units could be sold at some point in the future.

- **Mass Property Net Salvage** – The Company claims to have performed a net salvage analysis for its various mass property (i.e., transmission, distribution and general plant) accounts. A review of Company's testimony, exhibits, work papers and responses to data request demonstrates that the Company has only performed a simplistic mathematical averaging of 23 years of historical data for almost all accounts. The Company's analysis for this component of depreciation is devoid of a proper evaluation phase of a depreciation study. The Company failed to perform any form of evaluation of the historical data, a requirement that its prior depreciation consultant stated was mandatory, and that is the standard approach for a meaningful and valid study.

  Any claim that the results of simple historical averages that may include many work orders each year without actual knowledge as to whether the historical data is representative of the current investment is illogical. The Company's approach relies on assumed coincidence that what has retired historically is precisely proportionate to what will retire in the future. The Company's approach of intentionally removing judgment from its analysis process ensures that standard concepts such as recognizing the impact of economies of scale or normalizing excessive costs due to storm or unusual events are recognized. Mr. Pous has demonstrated that the Company's assumptions and practices to be without merit and produce erroneous results. The Company's selected historical values are not true pictures of can be expected associated with the retirement of the current plant in service.

The Company's blind reliance on historical averages yields results that in many instances are noticeably different than what it requested less than two years ago in the last rate case. In fact, for Account 364 the Company is now proposing a $60 million overall change in net salvage from what the same witness proposed in the last case less than 2 years ago. While one might expect substantial evidence supporting such a significant movement in costs in such a short time frame, the Company provided essentially nothing of value. The Company's presentation does not rise to the level of being considered a valid depreciation study.

The Company's current proposals are still near or at the high end of the negative net salvage values that can be identified in the industry. This fact, significant variation from the industry, continues to be unexplained by the Company. The Company's arbitrary, but unexplained, allocation of amounts received from outside parties between construction and retirement expense is but one example of its failure to substantiate an internal accounting process that can significantly impact cost of removal relationships and possibly explain its unusual proposals. It must be noted that while such internal accounting practices do not impact rate base currently, they can and do impact depreciation proposals and the level of rate base in the future.

Correction of the net salvage value proposed for 10 mass property accounts results in $11,413,262 reduction to depreciation expense based on plant as December 31, 2007. A summary of the recommended changes follows.

| **ACCOUNT** | **EXISTING %** | **PSO PROPOSAL %** | **AG RECOMMENDED %** | **IMPACTS $** |
|---|---|---|---|---|
| 354 Transmission Towers & Fixtures | (35) | (69) | 0 | $225,870 |
| 355 Transmission Poles & Fixtures | (57) | (93) | (57) | $1,137,71 |
| 356 Transmission OH Conductor & | (38) | (72) | (38) | $881,695 |
| 364 Distribution Poles, Towers & Fixtures | (76) | (98) | (40) | $2,906,22 |
| 365 Distribution OH Conductor & | (74) | (80) | (50) | $1,679,81 |
| 367 Distribution UG Conductor & Devices | (20) | (21) | (10) | $326,463 |
| 368 Distribution Line Transformers | (24) | (17) | (5) | $1,111,72 |
| 369 Distribution Services | (40) | (76) | (25) | $1,860,31 |
| 371 Distribution Installation on Cust. | (85) | (56) | (10) | $618,075 |
| 373 Distribution Street Lighting | (85) | (54) | (15) | $705,368 |

- **Requirements For Next Case** – The Company's depreciation practices, in particular those associated with its mass property net salvage presentation, must be changed before the next rate case. It is recommended that the Commission order PSO, among other things, to perform and present a "cause of retirement" analysis as part of its support for its mass property net salvage proposals in the next case. The analyses should include, at a minimum, what level of the historical retirement data was associated with emergency situations and the net salvage differences that occurred due to such situation. The study should also address the relationships between the type of investment reflected in historical data compared to the remaining plant in service so as to establish whether a realistic and appropriate connection exists. The Company must also be ordered to justify its allocation of costs between cost of removal and the cost of a replacement installation when replacement activity occurs.

These types of presentations are required in order for the Commission to have a better record upon which to render its decisions. Neither the Commission nor customers are well served when the Company states that its proposals are reasonable simply because it believes or states that they are reasonable. Such lack of support by the Company for its proposals inappropriately attempts to transfer the Company's burden of proof to a presumption that it is correct until someone proves them wrong. This approach must be soundly rebuked.

**Daniel Lawton**

Mr. Lawton addressed the Public Service Company of Oklahoma (PSO or Company) requested overall cost of capital to be earned on rate base. In this proceeding, the Company has requested an overall cost of capital to be earned on invested capital of 8.64%.[18] The Company has requested a return on shareholder equity of 11.25% to 11.75%.[19] The Company's return request of 8.64% produces an annual return revenue requirement of $133,501,480 on a rate base of $1,545,156,028 (8.64% x $1,545,156,028), before income tax considerations.

Thus, return and cost of capital are significant components of the PSO annual cost structure and rate increase request in this proceeding.

<u>Cost of Equity</u>

Mr. Lawton reviewed current financial data for PSO's parent company American Electric Power (AEP) and for a group of seven comparable risk utility companies.[20] To develop a cost of equity analysis two Discounted Cash Flow (DCF) analyses were performed, a risk premium analysis and a Capital Asset Pricing Model (CAPM) analysis were calculated.

The results of these four analyses for AEP and the seven company comparable group is as follows:

| | **AEP** | **Comparable Group** |
|---|---:|---:|
| Constant Growth DCF | 9.5% - 10.3% | 9.83% - 10.04% |
| Non-Constant Growth DCF | 10.3% | 9.9% |
| Risk Premium/CAPM | 9.99% - 10.03% | 9.4% - 9.99% |

[18] *See* PSO Rate Filing at Schedule F-1.
[19] The 8.64% overall return request includes an 11.25% return on shareholder equity.
[20] The seven company comparable risk group is the same group of companies as employed in Company witness Murry's cost of capital analysis.

Based on the above results, the overall range is 9.5% - 10.3% for cost of equity with an approximate midpoint of 10%.

Given that the Commission reviewed PSO's cost of equity last October and concluded a 10% equity return is appropriate – current economic analyses indicate that a 10% ROE is appropriate for setting rates in this proceeding.

In terms of overall cost of capital and capital structure, Mr. Lawton recommended that PSO's proposed capital structure along with debt and preferred cost rates should be adopted by the Commission. Mr. Lawton's overall cost of capital recommendation is this case is 8.09% based on the following capital structure and cost rates:

| Description | Ratio | Cost Rate | Weighted Cost |
|---|---|---|---|
| Long-Term Debt | 55.57% | 6.60% | 3.668% |
| Preferred Stock | 0.33% | 4.02% | 0.013% |
| Common Equity | 44.10% | 10.00% | 4.410% |
| Total | 100.00% | - | 8.09% |

Finally, Mr. Lawton concluded that PSO witness Dr. Murry overstated that Company's cost of equity. Like PSO's last case Cause No. 200600285 where Dr. Murry recommended a return for shareholder equity of 11.75% to 12.0% - Dr. Murry has again recommended equity returns at the highest possible end of his estimates. While Dr. Murry's recommendations in this case of 11.25% - 11.75% are lower than his previous case estimates – such estimates overstate PSO's equity cost and would result in unfairly burdening consumers.

For all of the above reasons, Mr. Lawton recommended that the Commission adopt a 10% return on equity and an overall capital cost of 8.09% revenue requirements and rates in this case.

**Roya Soltani**

Ms. Soltani's testimony was responsive to the asserted revenue requirement of the Public Service Company of Oklahoma. The Attorney General's revenue requirement recommendations are summarized in the Accounting Exhibit of the Office of the Attorney General. Ms. Soltani sponsored rate base and income statements adjustments in her testimony and has limited her proposed levels of investment, revenue and expense to those levels that occurred and could be verified during the test year and the six-month post-test-year.

Ms. Soltani supported the elimination of test year end construction work in progress (CWIP) that is not completed by six-month post-test-year since Plants not completed and under construction are not used or useful for providing electric service and current PSO customers should not fund costs that may or may not benefit them in the future. She also proposed to increase accumulated depreciation to synchronize the additional growth in the depreciation reserve with plant in service additions through August 31, 2008.

Ms. Soltani recommended an update to prepayments average to the actual 13-month total average balance six months post test year. She proposed to update the Company's requested level of Customer Deposits, Accumulated Deferred Income Taxes, fuel inventories, Materials and Supplies and property tax expense to August 31, 2008, also. These adjustments are necessary to reflect the final known and measurable amounts in the rate base.

Ms. Soltani's testimony reflected PSO's direct payroll and AEPSC payroll allocation to PSO for the twelve months ending August 31, 2008. She also proposed to eliminate half of the PSO and AEPSC incentive compensation expense included in the Company's test year operating results. The Company's incentive plans mostly benefit the Company's shareholders. With respect to incentive compensation performance measures, the financial measures benefit shareholders and do not directly benefit ratepayers; however, the portion of the incentive pay related to operational, safety and service quality measures benefits both shareholders and ratepayers and it is reasonable that the ratepayers share a portion of the costs. Ms. Soltani recommended eliminating the Company's Supplemental Executive Retirement Plan (SERP) or excess pension benefit plans expenses intended to provide supplemental benefits to the executives that are limited by ERISA. SERP costs are not necessary costs to provide electric utility service. The AG's payroll taxes adjustment decreases taxes other than income taxes to correspond to the AG's payroll and incentive pay adjustments.

Legislative advocacy, civic and social dues and memberships should be disallowed. Ratepayers should not support costs that are not necessary to provide electric utility services.

Sound ratemaking theory supports the deferral and amortization recovery of utility costs to process a rate case, over a reasonable period of time. Ms. Soltani suggests a three-year amortization of this cost balances the need for the Company to recover costs with some form of safety mechanism to protect ratepayers against a substantial cost over-recovery.

PSO's fleet fuel expense adjustment increases O&M expenses to reflect the higher gasoline and diesel prices based on May 2008 prices. The price of gasoline has dropped significantly since May. The AG's adjustment reverses the Company's fleet fuel expense adjustment to reflect the lower gasoline prices at six months post test year.

Ms. Soltani recommended removing the part of the Company's transmission reliability programs costs that were not incurred as of six months post test year. The Company's adjustment is based on an estimate of costs and there is no certainty that the future costs levels will be achieved. Ms. Soltani also proposes that the OCC approved RCA rider provides the proper mechanism for PSO to recover its tree trimming and overhead to underground conversion program costs.

## Staff Witnesses

### Brandy L. Wreath

Brandy Wreath, Chief of Energy and Water testified that it was his responsibility to oversee the field investigation related to this filing, to supervise the preparation of schedules, scope of review of assignments, work papers, the Staff Revenue Requirement Exhibit, and testimony to support the Staff's quantification of PSO's current revenue requirement based upon a test year ended February 29, 2008. In addition, he testified that he reviewed as Staff analyst the areas of service corporation allocations, Board of Director's minutes, independent auditor reports, incentive compensation, moving/relocation expense, payroll taxes, and payroll/labor expense.

Mr. Wreath testified that Staff used the six months post test year as the cut-off period as is consistent with the language in 17 O.S Section 284, which states in pertinent part, "[T]he Corporation Commission shall give effect to known and measurable changes occurring or reasonably certain to occur within six (6) months of the end of the test period upon which the rate review is based." He stated that Staff utilized the six months post test year as a benchmark to check the reasonableness of the test year end levels and that Staff only made adjustments to the six months post test year that were consistent with areas in which pro-forma adjustments had been made by the company. He further stated Staff also utilized the information to set normalized levels if previously ordered to do so by the Commission.

Mr. Wreath also testified Staff had not found any items that warranted a change in PSO's service corporation allocations, Board of Director's minutes, independent auditor reports, or payroll calculations. Further, he stated Staff found the salaries, employee levels, and overtime amounts stated by the Company to be reasonable.

Finally, Mr. Wreath testified Staff had reduced PSO's requested amount for incentives by the total amount for Executive plan payments, then further reduced it by 50% to reflect an equal share between the ratepayer and shareholder. He stated Staff's total resulting adjustment H-18 was a reduction of $(7,711,851) which is consistent with the prior rate case order.

**Thomas Edward Lains**

Mr. Lains reviewed and analyzed PSO's proposed depreciation rates and supporting data as provided by Mr. Bertheau, of Sargent and Lundy; Mr. Clayton and Mr. Davis. In Mr. Lains' review he determined costs related to demolition and removal of assets that are included in the depreciation algorithm should be based on a review of historical data--that is to say, the actual costs incurred for demolitions completed in the past as opposed to PSO's proposed use of a current modeling routine completed for current conditions and costs. PSO's proposed current model involves the use of data bases such as R.S. Means, which tend to overstate costs, thereby skewing the resulting numbers early in the process. PSO then proposes that the resulting sums be escalated decades into the future by a multiplier derived from future projections of the Consumer Price Index. The number used as an escalation factor by PSO in the current case is 2.5 percent which is based on a Consumer Price Index inflation factor from December 2007 projected for this year. In keeping with the National Association of Regulatory Utility Commissioners' (NARUC) inclination to <u>not</u> allow the use of inflation factors for other elements of this process, Mr. Lains recommended carrying the current rates forward from Cause No. PUD 200600285 as set forth in Order No. 545168 dated October 9, 2007, resulting in a reduction of ($6,285,533).

**Fairo Mitchell**

Mr. Mitchell conducted an analysis of following analyses to estimate the cost of common equity: the Discounted Cash Flow (DCF); the Capital Asset Pricing Model (CAPM); and the Comparable Earnings (CE) methodologies to develop an estimate of the cost of common equity. He also included an analysis of rate of return (ROR) decisions from various other state regulatory commissions. The conclusion of his analysis of DCF, CAPM and CE models resulted in an estimated return on equity (ROE) range for PSO of 10.72 percent to 11.05 percent with a mean of 10.33 percent percent. However, a clerical was discovered which inadvertently omitted some information. After recalculations, including the omitted numbers, the results showed an estimated ROE range for PSO of 10.75 percent to 11.18 percent which is still lower than the 11.25 percent that PSO requested in its application.

In order to determine a fair and reasonable ROR, Mr. Mitchell used the criteria included in the economic guidelines and standards known as the Comparable Earnings and Capital Attraction Standards established in the *Bluefield Water Works v. Public Service Commission*, 262 U.S. 679 (1923) and *FPC v. Hope Natural Gas Co.*, 320 U.S. 591 (1944) decisions.

Before the clerical error was discovered, the ROE estimate based on the three calculated DCF medians was 11.33 percent. The theory supporting the CAPM method of determining a return rests on the premise investors require an ROR consistent with the investment's risk. Mr. Mitchell added a size premium to account for PSO's size (a small utility company) relative to the comparison groups. The computed CAPM medians indicate an ROE estimate of 11.38 percent for the proxy group. The CE test examines realized returns on common equity. This approach indicates whether a Company's ROE, based on PSO's market-to-book stock price, would be acceptable to investors. Mr. Mitchell's CE tests suggest an average of returns on common equity of 8.69 percent can support an average market-to-book ratio of 1.21, under the CE test. The average ROE from the DCF, the CAPM and the CE models results in a value of 10.33 percent. However, Mr. Mitchell made an adjustment to the ROE average in consideration of the small size of PSO in contrast to the relative size of the proxy group. This adjustment raised the average ROE of 10.33 percent to 10.88 percent. He agreed with PSO requested 6.60 percent for the cost of long-term debt and a capital structure of 55.57 percent long-term debt, 0.33 percent preferred stock and 44.10 percent common equity. With the recommendation of a ROE of 10.88 percent and PSO's recommended capital structure, he further recommended an ROR of 8.48 percent.

After the clerical error was discovered and the numbers recalculated, the results showed an estimated ROE range for PSO of 10.75 percent to 11.18 percent, which changed Staff's ROE recommendation to 10.97 percent, and the ROR to 8.52 percent.

In oral testimony, Mr. Mitchell said Mr. Purcell's recommendations were conservative but reasonable and that Mr. Lawton's recommendations were reasonable.

**Robert Thompson**

Revenue Requirement Exhibit:

Mr. Thompson recommended a revenue deficiency of $86,493,430 as shown on Line 7 of Schedule A. This finding of revenue deficiency for Public Service Company of Oklahoma (PSO or Company) incorporates Staff's recommended adjusted rate base of $1,517,523,025 and adjusted operating income of $128,685,953 and rate of return of 8.52 percent.

Accumulated Depreciation:

Mr. Thompson proposed an adjustment to update accumulated depreciation to the six-month post test year balance at August 31, 2008. This adjustment will decrease accumulated depreciation included in rate base by $11,248,507. He accepted the adjustment of the Company to his proposed accumulated depreciation of $3.2 million. The new adjusted accumulated depreciation at August 31, 2008 is $14,416,501.

Cash Working Capital:

Mr. Thompson recommended an adjustment to the cash working capital (CWC), which includes all of Staff's proposed changes to those accounts included within the cash working capital calculation. Staff determined PSO has a negative CWC requirement of $127,904,247. This adjustment will increase cash working capital included in rate base by $416,391 to be included in PSO's rate base.

Accumulated Deferred Income Tax:

Mr. Thompson recommended an adjustment to update accumulated deferred income tax to the six-month post test year balance ending August 31, 2008. This adjustment will decrease accumulated deferred income tax included in rate base by $47,907,051.

Prepaid Pension Asset:

Mr. Thompson agreed with the Company's inclusion of Prepaid Pension Asset in rate base.

<u>Factoring and Bad Debts Expense</u>:

Mr. Thompson recommended an adjustment to recalculate the factoring expense and bad debts expense adjustments proposed by the Company to reflect Staff's proposed return on equity and revenue requirement. This proposed adjustment to the factoring expense will decrease the amount requested by the Company by $1,071,976 to reflect Staff's revenue requirement.

<u>Interest Synchronization</u>:

Mr. Thompson recommended an adjustment to the interest expense within the income tax calculation to reflect changes to the rate of return and rate base. Interest synchronization is a method that provides an interest expense deduction for regulatory income tax purposes equal to the ratepayers' contribution to PSO for interest expense coverage. This adjustment for interest synchronization will increase the net income before income tax by $1,014,131.

<u>Current Tax Expense</u>:

Mr. Thompson recommended an adjustment to current income taxes to reflect Staff's adjustments to the operating income statement, resulting in a net decrease to PSO's operating income of $48,354,183.

**<u>Jason Thenmadathil</u>**

<u>Plant Investment and CWIP</u>:

Mr. Thenmadathil recommended increasing the rate base by $131,170,735 to include all plant investments providing service to customers as of August 31, 2008, which is six months after the test year. Including an updated plant-in-service balance in the rate base rather than treating it as construction work in progress (CWIP) more accurately reflects what was in service on August 31, 2008. Staff rate base adjustment No.3 decreases the rate base by $832,103 to reverse the Company's adjustment from the rate base.

With this adjustment to CWIP, Mr. Thenmadathil also adjusted plant-in-service to reflect the plant balance as of August 31, 2008, removing PSO's requested CWIP balance of $100,081,869. Due to the adjustment made to plant in service at the end of the six-month post test-year period, it is also necessary to correspondingly reduce PSO's rate base adjustment No.4 that included costs for the distribution automation program since no capital associated with this program would be included in Staff's plant balance.

The two peaking facilities located at the Southwestern and Riverside Stations were the result of Final Order No. 538439 in Cause No. PUD 200200038. The Commission made a determination in that case that the additional peaking capacity was needed, and PSO as of the date of the hearing had met the cap of $135 million set in that cause. According to PSO's response to Oklahoma Industrial Energy Consumers' data request 4-12(a) and (b), the last peaking unit to be placed in service was Riverside Station Unit #4 on June 15, 2008. The total cost for both facilities as of July 2008 was $118,390,522.

Mr. Thenmadathil also reviewed other major capital additions. These additions appeared to be reasonable. There was also a review of the budget variance reports for PSO capital spending. Actual capital expenditures did not vary significantly from budgeted capital expenditures in 2007.

Treatment of NOx Allowances:

Mr. Thenmadathil did not agree with PSO's proposal to be allowed to recover 100 percent of nitrous oxide (NOx) allowance costs through the Fuel Adjustment Clause (FAC) Rider. If allowance costs and credits were meant to provide an incentive for utilities to reduce emissions, then full automatic recovery of allowance costs from customers through the FAC would eliminate that incentive since customers, rather than shareholders, would be paying for 100 percent of the allowances. Instead, Mr. Thenmadathil recommended PSO classify NOx allowance costs as a regulatory asset for which PSO could request recovery in a subsequent rate proceeding, where a sharing of costs can be considered, if appropriate and necessary.

Additional $SO_2$ Allowances Proceeds include in base rates:

Mr. Thenmadathil's Adjustment H-12 increases expenses by $462,056 to reverse the Company's Adjustment H-29 to include additional sulfur dioxide ($SO_2$) allowance proceeds from the Environmental Protection Agency annual auction in the test year. He recommended PSO instead include these proceeds as an additional credit to the Regulatory Asset Recovery Rider. The Commission has already been determined that $SO_2$ allowance proceeds can be used as credits to the Regulatory Asset Recovery Rider in Cause No. PUD 200700397.

Test Year Storm Expenses:

The Company further proposed to normalize storm-related expenses, net of the 2007 ice storms, using a three-year average of calendar years 2005 through 2007. PSO recommended storm costs exceeding base rate levels be booked as a regulatory asset to allow for accounting of such costs and that a regulatory liability be established for storm costs that do not exceed the normalized level included in base rates. Mr. Thenmadathil agreed with this proposal, so long as there is an accounting for any cost increases or decreases via a regulatory asset or regulatory liability.

**Marvin Vaughn**

Ad Valorem Taxes:

Mr. Vaughn found that the level of ad valorem taxes included in the Company's filing was not reasonable and therefore proposed a decrease of $2,644,324 to the Company's pro forma adjustment based on the actual tax obligation as opposed to estimates used by the Company. During cross-examination, Mr. Vaughn testified to the actual tax obligation of the Company, which is lower than the amount requested by the Company.

Purchased Power:

Mr. Vaughn recommended decreasing operating expenses by $14,288,690 to remove the Company's purchased power capacity pro forma adjustment from the cost of service. Alternatively, he recommended that the Company's purchased power capacity costs be recovered through PSO's FAC, instead of a rider as proposed by the attorney general. He believed including this amount in the Company's FAC would allow the Company to recover its actual cost for purchased power capacity while allowing the Commission transparency of those costs.

**Javad S. Seyedoff**

FERC Assessment Fees:

The Company included $27,679 for fees assessed by FERC as a regulatory expense in schedule WP H-3.1 in cost of service. Mr. Seyedoff agreed with the amount of the assessment for 2007. He proposed no adjustment to the test-year end total.

Utility Assessment Fees (OCC)**:**

OCC utility assessment fees are collected by the Company and invoiced by the OCC for payment. The effect of these related transactions on the Company's books should be, and is, zero: therefore, Mr. Seyedoff accepted the Company's pro forma adjustment at schedule H-2-27 to decrease operation expenses by $892,407. He is proposed no adjustment to PSO's OCC assessment fees.

Regulatory Expense:

Mr. Seyedoff reviewed prior rate case expense amounts in schedule WP H-3.1, including those authorized in Cause No. PUD 200600285 and the Commission-approved collection time periods. The Company has included $136,668 in rate case expense for the test-year period or monthly amortization of $11,389. Mr. Seyedoff recommended no adjustment to the prior rate case expenses as requested by PSO in this proceeding.

Current Rate Case Expense:

The Company estimated its amount of current rate case expense in WP H-2-20, line 1, and WP H-13.2 at $782,500. Mr. Seyedoff recommended an amortization of two years instead of the eighteen months suggested by the Company. PSO's updated level of rate case expenses at the end of the hearing would be the level of expenses to recover over a two-year amortization period. Mr. Seyedoff's Adjustment H-6 would result in a reduction of $130,417 per year for current rate case expenses in this cause.

Postage:

The Company's pro forma adjustment of $95,054 is to increase the postal expenses for the number of regular customer billings and disconnect billings. In reference to Schedule WP H-2-30, line 7, the total customer mailings for March 2007 through February 2008 was 6,789,090; the number of customer mailings for March 2007 through May 14, 2007, was 1,358,178. United States Postal Service information indicates the two-cent postage increase is applicable for about three months (March 2007 through May 14, 2007) and the one-cent increase should only have been applied for the remaining nine months (May 2007 through February 2008) instead of twelve months. Mr. Seyedoff reduced H-7 in the amount of ($13,582) to adjust the Company's calculation of mailing expenses.

Regulatory Asset:

Mr. Seyedoff proposed no adjustment to the test-year end total. The regulatory asset approved by Commission Order No. 554328 on May 21, 2008, authorized in Cause No. PUD 200700465 (Red Rock) is the only regulatory asset the Company included in the filing. Mr. Seyedoff accepted the Company's total cost of $11,192,213.

Regulatory Liabilities:

The Company has included Independent Power Producer-System Upgrade Credits of $6,880,704 as a reduction to the rate base. Mr. Seyedoff recommended the acceptance of the Company's adjustment.

Outside Services/Attorney Fees:

Mr. Seyedoff reviewed PSO's submissions and looked for expenses not necessary to provide utility service to the customers. He further inquired into and verified numerous expenditures and performed a detailed review. Mr. Seyedoff proposed no adjustment to the total Company pro forma adjustment.

Miscellaneous General Expense:

Mr. Seyedoff's review involved non-recurring expenses and the Company's pro forma adjustment to office supplies and expenses Account 921 and miscellaneous general expenses Account 930.2. Account 930.2 includes miscellaneous general expenses; corporate and fiscal expenses; research, development and demonstration; and associated business development. He reviewed the miscellaneous general expense account for the test year, checked balances to the Federal Energy Regulatory Commission (FERC), and verified Company pro forma adjustments. He had no adjustment to the miscellaneous general expense.

**Kiran Patel**

Dues and Membership:

Ms. Patel proposed to disallow $140,522 in dues and memberships the Company had included in the cost of service. She is of the opinion that some of these costs are not entirely beneficial to the ratepayer and, therefore, should be shared between the stockholders and ratepayers. Her adjustment to H-5 is in the amount of $140,522.

Donations and Contributions:

The Company's donations and contributions were not included in the cost of service and the amount of $3600 of additional contributions was removed from the cost of service. The Company did not include any donations and contributions expenses in the cost of service. This is acceptable to Staff.

Customer Advances:

The Company's customer advances, advances for construction and customer deposits are very similar. The Company's explanation of having $0.00 balances for customer advances was reviewed. Ms. Patel had no adjustment to the Company's zero balances.

Customer Deposits:

Ms. Patel proposed an adjustment to B-4, by increasing the amount $849,401 to the Company's pro forma adjustment of $40,636,264, due to a continuous downward trend in deposit balances. She used a thirteen-month average, ending six months post test-year. Customer deposits are a form of non-investor supplied capital. The balance should be deducted from rate base, and the Company should not be able to earn a return on these deposits. The total amount of customer deposits decreased is reflected as an increase to rate base.

Interest on Customer Deposits:

Ms. Patel proposed an adjustment of ($42,579) for interest on customer deposits. She used the thirteen- month average ending August 2008 in her calculations. The Company used a balance of $40,636,294 for February 2008 for customer deposits. The Company used a balance of $1,814,919 for short-and long-term interest on the customer deposits for the test year. She then calculated the appropriate amount of customer deposits to be $39,786,863 and interest on the customer deposits to be $1,722,340. Applying the thirteen-month average ending August 2008, it was determined that the effective rate for long term interest was 4.70 percent and 3.91 percent for short-term interest. Ms. Patel applied the effective rate by multiplying it by the thirteen-month average of customer deposits ending August 2008, which resulted in a reduction of $42,579.

Miscellaneous Taxes:

Ms. Patel did not propose any adjustment to miscellaneous taxes after verifying these items and reviewing the laws under which they were assessed.

**George Kiser**

Pension Expense:

Mr. Kiser reviewed calculations of the pension expense adjustment proposed by PSO by comparing the calculations to the format approved in Cause No. PUD 200600285. The actuarial report used appeared consistent with the format approved in Cause No. PUD 200600285. The final actuarial amounts were reasonable and Mr. Kiser found no appreciable change. There were no changes proposed to the pension expense adjustments made by the Company.

Employee Medical Expenses:

Mr. Kiser made no adjustments to medical expenses since no adjustments had been proposed by Staff to PSO's adjusted payroll expense. Had Staff proposed changes to payroll there would be changes to the proposed medical expense. Employee medical expense is usually tied to a payroll change or the change in medical expense costs.

Employee Benefit Expenses:

Mr. Kiser also reviewed the employee benefits expense adjustment proposed by PSO which required the review of PSO's prior cause of the employee benefits expense. He reviewed the current cause for consistency with the prior cause, Cause No. PUD 200600285, and proposed no adjustment for employee benefits expense.

**Scott Grass**

Mr. Grass reviewed off-system sales trading deposits, prepaid expenses, repairs and maintenance expenses, research and development expenses, and generation operations and maintenance expenses. He recommended the amounts, as proposed by the Company, and is of the opinion that these adjusted amounts are fair, just, and reasonable. Furthermore, these adjusted amounts are in the public interest and should be approved.

**Sharon Fisher**

Ms. Fisher verified the sources used to support the Company's need for rate relief as stated in its application. Through independent analysis, she was able to verify financial data used to make certain calculations for the period of 2006-2007 was available in the public domain. Some of the public information is within the Company's report to the Securities and Exchange Commission, and some was obtained via the Company's website where it was listed as quarterly reports. The calculations discussed were based on that information and are correct. She verified the information through independent sources where possible.

The source of the information that could not be verified through public information was forecasted data that was derived from the Company's budget and expenses and was not publicly held or obtainable, which includes information for 2008-2009. Ms. Fisher does not make a recommendation in this area.

**Karen Forbes**

Vegetation Management / Underground Program:

Ms. Forbes reduced PSO's $7.7 million increase in base rates for recovery of distribution vegetation management costs and in its place, proposed a new rider to reflect two annual spending caps for recovery efforts between the tree trimming and undergrounding activities. The basis and justification for this proposed modification is addressed in the responsive testimony of James L. Jones.

Weather Normalization:

Ms. Forbes accepted the Company's weather normalization adjustment for weather non-fuel base revenues included in the cost of service.

Fuel and Off System Sales Revenues:

Ms. Forbes accepted PSO's adjustment to exclude fuel and related off-system sales revenues from the cost of service. This adjustment is in line with the OCC-approved FAC to allow fuel costs to be recovered in the clause.

Unbilled Revenues:

Ms. Forbes accepted the unbilled revenues recorded for the test year ending February 29, 2008, that were removed from the amounts included in the cost of service.

Advertising Expenses:

Ms. Forbes removed $54,723 from the total Company pro forma level for advertising campaigns and associated costs included within the operations and management expense in the test year.

Marketing and Sales Expenses:

Ms. Forbes removed $27,650 of marketing and sales expenses PSO included in the cost of service. This adjustment removed test-year marketing and sales expenses that she believed promoted the Company to improve its public image.

Legislative Advocacy:

Ms. Forbes accepted the Company's treatment to exclude test year legislative advocacy expenses from the cost of service. These expenses are not a necessary cost of providing utility service.

Associated Business Development Expense:

Ms. Forbes accepted the Company's pro forma adjustment that reflects a net reduction margin to its rate base revenue requirement for an on-going level of ABD associated business development expense activities.

Fleet Vehicle Fuel:

Ms. Forbes accepted the Company's fleet vehicle fuel adjustment. She reviewed the general ledger costs by months as well as verified retail gasoline and diesel costs and quantities incurred during the test year. Upon the completion of her review, she determined the fleet fuel adjustments were consistent with the Energy Information Administration (EIA) Midwest region for Oklahoma retail motor prices. During oral surrebuttal, Ms Forbes accepted PSO's witness, John Aaron's testimony urging reversal of the $583,307 fleet vehicle fuel adjustment, in light of the significant drop in gasoline and diesel fuel prices from the time of Staff's prefiled testimony, which accepted PSO's fleet vehicle fuel adjustment.

**Tonya Hinex-Ford**

Ms. Hinex-Ford prepared prefiled testimony addressing smart grid technology, which includes smart meters and its future implementation in the State of Oklahoma. She concluded from her research that there is not an industry agreed upon definition of smart grid, but, there are general characteristics defined by the FERC. Ms. Hinex-Ford recommended a notice of inquiry be opened to further investigate whether the electric utilities have considered investment in a smart grid system prior to making further investment in non-advanced grid technologies. Ms. Hinex-Ford did not make a recommendation specific to PSO and her testimony was admitted without cross-examination.

**James L. Jones**

Reliability Cost Adjustment Rider:

In this cause, PSO proposed a $7.7 million pro-forma adjustment, outlined in WP H-2-27, to increase base rates to recover some of the expenses associated with vegetation management. Through the current RCA Rider, vegetation management expenses and the carrying charges associated with the conversion of overhead conductor to underground compete for RCA Rider revenues. As carrying charges increase, there are fewer dollars to cover vegetation management expenses under the current RCA Rider cap. Mr. Jones disagreed with PSO's adjustment and, instead, proposes to eliminate the existing RCA Rider and establish a new Reliability Vegetation/Undergrounding (RVU) Rider with two caps. The proposed rider would have one cap ($23.685 million) for vegetation management activities and a separate cap ($6 million) for the carrying charges associated with the conversion of overhead conductor to underground. Mr. Jones also proposed that PSO direct some of its new capital expenditure towards other network hardening activities, in addition to vegetation management and undergrounding.

Proof of Revenues:

Mr. Jones compared PSO's current tariffs with the tariffs filed in this cause, as well as, reviewed the proof of revenue workpapers (WP M-4-1) for all classes of customers. He discovered that the language in the Residential and Commercial Net Metering Tariff altered the tariff's application. Staff also discovered tariff rates were inconsistent with WP M-4-1. On August 27, 2008, PSO filed an errata correcting these discrepancies.

**David W. Smith**

Mr. Smith recommended Staff's proposed revenue distribution be approved because it moves classes closer to the cost to serve them-- the parity rate--and continues Staff's policy of moving classes towards parity.

Mr. Smith recommended interested parties and stakeholders start discussions to form a policy to move classes towards the rate of parity with the goal to eliminate/mitigate inter class cross subsidization.

Mr. Smith recommended the rejection of PSO's proposed reactive power charge increase from $0.31 and $0.33 to $3.33 per kilovolt-ampere reactive power (KVAR0 beyond 30 percent because the increases are based on estimates.

BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

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|---|---|---|
| APPLICATION OF PUBLIC SERVICE<br>COMPANY OF OKLAHOMA, AN<br>OKLAHOMA CORPORATION, FOR<br>AN ADJUSTMENT IN ITS RATES AND<br>CHARGES FOR ELECTRIC SERVICE<br>IN THE STATE OF OKLAHOMA | )<br>)<br>)<br>)<br>)<br>) | CAUSE NO. PUD 200800144<br><br><br><br>ORDER NO. |

HEARING: December 8, 2008 through December 17, 2008
Before the Commission *en banc* with Maribeth D. Snapp, Referee

APPEARANCES: Jack P. Fite, Joann T. Stevenson, Rhonda C. Ryan and Philip F. Ricketts, Attorneys for Public Service Company of Oklahoma
Elizabeth Ryan, Whitney Weingartner and William L. Humes, Assistant Attorneys General for Office of Attorney General, State of Oklahoma
Thomas P. Schroedter, Grayden Dean Luthey, Jr. and J. Fred Gist, Attorneys for Oklahoma Industrial Energy Consumers
Lenora F. Burdine and James L. Myles, Deputy General Counsels, Elizabeth J. Stefanik, Christian D. Szlichta and Don A. Schooler, Assistant General Counsels for Public Utility Division, Oklahoma Corporation Commission
Lee W. Paden, Attorney for Quality of Service Coalition
Rick D. Chamberlain, Attorney for Wal-Mart Stores East, LP
Deirdre O. Dexter, Nancy J. Siegel and Mary Lockhart, Attorneys for City of Tulsa
Robert W. Dace and Robert A. Weishaar, Jr., Attorneys for Gerdau Ameristeel Corporation

# FINAL ORDER

BY THE COMMISSION:

The Corporation Commission of the state of Oklahoma ("Commission" or "OCC"), being regularly in session and the undersigned Commissioners being present and participating, there comes on for consideration and action, the application of Public Service Company of Oklahoma ("PSO" or "Company") to adjust its rates and charges for electric service in the State of Oklahoma.

## PROCEDURAL HISTORY

On May 15, 2008, PSO filed with this Commission its Notice of Intent pursuant to OAC 165:70-3-7, that it intended to file an application seeking to implement a plan that would modify the rates and charges for PSO's Oklahoma jurisdictional customers.

On May 21, 2008, the Oklahoma Industrial Energy Consumers ("OIEC") filed its Motion to Intervene and the Attorney General of Oklahoma ("AG" or "Attorney General") filed their Entry of Appearance on May 29, 2008. On May 29, 2008, the Quality of Service Coalition ("QOSC") filed a Motion to Intervene. On June 3, 2008, the Commission issued Order Nos. 555050 and 555051 granting OIEC's and QOSC's Motions to Intervene. Wal-Mart Stores East LP ("Wal-Mart") filed a Motion to Intervene on August 12, 2008, which was granted by the Commission by Order No. 559085 issued on September 5, 2008. The City of Tulsa filed a Motion to Intervene on August 27, 2008, which was granted by Commission Order No. 559352 on September 4, 2008. The U.S. Department of Defense filed a Motion to Intervene on October 9, 2008, and filed a Motion to Withdraw on November 3, 2008. The Commission entered an Order approving the withdrawal of the U.S. Department of Defense in Order No. 562120 issued November 6, 2008.

On July 11, 2008, PSO filed its Application and supporting documentation basing its request for a general rate change upon a test year ending February 29, 2008.

On July 11, 2008, PSO filed a Motion for Protective Order which was granted by Commission Order No. 557177 on July 17, 2008.

PSO tendered with the filing of its Application its complete Application Package pursuant to OAC 165:70-3-1. Concurrent with the filing of its Application Package, PSO provided to the OCC its Supplemental Application Package pursuant to OAC 165:70-5-20. Along with its Application, PSO filed the direct testimony of Michael Morris, Stuart Solomon, David P. Sartin, Donald A. Murry, John O. Aaron, Preston S. Kissman, E. Kevin Bethel, David A. Davis, Hugh E. McCoy, David A. Jolley, Donald R. Moncrief, and Kathy J. Champion.

On October 9, 2008, the various parties filed their Lists of Major Issues.

Gerdau Ameristeel ("Gerdau") filed a Motion to Intervene on October 24, 2008, which was granted by Commission Order No. 561848 on November 30, 2008.

On October 29, 2008, PSO filed an Errata to the proposed service charges.

On October 31, 2008, PSO filed a Motion to Determine Notice, after which the Commission issued Order No. 562384 on November 20, 2008, determining notice.

Both PSO (for Philip F. Ricketts and Rhonda C. Ryan) and Gerdau (for Robert A. Weishaar, Jr.) filed Motions to Associate Counsel which were granted by the Commission. The Commission issued Order Nos. 562383, 562898, 562899 approving the Motions.

A Settlement Conference was held on December 1, 2008, pursuant to the Procedural Schedule. A pre-hearing conference which included the exchange of exhibit lists and witness summaries was held on Tuesday, December 2, 2008. On December 5, 2008, the issue spreadsheet was submitted by the parties.

The Hearing on the Merits began Monday December 8, 2008.

The Staff has filed all public comments accumulated to date. Additionally, at the Hearing on the Merits, time was allotted daily for citizens to make public comment, and certain citizens did make such comment on the record.

## SUMMARY OF EVIDENCE

The summary of testimony of each of the witnesses is attached hereto as "Attachment A" and is incorporated herein by reference.

## FINDINGS OF FACT AND CONCLUSIONS OF LAW

A. Jurisdiction

PSO is an Oklahoma corporation authorized to do business in the state of Oklahoma. The Commission finds that PSO is a public utility with plant, property, and other assets dedicated to generation, production, transmission, distribution, and sale of electric power and energy within the state of Oklahoma. This Commission has jurisdiction over this Cause by virtue of the provisions of Article IX, Section 18 of the Constitution of the State of Oklahoma, 17 O.S. §§ 151 *et seq*., and the Rules and Regulations of this Commission, including the Commission's Minimum Standard Filing Requirements ("MFR") as set forth in OAC 165:70. Due and proper notice of these proceedings was given as required by law and the orders of this Commission.

B. Test Year

The test year in this cause is a twelve month period ending February 29, 2008. The Commission finds that 17 O.S. § 284 requires the Commission to give effect to certain known and measurable changes occurring or reasonably certain to occur within six-months of the test year-end. Many of the Staff, Attorney General, and OIEC adjustments updated rate base and operating income accounts to the actual balances in those accounts at August 31, 2008, which is six-months after the test year. PSO was critical of this approach asserting that it is inappropriate to update some accounts and not others and argued that if the Commission were going to update the test year it should update all accounts. PSO took the position that if the Commission were to accept adjustments updating six-months post-test year, there are additional adjustments that need to be made to reach the correct result. Aaron, Dec. 12 Tr. p. 38.

The Commission finds the concept of "Known and measurable" is most easily applied to categories such as plant in service and accumulated depreciation, since those can be utilized as "booked numbers", without adjustments to normalize them. In contrast, expenses and revenue are typically "normalized" using what can sometimes be a subjective methodology. Arguably, if something is "known and measurable" all parties should be in general agreement regarding the quantification of the amount. The concept behind updating for "known and measurable changes" is to have rates based upon the levels of expenses, revenues and rate base that will most likely be reflective of the expenses and revenue during the time that rates are in effect. Accordingly, adjustments to expenses and revenues, which fluctuate based upon the number of customers, the weather, the time of year, etc., should be closely reviewed to make certain the normalization methodology captures the best possible estimate of future expenses and revenues. The Commission finds that simply "updating" expenses and revenues to the six-month post-test year period, without an analysis regarding the reasons for the change since test year-end, has the potential for creating a new test year that has incomplete and/or mismatched information within it.

C. Rate Base

1. Plant in Service

a) Utility Plant.

The Company proposed to include in rate base the gross amount of utility plant in service at the February 29, 2008, test year-end of approximately $3.374 billion.

OCC Staff, the AG and OIEC updated plant in service amounts to August 31, 2008. The Staff and the AG recommend a total electric plant balance of approximately $3.505 billion. OIEC recommends an approximate $3.447 billion total electric plant in service balance. The Staff, the AG, and OIEC argued that 17 O.S. § 284 requires an update to reflect known and measurable plant balances at the end of the six-month post-test year period.

The Commission finds that plant balances are clearly known and measurable at the end of the six-month post-test year period. All projects actually completed and in service within six-months of test year-end should be included in rate base**.** Also, all off-setting decreases in the plant investment levels – in effect, all changes in the Accumulated Depreciation accounts should be recognized as well. With this approach, PSO's adjustment to include Construction Work in Progress ("CWIP") at test year-end is not needed. With the 6-month update, all CWIP projects completed by August 31, 2008, are included in the adjustment. The Commission finds that the Utility Plant in service balance as of August 31, 2008, should be adopted as the Utility Plant in service to be included in the rate base in this Cause. There were some differences between the August 31, 2008, amounts proposed by the interveners and the Commission finds that, as Company witness Aaron's Rebuttal Testimony indicates at p. 13, the actual plant in service balance at August 31, 2008, is $3,506,142,455. This includes both Plant in Service recorded in FERC Account 101 and Completed Construction Not Classified recorded in FERC Account 106.

b) Construction Work in Progress ("CWIP").

Since the Commission has adopted the Utility Plant in service balance as of August 31, 2008, the Commission finds that no CWIP should be included in the rate base of PSO. No adjustment is necessary to reflect this decision, since the booked utility plant in service as of August 31, 2008, captures all CWIP requested for those plants that were actually placed in service as of August 31, 2008.

2. Accumulated Depreciation

PSO requested to include as a reduction to rate base the February 29, 2008, balances of the Accumulated Depreciation recorded in FERC Account 108 and the Accumulated Amortization of intangible plant recorded in FERC Account 111. The accumulated depreciation in Account 108 was $1,416,538,946 and the Accumulated Amortization in Account 111 was $40,511,990 for a total of $1,457,050,936.

The OCC Staff recommended an $11,248,507 increase to Accumulated Depreciation, the AG recommended a $14,416,501 increase to Accumulated Depreciation, and the OIEC recommended a $17,685,381 increase to Accumulated Depreciation. All three recommendations relied upon a six-month post-test year update. The adjustment proposed by the AG results in the actual book balance at August 31, 2008. The adjustment to Accumulated Depreciation proposed by the OCC Staff, according to PSO, was understated by approximately $3.2 million. Aaron Rebuttal p. 16. The OCC Staff's adjustment included $3,467,071 accumulated amortization on Plant Acquisition Adjustments for which the associated asset is not included in PSO's rate base and excludes $6,635,064 accumulated depreciation for Asset Retirement Obligations recorded in FERC Account 230.

The Commission finds that since the August 31, 2008, plant investment is adopted, the adjustment recommended by the AG should be adopted and the amount of total accumulated depreciation and amortization of $1,471,467,436 is the appropriate level of accumulated depreciation and amortization. That amount reflects the actual changes that have occurred consistent with the changes in total plant in service. Aaron Rebuttal pp. 16-17.

3. Pre-Paid Pension Obligation

PSO included approximately $77.7 million in prepaid pension assets, the 13-month average balance at February 29, 2008, in rate base.

OCC Staff witness Thompson agreed with PSO's inclusion of the prepaid pension asset in rate base. Thompson Responsive Testimony p. 17. OIEC witness Garrett recommended removal of the prepaid pension asset from PSO's rate base. OIEC allowed, however, an annual 6.6% long-term debt return on the amount in PSO's cost of service on the basis that PSO should not be allowed to recover more than the cost of making the contribution. Aaron Rebuttal at p. 20.

The Commission adopts OIEC's recommendation to reduce PSO's proposed rate base by the balance in this account and increase operating expense by an amount equivalent to a cost of debt return on the balance. The effect of this adjustment is to provide a cost-of-money return, as opposed to a full rate base return, on these discretionary contributions.

The Commission finds that the amount of $77,686,018 should be removed from the Company's proposed rate base, consistent with the recommendation of OIEC. (Garrett Surrebuttal Testimony beginning at p. 176; Hearing Ex. 4.) The deferred taxes of $26,548,865, associated with the prepaid pension balance were removed from the Accumulated Deferred Income Tax adjustment, based upon the rate base amount at August 31, 2008. A cost of money return of 6.6% should be applied to the net prepaid pension balance removed of $50,495,912. *Id.* This results in an increase in operating expense of $3,332,730 (50,495,912 x 6.6%). *Id.*

4. Other Prepayments

The Attorney General reduced rate base by $722,665 by taking a 13-month total average balance of other prepayments through August 31, 2008. Neither Staff nor OIEC recommended an adjustment to PSO's proposed level of prepayments. PSO argued that the AG's recommendation to update the prepaid balances to August 31, 2008, recognized reductions in the prepayment balances for expense amortization that had not been included in PSO's cost of service. PSO further argued that the items removed by the AG represent reasonable prepaid costs incurred by PSO in the normal course of its business and so should be included in the Company's test year-end rate base.

The Commission finds that no adjustment to the Other Prepayments of PSO is required. The basis given for the AG's adjustment was to utilize the average balance of other prepayments at August 31, 2008, but no explanation was given regarding why the 13 month average of prepayments at August 31, 2008, is more likely an accurate reflection of the ongoing expense PSO will incur for these types of expenses, than the 13 month average at February 29, 2008. In the absence of an analysis to examine the reasons behind the changes, the Commission finds that the adjustment recommended by the AG does not reflect a "known and measurable change" and should therefore not be adopted.

5. Materials and Supplies

PSO included in its rate base the 13-month average balance of materials and supplies through February 29, 2008. Because the materials and supplies balance varies over time, a 13-month average balance is required by OAC 165:70-5-22(4) to be filed in the Minimum Filing Requirements.

The Attorney General and OIEC recommended updating the materials and supplies balances to August 31, 2008, but provided no analysis regarding whether the 13 month average at August 31, 2008, is more likely an accurate reflection of the ongoing expense PSO will incur for these types of expenses than the 13 month average at February 29, 2008. The Staff did not recommend an adjustment to PSO's filed level of materials and supplies. In the absence of an analysis to examine the reasons behind the changes, the Commission finds that the adjustment recommended by the AG and OIEC does not reflect a "known and measurable change" and should therefore not be adopted. The Commission therefore adopts the Company's proposed amounts for materials and supplies.

6. Fuel Inventories

PSO included in rate base the optimal target tons of coal required of PSO's coal fired plants and a 13-month average through February 29, 2008, for the oil and gas inventories. PSO testified that its pro forma adjustment to reflect PSO's target level of coal inventory appropriately balances the cost of building and maintaining fuel reserves against the risk of running out of fuel and experiencing shortage costs. OIEC witness Mr. Garrett updated the balances to reflect the six-month post-test year period ending August 31, 2008, resulting in an increase to fuel inventory of $2,771,748. Ms. Soltani made a similar adjustment resulting in an increase to fuel inventory of $2,610,781.

Staff did not make an adjustment to PSO's proposed fuel inventories.

In the absence of an analysis to examine the reasons behind the changes, the Commission finds that the adjustment recommended by the AG and OIEC does not reflect a "known and measurable change" and should therefore not be adopted. The Commission therefore adopts the Company's proposed amounts for fuel inventories.

7. Customer Deposits

PSO reduced rate base for the $40.6 million of customer deposits recorded on its books at February 29, 2008, the test year-end. Staff and the AG recommended an additional $849,401 decrease to customer deposits to reflect the 13-month average balance of customer deposits through August 31, 2008, because there has been a continuous downward trend in customer deposit balances. OIEC recommended an additional decrease of $173,904 to rate base to reflect the difference between the February 29, 2008, and the August 31, 2008, balance of customer deposits on PSO's books.

A customer deposit represents funds provided by the customer rather than the investor. Thus, it is appropriate to remove these funds from PSO's rate base so that PSO does not earn money on funds provided by customers. The analysis performed by Staff and the AG appropriately identifies a known and measurable change in the balance of customer deposits. The Commission is not convinced however that this downward trend will continue, due to economic changes which have occurred since August 31, 2008. Although the Commission is mandated to adopt known and measurable changes that occur within the 6 months post-test year, the Commission also has the option of going beyond the 6 months post-test year to consider appropriate adjustments. Therefore, the Commission declines to adopt the recommended adjustments to customer deposits and finds that rate base should be reduced by $40,636,264 rather than by the $39,786,863 reduction recommended by Staff and the AG.

8. Sales Trading Deposits

PSO added $9,984,413 of Off System Trading Deposits to rate base, which represents the net amount of funds on its books at February 29, 2008, the test year-end, which were deposited by and with PSO for its off-system purchase and sales activities. During the test year, PSO had more funds on deposit with counterparties than it required from counterparties, resulting in the test year rate base addition. These funds are required both by PSO and of PSO as security for purchase and sales activities. No party suggested an adjustment to PSO's proposal. The Commission finds that customers benefit from off-system trading and therefore approves this adjustment.

9. IPP System Upgrade Credits

The independent power producers ("IPPs") transmission credits of $6,880,704 represent funds deposited with PSO by the IPPs to offset the transmission system upgrades necessary to interconnect the IPPs with PSO's transmission system. These funds were supplied by the IPPs as required by FERC Order 2003, and not supplied by PSO's investors. PSO proposed a reduction in rate base in the amount of $6,880,704 to remove these funds from rate base. No party suggested an adjustment to PSO's proposal. The Commission finds there should be a reduction to PSO's rate base consistent with PSO's proposed adjustment.

10. Cash Working Capital ("CWC")

PSO reduced its rate base by approximately $128.3 million to reflect the negative CWC allowance determined by a lead-lag study based on the 12-month period ending February 29, 2008. Staff proposed an adjustment to CWC which would reduce the amount of CWC removed from rate base by $416,391. OIEC proposed to reduce rate base by CWC in the amount of $9,683,861. Both Staff's proposed CWC adjustment and OIEC's proposed CWC adjustment reflect their respective proposed changes to those accounts included within the CWC calculation.

PSO maintained that the final CWC amount should reflect the level of expenses approved by the Commission in this proceeding. The Commission finds that the CWC in this Cause should be calculated utilizing the amounts adopted by the Commission for those accounts included within the Company's CWC calculation methodology. Since CWC is a negative allowance, the result of that calculation is a $124,455,821 reduction to rate base.

11. Accumulated Deferred Income Taxes ("ADIT")

PSO deducted the February 29, 2008, test year-ending net ADIT balance of $468.2 million from rate base as required by the OCC Minimum Filing Requirements. OAC 165:70-5-4(d)(3)(B)(iii). Adjustments were made to the February 29, 2008, balances to remove ADIT related to items that are not included in PSO's rate base. Aaron Rebuttal at p. 27.

Staff, AG, and OIEC all recommended increasing ADIT by $47.9 million to reflect the six-month post-test year amount at August 31, 2008. The large increase is due to approximately $18.8 million ADIT recorded in March of 2008 associated with PSO's deferred ice storm costs and approximately $17 million ADIT PSO began recording in April of 2008 related to bonus depreciation associated with the Economic Stimulus Act of 2008. These two deferred tax items were not included in PSO's original base rate revenue requirement calculation. Mr. Aaron did agree that $47.9 million ADIT was the adjustment at August 31, 2008, unless OIEC's recommendation to exclude PSO's prepaid pension asset from rate base is adopted by the Commission, in which case PSO's ADIT balance at August 31, 2008, should be reduced by $26,548,865 to reflect the exclusion of the prepaid pension asset from rate base. Aaron Rebuttal p. 28 and Garrett Ex. MG-25R, Dec. 15 Tr. p. 171). If the Commission adopts PSO's calculation of rate base as of February 29, 2009, there is no need for an adjustment to ADIT.

The amount of ADIT is a booked number which does not require the use of subjective methodologies to calculate and the amount of ADIT as of August 31, 2008, reflects several easily identified changes which occurred within the six-months post-test year. The Commission therefore finds the increase to ADIT in rate base is a known and measurable change that should be made. Since the Commission adopted the adjustment recommended by OIEC to remove PSO's prepaid pension asset from rate base, the Commission finds that PSO's ADIT balance at August 31, 2008, should be reduced by $26,548,865.

12. Capitalized Incentives

PSO disagreed with the adjustment proposed by OIEC witness Mark Garrett to reduce rate base $3.2 million for capitalized incentives, which was the amount OIEC indicated had been capitalized since the Commission updated PSO's rate base to December 31, 2006, in PSO's last rate case. OIEC used 50% of the amount of executive incentives, which OIEC stated was a more conservative adjustment, because the Company does not track executive incentives separately in rate base.

The Commission makes no finding in this Cause that PSO's incentive compensation costs are unreasonable and therefore declines to adopt the adjustment proposed by OIEC.

13. Blanket Funded Capital Additions

OIEC witness, Mr. Norwood testified that PSO failed to provide documentation to justify approximately $310 million (69.8%) of the total capital investment which it is seeking to place in rate base in this case as part of the projects funded by "blanket funding." In light of this failure, Mr. Norwood recommended that PSO's plant in service balance in this case be reduced by $47,936,678, which is equivalent to 25% of the total expenditures for capital projects subject to blanket funding. Moreover, he recommended that that the Commission order PSO to file capital project requisition forms for all capital projects whose cost is $500,000 or more, along with summary information documenting the nature, cost and justification for all projects having a budget of more than $150,000, along with its direct testimony in all future base rate cases.

PSO Witness John Aaron explained in his rebuttal testimony that PSO has identified certain types of projects that are routine work and best controlled at an aggregate total dollar level rather than a project by project level Aaron Rebuttal at p.35. Accordingly, funding is approved by the Board of Directors in a blanket capital improvement requisition. A blanket capital improvement requisition is a formal request for annual authorization of capital expenditures expected to be completed within the calendar year for which they are authorized. Examples include the purchase of meters and transformers, normal customer services and upgrades, and asset improvements. These activities are routine and repetitive for PSO but not predictable in exact detail. Decisions about such projects are made by the employees in the field where the work needs to be performed. *Id.*

Blanket authorizations are established for each AEP operating company, including PSO, and grouped by the type of expenditure or functional business area within those companies. In January, the Board of Directors of PSO approves the budgeted amount included in the various blanket funding requests for use in that year. Company managers then approve expenditures under the blankets up to a pre-determined amount. A separate Capital Improvement Requisition ("CI") must be prepared for an individual project that exceeds the blanket limitation. Blanket requisitions provide management the discretion within the approved amount to prioritize and allocate funds to complete planned and unplanned projects. This process provides management the flexibility when needed to reallocate funds to projects as necessary and provides the necessary cost control. *Id.* at pp. 35-37.

Based upon a review of the prefiled testimony and the testimony given during the hearing, the Commission finds that PSO has adopted an administratively effective method for dealing with routine expenditures necessary to provide safe and reliable service to its customers. Adequate safeguards appear to be in place to ensure that PSO's management reviews expenditures needed to restore service, maintain meters, and do the myriad of other routine services that are covered by the blanket project funding. Accordingly, the Commission finds that no adjustment to the blanket funded projects should be made and declines to adopt the $47.9 million reduction to blanket projects recommended by OIEC.

14. Red Rock Regulatory Asset

The Red Rock Regulatory Asset represents $10,508,157 of pre-construction and engineering funds expended by PSO for the cancelled Red Rock facility and related carrying costs of $684,056 for a total of $11,192,213. In PUD 200700465, PSO requested the Commission to allow PSO to defer the prudently incurred Red Rock pre-construction and engineering costs carrying charges and recover those costs in rates. Order No. 554358 issued in PUD 200700465 allowed PSO to defer as a regulatory asset a total of $10,508,157 and, beginning with March 1, 2008, to accrue a carrying cost equal to PSO's AFUDC rate until the regulatory asset is recovered in base rates. Thus, in this filing PSO has included the regulatory asset and the carrying costs that will accrue through January 31, 2009, in rate base. No party took issue with PSO's proposal and the Commission finds this adjustment should be adopted.

15. Distribution Automation

No party disagrees that $1.335 million of the $2 million Distribution Automation project that was in service by August 31, 2008, should be included in the rate base. *See* Dec. 15 Tr. at pp. 101-102 (Kissman Direct) and Kissman Rebuttal at p. 13. Since the Commission has adopted the plant in service as of August 31, 2008, the Commission finds that no additional adjustment is necessary to cause the $1.335 million of the Distribution Automation project to be included in rate base.

D. Rate of Return

1. Capital Structure

The Commission finds that all parties agree the actual capital structure for PSO is 44.1% common equity, 0.33% preferred stock, and 55.574% long-term debt. As of February 29, 2008, the capital structure for PSO includes $712,861,433 in common equity, $5,261,700 in preferred stock, and $898,330,122 in long-term debt.

2. Cost of Capital

a) Cost of Debt and Preferred Stock

The Commission finds the parties agree that PSO's embedded cost of long-tem debt is 6.60% and the cost of preferred stock is 4.02%.

b) Return on Equity

Four witnesses testified to the appropriate ROE: Dr. Murry for PSO, Mr. David Parcell for OIEC, Mr. Dan Lawton for the AG, and Mr. Fairo Mitchell for the Staff. PSO argued that an appropriate ROE for PSO would be 11.25%, which was the bottom of the 11.25% to 11.75% range of ROE Dr. Murry found to be reasonable for PSO. OIEC argued that an appropriate ROE for PSO would be 9.5%, which was within the range of 8.9% to 10.5% calculated by Mr. Parcell as the range for an ROE from the results of his DCF, CAPM, and CE analyses. The AG argued that the ROE for PSO should be set at 10.0%, which was within the range of 9.5% to 10.3% calculated by Mr. Lawton. Staff recommended that the ROE for PSO be set at 10.97%, which was within the ROE range of 10.75% to 11.18% calculated by Mr. Mitchell, by performing a DCF analysis, a CAPM analysis, and a comparable earnings test. Wal-Mart and QOSC requested the Commission adopt the 10.0% ROE recommended by the AG.

A complete discussion of the various methodologies for determining ROE is set forth in the summary of the testimony of each witness, which is contained in Attachment A to this Order. For that reason, the Commission will not repeat all the arguments of the parties regarding an appropriate ROE in this section of the Order. Based upon all the arguments of the parties and the testimony of the witnesses, the Commission finds that a ROE of 10.5% should be adopted for PSO. This ROE, although higher than the ROE recommended by the AG, OIEC, QOSC and Wal-Mart, and lower than the ROE recommended by PSO and the Commission Staff, is reasonable and is within the range recommended by the various parties for ROE.

Although only PSO argued that the Commission should give consideration to the current financial markets in determining an appropriate ROE for PSO, the Commission recognizes that the uncertainty of the economic markets for at least the near future may have a negative impact on the expectations of investors. The Commission desires that PSO be able to raise the capital it needs to maintain its infrastructure in a safe and reliable manner and implement the Demand Side Management Programs recommended by the Commission. The Commission believes that an authorized ROE of 10.5% will allow the company the opportunity to quickly begin implementing the capital projects necessary to accomplish these goals.

3. Overall Rate of Return

The overall rate of return that results from the capital structure and cost of capital determined above is 8.31%.

| Description | Capital Ratio | Cost Rate | Weighted Avg. Cost |
|---|---|---|---|
| Long Term Debt | 55.574% | 6.60% | 3.67% |
| Preferred Stock | .0326% | 4.02% | 0.01% |
| Common Equity | 44.100% | 10.50% | 4.63% |
| Total Capital | 100.00% | | 8.31% |

E. Expenses

1. Overhead to Underground/Vegetation Management Adjustment

PSO proposes to increase base rates by $7.7 million for additional vegetation management costs. PSO is currently authorized to recover $23.685 million per year of vegetation management cost through the Reliability Cost Adjustment ("RCA") Rider. OCC Staff witness Jim Jones recommended two separate funding levels, one for the recovery of vegetation management expenses and the other for the recovery of costs attributable to converting overhead lines to underground. When cross-examined, PSO witness Pressman Kissman agreed with Mr. Jones' recommendation, which would authorize the modification of the existing rider to include two separate funding caps, one for vegetation management and one for underground carrying charges.

On November 19, 2008, PSO filed rebuttal testimony announcing the delay of any future conversion of overhead distribution to underground until such time as the economy recovers from its current distressed condition. (Rebuttal Testimony of David P. Sartin, November 19, 2008, page 7, lines 5-11; Rebuttal Testimony of Preston Kissman, November 19, 2008, page 4, lines 11-23 and page 5, lines 1-3). During cross examination about this adjustment, PSO witness Kissman stated that none of the requested $7,700,000 had been spent during the test year or during the 6 months following the test year and that "It's something in the future that would happen. It hasn't happened at this point" (Transcript, December 15, 2008, page 44, lines 2-3).

QOSC argued that the recovery of $7.7 million in additional expenses associated with PSO's intention to increase the amount of conversion of overhead distribution to underground in the future, should not be allowed in this Cause, because of the Company's stated intention to delay such conversion for an unspecified time. Instead, QOSC recommended that PSO be required to file a new cause to recover any additional expenses associated with undergrounding distribution lines, after PSO has recommenced its efforts to increase conversion of overhead distribution to underground above the level of conversion that occurred during the test year.

Although PSO has indicated there will be a delay in the increased conversion of overhead distribution lines to underground, the Commission encourages PSO to re-examine the suspension of the conversion of overhead distribution facilities to underground facilities because the Commission is convinced that enhanced reliability will occur while also reducing operations and maintenance costs over the long term, when lines are undergrounded. The Commission finds that PSO should be authorized to recover up to $7.7 million annually for the carrying charges associated with such conversion through the modification of the existing rider as recommended by Staff witness Jones. It is important that the Company manage its vegetation so that the distribution system is on a 4 year trim cycle, as required by the Commission's rules and previous Commission orders. Additionally, it is important that PSO accelerate its overhead to underground conversion in order to reduce outages during ice storms and otherwise increase the reliability of PSO's distribution system. The RCA rider in its current form, because of the funding conflict, will eventually result in either preventing PSO from achieving a four-year trim cycle of vegetation management or reducing or eliminating the overhead to underground conversion activities. Recovery of the overhead conversion expenses through a rider rather than through base rates, will ensure that the ratepayers do not pay any costs for the conversion until such time as the conversion actually occurs. Increasing the existing cap on the RCA Rider, so that there are separate caps for vegetation management and for overhead conversion, will enable the company to better decide how to increase the reliability of its system, without having to cut back on its vegetation management program in order to perform additional overhead conversion. Staff's proposal of a new rider, with two separate components, represents an effective resolution to the current conflict for dollars in the RCA rider.

The Commission adopts OCC Staff witness Jones' recommendation that the existing rider be modified to include two separate funding caps, one for vegetation management, and one for underground carrying charges, which would allow for the recovery of an additional $7.7 million in vegetation management costs as proposed by PSO. The Commission further finds that the RCA rider, as amended by this order, shall contain the same class allocation methodologies as are provided for in the current vegetation management rider.

Staff Witness Jones made recommendations with respect to system hardening, including burying customer service drops or studying the "Service Entrance Disconnect System" to determine whether such devices are reasonable alternative to burying customer service lines. He also recommended the Company identify strategic road crossings where downed lines could prevent response by emergency personnel and target such locations for undergrounding. Jones Responsive Testimony at pp. 13-15. Mr. Kissman agreed to work with Commission Staff in implementing these recommendations. Kissman Rebuttal at pp. 5-7. The Commission orders the Company and Staff to collaborate on the best method of implementing the system hardening recommendations of Staff Witness Jones.

2. Ad Valorem Taxation

The Company included in its cost of service ad valorem tax expense of $37,405,762. This amount was based on test year ad valorem tax payments to applicable jurisdictions and test year-end plant balances. In his rebuttal testimony, Company Witness John Aaron updated the ad valorem tax expense calculation based on information received from the Oklahoma Tax Commission ("OTC") regarding Company fair cash value for the 2007 calendar year (or as of January 1, 2008). This resulted in a reduction of $34,767 and a revised request of $37,370,995. Aaron Rebuttal at p. 49-50 and Exhibit JOA-8R. OCC Staff witness Mr. Vaughn recommended a $2.6 million reduction to the ad valorem tax expense included in PSO's filing. Ms. Soltani recommended a $3.3 million decrease and Mr. Garrett recommend a $2.3 million reduction to PSO's requested ad valorem tax expense. On direct examination, Ms. Soltani revised her recommendation to account for the ad valorem taxes associated with new peaker plants which were deferred as regulatory asset as approved by an order in PUD 2002000038. Dec. 16 Tr. at pp. 9-10 (Soltani Direct Examination).

Ms. Soltani arrived at her calculation by updating the test year ad valorem tax expense to reflect the total paid for the twelve month period ending August 31, 2008. Soltani Responsive at p.16. Mr. Garrett recommended a $1 million dollar increase over the 2008 calendar year estimated ad valorem tax accrual. Garrett Responsive at p. 60. Mr. Garrett made no adjustment attributable to the deferral of ad valorem taxation on the new peaker plants. PSO argued against the adjustments of the AG and OIEC because their respective recommendations did not reflect the plant in service that each recommended be included in PSO's rate base.

Staff's recommendation for the Oklahoma portion of ad valorem taxes (which represents the bulk of the expense for PSO) was based upon an average of estimated 2008 taxes (based in part upon the Fair Cash Value ("FCV") of plant investment at December 31, 2007,) and projections of 2009 and 2010 ad valorem taxes, each initially based upon FCV of plant investment at December 31, 2007. Vaughn Responsive at pp. 10-11 and Dec. 16 Tr. at 75. PSO argued that relying on FCV at December 31, 2007, is both non reflective of plant investment at test year-end, but, also leads to a depressed valuation, because FCV is determined in part by the

Income Approach, and in calendar year 2007, the Company experienced negative earnings due to January and December ice storms. *See* Aaron Rebuttal at pp. 43-48.

To derive his adjustment, Mr. Vaughn first separated PSO's ad valorem taxes into Oklahoma and Texas portions. He based his Texas portion on actual taxes paid for 2008 with a three year average of taxes paid from 2006 to 2008 serving as an estimate for each of the 2009 and 2010 amounts. His Oklahoma portion is based upon first estimating 2008 ad valorem tax based on Fair Cash Value on 2007 calendar year-end plant. He then estimated 2009 and 2010 amounts by escalating the 2007 calendar year-end Fair Cash Value by 2.784% annually. He then multiplied the Fair Cash Values by an assessment ratio of 22.85% and an estimated millage rate of 10%. Mr. Vaughn then totaled his estimates for the Oklahoma and Texas portions to determine PSO's total company estimated ad valorem tax expense for 2008 through 2010 and then took a three-year average of total company taxes for 2008 through 2010 to determine the amount of recovery for ad valorem taxes, $34,761,438. Vaughn Responsive at pp. 10-11.

PSO explained that for electric utilities, the OTC relies on a combination of three approaches to determine fair cash value, the Income Approach, the Cost Approach, and the Stock and Debt Approach. Aaron Rebuttal at p. 47. PSO further indicated that the OTC has given significant weight to the Income Approach which would be based on the Company's recent earnings history. Aaron Rebuttal at page 47-48. PSO witness David Sartin discussed in his direct testimony the Company's negative earnings in 2007 due to the ice storms, and significant under-earning even when accounting for the Commission's order in PUD 200700397 issued earlier this year permitting deferral and recovery of ice storm expenses. Mr. Sartin reported that net income in 2007 was actually a net loss of $24.3 million, primarily due to the $83 million in operation and maintenance expenses incurred as a result of the January and December ice storms. Even without the effect of the ice storms, PSO's return on equity would have been only 4.3% in 2007. Sartin Direct at p. 6. Mr. Aaron testified that given these earnings and their deficiency with respect to the Company's 10% ROE and 8.01% overall weighted return authorized in its last rate case, the OTC has held down the increase in taxable value and the resulting ad valorem taxes. Aaron Rebuttal at pp. 43-44.

The Commission recognizes that a calculation of the ad valorem tax which will be paid by PSO during the time the rates set by this case is a "best estimate" since the ad valorem tax assessed by the OTC changes annually and is negotiated to some extent between the Company and the OTC. The Commission finds that the adjustment recommended by Staff is well reasoned and adopts it as the finding of the Commission for establishing the level of ad valorem taxes to be recovered through the rates set in this Cause. Accordingly, the Commission finds that Ad Valorem Taxes should be reduced $2,644,324.

3. Generation-Related O&M Expenses

The Commission finds that PSO should be permitted to recover its requested $91.6 million of generation-related O&M costs. (This amount includes the $14.3 million for purchased capacity costs that Staff Witness Vaughn recommended should be recovered through the Company's Fuel Adjustment Clause, as discussed below.) The test year adjusted generation O&M expenses were prudently incurred, are reasonable, are recurring in nature and were not rebutted by interveners. Company Witness Knight's Direct Testimony adequately supports these costs. Knight Direct at pp. 19-25.

The Commission also agrees with the proposal by Company Witnesses Knight and Aaron to defer as a regulatory asset the $6,000,000 incurred for the major overhauls at Northeastern Station Units 3 and 4, and Southwestern Station and to amortize this $6 million to PSO's cost of service in the amount of $1,000,000 per year for six years, on the basis that this type of activity is performed at six year intervals. Aaron Direct at pp. 32-33, Knight Direct at pp. 18. This deferral and amortization will be effective with the rates that are implemented as a result of this final order.

4. Distribution-Related O&M Expense, Service and Reliability

The Commission finds that it is reasonable to approve distribution-related O&M expense in the amount of $56.1 million. PSO demonstrated that this level of expense is reasonable and necessary to continue to maintain a reliable and safe distribution system capable of meeting the demands of PSO's customers. Kissman Direct at pp. 6-12. No intervener proposed adjustments to PSO's requested level of Distribution O&M expenses.

No party objected to PSO's proposal to defer as a regulatory asset, any storm expense that exceeds the $2.87 million embedded in base rates (i.e., an under recovery of storm expense), or defer as a regulatory liability the over recovery of storm expense that could occur should PSO's storm expense not exceed the level embedded in base rates. Kissman Direct at p. 6; Aaron Direct at pp. 29-30. Accordingly, the Commission adopts the Company's proposal in this regard.

5. Transmission Expense and Reliability

PSO seeks to recover adjusted test year transmission O&M expenses of approximately $40.2 million. The $40.2 million adjusted O&M expenses are partially offset by the associated transmission service revenues of approximately $20.1 million, as discussed by Company Witness Pennybaker.

PSO requested a $5,658,100 increase to cost of service for additional expenses required to enhance PSO's transmission system reliability and Ms. Soltani and Mr. Garrett recommended exclusion of all or most of the expenses for the following projects:

Table 1 – PSO Transmission O&M Adjustments for Reliability Programs

| | PSO's Request | Ms. Soltani's (AG) Adjustment | Mr. Garrett's (OIEC) Adjustment |
|---|---|---|---|
| Transmission Operation Center Enhancement | $712,100 | ($304,469) | ($712,100) |
| Transmission Vegetation Management Program | $3,100,000 | ($3,100,000) | ($3,100,000) |
| Hiring and Training of Additional Employees | $576,000 | ($576,000) | ($576,000) |
| Transmission Station Programs | $540,000 | ($540,000) | ($540,000) |
| Animal Mitigation | $100,000 | ($100,000) | ($100,000) |
| Transmission Line Programs | $630,000 | ($630,000) | ($630,000) |
| Total | $5,658,100 | ($5,250,469) | ($5,658,100) |

Matthews Rebuttal at p. 5. Ms. Soltani and Mr. Garrett recommended exclusion of the programs for which expenses were not incurred in the test year or the 6 month period post-test year.

Soltani Responsive, at p. 17; Garrett Responsive, at pp. 55-56. Staff proposed no adjustments and indicated that Staff's position was that the expenditures were in the public interest and should be considered by the Commission. Dec. 16 Tr. at pp. 32-34, 39-40.

With respect to the first program, the Transmission Operation Center ("TOC") Enhancement, the Commission notes that the TOC was placed in service in early 2008, and PSO had incurred $407,630 in expenses for eight months ending August 31, 2008, and will continue to incur expenses at the approximately $51,000 per month amount reflected in the incurred expenses. Annualized, the amount is $612,000. Additionally, software upgrades and digital wall installations will cost an additional $100,100. Matthews Rebuttal at p. 6. Ms. Soltani and Mr. Garret both acknowledge this. Soltani Responsive Testimony at p. 17; Dec. 15 Tr. at 172-173. Accordingly, the Commission finds that the total $712,100 for the TOC should be recovered.

With respect to the Transmission Vegetation Management program, Company Witness Matthews pointed out that this program will enable PSO to achieve a four-year trim cycle for all transmission voltages consistent with PSO's program for Distribution vegetation management. PSO argued that ratepayers will not extract the full benefit of the costs of Distribution vegetation management if not performed in conjunction with Transmission vegetation management, where widespread and costly outages can occur if this new program is not implemented, Matthews Direct at p. 19, Matthews Rebuttal at p. 7). Although the Commission has decided that the Company's Distribution vegetation management and a four-year trim cycle is in the interest of ratepayers, *see* Order No. 515349, Cause No. PUD 200500218 and Commission rule OAC 165:35-25-15, the Commission declines to adopt a similar program on the Transmission side of operations in this rate case. If PSO implements such a program and actually begins incurring costs for a Transmission Vegetation Management program, the Commission finds that the costs shall be treated as a regulatory asset until such time as the Commission is requested to allow PSO recovery of the costs, at which time the Commission will review the costs to determine how much of those costs should be recovered from retail ratepayers.

With respect to the hiring and training of additional employees, Mr. Matthews testified that PSO is challenged by an aging workforce and anticipates the retirement of 12 full-time employees and the loss of their technical knowledge and system experience in the next five years. Matthews Rebuttal at p. 8. Two of those employees have already retired as of the date of Mr. Matthews's oral testimony, and others have expressed their intent to do so. Dec. 15 Tr. at pp. 33-34. Mr. Matthews further explained that the employees that the Company anticipates will retire have, respectively, 25 to 30 years of experience. Dec. 15 Tr. at pp. 22-23. New employees will have the educational background through Company efforts to forge partnerships with Oklahoma technical schools, colleges and universities, but they will not have the four to five years of experience required to attain journey level, thereby allowing them to work independently. Matthews Direct at p. 21, Dec. 15 Tr. at pp. 22-23, 33-34 (Matthews Cross Examination). PSO argued that this is a significant knowledge and experience gap, and the individuals that could fill that gap will not be available once that knowledge and experience walks out the door if PSO is not provided funds to allow new inexperienced employees and experienced employees to work concurrently. PSO further argued it is in the interest of ratepayers that transmission reliability does not suffer due to a knowledge and experience gap easily remedied by the Company's suggested pro forma adjustment regarding hiring.

PSO argued that the other programs, the Transmission Station Inspection Program and the Animal Mitigation Program, similarly benefit ratepayers and will allow to the Company to increase inspection, maintenance, and replacement of transmission infrastructure and prevent and mitigate problems before they become more serious and more costly. Mr. Matthews indicated such programs are viewed as necessary and beneficial by RTOs and reliability organizations given their close attention to transmission reliability issues and standards. *See* Matthews Direct at p. 17.

The Commission finds that recovery of costs for hiring and training additional employees is best addressed after such costs are incurred. Therefore, the Commission finds that PSO's proposed adjustment in the amount of $576,000 for hiring and training employees to replace those who are familiar with PSO's transmission system and whom are anticipated to retire in the next few years, should not be adopted.

The Commission further finds that there are benefits to the ratepayers of PSO if PSO's transmission system reliability is improved. Therefore, if PSO implements the Transmission Station Program, the Animal Mitigation Program and/or the Transmission Line Program, the costs actually incurred for such programs shall be treated as a regulatory asset until such time as the Commission is requested to allow PSO recovery of the costs. When recovery of the regulatory asset is requested, the Commission will review the costs to determine how much of those costs should be recovered from PSO's retail ratepayers.

6. RTO Expenses

Company Witness Pennybaker supported the Company's RTO expenses, and no intervener proposed any adjustments to the expenses. Mr. Pennybaker was questioned on cross-examination about an increased payment in accordance with a formula rate accepted by FERC, subject to final hearing and refund, but Mr. Pennybaker confirmed that PSO was currently incurring those costs. Dec. 12 Tr. at pp. 194-196. The Commission finds that the Company's RTO expenses as filed are reasonable and should be adopted for recovery in base rates.

The Commission finds that Mr. Matthews adequately supported all other non-RTO Transmission expenses, Matthew Direct at pp. 17-27, and finds that they should be recovered in base rates as being reasonable and necessary for the provision of service.

7. Payroll Expense

Staff witness Wreath recommended no change to PSO's pro-forma base payroll, finding the salaries, employee levels and overtime amounts reasonable. Wreath Responsive at p. 8. AG witness Soltani recommended a $1.9 million reduction to PSO's pro-forma payroll. Her adjustment included a $322,000 decrease for PSO's base payroll, a $1.260 million reduction for overtime payroll, and a $274,000 reduction for AEPSC base payroll billed to PSO. Soltani Responsive at pp. 7-8, Exh. RZS 7. OIEC witness Garrett recommended a $1.814 million reduction to PSO's payroll expense. His adjustment included a $1.464 million reduction for PSO's base payroll, and a $350,000 reduction for AEPSC base payroll billed to PSO. Garret Responsive at p. 28.

PSO requested payroll expense based on annualized base payroll in effect at April 15, 2008, for active employees on the payroll at February 29, 2008. PSO included the scheduled annual salary increase for the Company's non-union employees, stating that this was a known and measurable adjustment that should be reflected in cost of service. The result of this calculation was approximately $72.5 million total base payroll at April 15, 2008, for PSO. For the test year, PSO expensed 66.7% of its base payroll costs. Only the expensed portion of total annualized base payroll is included as an expense in PSO's cost of service. Applying the test year O&M percentage of 67.7% to PSO's $72.5 million annualized payroll results in approximately $48.4 million of base payroll expense. When compared to the test year expensed level of $46.4 million, a $2.0 million increase is required. Only base payroll was annualized; overtime payroll was not. There was, however, a pro-forma adjustment for overtime payroll incurred by PSO related to the December 2007 ice storm, reducing test year overtime payroll included in cost of service to $9.2 million. In summary, PSO's total requested pro forma payroll expense (annualized base payroll plus test year overtime payroll) was $57,566,085 for the test year ending February 29, 2008. Aaron Rebuttal at pp. 50-51.

As previously discussed, the Commission finds it is inappropriate to adjust to post-six-month test year amounts without an analysis that examines the reasons behind the changes. Therefore, the Commission rejects the proposed adjustments recommended by the AG and OIEC. The Commission finds that the adjustment made by PSO to payroll expense is reasonable and adopts PSO's proposed payroll expense level without additional adjustment.

8. Payroll Taxes

The level of payroll tax included in PSO's cost of service should be consistent with the level of payroll expense included in cost of service. Staff recommended a reduction to payroll taxes consistent with Staff's recommendation to reduce long term incentive compensation and 50% of other incentive compensation programs. The AG recommended a $968,020 reduction to payroll tax included in PSO's filing. OIEC recommended a $571,337 reduction to payroll tax included in PSO's filing. All of these adjustments to payroll tax reflect the individual recommendations to base payroll, overtime payroll and incentive compensation proposed by these respective parties. The AG corrected its testimony regarding the portion of the adjustment which would exclude payroll taxes PSO must pay on overtime payroll and incentive compensation. Aaron Rebuttal at p. 56 and 57; Dec. 16 Tr. at p. 9.

The Commission finds that payroll taxes should be calculated based upon the adjustments adopted by the Commission regarding the level of payroll expenses and incentive compensation. Accordingly, the Commission finds that the adjustment recommended by Staff to reduce payroll taxes consistent with Staff's recommendation to reduce long term incentive compensation and 50% of other incentive compensation programs should be adopted.

9. Legislative Monitoring Expense

AG witness Soltani and OIEC witness Garrett recommended excluding the $450,053 legislative monitoring expenses included in PSO's cost of service. The AG argued that these charges recorded "below-the-line" should be borne by shareholders and do not represent a necessary cost of providing utility service. The AG also argued that PSO already included the necessary legal and regulatory costs to monitor compliance with laws and regulations. OIEC argued that the costs requested by PSO are not reasonable.

PSO argued that PSO incurs legal and regulatory costs, the majority of which support PSO's regulatory activities such as this proceeding and other legal proceedings and none of which are legislative monitoring. PSO argued that the AG's and OIEC's disallowance would remove from PSO's cost of service the reasonable and necessary expenses for the support staff at PSO's Oklahoma City State Office and, also, exclude payroll charges for Community Affairs Managers that were approved in PSO's last rate case, PUD 200600285.

The Commission finds that the $450,053 expense recorded "above-the-line" should be allowed in PSO's cost of service as reasonable and necessary costs incurred by PSO for providing electric utility service. The Company accounts for legislative monitoring and legislative advocacy separately. These "above-the-line" expenses are associated with legislative monitoring, not legislative advocacy. Aaron Rebuttal at pp. 59-62. It is reasonable and necessary for PSO to monitor legislation to determine its impact on its operations and cost to serve its customers.

10. Employee Benefits

PSO initially requested to increase test year employee benefits by $1,787, 480. However, PSO discovered an error in its calculation and revised its request to an $115,242 increase rather than the amount requested in the initial filing. Ms. Soltani on behalf of the Attorney General recommended a $387,669 reduction to employee benefits as originally filed. Mr. Garrett for the OIEC recommended a $1,784,480 reduction to employee benefits included in PSO's filing.

Mr. Garrett and Ms. Soltani both adopted the Company's revised request. Dec. 12 Tr. at p. 172; Dec. 16 Tr. at 10. The Commission accordingly finds that the employee benefits expense request of $115,242, as revised in the rebuttal testimony of Company Witness John Aaron, is the appropriate level to include in cost of service.

11. Supplemental Executive Retirement Plan ("SERP")

The AG and OIEC recommend reductions to reflect the elimination of SERP expense from PSO's cost of service. Staff proposed no adjustment to PSO's recommendation. SERP is AEP's non-qualified defined benefit retirement plan that allows PSO argued allows AEP the flexibility to attract and retain key employees and provides benefits that cannot be provided under AEP's qualified defined benefit plans. PSO stated that the combined plans, of which SERP is a part, allow employees to accumulate an appropriate level of replacement income upon retirement. According to PSO, SERP plans and other benefits are part of a market competitive benefits program for the utility industry and large employers in general. The Commission finds that the SERP expenses do not provide a benefit to the ratepayers of PSO and therefore adopts the recommendation of the AG and OIEC to deny recovery of these costs from PSO's ratepayers.

12. Annual and Long-Term Incentive Compensation

PSO testified that AEP and its operating companies provide total compensation packages to their employees that target median wage levels for companies of similar size and scope within the electric utility industry for most positions. Employees are compensated through a combination of base pay and incentive pay programs. All employees are eligible for some level of annual incentive compensation, and approximately 525 executive level positions are also eligible for long-term incentives. PSO and AEPSC utilize a "pay for performance" program for all salaried positions whereby each employee's performance is evaluated on at least an annual basis against pre-determined performance objectives. Jolley Direct at pp. 5-6.

PSO stated the Company is not requesting that all of the annual and long-term incentive compensation from the test year be included in its revenue requirement in this case. It is only requesting that the target amount of annual incentive compensation during the test year, $8,079,012, be included in cost of service, rather than the $13,451,337 in actual accruals made during the test year. Jolley Direct at p. 17. For long-term incentive compensation, PSO requested $3,660,113 rather than the $6,387,457 in actual accruals made during the test year. Jolley Direct at p. 23. PSO explained that incentive compensation during the test year exceeded target amounts because the AEP earnings and the earnings per share modifier used in the formula were higher than expected during 2005 and many of the plan measures were met or exceeded. However, this is unusual and the Company is only requesting that target amounts be included in cost of service because this is the amount that is designed to ensure that employee salaries will be competitive.

PSO testified the payment of both annual and long-term incentive compensation is necessary for PSO and AEPSC to attract and retain qualified employees and provide quality utility service, as well as to incent the employees to achieve goals which positively affect customer satisfaction, safety, and financial performance. Moreover, each of the performance measures promotes either cost control and fiscal responsibility (net income, capital expenditure, utility group O&M measures), service reliability and customer satisfaction (SAIFI, CAIDI, customer satisfaction and Commission complaint measures), or operational safety (safety measures). PSO explained that these measures are consistent with the provision of quality utility service at reasonable cost. Jolley Rebuttal at pp. 10-11.

The AG, OIEC and Staff witnesses proposed disallowing portions of annual incentive compensation. Specifically, the AG and Staff recommended that the Company's proposed annual incentive costs be reduced by $4,039,066 (50%). OIEC recommended that the Company's proposed incentive costs be reduced by $5,654,608 or 70%.

The AG and Staff argued that the Company's and AEPSC's incentive compensation programs benefit rate payers and shareholders equally and they should each share 50% of the cost. OIEC considered the extent to which "financial" measures are contained in the various annual incentive compensation plans. OIEC concluded that the Company's requested annual incentive costs are overwhelmingly weighted toward Company, rather than customer, objectives. OIEC also argued that the earnings per share ("EPS") modifier, by its very nature, shifts the risks associated with incentive compensation payments to ratepayers since there is no certainty that incentive payments will be made from year to year. As a result, OIEC recommended that 70% of incentive compensation be removed from the cost of service. Jolley Rebuttal at pp. 5-6.

The AG, OIEC and Staff all recommended that the entirety of PSO's test year long-term incentive compensation for senior employees, in the amount of $3,672,845 incentive expense, be denied. They contended that all of the performance measures used in the long-term incentive program are based on achieving financial goals that only benefit shareholders and should not be paid by ratepayers.

PSO argued that the long-term incentive compensation for senior employees and the annual incentive payments should be recovered from ratepayers because no testimony was provided to indicate that the requested overall level of compensation is unreasonable. PSO further argued that providing a substantial component of compensation as incentive-based is normal in business today and considered to be good industry practice. PSO also indicated the requested incentive compensation expense is not a bonus for performance that exceeds targeted expectation. In fact, PSO already eliminated the test year amount of that portion of compensation from its request. Finally, PSO argued that providing an incentive for improved financial performance benefits customers by supporting overall financial health, which can have a positive impact on financial costs.

The Commission finds that although there is no evidence to conclude PSO's and AEPSC's overall salary levels are excessive, that the recommendation of the AG and Staff to disallow 50% of PSO's and AEPSC's incentive compensation should be adopted. Incentive compensation benefits both shareholders and ratepayers equally, by encouraging the attainment of goals that provide good customer service and increase the earnings of the shareholders. Accordingly, the Commission finds that OIEC's recommendation to disallow 70% of incentive compensation should be rejected.

With regard to long term incentive compensation, the Commission finds that the recommendation of the AG, OIEC and Staff to disallow 100% of long term incentive compensation is reasonable and should be adopted by the Commission. The performance measures that result in the payment of long term incentive compensation are financial goals that benefit shareholders, rather than ratepayers.

The result of the above disallowances reduces the expenses of PSO by $7,711,851.

13. Interest on Customer Deposits

PSO included in its cost of service the appropriate level of interest expense using the OCC-prescribed interest rates and the February 29, 2008, test year-ending balance of customer deposits. Aaron Rebuttal at p. 74. OCC Staff witness Patel recommends an adjustment to reflect the 13-month average balance through August 31, 2008. AG witness Soltani recommended an adjustment to reflect the August 31, 2008, balance

The Commission adopted the Company's level of customer deposits at February 29, 2008, and accepts the Company's treatment of interest on customer deposits. The Commission recognizes that the interest rate on customer deposits will be less in 2009 than it was during the test year, but declines to make an adjustment based upon this new factor because it is so far beyond the end of the test year.

14. Factoring

The Commission finds that an amount of factoring expense should be adopted which is equal to the amount that reflects the return on equity and bad debt rate component approved by the Commission in this order and synchronized with the revenue requirement that is approved by the Commission in this case. In this rate cause the factoring expense is $12,994,987.

15. Postage

Staff Witness Seyedoff recommended a $13,582 adjustment to PSO's $95,054 postage expense based upon a calculation to incorporate respective one-cent and two-cent United States Postal Service increases. However, Staff's calculation does not reflect the actual postage increase that was effective in May 2008. PSO's calculation is a two step adjustment that first annualizes the May 2007 increase of two cents for the entire test year, then accounts for the May 2008, one cent increase. Staff's adjustment negates the second step of the Company's adjustment which will not reflect ongoing postage expense. The Commission therefore rejects this postage adjustment.

16. Rate Case Expense

PSO requested recovery of its estimated $782,500 in rate case expense over an eighteen month period. Staff Witness Seyedoff recommended a two year recovery of PSO's estimated rate case expense or a $130,417 reduction to PSO's requested amortization. AG Witness Soltani recommended a three year recovery of PSO's estimated expense or a $260,833 decrease to PSO's requested amortization.

PSO accepted the OCC Staff's recommendation to recover rate case expenses over a two year period. The Commission finds that the two year period is reasonable and PSO's estimated $782,500 in rate case expenses should be recovered over a two-year period, as proposed by Staff. The amortization will begin in the month the new rates resulting from this proceeding are placed into effect. Further, the Commission finds that PSO may defer as a regulatory asset or liability the difference between the actual costs incurred and the estimated amounts included in this filing. If the actual costs are less than the estimate, the regulatory liability will be addressed in PSO's next base rate filing and the reasonable amount thereof included in rates. Likewise, if the actual costs incurred by PSO exceed the estimated amount, PSO may defer the additional costs as a regulatory asset to be recovered in PSO's next base rate filing.

17. $SO_2$ Auction Proceeds

The Commission agrees with Staff Witness Thenmadathil's proposal to credit $SO_2$ auction proceeds to the Ice Storm Regulatory Asset, on a prospective basis, rather credit the proceeds for recovery in PSO's base rates. Thenmadathil Responsive at p. 9.

18. Dues and Memberships

Staff Witness Patel recommended a $140,522 reduction to PSO's dues and memberships by excluding one-half of the professional and business dues and memberships such as the Edison Electric Institute and the Oklahoma Business Roundtable. AG witness Soltani recommended a $274,061 reduction by excluding specific professional, business and civic dues and memberships from PSO's cost of service.

Company Witness Aaron revised PSO's request, recommending that PSO's dues and memberships included in cost of service be reduced by $102,895 to exclude the civic, educational and miscellaneous dues identified on WP H-16 as well as the membership in the Oklahoma Utility Shareholders Association listed as professional on that work paper. Aaron Rebuttal at p. 68. The dues and memberships remaining in PSO's cost of service would be $376,243. The AG revised the adjustment to include professional dues and memberships and to only exclude certain civic and business dues. Dec. 16 Tr. at p. 9. The Commission finds that the adjustment recommended by Staff is reasonable and should be adopted.

19. Advertising and Marketing and Sales Expense

Staff proposed to exclude $54,273 in advertising expenses and $27,650 in marketing expenses that it found to be more promotional in nature and designed to improve the Company's image. Forbes Responsive at p. 9-11. The Company did not object to the exclusion and the Commission determines that this adjustment is proper.

20. Purchased Power Capacity Costs

PSO requested to include $14.3 million of purchased power capacity costs in its base rate revenue requirement. PSO agreed with Staff Witness Vaughn's recommendation to recover purchased power capacity costs through the PSO Fuel Cost Adjustment Clause using a demand allocation factor, or some other similar mechanism, so long as the method enables PSO to recover all capacity purchase costs. Aaron Rebuttal at p. 62; Direct Testimony of A. Naim Hakimi at pp. 11-12. The Commission agrees that Staff's recommendation is a reasonable alternative and determines that purchased power and capacity costs may be recovered through the FAC, or a similar rider mechanism, since the Company's purchased power capacity contracts are short term in nature and largely fuel-related. Vaughn Responsive at pp. 6-7.

21. Amortization Expense

The Commission updated plant balances to August 31, 2008, which requires an increase to the Company's amortization expense, from $9,036,292 as filed, to $9,722,490 as shown on Exh. JOA-10R attached to the Rebuttal Testimony of John Aaron.

22. NOx Fuel Emission Allowances

The Company requested recovery of the costs of purchasing NOx annual allowances through the Company's Fuel Adjustment Clause to comply with the EPA's Clean Air Allowance Rule ("CAIR") Annual NOx allowance Program which was to begin in 2009. This program will affect PSO through its ownership of the Oklaunion plant. Hakimi Direct at p. 12. The Company explained that the number of NOx Annual allowances ("NOx allowances") allocated to the plant under the program would not be sufficient to account for projected NOx emissions at Oklaunion. *Id.* Thus, PSO will incur a cost for purchasing additional NOx allowances on the market to cover its annual NOx emissions. These costs will be variable in nature similar to fuel consumption, and vary each month depending on the amount of energy dispatched from PSO's share of the Oklaunion plant. *Id.* at pp. 12-13.

PSO stated that the Company is not requesting the recovery of current dollars, but requests the establishment of a mechanism to recover those dollars once the Company begins to incur them. Dec. 12 Tr. at p. 119. On oral direct examination Mr. Hakimi entered into the record the Company's response to data request JT-7 (marked as Hearing Exh. 3) which asked what effect the District of Columbia Court of Appeals' decision in *North Carolina v. EPA*, No. 05-1244 (D.C. Cir. July 11, 2008), vacating the EPA's CAIR rules would have on the Company's request for this recovery mechanism. Dec. 12 Tr. at pp. 96-100. The response to the data request explained that the vacated CAIR is not definite since the court has not yet issued its mandate. On September 24, 2008, the EPA, as well as several other groups, filed petitions for rehearing in the case. Until all of the petitions for rehearing are considered and, if rejected, a mandate issued, the ultimate outcome cannot be predicted with any certainty. The response to the data request affirmed that PSO will continue to plan to comply with the CAIR. *See* Hearing Exh. 3.

On December 29, 2008, PSO filed a Supplement to PSO's Proposed Referee Recommendation, which indicates the District of Columbia Court of Appeals will not vacate the EPA's existing CAIR rules while the EPA is working on new rules for compliance with the Clean Air Act.

The Commission finds that once the costs associated CAIR are known, the Commission will need to review those to determine how much of those costs should be recovered from ratepayers. Accordingly, the Commission adopts Staff recommendation to allow PSO to accrue the costs associated with purchasing NOx credits in a regulatory asset account and address recovery of those costs in PSO's next rate case.

23. Depreciation Expense

PSO proposed to increase its depreciation expense based upon the result of applying the depreciation rates from PSO's new depreciation study to the pro forma plant balances at test year-end. The most significant changes in the new depreciation study are proposed increases in estimated future removal costs in PSO's transmission and distribution accounts. These estimated increases in future removal costs are reflected in the increased negative salvage values calculated for these accounts. The removal cost increases in accounts 355, 356, 364, 365 and 369 are the basis for most of the requested increase.

Current depreciation rates for PSO were established in the Company's last rate case, Cause No. PUD 200600285. Based on the results of a depreciation study it conducted in connection with this case, PSO requests an increase in annual depreciation expense of $5,976,292, or an increase in the overall composite depreciation rate to 2.65% from the current 2.47%. PSO's depreciation study is based on plant in service as of December 31, 2007, adjusted to include four new peaking generation units placed in service on February 29, April 30, and June 15, 2008. Davis Direct at pp. 6-8, Exh. DAD-1.

For each depreciable plant account, the depreciation rate consists of two components - a life parameter and a net salvage parameter. The life parameter is based on an actuarial, o/r statistical, analysis of the historical retirement experience and retirement characteristics of the property in the account. The net salvage parameter is calculated to account for the net proceeds expected to be recovered from the disposition of retired plant less the costs incurred to retire and remove the plant. *Id.* at p. 9-11, Exh. DAD-1 at pp. 3-10; Clayton Direct at pp. 6-7.

PSO developed the life parameters for its requested depreciation rates based on the Average Remaining Life Method. Davis Direct at pp. 9-11, Exh. DAD-1 at pp. 5-8. No party disputed the life parameters utilized in developing PSO's requested depreciation rates.

PSO based the net salvage parameter for Production Plant on an analysis of interim retirements and on a demolition study performed by Sargent & Lundy ("S&L"). *Id.* at pp. 11-12, Exh. DAD-1 at 10. S&L is an engineering firm with extensive experience in preparing estimates of electric utility generation plant dismantling. Bertheau Rebuttal at pp. 4-5, 11-12. S&L's demolition study provided removal and salvage amounts specific to each of PSO's generating units. Davis Direct at p. 11. Since S&L's dismantling cost estimates were stated in 2008 dollars, in order to determine the amount of net salvage at each unit's retirement year, PSO escalated the S&L estimate for a unit to the expected year of retirement using an escalation factor of 2.5% developed by the research department of the Federal Reserve Bank of Philadelphia. *Id.* at pp. 11-12.

For other depreciable property accounts, PSO developed the net salvage parameter as a percentage of the original cost using actual historical experience for the 23-year period 1985-2007. The salvage program in PSO's depreciation model analyzed historical experience for property in an account on an annual basis, on a cumulative history basis, and for 5-year moving averages to produce the historical net salvage, as well as indicated trends. *Id.* at p. 10, Exh. DAD-1 at pp. 9-10.

Pursuant to the order in Cause No. PUD 200600285, PSO's depreciation study included a section labeled "Pennsylvania Method" that calculated net salvage amounts for Transmission and Distribution ("T&D") depreciable property using the most recent five years of data. *Id.* at pp. 8-9, Exh. DAD-1 at p.12.

PSO's requested composite depreciation rate for Production Plant is 2.13%, compared to the current rate of 1.77%. The change is attributable to the net effects of changes (both increases and decreases) in the interim plant retirements and changes in net salvage ratios. *Id.* at p. 12, Exh. DAD-1 at p. 9.

For Transmission Plant, PSO's requested composite depreciation rate is 2.29%, or a 0.32 percentage point change from the current rate of 1.97%. The change is attributable to increases in the negative net salvage ratios for four accounts, partially offset by a decrease in the net salvage ratio for one account and an increase in the average service life for one account. For Distribution Plant, PSO's requested composite depreciation rate is 3.14%, or a 0.01 percentage point change from the current rate of 3.13%. The change is attributable to increases in the negative net salvage ratios and decreases in average service lives for some accounts offset by decreases in the negative net salvage ratios and increases in the average service lives for other accounts. For General Plant, PSO's requested composite depreciation rate is 3.73%, or a 0.18 percentage point change from the current rate of 3.55%. The change is mainly attributable to the increase in the requested rate for Account 397 to 4.16%, from the current 3.73%. Davis Direct at pp. 12-13, Exh. DAD-1 at p. 11.

The AG, OIEC, Wal-mart and Staff proposed adjustments to the depreciation rates requested by PSO. Most of the adjustments recommended were to the net salvage amounts requested by PSO. Net salvage is the amount received upon retirement less any costs incurred to sell or remove the property. In those cases where the cost to remove plant will be greater than the value of the plant removed, net salvage value is negative and is an increase to the plant balance to be depreciated.

A very good explanation of all the reasons for the recommended adjustments to the depreciation rates of PSO is set forth in the testimony summaries attached to this order and the Commission will not repeat those explanations here. The Commission finds that of the witnesses who recommended changes to the net salvage values, AG witness Pous was the most persuasive. The Commission adopts the recommendation of the AG that an overall 3.10% negative net salvage is appropriate for production plant. The Commission further adopts the recommendation of the AG regarding the net salvage value proposed for the ten mass property accounts results. The effect of adopting the adjustments recommended by the AG regarding depreciation expense for the production plant and the ten mass property accounts results in a reduction to depreciation expense in the amount of $17,107,020, based on plant as of August 31, 2008. The Commission makes no requirement regarding the reporting methodology concerning depreciation that was recommended by the AG for the next rate case.

24. Affiliate Costs

In its filing, PSO sought recovery of $76,097,053 of affiliate costs billed to it during the test year. Of this amount, $74,419,475 was billed by American Electric Power Service Corporation ("AEPSC") and $1,677,578 was billed by other affiliates of PSO. Hoersdig Direct at p. 6.

PSO witness Jeffrey Hoersdig, testified that AEPSC provides a wide array of operational and administrative services to PSO at cost and with economies of scale that would not be available to PSO if it provided these services to itself. Among the services provided are customer and distribution services, generation and transmission services commercial operations, environmental and safety services, human resources, accounting, legal and regulatory services. Hoersdig Direct at pp. 11-26. Mr. Hoersdig explained that PSO has and exercises the right to question all billings made to it by AEPSC and actively participates in decisions determining what services are to be provided to it by AEPSC. Dec. 15 Tr. at 120, 129-130. Mr. Hoersdig also provided in rebuttal a detailed explanation of the reasons for the increased AEPSC charges to PSO over the last Commission approved amounts. Hoersdig Rebuttal at p. 10-15.

No party challenged the central premise of PSO regarding its requested recovery of its test year affiliate costs, namely that AEPSC provides these services in an efficient and cost effective manner which results in significant savings to PSO due to the centralized nature of AEPSC.

OIEC witness Norwood argued that $6,873,969 in AEPSC charges should be disallowed, because PSO did not adequately explain in direct testimony why its charges from AEPSC had increased at a greater rate than certain other AEP operating companies from 2005 through the test year. Specifically, Mr. Norwood limited PSO's test year charges to a 3.5% annual increase from 2005, which he stated was the equivalent average increase for the AEP East operating companies for the same period.

Mr. Hoersdig testified that the amount of direct billed charges for services provided by AEPSC exclusively to PSO accounted for over $5 million of the $9.8 increase in PSO's billings. He explained that PSO required a greater level of services than the other AEP operating companies during the period in question and discussed in detail the various services to PSO which resulted in increased billings. Hoersdig Rebuttal at pp. 10-15.

Mr. Hoersdig further testified that the increase in AEPSC billings to PSO was due to (1) the increase in direct billings to PSO and (2) a change in the allocation methodology for commercial operating employees. *Id.* at 10-15. Mr. Hoersdig explained again that an increase in direct billings reflects a greater need for services unique to a particular company. With respect to the allocation methodology for commercial employees, Mr. Hoersdig pointed out that the AEP System Integration Agreement was altered so that off-system sales margins are now directly assigned to the zone in which the transaction occurs rather than being allocated. Consistent with that change, he stated that costs related to these transactions are now directly assigned, which resulted in greater costs to AEP West companies. Dec. 15 Tr. at 125-126 and 132-133. He also pointed out that direct assignment of costs as is now being done is a more precise form of billing. Dec. 15 Tr. at 114.

The Commission finds that PSO provided support for the affiliate costs paid by PSO and that no adjustment to these expenses is necessary. The Commission further finds that there is sufficient evidence to conclude that AEPSC's allocation factors are specific, reasonable and allocate costs to PSO on an appropriate basis. Accordingly, there is no need for a study as proposed by OIEC.

25. Smart Grid pilot project

The Commission is persuaded that one way to allow customers to better manage their electric costs and at the same time increase the reliability on PSO's system, is the implementation of a Smart Grid. The Commission recognizes this is a costly project and in order to provide funding that will encourage PSO to expand its pilot project to test the feasibility of implementing a Smart Grid throughout PSO's system, the Commission grants PSO $2 million annually for this purpose. The Commission intends that this $2 million be expended on projects that are in addition to programs being recovered through the existing DSM program. PSO should maintain data indicating whether there are benefits achieved by PSO in increasing the reliability of its system upon which the Smart Grid is implemented and whether customers within the Smart Grid pilot project take advantage of the increased capabilities of information regarding their electric usage.

F. Revenue Requirement

1. Off-System Sales Margins, Standby Service Margins and RTP Margins

OIEC Witness Mark Garrett proposed to change PSO's historical sharing of off-system sales margins between ratepayers and shareholders through reductions in the fuel adjustment clause from 75% ratepayers/ 25% shareholders to 100% being credited to ratepayers. Mr. Garrett also recommended that standby service margins and RTP margins flow 100% to ratepayers rather than the current 75/25 sharing for standby margins and 50/50 for RTP margins. As an alternative, he recommended that a 90/10 sharing of off-system sales be used since that is how OG&E shares its $SO_2$ allowance proceeds. Garrett Responsive Rate Design Testimony at pp. 20-21.

Mr. Garrett argued that PSO's recent (June 2008) increase in fuel rates and the proposed increase in base rates from this case should cause the Commission to change the historical sharing ratios. PSO pointed out that the overall impact of the increase in rates in this case, if approved by the OCC at PSO's requested amount, is estimated at only 9%. As to the recent fuel rate increase, natural gas prices have declined dramatically since June 2008 when fuel rates were last increased, and PSO has reduced them. Amended Sartin Rebuttal at p. 9; Dec. 8 Tr. at p. 155 (Sartin Cross Examination) PSO argued that the fuel rate decline will more than offset PSO's base rate increase resulting in a net decrease in customers' electric bills. *Id.*

The Commission finds there is no justification for changing the allocation of PSO's off-system sales margins based upon the treatment utilized for OG&E's $SO_2$ allowances. As a part of an OCC approved settlement agreement in the 2007 ice storms case (Cause No. PUD 200700397), PSO's $SO_2$ allowances are currently being allocated 100% to customers. For most customers this is accomplished by applying $SO_2$ margins to offset PSO's 2007 ice storm costs. However, for PSO's service level 1 and 2 customers, 100% of the $SO_2$ allowance proceeds applicable to these classes are provided as current month bill reductions. So, while most PSO customers' rates increased as a result of the extraordinary 2007 ice storms, large customers' electric bills actually declined. PSO's customers are already in a better position than OG&E's for $SO_2$ allowances. Sartin Rebuttal at p. 9-10.

The Commission finds that there should be no change to the existing 75/25 sharing of off-system sales margins, which has been in place during at least the past 20 years. A sharing of these margins provides PSO an incentive to aggressively pursue these sales for the benefit of both ratepayers and PSO's shareholders. The Commission further finds that Mr. Garrett's proposal with respect to standby service margins and RTP margins should also be rejected.

2. Post-Test Year Revenue Adjustment

OIEC was the only party that recommended making changes in PSO's revenue levels Dec.15 Tr. at pp. 174-175. OIEC argued that to the extent rate base and operating expenses are changed to the Company's advantage, revenue levels also need to be synchronized to the advantage of ratepayers Dec. 15 Tr. at p.175. OIEC testified that an adjustment to revenues is important because rates are set based upon a synchronized review of (1) the utility's investment levels (rate base), (2) the utility's expense levels, and (3) the utility's revenue levels that exist at a particular point in time, a test year. This synchronized review compares the revenue levels achieved with existing rates with the cost obligations of the utility. From this comparison, the regulator determines if rates should be increased or decreased to provide sufficient revenues to cover the utility's operating costs and a return on capital investment. OIEC explained that some jurisdictions, including Oklahoma, provide a specific additional period of time, after test year-end, where known and measurable changes occurring during this period can be incorporated in the rate review. OIEC stated that when a post-test-year period is used, all three components of the revenue requirement calculation must be reviewed together to arrive at an accurate rate determination. A synchronized update of these components is important because, although rate base and expenses levels may tend to increase over time, to the disadvantage of ratepayers, these increased cost levels are typically offset, to some extent, with higher revenue levels.

OIEC witness Garrett initially proposed an upward adjustment to test year revenues in the amount of $4.5 million to recognize load growth over the six-month post-test year period. Garrett Responsive at p. 20. He based his adjustment on a statement from the direct testimony of PSO witness David Sartin that PSO's base revenues grow by about $9 million per year on a weather normalized basis, due to customer growth. Garrett Responsive at p. 19. PSO testified that Mr. Sartin's statement was a general statement based on historical average annual growth in weather normalized kWh over the 10-year period 1996-2006 (2.0%), but it should not be taken as a forecast of revenues for the specific post-test year period. Burnett Rebuttal at p. 4. As PSO witness Chad Burnett explained, there is no need to base such an adjustment on forecasts since the actual load growth data from the six-month post-test year is available. Burnett Rebuttal at p. 4. PSO's weather normalized MWh for the six-month period ending August 2008 was 9,464,635 compared to the six-month period ending August 2007 of 9,697,071, which is actually a decline of 2.4% and is significantly less than the 2% increase assumed in Mr. Garrett's calculation. Burnett Rebuttal at p. 5. Mr. Burnett showed that the trend seen in the six-month post-test year period is consistent with recent experience and has continued, and that PSO's forecasts and budgets have been revised to reflect the slowing load growth. Burnett Rebuttal at pp. 5-6. Using the approach proposed by Mr. Garrett, if he had chosen to use the actual growth for the six-month post-test year data, the load growth adjustment for PSO would result in a revenue reduction of $5.4 million instead of the $4.5 million increase filed in Mr. Garrett's testimony. Burnett Rebuttal at p. 6.

In sur-rebuttal, Mr. Garrett abandoned his $4.5 million load growth adjustment and sponsored a new analysis that he testified updated PSO revenues for the six-month post-test year period. Dec. 17 Tr. at p. 118; Hearing Exh. 7. The revised proposed adjustment of Mr. Garrett would increase revenues $6.5 million based upon his adjustments. Although the amount of time the Company and other parties had to review the new study was limited and PSO did not have time to conduct a full review, PSO witness Williamson was able to identify errors in that study in addition to the two corrections Mr. Garrett made on the witness stand. Dec. 17 Tr. at pp. 173, 177. Included in those errors was the failure to make a customer adjustment; failure to exclude the non-CBL portion of the RTP revenues, which during the test year amounted to $7 million; and erroneous assumptions about weather normalization. Dec. 17 Tr. at pp. 73-175, 180.

OIEC questioned whether PSO had made any attempts to update test year revenues for known and measurable changes. Dec. 17 Tr. at pp. 28-29. Ms. Williamson explained that PSO did investigate post-test year changes in revenues, including information provided by the Company's Customer Service Representatives regarding customers leaving the system or changing load that would impact revenues in the six-month post-test year period. Dec. 17 Tr. at p. 29. She explained that PSO conducts studies and makes changes to data to normalize the test year to be representative going forward including the six-month post-test year period. Dec. 17 Tr. at p. 30. Those adjustments include removing rider revenues, annualizing customer counts, weather normalization, and adjusting for changes in customer loads and movement between classes. Dec. 17 Tr. at pp. 33-34. She did not simply substitute the six-month post-test year revenues for test year amount. Dec. 17 Tr. at p. 30. She explained that while the six-month post-test year data did become available by the time PSO filed its rebuttal testimony, the Company did not have the time to conduct the analysis necessary to normalize the revenues and make all necessary adjustments. Dec. 17 Tr. at pp. 30-31.

The Commission finds that OIEC's initial adjustment was based upon a forecast and did not meet the standard of being known and measurable. The Commission further finds that OIEC's new study, does not meet the known and measurable standard and is not sufficiently reliable to be adopted. Therefore, the Commission finds that neither post-test year revenue adjustment proposed by OIEC should be made.

3. kVAR Adjustment

OIEC witness Garrett adjusted SL1 and SL2 revenues to correct an error in the proof of revenues for kVAR billing units. Garrett Responsive at p. 21. PSO agreed that OIEC's proposed change in total kVAR billing units for SL1, SL2, as well as SL3 in the proof of revenues is appropriate, based on its response to discovery request OIEC DR 23-1. Moncrief Rebuttal at p. 6. PSO testified that this adjustment only affects the proof of revenue schedules and does not affect the present booked revenues, because the kVAR revenues are already accurately represented in the booked revenue numbers. Moncrief Rebuttal at p. 6. These adjustments will be reflected in the compliance proof of revenue. OIEC and PSO agreed that this issue is no longer contested. Dec. 17 Tr. at p. 154.

The Commission adopts OIEC's recommendations to add 311,597 kVAR units to reflect the kVAR units actually billed to SL2 customers during the test year. This adjustment affects only the proof of revenue schedules and does not affect test year booked revenues because the kVAR revenues are accurately reflected in booked revenues. The correction should be made in the compliance proof of revenues filed in this docket.

4. Booked versus Billed Revenues

OIEC witness Garret adjusted SL1, SL2, and SL3 revenues based on billed amounts. Garrett Responsive at pp. 21, 22, 25. PSO disagreed with OIEC's use of billed revenues rather than booked revenues. As explained by PSO witness Williamson, the booked revenues are from the Company's official books and records and tie to the Company's financials and should be the starting point for determining the revenues produced by each class under current rates. The "billed" revenue that OIEC referred to was provided as a work paper to a response to a data request. PSO explained that the work paper was a snapshot in time and the billed revenues shown on the work papers fluctuate daily, based on billing corrections such as cancel and re-bills due to meter re-reads or other data corrections. Had the same work paper been generated a day earlier or later, the numbers would have been different. PSO testified it has always been the practice of PSO, and accepted by the Commission, to use the Company's booked revenues adjusted for known and measurable changes in determining revenues produced under current rates. Williamson Rebuttal at pp. 4-5; Dec. 17 Tr. at p. 33.

OIEC included booked revenues instead of billed revenues in Mr. Garrett's sur-rebuttal exhibits. Dec. 17 Tr. at pp. 118, 156.

The Commission finds that PSO's use of booked revenues rather than billed revenues is the appropriate starting place for determining the revenues for each class under current rates, because the booked revenues come from PSO's actual books and records and tie to the Company's financials, while billed revenues fluctuate daily due to billing corrections.

5. Customer Data - SL2 Class

OIEC witness Garrett made several additional adjustments to SL2 revenues. First, he adjusted revenues because PSO's pro forma adjustment for a special contract customer was removed from non-fuel base revenues twice and in effect, the adjustment "double-counted the revenue deduction." Garrett Responsive at p. 22. PSO testified that the base revenue amount for the special contract customer was inadvertently removed during the calculation and removal of the embedded fuel amount from the unadjusted, booked test year revenues. Williamson Rebuttal at pp. 5-6. However, PSO did not agree with OIEC's revised revenue calculation, indicating it did not properly account for the "double counting" error, nor did it account for the accompanying change in the rate change pro forma adjustment. Williamson Rebuttal at p. 6. PSO will make the appropriate correction to the historical test year billing determinants. PSO and OIEC agreed that this issue is no longer contested. Dec. 17 Tr. at p. 155.

OIEC's second adjustment to SL2 revenues was the result of the fact that the kWhs included in the cost-of-service study did not match the kWhs in the proof of revenues. Garrett Responsive at p. 23. PSO witness Williamson testified that one customer's kWh's were properly excluded from the cost-of-service study. However, in the SL2 proof of revenue filed in this case, one special contract customer's kWhs were inappropriately subtracted from the kWhs that were input into the cost-of-service study. This caused a mismatch of kWhs in the cost-of-service study and the proof of revenue. Williamson Rebuttal at p. 6. Further, after reviewing the kWh billing determinants in more detail another error was discovered. Both special contract customers' kWhs were originally excluded from the SL2 class in the cost-of-service study when only one customer's kWhs should have been excluded. Only one of the special contract customers should have been removed since the other customer's revenues were calculated at standard rates. PSO will make a correction to the historical test year billing determinants. Williamson Rebuttal at p. 7. PSO and OIEC agreed that this issue is no longer contested. Dec. 17 Tr. at p. 156.

OIEC's third adjustment was to impute 12 months of revenues and billing determinants to reflect the addition of two new customers toward the end of the year. Garrett Responsive at p. 24. PSO explained that these two customers were actually existing customers that had a name change on their account. Therefore, there is no need to "annualize" revenues and billing determinants because these customers are already represented in the test year adjusted data. Williamson Rebuttal at p. 5.

The Commission finds that a correction should be made to correct for the "double counting" of the revenues associated with the special contract customer and finds that the correction proposed by PSO in Ms. Williamson's Rebuttal Testimony properly accounts for the "double counting" error and accounts for the accompanying change in the rate change pro forma adjustment. Further, the Commission finds that an adjustment to test year kWhs should be made because two special contract customers' kWhs were originally excluded from the SL2 class in the cost-of-service study when only one customer's kWhs should have been excluded, because one customer's revenues were calculated at standard rates and should not have been excluded.

The proof of revenues should be corrected to reverse the inappropriate subtraction of one special contract customer's kWhs. Finally, OIEC's proposal to impute 12 months of revenues and billing determinants for two new customers should be rejected because the customers are not new, but have simply had name changes, and their revenues and billing determinants are already represented in the test year adjusted data.

The Commission finds that the revised non-fuel base revenues for the entire SL2 customer class should be $28,567,633, rather than the $24,403,490 included in PSO's cost-of-service study in PSO's original filing. Williamson Rebuttal at p. 6.

6. Miscellaneous Revenues

Miscellaneous Revenues are generated by miscellaneous service charges, pole rentals, other rentals, and services to third parties. These revenues offset the Company's revenue requirement that would otherwise be collected from all customers through base rates. Williamson Direct at pp. 21-22. PSO determined the level of Miscellaneous Revenues by adjusting the recorded test year level of Miscellaneous Revenues for elimination of non-recurring entries, known rate changes, and reclassification of revenue between accounts. Williamson Direct at p. 21.

No party challenged PSO's adjustment to Miscellaneous Revenues, and the Commission finds PSO's adjustment to be reasonable.

G. Cost-of-Service Studies

PSO conducted two cost-of-service studies, one for jurisdictional cost separation between PSO's wholesale and retail customers and one for assignment of costs to the retail classes, which it used to determine the costs that different classes of customers impose on the PSO system. PSO testified that the result is a fully allocated embedded cost-of-service study that establishes class cost responsibility. The retail cost-of-service study attributed costs to the classes of customers in a way that reflects the costs of providing service, using a three-step process: functionalization, classification, and allocation. Williamson Direct at pp. 7-12.

1. Jurisdictional Cost-of-Service Study

PSO witness Williamson testified that the jurisdictional cost-of-service study serves to divide costs between the retail and wholesale (FERC jurisdictional) customers. Williamson Direct at p. 14. No party challenged PSO's jurisdictional cost-of-service study and the Commission finds that it should be accepted.

2. Retail Class Cost-of-Service Study

PSO witness Williamson testified that the embedded class cost-of-service study assigns the retail jurisdictionally-allocated total Company costs to the individual retail customer classes to determine the cost that PSO incurs in providing electric service to each retail customer class. Williamson Direct at p. 27. The results of the class cost-of-service study are used to provide embedded cost information that can be used to develop the pricing structures for each customer class, to provide information with which present and proposed relative rates of return by customer class can be compared and reviewed, and to comply with OCC filing requirements. Williamson Direct at p. 31.

OIEC argued that utility rate design consists of two broad phases: cost allocation and rate design. In the cost allocation phase, each customer class is allocated its proportional share of the total costs based on the costs incurred to provide service to that class. Then, the revenues produced by each class are compared with the class cost levels to determine which classes are under-paying and which classes are over-paying their respective costs. From this comparison OIEC argued that a determination can be made regarding which classes need rate increases and which classes need rate decreases to bring all the classes to the same rate of return, or to *equalized rates of return*. OIEC explained that when the revenues collected from each class fully cover the costs caused by that class then rates are said to be set at *cost-of-service*. When rates are not set at cost-of-service, then some customers are paying costs caused by other customers. OIEC described these over- and under-payments among the classes as *inter-class subsidies*.

OIEC argued that when costs are correctly allocated to the individual classes, rates can be developed to recover the actual cost of providing service to each class. These cost-based rates are equitable because customers pay only the costs incurred to serve them. Cost-based rates are also more efficient in that they ultimately tend to reduce the overall cost to the electric provider. This efficiency occurs because cost-based rates send better economic price signals to customers who then make better choices in rationing their use of electricity. OIEC stated that rates which are not cost-based tend to promote inefficiencies. These inefficiencies occur when prices are set below cost for certain customers. These artificially lower rates tend to cause the subsidized customers to increase consumption of energy based on incorrect price signals. Ultimately, the increased consumption brought about from artificially lower rates causes the utility to increase its overall cost over time, to meet the increase in demand to serve subsidized customers. OIEC argued that for many utilities, such as PSO, the problem is exacerbated when the subsidized customers are already the utility's most inefficient users of electricity, the residential class, and the subsidy providers are the utility's most efficient users of electricity, the industrial class. This creates a situation where distorted price signals cause inefficient users to use more electricity and efficient users to use less. Over time, this creates a more costly system for all users when additional capacity is continually being added to keep up with the artificially created increased demand during peak hours. According to OIEC, the only party that actually benefits from the artificially higher demand brought about from the distorted price signals is the utility, since the utility gets to earn a return on the additional capital investment needed to meet the higher demand levels.

3. PSO's Demand-Only Methodology for Distribution System Costs

Pursuant to the Commission's Order in PSO's last rate case, Cause No. PUD 200600285, PSO performed and filed a minimum-system study that allocated a portion of the distribution costs in Accounts 364-368 on the basis of number of customers, instead of allocating those costs based upon demand. Moncrief Direct at pp. 24-25. Although PSO performed the minimum-system study as required, PSO did not utilize the minimum-system study in its cost-of-service study and advocated the continued allocation of the distribution costs in Accounts 364-368 on a demand-only basis, as has been approved by the Commission for PSO since the 1980s. Moncrief Direct at pp. 25-26.

PSO explained that it used a demand-only allocator for distribution costs in Accounts 364-368 because the distribution system poles, wires, and conduit contained in those accounts are sized to meet the maximum load demand imposed on the system and the cost of those facilities does not vary directly with the number of customers, unlike distribution costs such as service drops and meters, which are allocated based on the number of customers. Moncrief Direct at p. 25. If the minimum-system study had been used in PSO's current cost-of-service study, the residential class would have been allocated more distribution costs than the residential class was allocated in previous cost-of-service studies, due to the addition of a customer allocator. For instance, Account 364 (Poles, Towers, and Fixtures) would now have a customer allocation of 48.71% compared to 0% previously, which would shift excessive costs to the residential class. Moncrief Direct at p. 29. Wal-Mart witness James Selecky argued that PSO's cost-of-service study should incorporate the results of the minimum-system study. Selecky Direct at p. 2. Wal-Mart did not however, recommend that any revenue increase be allocated to classes on the basis of a cost-of-service study, including a minimum-system study. Instead, Mr. Selecky testified that "If PSO gets every dime they have asked for we [Wal-Mart] are willing to go with the Company's allocation." Dec. 9 Tr. at p. 170.

PSO testified that minimum-system studies are by definition company-specific, produce widely varying results, can produce statistically-unreliable results, vary greatly depending on the assumptions used, and can result in over-allocation of costs to some classes. Moncrief Direct at p. 28. Further, changing the allocation from demand-only to a combination of demand and customer numbers will result in shifting costs from commercial to residential customers. Moncrief Rebuttal at p. 15; Selecky Redirect, Dec. 9 Tr. at p. 172. Finally, PSO has used the demand-only allocator for Accounts 364-368 in all its rate cases since the 1980's. Moncrief Direct at pp. 25-26. The Commission finds that PSO's demand-only methodology for classifying distribution system costs in Accounts 364-368 is reasonable and finds that PSO's retail cost-of-service study should be accepted.

H. Revenue Distribution

Revenue distribution involves assigning revenue responsibility to customer classes after the consideration of the cost-of-service studies and other relevant factors. For this case, PSO proposed increasing each rate class and each component of the rates (e.g., the Customer Charge, Demand Charge, and Energy Charge) equally, given the size of the requested revenue increase. Moncrief Direct at p. 8. PSO testified it has not abandoned its goal of equalized relative rates of return but, if rates are designed to produce equalized rates of return as shown in the cost-of-service study, there will be additional significant increases to certain rate classes, including up to a 447 percent increase to the Lighting Class. Moncrief Direct, Exh. DRM-1; Dec. 17 Tr. at p. 66. PSO argued that the proposed revenue distribution, using an equal percentage increase to each class and each component of the rates, mitigates customer impacts that otherwise would have varied widely from the system average if equalized rates were pursued in this filing. Moncrief Direct at p. 9.

Several parties recommended a more rapid movement to equalized rates of return. OIEC witness Garrett, representing customers in the industrial class, proposed that the rates for all classes recover an equalized rate of return, regardless of the magnitude of the rate increase. Garrett Rate Design at p. 16. QOSC witness Joe Robson, who acknowledged he was not an expert witness, criticized PSO's proposal because it continues the disparity in relative rates of return among the customer classes and does not move the classes toward recovery of equalized rates of return, which he views as important. Robson Direct at pp. 13-14. On the other hand, QOSC witnesses Paul Kane and Rodney Ray advocate consideration of customer impact when setting rates. Kane Direct at p. 13; Ray Direct at p. 9. Wal-Mart witness Selecky recommended that any reduction from PSO's requested revenue requirement be allocated to those classes whose rates are above an equalized rate of return, in order to move classes closer to full recovery of their allocated costs. Selecky Direct at pp. 22-23. Staff witness David Smith pointed out that PSO's proposed revenue allocation moves all but the lighting class closer to equalized rates of return. Smith Responsive at p. 15. Mr. Smith supported the movement toward equalized rates of return, while recognizing that gradualism should be employed to avoid rate shock to customer classes that are currently under-recovering their costs. Smith Responsive at pp. 17-19; Dec. 17 Tr. at p. 152.

PSO argued that its proposed revenue distribution should be used in this cause, because PSO is the only party that moved the classes toward equalized rates of return while also being mindful of the impacts of such movement on the customer classes, specifically the residential class. PSO initially requested an overall $132.6 million increase in non-fuel base rates, which would have resulted in a 30.34 percent overall base rate increase. According to PSO, this would have caused an 8.89 percent increase in total revenues, including fuel, based on the fuel factors in effect at the time of the filing. Moncrief Direct at p. 9; Dec. 17 Tr. at p. 68. PSO proposed to limit impacts on customer classes and individual customers by applying the same percentage increase to each rate class and to each individual component of the rates in each rate class. This strategy limits inter-class impacts to the system average increase, with the exception of those classes, such as the Good Cents classes, that were eliminated. As shown in the filed cost-of-service study, Workpaper L-1, this strategy did move all classes, with the exception of the lighting class, closer to an equalized return and limited impacts to customers. PSO argued that the additional objective of sending appropriate price signals is also achieved by PSO's proposed rate structure, which includes seasonal prices, blocked energy rates, and demand charges to send reasonable price signals to customers. Moncrief Rebuttal at p. 19.

The Commission finds that OIEC's and Wal-Mart's proposal to move all customers to parity, would cause unacceptable impacts on many of the customer classes. The Commission finds, however, that an effort should be made in this rate case to move customer classes closer to their full cost of service, without causing unacceptable levels of rate shock.

The Commission finds that the SL1, SL2, and the SL5 classes should not be allocated any of the first 20% of the rate increase approved by the Commission in this Cause. The SL1, SL2 and SL5 customer classes currently pay more than their cost of service. Not allocating a portion of the rate increase to the SL1, SL2 and the SL5 customers will move these three customer classes toward their cost of service.

The first 20% of the rate increase adopted by the Commission should be allocated in an equal percentage increase to each class and each component of the rates, other than the SL1, SL2, and the SL5 classes.

With regard to the remaining 80% of the increase the Commission adopts herein, the Commission finds that this portion of the increase should be allocated to all customer classes, including the SL1, SL2, and the SL5 classes, as an equal percentage increase to all customer classes and each component of the rates. The Commission finds that this form of gradualism will move all customers closer to parity, without causing unnecessary rate shock to customers.

I. Rate Design

1. Fuel in Base Rates

PSO recommended that the current cost of fuel be included in base rates. Dec. 17 Tr. at p. 71. PSO acknowledged that the current cost of fuel is less than the $0.061 per kWh requested when its testimony was originally filed in July 2008. OIEC witness Scott Norwood recommended that the base rates retain the current $0.034 per kWh for fuel in base rates. Norwood Responsive at p. 5.

The Commission finds that the $0.034 per kWh for fuel recommended by OIEC should be included in the base rates established by this Cause. The Commission finds that this level of fuel costs reasonably reflects the most recent actual fuel costs on PSO's system. The Commission further finds that that PSO's proposed FAC Rider should reflect the $0.034 per kWh embedded base rate fuel charge so that future adjustments for differences between fuel expenses incurred and fuel revenues collected each month will be appropriately calculated.

2. Reactive Power Charge

Power factor is an electrical engineering term that describes the amount of effort it takes to generate the "work" supplied by electrical power. Power factor can be described as the percent of effort (kVA) that is translated into work (kW). That relationship illustrates the efficiency of the power used by a customer and is expressed by a percent between 0% and 100%; 100% expressing that all effort is turned into work while 0% represents wasted effort or nonworking or reactive power. As the power factor improves, the nonworking or reactive power moves toward zero. In other words, it takes less total power to produce work because more real power is used and less reactive or nonworking power is required. PSO testified that a low power factor is expensive and inefficient and can affect PSO's distribution capacity. When a customer's operation reflects a poor power factor condition, that customer's operation could cause problems on the PSO system that could affect other customers' power quality. In that situation PSO will install a kVAR meter and measure kVAR. If a customer's KVAR requirement exceeds 30% of the monthly maximum demand (kW) requirement, PSO currently requests that the customer take action to improve its power factor and notifies the customer that PSO will begin charging $0.31 (or $0.33 depending upon the customer's service level) for each additional kVAR above 30% of monthly maximum demand. PSO testified that the action a customer must take usually requires a customer to install capacitors on its side of the meter. If a customer declines to correct its poor power factor and instead elects to pay the reactive power charge, PSO must install a capacitor in its distribution system to correct the situation. Moncrief Direct, p. 19 – 20.

PSO testified that the purpose of the reactive power charge is to encourage commercial and industrial customers to correct their power factors up to the level PSO requires for optimal system operation and to compensate PSO for the additional cost on its system created by poor power factor customers. Moncrief Direct at p. 19. PSO proposes to increase the kVAR charge in this cause because the current charge of $0.31 (or $0.33 depending on a customer's service level) for each kVAR required above 30% of the monthly maximum kW requirement does not reflect the entire cost to correct a customer's power factor on the PSO distribution system and does not motivate customers to correct poor power factors. This causes PSO and other customers to pay for an individual customer's correctable power factor issue, because the cost of the correction is spread to all other customers. Moncrief Direct at p. 21. Although difficult to quantify, the PSO testified that the cost to PSO to make the correction is $1.00 to $1.33 per kVAR per month. Dec. 17 Tr. at p. 77.

PSO testified that it is proposing to increase the kVAR charge to a level that will better recover the costs of PSO for the installation and operation of the equipment needed on PSO's side of the meter to correct the customer's poor power factor. PSO explained that this increased charge is an attempt to better motivate customers to correct their poor power factors and would only be applied when customers decline to correct the poor power factor by installing equipment at the customer's expense on the customer's side of the meter. PSO proposes to increase the reactive power charge from the current rate of $0.31 and $0.33, to $3.33 for each kVAR above 30% of a customer's monthly maximum demand. Moncrief Direct at p. 21.

PSO proposes to implement the revised power factor charge 12 months after the approval of the new reactive power charge, to give those customers who choose to do so, time to install the equipment necessary to correct the power factor situation on their side of the delivery point. PSO stated that its goal is not to charge the new fee but to motivate customers to correct their power factor on their side of the electric service meter. Moncrief Direct at p. 22.

PSO acknowledged that the proposed kVAR charge is a dramatic increase over the current kVAR charge, but pointed out that it is intended to provide incentive for those customers that cause problems on the PSO system due to poor power factors to make the correction. PSO testified that the proposed charge is avoidable if the customer takes the responsibility to correct the issues that cause the poor power factor on its side of the meter. Moncrief Rebuttal at p. 26.

OIEC witness Norwood contended that PSO did not show that the $3.33 charge is necessary to compensate for the additional cost imposed on the PSO system by poor power factors. Norwood Responsive at p. 7. PSO testified that it provided an analysis in response to OCC discovery request DWS 2-1 to illustrate the cost of correction based on an $80 per kVAR engineering estimate to correct the power factor on the customer's side of the meter. PSO considered the pay back period and the cost for a consumer considering installing capacity banks on its system in determining the level of the proposed kVAR rate. PSO testified it used the cost of the equipment necessary to correct a customer's power factor to 95% on the customer's side of the meter to determine the proposed kVAR charge. The proposed $3.33 per kVAR charge is based on a two-year pay back on the customer's investment in the corrective equipment. Moncrief Rebuttal at p. 26.

PSO testified that if the customer installs power factor correction on its system, it will reap other benefits such as freed capacity on its electric system, reduced losses, less voltage drop and motors that run cooler, which will reduce maintenance cost. PSO provided an example in its response to DWS 2-1, included as Exhibit DRM-3R to Mr. Moncrief's Rebuttal Testimony. PSO's illustration showed that PSO can attempt to correct the problem on its side of the meter by installing, for instance, a larger transformer, based on the current cost of $56,400. PSO explained this estimate does not include any maintenance cost, loss of capacity, voltage drop or cost to generate kVARs in PSO's system. The customer in the example currently pays an approximate penalty of $370 per month based on the current kVAR charge of $0.31. Based on a two-year pay back, this customer costs PSO at least $2,350 per month, which is distributed among all the customers. PSO argued that the present kVAR charge is not enough to encourage the customer to install the correction on the customer's side of the meter and, as stated above, the most efficient way to correct for poor power factor is on the customer's side of the meter. Moncrief Rebuttal at p. 25.

Mr. Garrett argued that PSO has not recognized the additional revenue that would be generated if the kVAR charge were to be charged to customers. Garrett Rate Design Responsive at p. 22. PSO explained it did not impute any additional revenue associated with the proposed kVAR charge because PSO hopes that by giving customers notice and time to budget for and correct their poor power factors, the charge will not have to be billed. PSO also hopes by working with customers to correct the problem of poor power factor that all customers and the PSO system will benefit and that the level of kVAR billing units will be dramatically reduced before any additional revenue is gained. PSO testified it would reflect any revenue and reduced kVAR billing units in its next rate case. Moncrief Rebuttal at p. 28.

The Commission finds that although it is reasonable to require a customer with power factors below 95% to install equipment on the customer's side of the meter or to pay a charge to PSO for taking corrective action on PSO's side of the meter, the kVAR charge recommended by PSO should not be adopted in the amount requested by PSO. Although the requested amount is based upon estimates produced by two external consulting engineering firms, the Commission is unwilling to initiate such a severe penalty upon customers with poor load factors, without additional study. The Commission concurs however that customers should be strongly encouraged to correct poor load factors by installing equipment on the customer side of the meter, so that all of PSO's customers do not pay the cost for correcting poor load factors of individual customers.

The Commission finds that customers with load factors below 95% should be notified by PSO within 60 days of this order that the Customer has 12 months to correct the load factor by installing the necessary equipment on the customer's side of the meter or the customer will be assessed $1.75 per kVAR above 30% of a customer's monthly maximum demand. Since the amount proposed by PSO is based upon an estimate and reflects a two year payback of the costs PSO believes it will incur to correct the load factor by installing equipment on PSO's side of the meter, the Commission finds that the $1.75 per kVAR amount is a fair compromise and will hopefully result in a strong incentive to customers to correct the load factor, without hitting the customer with a baseball bat. The Commission finds that the kVAR charge must be sufficient to incent a customer to make equipment changes on the customer side of the meter and the current charge has not provided that incentive. The proposed tariff gives current low power factor customers 12 months from the date of notification by PSO to avoid the charge by taking corrective action. Any revenue received by billing for kVAR will be considered in PSO's next rate, to the extent it occurs within the test year selected by PSO.

3. Net Metering Tariff

PSO has received requests for net metering service from residential and commercial customers. To date the customers are being served on the Net Metering Schedule for qualifying facilities or small power producers. With the resurgence of solar and wind applications to residential and commercial customers, PSO is requesting approval of a Net Metering Schedule that is more appropriate for residential and commercial customer use. The proposed Net Metering Schedule is available to any retail customer in PSO's service territory taking service under one of the standard rate schedules listed in the Net Metering Schedule and who has on-site power production facilities located on the customer's premises, which are intended primarily to offset some or all of the customer's energy usage at that location. Moncrief Direct at p. 22. The proposed Net Metering Schedule requires the installation of net metering equipment and the signing of an interconnection agreement. On a monthly basis, the customer will be billed the charges applicable under the current standard tariff and any appropriate rider schedules. The net metering only affects the kWh units of the customer's bill.

No party objected to PSO's proposed net metering tariff, Revised Exhibit DRM-5, (August 27, 2008, Errata) and the Commission finds it is reasonable and should be approved.

4. Service Fees

PSO proposed to add language to the Service Connect Fee to address seasonal customers who may connect and disconnect service within the same year to avoid a demand ratchet. In the Radio Frequency Meter Installation Fee, PSO proposed price changes to reflect the current cost to install the meters and the addition of prices for three-phase service meters. Moncrief Direct at p. 23. PSO also proposed a Special Meter Reading Fee. The tariffs for the service fees are contained in the Company's Oct. 29, 2008, Errata. Dec. 17 Tr. at p. 38.

No party objected to PSO's proposals regarding increased service fees and the Commission finds they should be approved.

5. Residential Service

PSO currently has four residential tariffs. They are: Limited Usage Residential Service ("LURS"), Good Cents LURS ("GCLURS"), Residential Service ("RS"), and Good Cents RS ("GCRS"). PSO proposes to eliminate the closed Good Cents residential rates (GCRS and GCLURS) and move those customers to the standard rates. PSO argued that the elimination of the residential Good Cents rates and movement of those customers to the standard rate simplifies the residential basic rate structure. PSO further stated that the qualification for the Good Cents rates is based on outdated energy efficiency standards and no longer represents the cost savings characteristics of the Good Cents customers. Moncrief Direct at p. 11.

PSO also proposes to close the LURS rate to new customers. Currently, residential customers can move between the LURS and standard RS rate schedules based on on-peak average usage. The amount of customer movement between these two rates in the test year was not anticipated or intended in the design of the LURS rate. The LURS rate was intended to accommodate customers who required little capacity from PSO and could maintain low usage. The fluctuation in usage causing customer movement between the classes indicates that some customers are not able to sustain the low level of usage required by the LURS rate, so the LURS rate is not appropriate for those customers. PSO proposes that once rates are approved in this docket, a customer who exceeds the LURS usage criteria will be moved to the standard residential rate and will not be allowed to move back to the LURS rate. Likewise, RS customers will not be allowed to qualify for the closed LURS rate. Attrition will gradually lower the number of customers on the LURS rate. Closing the LURS rate eliminates the customer migration between the two rates. PSO's plan is to eventually move the remaining LURS customers to the standard RS rate in a future proceeding while making accommodations for lower use customers within the RS rate. Moncrief Direct at p. 12.

PSO's proposals regarding the four residential tariffs were not contested and the Commission approves them as reasonable.

6. Commercial Service

Most of PSO's commercial customers are served from one of three major commercial tariffs: Low Use General Service ("LUGS"), General Service ("GS"), and Power & Light ("PL"). There are also customers served under the closed Good Cents tariffs. In this case, PSO proposes to eliminate the closed Good Cents commercial rates and move those customers to the standard rates. The elimination of the commercial Good Cents rates, and movement of those customers to the standard rate, simplifies the commercial basic rate structure. PSO argued that as is the case with the residential Good Cents rate schedules, the commercial Good Cents schedules are based on outdated standards, and have outlived their effectiveness. Moncrief Direct at p. 15.

PSO also has a school classification under the LUGS, GCLUGS, GS, and GCGS tariffs. The school rates were offered to all Public Schools grades K-12. Although the school rates use the same structures as the other commercial tariffs, the school charges were reduced pursuant to an agreement of the parties approved by the Commission in a previous rate case, Cause No. PUD 200300076. PSO proposes to maintain a discount for schools. PSO proposes to clarify the school tariffs to specifically define the "Public School Facilities" as K-12. Moncrief Direct at p. 15. QOSC witness Rodney Ray recommended that the rate codes for municipalities and counties be consolidated with the schools. Ray Direct at p. 8. However he did not offer any evaluation to support such a consolidation. PSO argued against consolidation of the rate codes for municipalities and counties with the rate code for schools, explaining that anytime a particular class of customers receives a discount, the remaining customers have to pick up that difference. Dec. 17 Tr. at pp. 55, 78.

Mr. Ray also suggested "billing consolidation" for municipal accounts, which he described as one overall monthly basic service charge covering all points of delivery. Ray Direct at p. 7. PSO testified that the basic service charge is assessed for each point of delivery to recover the costs associated with that delivery point, which includes the cost of metering, the service drop, and meter reading. Those costs are actually incurred for each location and any consolidated basic service charge would have to reflect all of those costs.

In addition to eliminating the Good Cents rate and specifying that the public school rate applies to grades K-12, PSO proposes that the rate increase adopted in this Cause be added to each rate element on an equal percentage basis. Moncrief Direct at p. 15.

The Commission finds PSO's proposed changes to its Commercial Service rates and tariffs to be reasonable and approves them. Mr. Ray's recommendations are not supported by sufficient analysis, and in the case of his proposed municipal discounts would require other customers to pick up the discount. Therefore, the Commission declines to adopt the proposal to include municipal and county rates in the same rate code as that of schools and declines to adopt billing consolidation for municipal accounts in the absence of a study to identify the actual cost of consolidating the accounts.

PSO is directed to provide a cost study in its next rate case that quantifies the impact of adding municipalities and counties to the rate code under which schools are currently served. Additionally, PSO should conduct a study to determine if there are any savings to the Company which might accrue if municipal accounts are consolidated in some logical fashion to save meter reading expenses or other costs associated with billing multiple accounts to the same customer.

7. Large Industrial Service

Large Industrial customers are provided service under PSO's Large Power and Light (Primary, Primary Substation, and Transmission) tariffs which are all ratcheted demand Time of Day tariffs. These tariffs encourage conservation during PSO's highest use hours, 2 p.m. to 9 p.m., during the on-peak months of June through September. PSO did not propose any structural rate changes for the industrial customer classes. However, as is the case in the other classes of customers, PSO proposed an equal percentage increase to all components of the industrial rates. Moncrief Direct at p. 16.

The Commission finds that the rate design adopted herein for all classes of customers is reasonable when applied to the Large Industrial Service Class.

8. Lighting

PSO'S lighting schedules consist of flat rates for Security Lighting, Non-Roadway Lighting, Municipal Street Lighting, and Governmental Street Lighting. The municipal and governmental street lighting tariffs also include a rate for customer-owned lights. In addition to these, PSO offers an Outdoor Lighting schedule for metered and non-metered installations as well as a Recreational Lighting offering. These schedules consist of a basic service charge and an energy charge. Moncrief Direct at p. 16. PSO is not proposing structural changes for any of the lighting classes. However, as is the case in the other classes of customers, PSO is proposing an equal percentage increase to all components of the lighting rates. Moncrief Direct at p. 18.

QOSC objected to PSO's proposed increase to the Lighting rates and argued that the proposed increase to Lighting rates exceeds the across the board increase proposed by PSO. Twombley Direct at p. 8. PSO argued that Mr. Twombley's calculations are in error, because he omitted the cost of fuel recovered through the Fuel Adjustment Clause in his comparisons. Dec. 17 Tr. at p. 86.

The Commission finds that lighting, like all other classes of customer service, should receive an increase equal to the percentage increase applied to all of PSO's customer classes in the manner recommended herein. Ironically, according to Staff's testimony, applying an equal increase to the lighting class will still not move them closer to their cost of service and will actually move the lighting class further away from their cost of service. Smith Responsive, p. 15.

9. Fuel Cost Adjustment

OIEC witness Garrett recommended that PSO introduce a fuel cost adjustment that reflects on-peak and off-peak energy costs and consumption, or hourly fuel prices. Garrett Rate Design Responsive at p. 18. PSO witness Moncrief pointed out that OIEC overlooked the fact that higher cost base load generation goes along with the lower cost fuel. PSO argued that OIEC seeks the benefits of the lower cost fuel and ignores the associated base load plant that uses it. Higher load factor customers have a higher capacity cost. If one were to take generation capacity cost to time periods, high load factor customers would be responsible for more of the higher cost base load plant and therefore have a higher capacity cost which would be partially offset by the lower fuel cost. PSO argued that just looking at the fuel cost, without the corresponding capacity cost, would be inappropriate. PSO also argued that the OIEC proposal departs from average ratemaking. Moncrief Rebuttal at pp. 28-29.

OIEC proposed that hearings be held before price changes are made to the Fuel Adjustment Clause. Garrett Rate Design Responsive at p. 20. As explained by PSO witness Sartin, PSO changes its fuel cost adjustment according to the fuel cost adjustment rider tariff approved by the OCC, which states: "...The Director of the Public Utility Division shall approve the requested change effective with the first billing cycle of the month subsequent to the approval." PSO follows this OCC prescribed method for changing its fuel cost adjustment rider. Sartin Rebuttal at p. 10. OIEC cited no specific issues with the current process wherein the Director of the PUD approves changes in factors, but recommended the change because fuel represents a large percentage of customers' total electric bills. Garrett Rate Design Rebuttal at p. 20. PSO recently participated in an OCC Staff application before the OCC to review PSO's monthly fuel filing and annual fuel factor determination in Cause No. PUD 200800150. This Cause resulted in extensive testimony, discovery and cross-examination of ten witnesses from PSO, the AG, OCC Staff, and OIEC. The OCC's final order (No. 556232) concluded "IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA that the FAC fuel factor proposed by PSO in its Annual Fuel Factor Report is justified." PSO testified it plans to continue to follow the process in setting fuel factors in the future as set forth in that case. Sartin Rebuttal at p. 11. PSO further testified there are both customer and Company protections in the current process. In the event that the annual cost of fuel begins to differ significantly from the cost used in the annual Fuel Cost Adjustment factor, or if as a result of applying new fuel factors the actual fuel costs cause PSO to over- or under-recover fuel costs by $50 million or more, an interim adjustment may be filed. This protects both PSO and customers if fuel factors are significantly too high or too low. In addition, all over- and under-recoveries of fuel costs accrue interest to the benefit of customers or PSO. Sartin Rebuttal at pp. 11-12.

The Commission finds that time-differentiated fuel, without allocation of generation plant on the same basis, mismatches fuel and plant costs and departs from average ratemaking. The Commission therefore does not adopt the proposal of OIEC to establish a fuel adjustment clause that includes on-peak and off-peak energy costs and consumption, or hourly fuel prices. The Commission further finds the current mechanism for adjusting the Fuel Adjustment Clause practice is working properly, provides protections for both PSO and its customers, and should be continued.

10. Customized Contracts

OIEC witness Garrett testified that the Customized Contract Rate ("CCR") should require Commission approval whenever a customer is offered a contract price and in any situation where other customers are being required to subsidize an individual customer. In the absence of Commission approval, Mr. Garrett recommends that the CCR be repealed. Garrett Rate Design at p. 19. PSO witness Moncrief testified that PSO's customers are not required to subsidize the customers served under a CCR contract rate. Further, the CCR tariff, in its current form, including all the provisions of service under the tariff, has been reviewed and approved by the Commission. PSO explained that the CCR is only available under very specifically defined and limited conditions. The customer requesting service under the CCR must have a connected load of 250 kW or greater and have a non-Corporation Commission rate-regulated economic alternative to service from PSO's standard tariff rates. The final pricing arrangements under the CCR are part of the contract for electric service, which is filed at the Commission. The CCR has been subjected to Commission oversight and PSO does not agree that the CCR should be repealed. Moncrief Rebuttal at pp. 29-30.

The Commission finds that the CCR has been approved by the Commission and is subject to Commission oversight. The CCR is a useful tool for retaining customers on the system of PSO, when they have a non-Corporation Commission rate-regulated economic alternative to obtaining service from PSO's standard tariff rates. This benefits all customers on PSO's system by enabling some portion of the fixed costs of PSO's system to be allocated to the CCR customer. Further, no other customers subsidize customers receiving CCR service. Therefore, the Commission finds that the CCR should remain in place in its current form.

11. Demand-Side Management ("DSM") Proposals

Both QOSC witnesses Robson and Kane offered specific programs for PSO to consider for inclusion in future DSM/Energy Efficiency ("EE") offerings. The programs they suggested include a rehabilitation program for existing homes and a Green Building program for new homes. Robson Direct at pp. 7-10; Kane Direct at p. 11. PSO expressed appreciation for the support offered by both Messrs. Robson and Kane for PSO's DSM/EE programs. Both of the programs suggested by Messrs. Kane and Robson are being considered by PSO for inclusion in the new offerings planned for implementation in 2010. PSO stated that it would be premature, however, for PSO to agree to include either program at this time. PSO has just begun implementation of its Quick Start programs. The results of the Quick Start programs, how the programs performed and the implementation processes used, will be important information to consider in developing additional offerings. Secondly, selecting additional programs will include many steps, none of which have yet been completed. The process for selecting new programs will include: soliciting input from stakeholders; review of best programs in place in other jurisdictions; establishing clear goals for the programs and for the portfolio of programs to be offered; and integration of potential offerings into a portfolio of programs that will best fit the class of customers they are targeted towards and the overall goals and objectives for that portfolio of programs. PSO will be working with Mr. Robson, Mr. Kane, and other stakeholders in developing new DSM/EE offerings for its customers. Champion Rebuttal at pp. 4-5.

QOSC questioned PSO witness Kathy Champion regarding additional sources of educational materials for possible use in conjunction with the Quick Start programs. Dec. 17 Tr. at pp. 8-11. Ms. Champion stated that she is willing to review informational tools offered by QOSC, but the tools suggested by Messrs. Robson and Kane in their testimony could create a demand that cannot be met by the resources allocated to the Quick Start programs. Dec. 17 Tr. at pp. 9, 10, and 12.

OIEC witness Garrett recommended that a limitation be added to the DSM Rider so that it would be applicable to only the Quick Start programs. Garrett Rate Design Responsive at pp. 21-22. PSO argued that while the DSM Rider is currently being used only to recover the costs and incentives for the Quick Start programs, there is no reason to assume it would or could not be used to recover costs for future DSM/EE programs. However, since recovery of costs for additional programs would need to be reviewed and approved by the Commission, PSO argued the additional limitation is simply unnecessary. Champion Rebuttal at p. 6; Dec. 17 Tr. at pp. 13, 14, 15, and 17.

OIEC commented that by sending price signals, demand response will occur naturally. Garrett Rate Design Responsive at pp. 5-8. However, PSO's own experience with pricing options has shown that customers typically respond to high price signals by changing their behavior, altering their schedules, or operating practices. PSO testified that while these changes can be significant, experience with the participating Real Time Pricing customers has demonstrated that the changes typically are not permanent and subside over time as customers adjust to the higher costs or respond to higher demand for their own product. Champion Rebuttal at p. 6. PSO testified that some customers may have the ability and the financial resources to respond to Real Time Pricing signals, while other customers, like many small commercial or residential customers, may not have the same flexibility to respond. If smaller customers continue to use the same amount of power, even in the face of higher prices, the result may nevertheless be an increased need for resources. Champion Rebuttal at pp. 6-7.

OIEC characterized DSM programs as more costly than price signals. Garrett Rate Design Responsive at pp. 8-9. PSO pointed out that PSO, by request from this Commission, has implemented and will pursue DSM programs that by definition are cost effective, which means they cost less than the resources they are targeted to replace. The Quick Start DSM programs are targeted to reduce kWh sales by 20 million kWhs. The cost of that reduction, including the Lost Revenues and the Net Shared Savings Incentive, was less, or was more cost effective, than the long-term cost of purchasing power or building additional resources. Champion Rebuttal at p. 7.

The Commission, having considered the arguments of the parties finds the recommendations of QOSC and OIEC regarding Demand Side Management should not be approved. The Commission has expressed its desire for PSO to continue to explore cost effective Demand Side Management programs and recommends PSO work with QOSC and OIEC and other stakeholders in the future development of those programs.

**ORDER**

IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION of the State of Oklahoma that the above findings of fact and conclusions of law are adopted as the Order of this Commission.

IT IS FURTHER ORDERED that the Summary of Testimony attached hereto as "Attachment A" is hereby adopted as the summary of the testimony in this Cause.

IT IS FURTHER ORDERED that Public Service Company of Oklahoma is hereby authorized to file tariffs, rate schedules, and terms and conditions of service in accordance with the findings and Order made herein, which will allow Public Service Company of Oklahoma the opportunity to recover from its Oklahoma retail jurisdictional customers total additional revenues of $59,255,989, until the next rate review by the Commission. Attachment 1 to this order contains the Accounting Exhibits that reflect the revenue requirement and adjustments set forth in this Order.

IT IS FURTHER ORDERED that Attachment 2, Revenue Distribution, reflects the Order of the Commission herein.

IT IS FURTHER ORDERED that the rates, charges and tariffs reflecting the terms of this Order be and the same are hereby approved and shall become effective with the first regular billing cycle after the Company has filed tariffs with the Commission that conform to this Order and the tariffs have been reviewed by the Director of the Public Utility Division.

OKLAHOMA CORPORATION COMMISSION

________________________________
BOB ANTHONY, Chairman

________________________________
JEFF CLOUD, Vice Chairman

________________________________
DANA L. MURPHY, Commissioner

DONE AND PERFORMED THIS _______ DAY OF JANUARY 2009, BY ORDER OF THE COMMISSION:

________________________________
JOYCE CONNER, Assistant Secretary

APPROVED AS TO FORM:

________________________________ __________________________
MARIBETH D. SNAPP, Referee Date

PUD Cause No. 200800144
Final Order
Attachment 1
Schedule B-1

PUBLIC SERVICE COMPANY OF OKLAHOMA
REVENUE REQUIREMENT
FOR THE TEST YEAR ENDED FEBRUARY 29, 2008

| Line No. | (1) Description | (2) Schedule Reference | (3) Total Company Per Books | (4) Adjustment | (5) Final Order Total Company Pro Forma |
|---|---|---|---|---|---|
| 1 | Rate Base | B-2 | $ 1,566,283,234 | $ (98,992,985) | $ 1,467,290,249 |
| 2 | Rate of Return | F-1 | 8.31% | | 8.31% |
| 3 | Operating Income Requirement | | 130,158,137 | (8,226,317) | 121,931,820 |
| 4 | Pro Forma Operating Income | B-2 | 27,595,842 | 58,357,427 | 85,953,269 |
| 5 | Difference | | 102,562,295 | (66,583,744) | 35,978,551 |
| 6 | Revenue Conversion Factor | | | | 1.646981 |
| 7 | Change in Revenues | | | | $ 59,255,989 |

PUD Cause No. 200800144
Final Order
Attachment 1
Schedule B-2

PUBLIC SERVICE COMPANY OF OKLAHOMA
RATE BASE/RATE OF RETURN
FOR THE TEST YEAR ENDED FEBRUARY 29, 2008

| Line No. | (1) Description | (2) Schedule Reference | (3) Total Company Per Books | (4) Pro Forma Adjustment (B-3) | (5) Total Company Pro Forma | (6) Final Order Adjustment | (7) Total Company Final Order Amount |
|---|---|---|---|---|---|---|---|
| 1 | Plant in service: | | | | | | |
| 2 | Plant in service | C-1 | $ 3,344,590,744 | $ 30,380,975 | $ 3,374,971,719 | $ 131,170,736 | $ 3,506,142,455 |
| 3 | Construction work in progress | C-1 | 145,341,393 | (45,259,525) | 100,081,869 | (100,081,869) | 0 |
| 4 | Plant held for future use | W/P C-13 | 0 | 0 | 0 | - | 0 |
| 5 | Gross Plant | C-1 | 3,489,932,137 | (14,878,550) | 3,475,053,587 | 31,088,868 | 3,506,142,455 |
| 6 | Accumulated depreciation | D-1 | (1,453,715,580) | (3,335,356) | (1,457,050,936) | (14,416,501) | (1,471,467,437) |
| 7 | Net Plant | | 2,036,216,557 | (18,213,906) | 2,018,002,651 | 16,672,367 | 2,034,675,018 |
| 8 | Working capital: | | | | | | |
| 9 | Cash working capital | E-1 | (128,320,638) | 0 | (128,320,638) | 3,864,817 | (124,455,821) |
| 10 | Prepayments (13 Mo Avg) | W/P B-5 | 81,813,803 | (2,134,624) | 79,679,179 | (77,686,018) | 1,993,162 |
| 11 | Materials, supplies and fuel inventories (13 Mo Avg) | W/P B-5 | 71,662,311 | (47,061) | 71,615,249 | - | 71,615,249 |
| 12 | Additions and deductions: | | | | | | |
| 13 | Customer deposits (Year End)) | W/P B-6 | (40,636,264) | 0 | (40,636,264) | - | (40,636,264) |
| 14 | Customer Advances for Construction (Year End) | W/P B-6 | 0 | 0 | 0 | - | 0 |
| 15 | Off System Trading Deposits (13 Month Avg) | W/P B-6 | 9,984,413 | 0 | 9,984,413 | - | 9,984,413 |
| 16 | Regulatory assets | B-3 | 0 | 11,192,213 | 11,192,213 | - | 11,192,213 |
| 17 | Other | B-3 | 0 | (6,880,704) | (6,880,704) | - | (6,880,704) |
| 18 | Net total investment | | 2,030,720,182 | (16,084,081) | 2,014,636,101 | (57,148,834) | 1,957,487,267 |
| 19 | Accumulated deferred income taxes | W/P J-3 | (464,203,608) | (5,043,125) | (469,246,733) | (20,716,945) | (489,963,678) |
| 18 | Excess deferred taxes | W/P J-4 | 0 | | 0 | - | 0 |
| 20 | Deferred investment credits (pre-1971) | | (233,340) | 0 | (233,340) | - | (233,340) |
| 21 | Rate base | | 1,566,283,234 | (21,127,206) | 1,545,156,028 | (77,865,779) | 1,467,290,249 |
| 22 | Net operating income | H-1 | $ 27,595,842 | $ 58,357,427 | $ 85,953,269 | | $ 121,931,820 |
| 23 | Rate of return | | 1.76% | | | | 8.31% |

PUD Cause No. 200800144
Final Order
Attachment 1
Schedule F-1

PUBLIC SERVICE COMPANY OF OKLAHOMA
COMPONENTS OF CAPITAL
FOR THE TEST YEAR ENDING FEBRUARY 29, 2008

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) | (8) |
|---|---|---|---|---|---|---|---|---|
| Line No. | Description | Schedule Reference | Capital Per Books | Pro-Forma Adjustments | Adjusted Capital | Capital Ratio | Cost Rate | Weighted Average Cost |
| 1 | Long-Term Debt | WP F-3 | $ 898,330,122 | $ - | $ 898,330,122 | 55.574% | 6.60% | 3.67% |
| 2 | Preferred Stock | WP F-2 | 5,261,700 | - | 5,261,700 | 0.326% | 4.02% | 0.01% |
| 3 | Common Equity | | 633,426,224 | 79,435,209 | 712,861,433 | 44.100% | 10.50% | 4.63% |
| 4 | Total Capital | | $ 1,537,018,046 | $ 79,435,209 | $ 1,616,453,255 | 100.000% | | 8.31% |

PUD Cause No. 200800144
Final Order
Attachment 1
Schedule H-1

PUBLIC SERVICE COMPANY OF OKLAHOMA
TEST YEAR ACTUAL AND PRO FORMA OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED FEBRUARY 29, 2008

| Line No. | (1) Description | (2) Schedule Reference | (3) Total Company Per Books 2/29/2008 | (4) Sched. H-2 Pro Forma Adjustment | (5) Total Company Pro Forma | (6) Revenue Deficiency | (7) Pro Forma with Revenue Increase |
|---|---|---|---|---|---|---|---|
| 1 | Operating Revenue | | $ 1,399,265,224 | $ (914,794,846) | $ 484,470,378 | $ 59,255,989 | $ 543,726,367 |
| 2 | Operating Expenses: | | | | | | |
| 3 | Fuel and Purchased Power | W/P H-3 | 898,478,885 | (893,310,477) | 5,168,408 | 0 | 5,168,408 |
| 4 | Other Operation and Maintenance | W/P H-3 | 355,480,280 | (101,640,277) | 253,840,002 | 583,319 | 254,423,321 |
| 5 | Other Taxes | | 40,438,953 | (600,651) | 39,838,303 | 0 | 39,838,303 |
| 6 | Depreciation and Amortization | I-1, I-2 | 93,566,333 | (10,903,885) | 82,662,448 | 0 | 82,662,448 |
| 7 | Operating Expenses Before Income Taxes | | 1,387,964,450 | (1,006,455,289) | 381,509,161 | 583,319 | 382,092,480 |
| 8 | Operating Income Before Income Taxes | | 11,300,774 | 91,660,443 | 102,961,217 | 58,672,670 | 161,633,887 |
| 9 | Income Taxes | J-1 | (16,295,068) | 33,303,016 | 17,007,948 | 22,694,119 | 39,702,067 |
| 10 | Net Operating Income | | $ 27,595,842 | $ 58,357,427 | $ 85,953,269 | $ 35,978,551 | $ 121,931,820 |
| 11 | Rate Base | B-1 | $ 1,570,148,051 | $ (102,857,802) | $ 1,467,290,249 | | $ 1,467,290,249 |
| 12 | Rate of Return | | 1.76% | | | | 8.31% |

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED FEBRUARY 29, 2008

| Line No. | (1) Adjustment Number | (2) Description | (3) Sponsor | (4) Company Filed Adjustment Amount | (5) Final Order Section Reference | (6) Final Order Adjustment | (7) Final Order Adjustment Amount |
|---|---|---|---|---|---|---|---|
| 1 | WP H-2-1 | Adjust cost of service for payroll annualization | Aaron | 1,955,558 | EXP 7 | - | 1,955,558 |
| 2 | WP H-2-2 | Adjust cost of service related to AEPSC payroll annualization | Aaron | 1,316,699 | EXP 7 | - | 1,316,699 |
| 3 | WP H-2-3 | Adjust pension expense to reflect 2008 SFAS 87 actuarial study | Aaron | 94,621 | EXP 11 | (698,720) | (604,099) |
| 4 | WP H-2-4 | Adjust cost of service to reflect 2008 SFAS 106 actuarial expense | Aaron | (20,580) | | - | (20,580) |
| 5 | WP H-2-5 | Adjust cost of service to reflect 2008 SFAS 112 actuarial expense | Aaron | 572,485 | | - | 572,485 |
| 6 | WP H-2-6 | Adjust cost of service for annualized employee benefits | Aaron | 1,787,480 | EXP 10 | (1,672,238) | 115,242 |
| 7 | WP H-2-7 | Adjust cost of service for PSO incentive compensation | Jolley | (2,487,684) | EXP 12 | (7,711,851) | (10,199,535) |
| 8 | WP H-2-8 | Adjust FICA expense consistent with base payroll and incentive payroll adjustments | Aaron | (13,386) | EXP 8 | (128,375) | (141,761) |
| 9 | WP H-2-9 | Adjust cost of service to include interest expense on customer deposits | Aaron | 1,814,919 | EXP 13 | - | 1,814,919 |
| 10 | WP H-2-10 | Adjust cost of service for Jan 2007 and Dec 2007 Ice Storm Expense | Aaron | (67,182,221) | EXP 4 | - | (67,182,221) |
| 11 | WP H-2-11 | Adjust cost of service for donations and contributions (and FO Mkt Exp) | Aaron | (3,600) | EXP 19 | (27,650) | (31,250) |
| 12 | WP H-2-12 | Adjust cost of service for certain dues and memberships | Aaron | (107,697) | EXP 18 | (140,522) | (248,219) |
| 13 | WP H-2-13 | Adjust cost of service to remove regulatory expenses | Aaron | (1,820,934) | | - | (1,820,934) |
| 14 | WP H-2-14 | Adjust cost of service for purchased power expenses | | | | | |
| 15 | | - Remove purchased power expense recovered via OCC approved FAC | Aaron | (299,423,154) | | - | (299,423,154) |
| 16 | | - Adjust purchased power capacity costs to on-going level (FO recover via FAC or rider) | Hakimi | 4,845,403 | EXP 20 | (14,288,690) | (9,443,287) |
| 17 | WP H-2-15 | Adjust cost of service to exclude advertising expenses | Aaron | (364,320) | EXP 19 | (54,273) | (418,593) |
| 18 | WP H-2-16 | Annualize depreciation expense to proposed annual rate | Davis | 11,121,959 | EXP 23 | (17,107,020) | (5,985,061) |
| 19 | WP H-2-17 | Annualize amortization expense to proposed annual rate | Aaron | (5,605,022) | EXP 21 | 686,198 | (4,918,824) |
| 20 | WP H-2-18 | Adjust revenues in cost of service. | | | | | |

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED FEBRUARY 29, 2008

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| Line No. | Adjustment Number | Description | Sponsor | Company Filed Adjustment Amount | Final Order Section Reference | Final Order Adjustment | Final Order Adjustment Amount |
| 21 | | - Adjust retail base for weather, customer, and pro-forma | Moncrief | (43,458,082) | RR 5 | 4,114,677 | (39,343,405) |
| 22 | | - Remove retail fuel revenues included in OCC approved FAC. | Aaron | (767,001,068) | | - | (767,001,068) |
| 23 | | - Adjust wholesale base revenue | Moncrief | 850,809 | | - | 850,809 |
| 24 | | - Remove wholesale fuel revenues | Aaron | (449,448) | | - | (449,448) |
| 26 | | - Remove off-system revenues included in OCC approved FAC or retained by PSO | Aaron | (115,017,858) | | - | (115,017,858) |
| 27 | | - Adjust miscellaneous revenues (forfeited discounts, misc svc, rentals, etc.) | Moncrief | 6,166,123 | | - | 6,166,123 |
| | | TOTAL | | (918,909,523) | | 4,114,677 | (914,794,846) |
| 28 | WP H-2-19 | Adjust cost of service related to AEPSC billing adjustments | Hoersdig | 166,003 | | - | 166,003 |
| 29 | WP H-2-20 | Adjust amortization expense for rate case amortization related to current proceeding | Aaron | 658,335 | EXP 16 | (130,417) | 527,918 |
| 30 | | and 12 months amortization expense related to PUD 200600285 | | | | | |
| 31 | WP H-2-21 | Adjust other taxes to reflect changes in revenues and rate base | Aaron | 2,185,434 | EXP 2 | (2,644,324) | (458,890) |
| 32 | WP H-2-22 | Eliminate fuel expense recovered via the OCC approved FAC | Aaron | (584,353,673) | | - | (584,353,673) |
| 33 | | (Test Year fuel expense = $589,612,443; amount remaining in base rate = $5,258,770) | | | | | |
| 34 | WP H-2-23 | Annualize factoring expense based on test year ending adjusted revenue and factoring rate | Aaron | (1,421,826) | EXP 14 | (7,945) | (1,429,771) |
| 35 | WP H-2-24 | Adjust cost of service to reflect ongoing level of SPP fees and expenses | Aaron / Pennybaker | 5,524,783 | EXP 6 | - | 5,524,783 |
| 36 | WP H-2-25 | Adjust cost of service related to ABD expense adjustment | Aaron | (1,182,379) | | - | (1,182,379) |
| 37 | WP H-2-26 | Adjust cost of service to reflect expenses recovered through RCA rider | Aaron | (25,179,036) | | - | (25,179,036) |
| 38 | WP H-2-27 | Adjust amount recovered in base rates related to Distribution Vegetation Management | Aaron | 7,700,000 | EXP 1 | (7,700,000) | 0 |
| 39 | WP H-2-28 | Adjust cost of service to reflect higher fuel prices for fleet vehicles. | Aaron | 583,307 | | (583,307) | 0 |
| 40 | WP H-2-29 | Adjust cost of service for SO2 auction proceeds and CO2 gains | Aaron | (462,056) | EXP 17 | 462,056 | 0 |
| 41 | WP H-2-30 | Adjust cost of service to reflect postage rate increases | Aaron | 95,054 | EXP 15 | - | 95,054 |
| 42 | WP H-2-31 | Adjust cost of service for expenses related to Red Rock facility | Aaron | (337,129) | | - | (337,129) |
| 43 | WP H-2-32 | Adjust cost of service for employee expenses | Aaron | (42,061) | | - | (42,061) |

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED FEBRUARY 29, 2008

| | (1) | (2) | (3) | (4) | (5) | (6) | (7) |
|---|---|---|---|---|---|---|---|
| Line No. | Adjustment Number | Description | Sponsor | Company Filed Adjustment Amount | Final Order Section Reference | Final Order Adjustment | Final Order Adjustment Amount |
| 44 | WP H-2-33 | Adjust cost of service for AEPSC incentive compensation | Jolley | (5,612,986) | | - | (5,612,986) |
| 45 | WP H-2-34 | Adjust cost of service to Include trading deposit interest income and expense | Aaron | (485,053) | | - | (485,053) |
| 46 | WP H-2-35 | Adjust cost of service to recognize annual interest on IPP System Upgrade Credits | Aaron | 456,251 | | - | 456,251 |
| 47 | WP H-2-36 | Adjust cost of service for transmission reliability programs | Matthews | 5,658,100 | EXP 5 | (4,946,000) | 712,100 |
| 48 | WP H-2-37 | Adjust cost of service for generation maintenance expense | Knight | (5,000,000) | EXP 3 | - | (5,000,000) |
| 49 | WP H-2-38 | Exclude non-recurring expense from cost of service | Aaron | (526,535) | | - | (526,535) |
| | | Provide Long Term Debt Return on Prepaid Pension Asset (net of ADIT) | | - | RB 3 | 3,332,730 | 3,332,730 |
| | | Provide annual funding for Smart Grid Program | | - | EXP 25 | 2,000,000 | 2,000,000 |

**Public Service Company of Oklahoma**
**Final Order Revenue Distribution**

**FINAL ORDER BASED REVENUE DISTRIBUTION**
**@ $59.256 MILLION INCREASE**

| | Base Revenue Increase | Proposed Revenues | Percentage Increase |
|---|---|---|---|
| Residential | $32,600,135 | $243,944,546 | 15.43% |
| Coml SL4 | $750,642 | $5,617,004 | 15.43% |
| Coml SL5 | $16,412,833 | $169,145,622 | 10.75% |
| Lighting | $1,293,575 | $9,679,734 | 15.43% |
| SL3 | $4,425,036 | $33,112,235 | 15.43% |
| SL2 | 3,069,909 | 31,637,542 | 10.75% |
| SL1 | 703,859 | 7,253,756 | 10.75% |
| Total | **$59,255,989** | **$500,390,439** | **13.43%** |

**Total Proposed Revenues @ Final Order Rev Dist**

| | Proposed Base Revenue Including Riders | Proposed Fuel Revenue @ 4.1 cents | Total Proposed Revenue | Percent Incr (Decr) From Present |
|---|---|---|---|---|
| Residential | $254,374,206 | $243,594,147 | $497,968,353 | 7.59% |
| Coml SL4 | | | | |
| Coml SL5 | $182,062,326 | $230,552,642 | $412,614,968 | 4.66% |
| Lighting | $9,807,894 | $5,391,135 | $15,199,030 | 10.32% |
| SL3 | $34,679,345 | $84,022,835 | $118,702,179 | 4.02% |
| SL2 | 32,927,782 | 122,707,256 | 155,635,038 | 1.75% |
| SL1 | 7,533,116 | 26,956,355 | 34,489,471 | 1.86% |
| Total | $ 521,384,669 | $ 713,224,369 | $ 1,234,609,038 | 5.36% |

**News** from the **Oklahoma Corporation Commission**
**Matt Skinner, Public Information**
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**February 5, 2009**

# Calling All Customers

***Big changes are coming to the 918 area code, and all telephone customers are encouraged to get involved***

**(Tulsa) The 918 area code is running out of telephone numbers, and the Oklahoma Corporation Commission is urging all within the region to get involved in the process of determining what to do about it.**

**Commission Chief of Telecommunications Bennett Abbott says public participation is critically important.**

**"The Commissioners want to be sure all those in the 918 area code are part of the process and have their voices heard," explained Abbott. "The feedback received will figure heavily in the recommendations that staff makes to the Commissioners."**

**The North American Numbering Plan Administrator (NANPA) has notified the Commission that the 918 area code is expected to run out of phone numbers (referred to as a "number exhaust") by the fourth quarter of 2011. Programs put in place by the Commission have enabled all the area code regions in the state to continue to function without changes for years past their original number exhaust dates.**

**There are two basic options to handle number exhaust:**

- **Option 1 – Area Code Split – This would involve splitting the present 918 area code into two sections. One would keep the 918 area code, the other would get a new area code. This "split" would not change local calling boundaries.**
- **Option 2 – Area Code Overlay – This would involve assigning a new area code to all new numbers within the 918 area code region. While local calling boundaries would remain the same, this would require ten-digit dialing for all local calls.**

**Full details about the matter, as well as a survey form, will be available at occeweb.com . Residents and businesses can also call the Commission at 405-521-2211 for information. Opinions can also be submitted at 1-800-522-8154.**

**The Commission will be holding town hall meetings in the coming months on the matter, as well as making public service announcements via local media.**

**-OCC-**

# **News** from the **Oklahoma Corporation Commission**

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**February 27, 2009**

## A NEW MONTH BRINGS NEW SAVINGS FOR PSO CUSTOMERS

***Commission action results in multi-million dollar refund for PSO customers***

**Starting with March bills that begin going out today, Public Service Company of Oklahoma (PSO) customers will see savings totaling more than $140 million. Approximately $54 million of that amount is the result of a victory the Oklahoma Corporation Commission won on behalf of customers in a case it filed last year before the Federal Energy Regulatory Commission (FERC). Another approximately $90 million is the result of a joint effort by the Corporation Commission and PSO to readjust the fuel charge based on the drop in natural gas prices. The total savings will be realized through an adjustment in the fuel charge PSO customers pay.**

**Commission Chairman Bob Anthony said the FERC case involved PSO's share of profits from the sale of excess power by its parent company, American Electric Power (AEP).**

**"This case presented a complicated jurisdictional question about allocating millions of dollars among AEP companies in different states. I personally directed our agency staff to argue Oklahoma's position to federal authorities," Anthony explained. "FERC ruled in the Commission's favor. PSO has filed an appeal of that decision, but we remain confident the original ruling will stand. In the meantime, PSO is proceeding with a process to refund the money to customers over a one-year period."**

**Commission Vice Chair Jeff Cloud explained the second element of the savings, conservatively projected as a $90 million dollar reduction in the fuel charge, is the result of a "trigger" put in place by the Commission in a previous PSO rate case.**

**"While the fuel cost factor is normally adjusted once a year, we put a mechanism in place which allowed Commission staff to act immediately if PSO's fuel cost account had a surplus of $50 million or greater, rather than wait until the end of the annual period," said Cloud,. "In this case, PSO and staff worked together to take action and pass the savings on to customers when that threshold was exceeded because of falling fuel prices.**

**"It should be noted that the $90 million figure is a conservative estimate," added Cloud. "The final number is expected to be greater, as fuel prices have continued to drop."**

**Commissioner Dana Murphy said the positive result for the consumer is a credit to all involved.**

**"Even though PSO and the Commission were on opposite sides in the FERC case, once FERC ruled on the Commission's complaint, the company worked in a constructive**

**manner with Commission staff to get the money back to the consumer," said Murphy. "The issue of the fuel charge surplus was handled in the same positive, pro-active manner."**

**The estimated monthly savings from the FERC-related refund for the average PSO residential customer (1,000 kilowatt hours/month) is $2.86. The estimated monthly savings from the refund on fuel costs is $4.11, for a total estimated savings of $6.97 a month.**

**Under Oklahoma law, a regulated utility is allowed to pass on to its customers its actual fuel costs. It may not make a profit on those costs.**

**-OCC-**

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**News from: Commissioner Dana Murphy** **Commissioner**

FOR IMMEDIATE RELEASE

For Further Information, Contact:
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# THE OG&E RATE CASE AND YOU

*Murphy wants to keep public "in the loop"*

Saying it is vitally important for the public to be kept informed on the rate-making process, Oklahoma Corporation Commissioner Dana Murphy today announced steps that will be taken to educate and inform the public as the Oklahoma Gas and Electric (OG&E) rate case moves through the Commission process.

"First, it's important that the public know that staff is already hard at work on the matter," Murphy said. "The Commission's Public Utility Division has 18 staff members dedicated to the case, and work assignments are being made as we speak. The staffers include auditors, rate analysts, economists, and an engineer. The complex areas they are looking at include the Company's rate base, operating income (revenues and expenses), capital structure, depreciation, the proposed return on equity, and other subjects. Staff's work includes not only extensive hours in the office, but on-site visits to OG&E facilities as well."

Murphy noted that other parties to the case are also hard at work.

"There are many parties to a rate case," she explained. "For example, the Attorney General represents the ratepayers before the Commission in such cases. Other parties include industrial consumers of electricity and shareholders of the company, to name just a few.

"It is the Commissioners' task to weigh all the arguments and evidence presented from all parties to the case, and make a fair and balanced decision," added Murphy.

Murphy said steps are being taken so the public can follow the case.

“We will soon have a link on our home page (www.occeweb.com) to all the documents that will be filed in the case. These include the original application, pre-filed testimony and other evidence, and many other items.” said Murphy. “The link will also include a section to allow the public to send comments on the case. The public can also comment on the case by mail or by calling (405) 521-2308.

“In addition, the public is welcome to attend all hearings in the matter. Once the Commissioners themselves get the case, time is set aside to allow the public to speak,” added Murphy.

The Corporation Commissioners are expected to make a decision in the OG&E case this summer. OG&E is requesting an annual increase of $110 million.

**-occ-**

**(All OCC advisories and news releases are available at the Commission web site www.occeweb.com)**

# News from the Oklahoma Corporation Commission

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**April 17, 2009**

# LOOK BEFORE YOU LEAP

***Corporation Commissioners warn President's budget will increase our reliance on foreign energy, put thousands out of work***

**(Oklahoma City) The Oklahoma Corporation Commissioners have sent a letter to President Obama and congressional leaders warning that the President's proposed budget will have "disastrous effects on Oklahoma's efforts to educate its children, clean its environment, and create jobs."**

**Among other things, the President's budget would repeal tax incentives needed by Oklahoma's independent energy producers, even though many of those incentives will still be in effect for all other manufacturers.**

**The Commissioners noted that Oklahoma's oil and natural gas industry provides, directly and indirectly, a huge percentage of the funding for public services, and is the single largest contributor to Oklahoma education. It is also the sole source of funding for one of the most successful environmental clean-up programs in the U.S., the OERB. Oil and natural gas production and related activities also directly and indirectly account for about 20 percent of Oklahoma's employment.**

**Commission Chairman Bob Anthony said the President's budget would "put the law of unintended consequences to work."**

**"The administration's defense of its approach is that this strategy is necessary to decrease our dependence on foreign oil. The tragedy is that this will, in fact, increase our dependence by driving America's domestic producers out of business," said Anthony.**

**Commission Vice Chairman Jeff Cloud agreed, saying recent history shows what can happen.**

**"In 1980, then-President Carter successfully pushed through the Windfall Profit Tax on energy producers. Much of President Obama's argument for his approach mirrors that used by the Carter administration. As Carter did, President Obama says the extra revenue could be used to fund alternative energy and reduce our dependence on foreign oil. But the same thing will happen today as happened under the Windfall Profit Tax. Our dependence on foreign sources grew by 13 percent and tax revenue from the industry decreased because domestic drilling budgets were slashed in order to meet the extra tax burden."**

**Commissioner Dana Murphy said what's needed is a balanced approach.**

**"While we do need to continue to develop and implement alternative energy sources, we also have a very real need for oil and natural gas. Our domestic supplies are critical to**

**(LOOK pg 2)**

**meeting that need. Adoption of the White House policy will destroy the progress our state has made in education, in cleaning up the environment, and in improving our economy."**

**-OCC-**

**All OCC advisories and releases are available at [www.occeweb.com](http://www.occeweb.com)**

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**News from Commissioner Dana Murphy**

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4/30/2009

# RIDE SAFE

*Corporation Commissioner Dana Murphy urges limo customers to do some homework*

The prom, wedding, and spring/summer party season is underway, and for many that means renting a limousine or planning a trip on so-called “party buses.” Oklahoma Corporation Commissioner Dana Murphy says when it comes to these rentals, a little homework now can prevent a lot of grief later.

"No one wants to think that an accident could happen," Murphy said. "But if it does and injuries result, we want to ensure that the required insurance coverage is in place. We don't want anyone who suffers a loss to find out the hard way that the company he or she trusted can't pay damages for which it might be legally responsible."

Commission Transportation Division Director Marchi McCartney says under state law, any limousine service operating between at least two incorporated cities or towns must be licensed by the Corporation Commission. In order to get that license, it must be properly insured.

“Vehicles for hire that can carry up to 15 passengers are required to have $1 million of liability insurance,” McCartney said. “Vehicles with a seating capacity of 16 or more passengers are required to keep $5 million of liability insurance.”

Commissioner Murphy pointed out that even barring an accident, your trip on an unlicensed carrier can come to an abrupt end.

“There have been instances where the vehicle was stopped by authorities and found to be operating illegally,” explained Murphy. “In some of those cases, the passengers were stranded, and had to arrange other rides.”

To check on a for-hire carrier, you can call the Commission at 405-521-2251, or go to the Commission’s web site, www.occeweb.com. The only for-hire motor carriers not required to have a license from the Corporation Commission are those that operate solely within city limits, with the exception of taxicabs, who are all required to have a license from the Corporation Commission.

**-OCC-**

**All OCC advisories and releases are available at www.occeweb.com**

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**News from Commissioner Dana Murphy**

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6/23/2009

# HORIZONTAL DRILLING LEADS TO NEW DIRECTIONS

**The Oklahoma Corporation Commissioners will hold a special meeting on Tuesday, June 30th at 10 a.m. as part of the Commission's continuous process to ensure the efficient development of Oklahoma's energy reserves.**

**Corporation Commissioner Dana Murphy says the meeting, focusing on horizontal drilling, is part of an ongoing effort to be responsive to changes taking place in oil and gas exploration and production.**

**"The oil and gas industry is in the midst of a technological revolution that has enabled the production of vast new reserves," noted Murphy. "The never-ending challenge our agency faces is to be sure it is doing all it can to foster such advancements while still fulfilling its mission to balance the rights of parties and prevent waste of Oklahoma's resources ."**

**Murphy said the special meeting will be an "open forum" for OCC staff, oil and gas producers, mineral owners, and other interested parties to discuss the various issues, including unitization and well spacing, raised by the increased use of horizontal drilling in Oklahoma in both conventional and unconventional natural gas reservoirs.**

**"We encourage all interested parties to come and present their ideas and comments for consideration," she said.**

**The meeting will be held in Room 301 of the Jim Thorpe Building, 2101 North Lincoln, Oklahoma City.**

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**All OCC advisories and releases are available at www.occeweb.com**

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7/02/2009

# MANY VOICES HEARD ON HORIZONTAL DRILLING

**Oklahoma Corporation Commissioner Dana Murphy says the hundreds who packed a special Commissioner meeting on horizontal drilling are owed thanks for the critical role they are playing in helping the Commission do its job, and will be counted on for continued input.**

**"I am pleased and gratified by the turnout at Tuesday's meeting," said Murphy. "The Commission is committed to fostering ongoing development of Oklahoma's oil and gas resources, while balancing the rights of parties. The Commission is forming an ad-hoc committee on horizontal drilling issues which will have members from all the groups that were at Tuesday's meeting."**

**The meeting was an open forum for OCC staff, oil and gas producers, mineral owners, and other interested parties to discuss the various issues, including unitization and well spacing, raised by the increased use of horizontal drilling in Oklahoma in both conventional and unconventional natural gas reservoirs.**

**-OCC-**
**All OCC advisories and releases are available at www.occeweb.com**

# News from the Oklahoma Corporation Commission

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**July 22, 2009**

## TOUGH TIMES, TOUGH DECISIONS

***Commissioners praise cooperative effort in OG&E rate case***

**(Oklahoma City) The Oklahoma Corporation is expected to vote Friday on a Final Order approving the settlement agreement in the Oklahoma Gas and Electric (OG&E) rate case. The Commissioners held a hearing on the matter today and concluded today's session by instructing the Commission Referee in the case to prepare the Final Order for a vote on Friday.**

**The Commissioners had words of praise for the cooperative effort that resulted in the settlement agreement.**

**Commission Chairman Bob Anthony said the settlement clearly addresses the need to provide electric service that is both reliable and affordable.**

**"Under the settlement, the total residential bill will stay about the same as it is now, as appropriate changes will be made in the rates and fuel charges for OG&E," Anthony said. "Most importantly, OG&E has indicated it can and will provide safe and reliable electric service to its Oklahoma customers under the new billing rates."**

**Commissioner Jeff Cloud called the effort an example of working in the public interest.**

**"Divergent interests came together, and working against the backdrop of a very difficult economy, each made the tough decision to give up something for the greater good," said Cloud. "It is noteworthy that those asking the Commission to approve the measure not only include the Public Utility Division and OG&E, but also the Attorney General's office – which represents the consumer before the Commission – and Oklahoma Industrial Energy Consumers (OIEC), which represents large industrial customers."**

**Commissioner Dana Murphy says the decision by the parties to work together couldn't have come at a better time.**

**"Both at home and on the job, the economy has us all counting our pennies and looking for ways to save. The effort at a compromise means a savings of hundreds of thousands of dollars by avoiding the expense of a protracted rate hearing. It is obvious there was a tremendous effort on the part of all concerned to work together, spurred by the realization that we live in a very difficult economic climate," Murphy said. "A decision for any rate increase is a very tough one, particularly given Oklahomans' current financial worries. We have to carefully balance Oklahoma's present and future power needs, the impact on the consumer, and the company's need for the means to provide reliable service."**

**Those asking for approval of the agreement are: The Oklahoma Attorney General's Office, the Public Utility Division of the Oklahoma Corporation Commission, Oklahoma Gas and Electric, Oklahoma Industrial Energy Consumers, OG&E Shareholders Association, Wal-Mart Stores East, LP and Sam's East, Inc., AES Shady Point, LLC, and PowerSmith Cogeneration Project.**

**OG&E originally asked for a $110 million dollar annual rate increase. The settlement calls for a $48 million dollar rate increase, and changes in the fuel adjustment charge which would minimize or negate the impact of the rate increase on the average customer.**

**-OCC-**

# News from the Oklahoma Corporation Commission

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**July 24, 2009**

# POWERING OKLAHOMA'S FUTURE

***Commissioners approve OG&E rate case settlement, direct that full details be made readily available***

**(Oklahoma City) The Oklahoma Corporation Commission today approved the compromise settlement agreement reached by the parties in the Oklahoma Gas and Electric (OG&E) rate case. The Commission also directed that full details of the settlement and its effect on customers be posted to the Commission's web site: www.occeweb.com**

**Those who asked the Commission to approve the settlement included: The Oklahoma Attorney General's Office – which represents ratepayers before the Commission, the Public Utility Division of the Oklahoma Corporation Commission, Oklahoma Gas and Electric, Oklahoma Industrial Energy Consumers, OG&E Shareholders Association, Wal-Mart Stores East, LP and Sam's East, Inc., AES Shady Point, LLC, and PowerSmith Cogeneration Project.**

**OG&E requested a $110 million annual rate increase. The settlement agreement calls for an annual rate increase of $48 million, with changes to the fuel cost formula to help offset the impact on consumers. It is estimated that the average residential consumer (1500 kilowatt hours/month) will pay slightly less (an average of 63 cents/month) under the settlement for at least the first year.**

**The settlement paves the way for expansion of use of devices to give the consumer more control over their power costs ("smart meters", "time-of-use programs"), and the so-called "smart grid." The settlement also will provide a senior citizens discount of $5 a month from June through October for those age 65 or older who participate in the utility's time-of-use program, and a discount for qualifying low income residential customers.**

**Full details of the settlement, including the final order in the case, the settlement agreement, and questions and answers concerning the matter are available on the Commission's web site: www.occeweb.com**

**-OCC-**

**All OCC advisories and releases are available at www.occeweb.com**

EDITORS, PRODUCERS: PLEASE NOTE ATTACHED FAQ AND IMPACT SHEETS.

# Q&A on OG&E's Oklahoma Rate Agreement

Summer 2009

**Q. What was OG&E's requested increase and what was approved?**

A. OG&E requested an increase of $110 million. The Commission approved a compromise settlement of $48.3 million.

Q. **Who asked the Commission to approve the compromise?**

A. Those who asked the Commission to approve the settlement included: The Oklahoma Attorney General's Office – which represents ratepayers before the Commission, the Public Utility Division of the Oklahoma Corporation Commission, Oklahoma Gas and Electric, Oklahoma Industrial Energy Consumers, OG&E Shareholders Association, Wal-Mart Stores East, LP and Sam's East, Inc., AES Shady Point, LLC, and PowerSmith Cogeneration Project.

**Q. What impact will I see on my monthly bill?**

A. That depends on your rate class and usage. The settlement includes changes in the utility's fuel cost adjustment that should largely offset the rate increase for many residential customers for at least one year. It is estimated that the average residential consumer (1500 kilowatt hours/month) will pay slightly less (an average of 63 cents/month) under the settlement for at least a year. *For further details, and the impact on other rate classes, please see the Rate Impacts chart on the Commission website.* (www.occeweb.com)

**Q. When will these changes show up on my bill?**

A. Customers should see the effects of both the rate increase and the fuel cost reduction on the August bill.

**Q. Do the new rates make provisions for low and fixed income customers?**

A. Yes. Residential customers who qualify for LIHEAP, the Low Income Home Energy Assistance Program administered by state and federal government agencies, receive a discounted rate, and under the new rate structure that discount will be even greater. The new rates also create an opportunity for those 65 and older to participate in a program that would offer a $5 per month credit.

**Q. It seems like rates are always going up. Didn't OG&E just receive a rate increase?**

A. OG&E's last rate increase in Oklahoma was effective in January 2006. Those rates were determined using costs for the 2004 calendar year. This means that the rates customers have been paying were largely based on what it cost OG&E to provide service five years ago.

In 2002, OG&E requested a rate increase of $26 million, and the Commission actually ordered a cut in rates of $25 million. In 2004, OG&E requested a rate increase of $91 million, but later withdrew the request.

**Q: I participate in the Guaranteed Flat Bill ("GFB") program. Will the increase change my monthly bill amount before it expires?**

A: No. All GFB agreements will continue to be billed under the original agreed amount and timeline. Your bill will not change until a new offer is made or you leave the GFB program upon expiration of your agreement.

**Q: I am on average billing. Will my bill go up?**

A: The averaged bill program is calculated using the average of your current bill plus the last 11 months. Your averaged bill will include the rate increase in the calculation after the first bill but you will not see the full impact of the rate increase for one full year. Energy costs are also included in your monthly average bill and will be lower per kWh based upon the fuel factor change. This should help offset the increase in base rates.

**Q: With the economy in recession, why does OG&E need an increase now?**

A: Even though the economy is in recession, OG&E is required to provide safe and reliable electric service. Many of the investments included in this rate review were made prior to the down-turn in the economy and are just now being approved for recovery.

**Q: Even with the reduction in the fuel factor, it appears OG&E will pay higher than market value for natural gas. Is that the case?**

A: No. OG&E is paying market rates for natural gas; however the OG&E fuel factor is changed once every year so customers will not experience the market rates that OG&E pays for gas until the fuel factor is changed. The fuel factor also includes more than just the cost of the fuel commodity. The calculation includes other expenses that are required to provide safe reliable electric service to ratepayers. These costs are audited by the Commission annually and OG&E is not allowed to profit on the fuel that they purchase.

**Q: Will this rate increase improve service outages problems?**

A: This rate increase will allow OG&E to continue their current reliability programs. This includes programs to recover from storm damage, improve the system's ability to withstand natural disasters, and to provide additional safety for the electric grid. If you are experiencing service outages or problems, please report the issue to OG&E immediately. If OG&E does not address the problem, you may file a complaint with the Consumer Services Division of the Oklahoma Corporation Commission at the following link: http://www.occeweb.com/Divisions/CS/Forms/PUTILCOMPLAINT.htm

**Q: I have been hearing a lot of information about renewable energy. Does any of this increase go towards wind energy or other renewable resources research?**

A: Yes, a portion of this increase pays for the Oklahoma Centennial Wind Farm which is located in northwestern Oklahoma. This wind farm provides OG&E with up to 120 megawatts of capacity. This increase also includes OG&E's research in "smart grid" technology.

**Q:** **Are other utilities seeking rate increases during this difficult economic time?**
A: Yes. Utilities all across the country are experiencing the need for increased rates due to increased costs and additional Federal requirements. The Federal requirements include environmental regulations on carbon emissions, security upgrades, and safety requirements.

**Q:** **Is there something I can do as a customer to lower my bills?**
A: Yes. OG&E offers a Time-of-Use Rate which rewards decreased usage during peak summer demand hours. June through September, you'll receive a much lower rate during off-peak hours but pay a higher rate during peak load hours (times vary according to your rate class), excluding weekends and holidays. During the winter season, Time-of-Use customers revert to OG&E's standard rates. You may also visit the Commission's Demand Programs page on the www.occeweb.com home page for more links and information to assist in reducing your energy bills. OG&E also offers a free Custom Energy Report which helps shed some light on how you spend your energy dollars. This report uses personalized information to calculate how much energy your home uses by fuel type and end-use. For more information please use the following link: http://www.oge.com/residential-customers/save-energy-and-money/EnergyEfficiency/Pages/CEROpenWP.aspx

**Q.** **What if I have trouble paying my electric bill?**
A. There is help available. First, call OG&E at 405-272-9741 or email the company at www.oge.com. They will work with you to establish a payment plan. OG&E can also refer you to programs specifically designed to help people with their energy bills.

**Q:** **What does the Commission do to ensure that the requested rate increase is fair and reasonable?**
A: The Corporation Commission Staff, Office of the Attorney General, and other intervening parties perform an audit of the requested rate increase. This includes a thorough review of the Company's books and records along with benchmarking their performance to other Companies across the country.

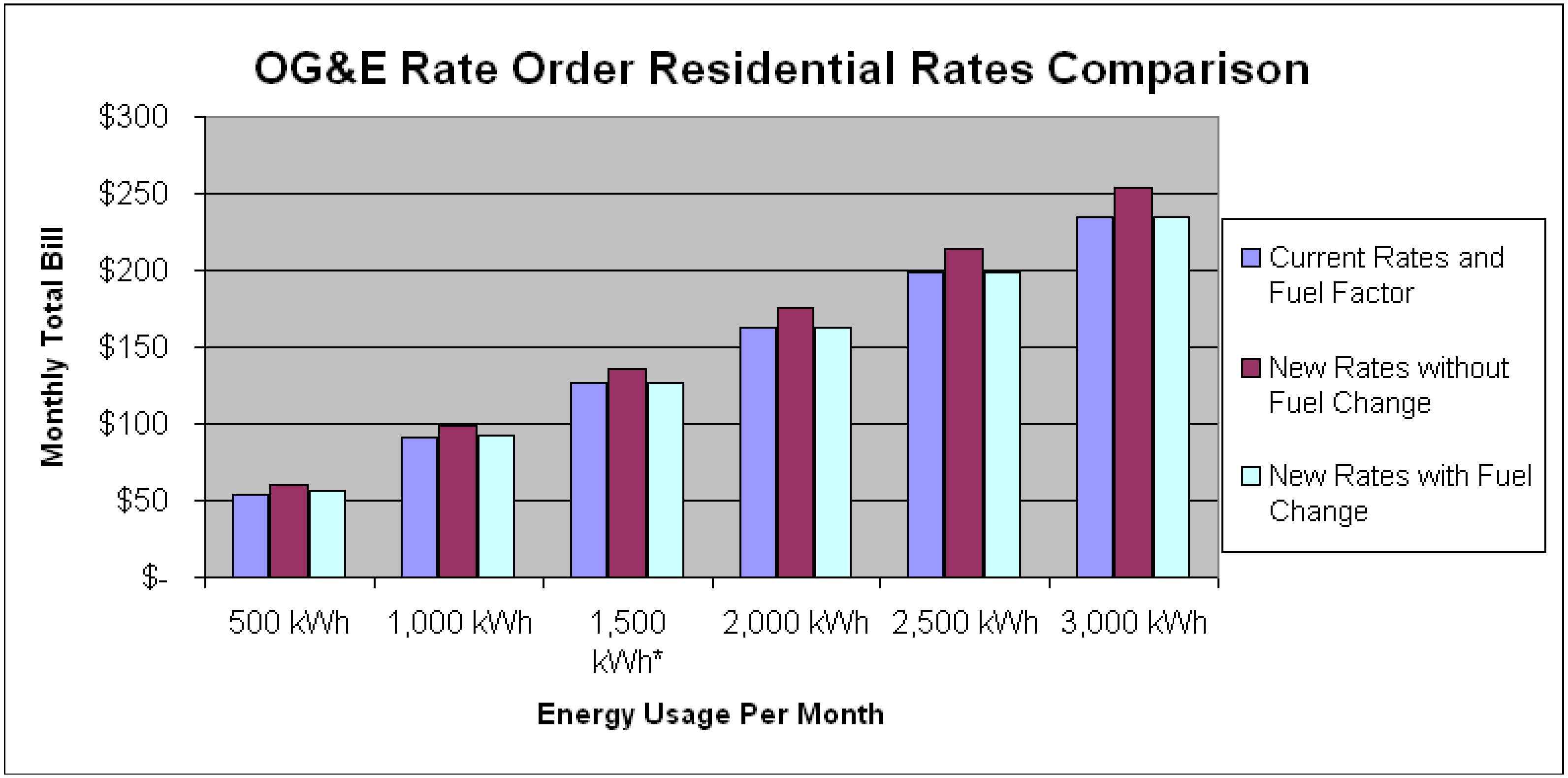
**Q:** **Where can I view the filed records for this rate case?**
A: The Oklahoma Corporation Commission maintains open records on all general rate cases. Information on this can be found on a link on the OCC website at www.occeweb.com.

# OG&E Rate Order Impacts 2009

Residential Customers

| ***Monthly Energy Usage*** | ***Current Rates and Fuel*** | ***New Rates without Fuel Change*** | ***Bill Impact from Rate Increase*** | ***New Rates and Fuel Change*** | ***Total Bill Impact*** |
|---|---|---|---|---|---|
| ***500 kWh*** | $ 53.71 | $ 59.75 | $ 6.04 | $ 56.70 | $ 2.99 |
| ***1,000 kWh*** | $ 91.65 | $ 98.92 | $ 7.27 | $ 92.82 | $ 1.17 |
| ***1,500 kWh**** | $ 127.37 | $ 135.90 | $ 8.53 | $ 126.74 | $ (0.63) |
| ***2,000 kWh*** | $ 163.26 | $ 175.11 | $ 11.85 | $ 162.90 | $ (0.36) |
| ***2,500 kWh*** | $ 199.15 | $ 214.30 | $ 15.15 | $ 199.04 | $ (0.11) |
| ***3,000 kWh*** | $ 235.03 | $ 253.51 | $ 18.48 | $ 235.20 | $ 0.16 |

***Average residential consumers use about 1,500 kWh per month.***




## General Service Customers

General Service customers are receiving a rate decrease of approximately .03%. In addition, the fuel factor change will result in a total bill reduction of 5.82%. That equates to a reduction of approximately $5.82 for every $100 in billing.

## Power and Light Customers

The overall Power and Light class will receive no change as this class, overall, is already paying its actual cost of service, inclusive of the rate increase. However, the PL-Time of Use customers will receive a small decrease and the remaining PL customers will receive a small increase. This change corrects rates that were causing time of use customers to pay more than their cost of service. There will, however, still be a reduction to the Power and Light fuel factor of 10.89%.

## Large Power and Light Customers

The LPL class will receive a 0.66% increase in base rates. There will also be a reduction to the LPL fuel factor for a net bill impact of 11.1%

# News from the Oklahoma Corporation Commission

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**August 3, 2009**

## OPEN FOR BUSINESS

***Corporation Commissioners praise effort that results in canceling of furloughs***

**(Oklahoma City) Thanks to efforts to allow the agency to broaden its use of existing revenue and internal cost cutting, plans to close all offices of the Oklahoma Corporation Commission one day a month and place employees on unpaid leave have been canceled.**

**Commission Vice-Chairman Jeff Cloud called the cancellation "the result of extraordinary commitment and cooperation."**

**"Legislative and administration officials worked closely with us in our efforts to keep the doors open for business," said Cloud. "We are grateful for the support shown by Governor Henry, Oklahoma Treasurer Scott Meacham, House Speaker Chris Benge, Senate President Pro-Tem Glenn Coffee, and House Appropriations and Budget Committee Chairman Ken Miller."**

**Commissioner Dana Murphy agreed.**

**"We went to these officials and others to explain the seriousness of the situation and develop solutions," Murphy said. "They responded, recognizing the concerns of those who do business in the state and know first-hand the negative impact closing the agency would have on business and the state's economy."**

**Commission Chairman Bob Anthony said the agency can now move forward.**

**"Given this agency's many responsibilities, we always have a very full plate," noted Anthony. "However, the current economic and energy challenges faced by the state make it more important than ever that the agency be able to devote its full attention to the issues and problems at hand."**

**Because of a funding shortfall, Commission Director of Administration Brooks Mitchell had scheduled the closure of the agency and the furlough of employees for one day a month from August through January, 2010. Mitchell today announced cancellation of that plan, citing the successful effort to find ways to avoid closure. The agency reduced personnel through voluntary buyouts and a reduction-in-force, and has received a commitment from the Governor's office and legislative leaders to allow the agency to broaden its use of some of its existing earmarked funds to pay for operational expenses, pending approval by the Legislature in the next session. In addition, there will be a review of the budget formula for the OCC. Agency officials say a flaw in the process resulted in a state funding cut of 18 percent, rather than the intended 5 percent.**

**The Oklahoma Corporation Commission has regulatory responsibility for oil and natural gas production, public utilities, telephone service, trucking, pipelines, rail crossings, and underground petroleum storage tanks.**

**-OCC-**

# News from the Oklahoma Corporation Commission

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**October 8, 2009**

(McAlester) A Town Hall meeting on horizontal drilling will be held in McAlester on Monday, October 12 at 6 p.m. in the Southeast Expo Center, 4500 W. Highway 270.

The issues raised by the increase in horizontal drilling by natural gas producers in Oklahoma are of concern to surface owners, mineral owners, producers, and many others. In addition to the working groups that have been formed at the direction of Corporation Commissioner Dana Murphy to address these issues, Commissioner Murphy is also joining with the National Association of Royalty Owners (NARO) for Town Hall meetings on the subject.

Topics to be addressed in the Town Hall meeting include: Shale development in Oklahoma, as well as technology and land use issues in horizontal drilling. There will also be substantial time for all attending to ask questions.

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**News from Commissioner Dana Murphy**

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10/15/2009

# NEW METHODS, NEW QUESTIONS

*Corporation Commissioner Dana Murphy urges mineral and surface owners, producers and others to attend town hall meeting on horizontal drilling*

(Clinton) Oklahoma Corporation Commissioner Dana Murphy is urging all interested parties to attend a Town Hall meeting on horizontal drilling in Clinton Tuesday, October 20 at 6 p.m. at the Frisco Center, 101 S. 4$^{th}$ Street.

Commissioner Murphy said the issues raised by the increase in horizontal drilling by natural gas producers in Oklahoma are of concern to surface owners, mineral owners, producers, and many others.

"At our town hall meeting in McAlester last week, we had 150 people attend," noted Murphy.

In addition to the working groups that have been formed at the direction of Corporation Commissioner Dana Murphy to address these issues, Commissioner Murphy is also joining with the National Association of Royalty Owners (NARO) for Town Hall meetings on the subject.

Topics to be addressed in the Town Hall meeting include: Shale development in Oklahoma as well as technology and land use issues in horizontal drilling. There will also be substantial time for all attending to ask questions.

**-OCC-**

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# News from the Oklahoma Corporation Commission

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**December 09, 2009**

## Oklahoma Gains A New Voice

**Oklahoma Corporation Commission Chairman Bob Anthony has been appointed to the Board of Directors of the National Association of Regulatory Utility Commissioners (NARUC). NARUC is a non-profit organization founded in 1889 made up of state governmental officials responsible for the regulation of utilities and carriers nationwide. NARUC's mission is to serve the public interest by improving the quality and effectiveness of public utility regulation.**

**Anthony said he will use his position to continue to raise questions and voice concerns that require national attention.**

**"At a time when our critically important domestic oil and gas producers are under attack over issues like hydraulic fracturing and global warming, and alternative energy such as wind power is raising new questions and issues, it is essential that Oklahoma's perspective be represented at national forums where dramatic and costly decisions are being made," Anthony said.**

**Earlier this year, Anthony was successful in getting NARUC approval of a resolution supporting continued state regulation of hydraulic fracturing, a process critical to domestic natural gas and oil production.**

**First elected in 1988, Anthony is currently the longest-serving utility commissioner in the United States. He is immediate past-Chairman and a current Board member of the National Regulatory Research Institute (NRRI), which is the official research arm of NARUC. He is also past-President of the 15 state Mid-America Regulatory Conference, and a member of the Environmental Protection Agency/Interstate Oil and Gas Compact Commission Task Force.**

**-OCC-**

**News** **from the** **Oklahoma Corporation Commission**
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**December 14, 2009**

# Fair, Just, and Reasonable

*Commission approves settlement offer from all parties in Oklahoma Natural Gas rate case*

**(Oklahoma City) Calling it a good balance between the need to ensure safe and reliable natural gas service and consumer concerns, the Oklahoma Corporation Commission today approved a settlement in the Oklahoma Natural Gas (ONG) rate case.**

**Commission Chairman Bob Anthony commended the parties for reaching a settlement and avoiding a prolonged and costly trial.**

**"It is noteworthy that all parties to the case asked the Commission to approve the settlement," said Anthony. "The Attorney General — who represents consumers before the Commission — asked for approval, as did Commission staff, Oklahoma Natural Gas, and others. All the parties are to be commended for meeting the challenge to formulate an agreement that all agree meets the requirement that rates be "fair, just and reasonable."**

**Vice-Chairman Jeff Cloud said he was pleased to see the agreement is balanced, has an eye toward the future, and protects the most vulnerable.**

**"Under the law, the Commission is charged with the difficult task of balancing what the company needs to provide safe and reliable service with the vital need of the customer to have service that is affordable," Cloud said. "The parties to the case worked diligently to strike that balance.**

**"Under the agreement, those Oklahomans who are clients of the Low Income Home Energy Assistance Program (LIHEAP), will not see a change in their rates," Cloud noted. "The agreement also helps efforts to promote the use of compressed natural gas (CNG) as a motor fuel, as it sets up tariffs for those who fuel CNG vehicles at home."**

**(more)**

**Oklahoma Corporation Commissioner Dana Murphy said she is mindful of the comments the Commission received by those opposing a rate increase.**

**"I understand people are very concerned about *any* rate increases right now," Murphy said. "They're feeling the pinch of the economic situation and every bit adds up when trying to make ends meet. In this economic climate, any utility's rate increase request must survive intense scrutiny. Our audits showed ONG has reduced operating costs through more efficiency. At the same time, ONG has paid significant amounts to make sure its system will reliably deliver gas to customers during the coming winter. This money was spent on new pipe, repairing customer lines, and replacing meters. These are costs consumers are willing to pay to make sure they have heat, but they are not willing to pay for unnecessary fringes. The Commission has made sure only necessary costs have been added. This is a fair result—making for a small bill increase and assuring safe, reliable service."**

**Under the agreement, the net amount of the increase to customers is $26.5 million. Approximately $28 million already being paid by customers will be shifted into the rate base, for a gross total of $54.5 million.**

**The average increase for ONG residential customers will depend on the price of natural gas and the plan the customer has chosen. When compared to last year, it is estimated that the average customer on Plan B will see a decrease of $1.41 a month, while the average customer on plan A will have an estimated increase of approximately $3.90 a month.**

**-OCC-**

**All OCC advisories and releases are available at www.occeweb.com**

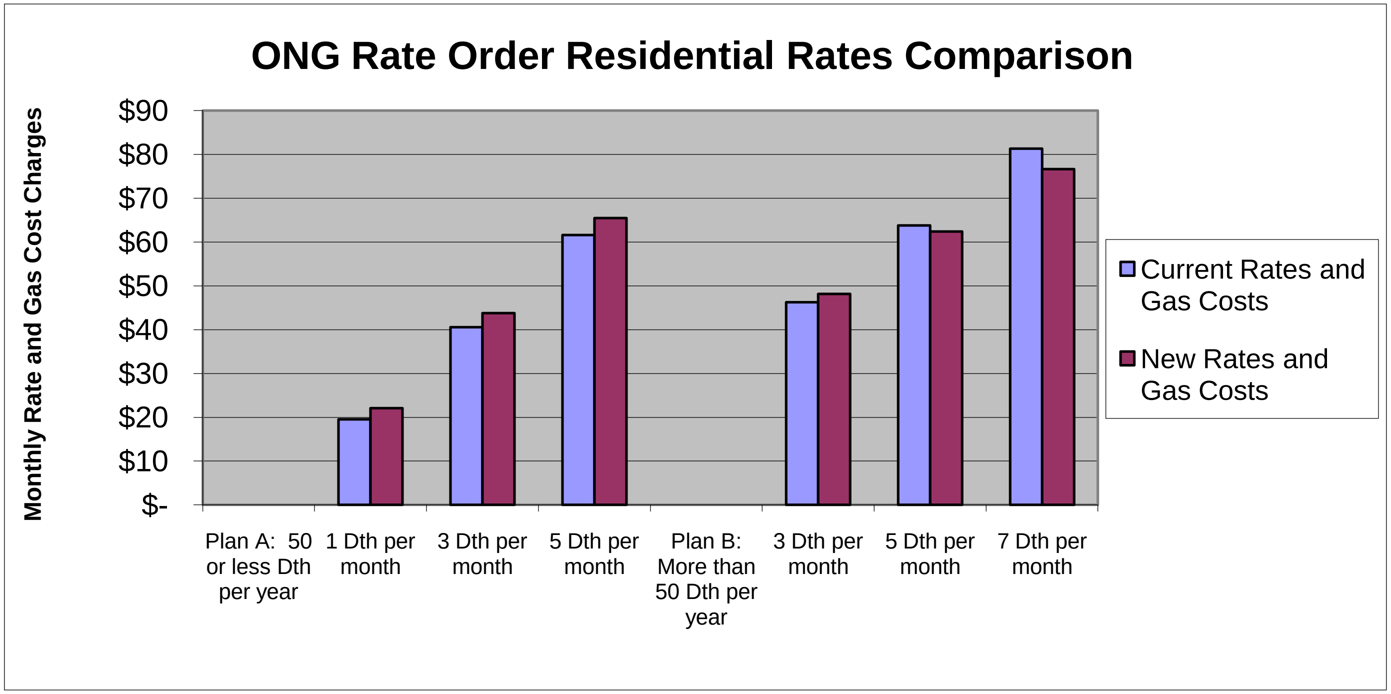
**NOTE – SEE ATTACHED RATE CHARTS**

# Oklahoma Natural Gas Rate Order Impacts 2009

Residential Customers based on Dekatherms ( Dth)

| *Rate Comparison with Cost of Gas Update* | *Current Base Charge* | *Current Volumetric Charge* | *Total Bill Current Rates and Gas* | *New Base Charge* | *New Volumetric Charge* | *Total Bill New Rates and Gas* | *Monthly Rate and Gas Cost Impact* |
|---|---|---|---|---|---|---|---|
| ***Plan A:*** **50 or less Dth per year** | | | | | | | |
| ***1 Dth per month*** | $9.00 | $1.9967 p/Dth | $ 19.52 | $ 11.20 | $3.7323 p/Dth | $ 22.06 | $ 2.54 |
| ***3 Dth per month*** | $9.00 | $1.9967 p/Dth | $ 40.55 | $ 11.20 | $3.7323 p/Dth | $ 43.77 | $ 3.22 |
| ***5 Dth per month*** | $9.00 | $1.9967 p/Dth | $ 61.59 | $ 11.20 | $3.7323 p/Dth | $ 65.49 | $ 3.90 |
| ***Plan B: More than*** **50 Dth per year** | | | | | | | |
| ***3 Dth per month*** | $20.00 | $0.2367 p/Dth | $ 46.27 | $ 26.75 | $ - | $ 48.13 | $ 1.86 |
| ***5 Dth per month*** | $ 20.00 | $0.2367 p/Dth | $ 63.79 | $ 26.75 | $ - | $ 62.38 | $ (1.41) |
| ***7 Dth per month*** | $ 20.00 | $0.2367 p/Dth | $ 81.30 | $ 26.75 | $ - | $ 76.63 | $ (4.67) |

| | ***2008*** | | | ***2009*** |
|---|---|---|---|---|
| ***Cost of Gas use for year over year comparison*** | $8.521 per Dth | | | $7.126 per Dth |




## Other Rate and Tariff Classes Impact Summaries

### LIHEAP- Low Income Home Energy Assistance Program

Customers currently on Tariff 102, LIHEAP, will not be impacted by the base rates increase. These customers will benefit from the lower cost of natural gas during this winter's billing period.

## Small Commercial- Tariff 200

| - | - | Old Rates | New 2009 Rates |
|---|---|---|---|
| Plan A | Service Charge | $ 15.00000 | $ 18.75000 |
| | Delivery Fee | $ 2.74660 | $ 4.55990 |
| Plan B | Service Charge | $ 27.00000 | $ 33.95000 |
| | Delivery Fee | $ 0.53120 | $ - |

## Large Commercial

| | | | |
|---|---|---|---|
| New rate has one plan. | Service Charge | | $ 79.40000 |
| | Delivery Fee | | $ - |
| Plan A | Service Charge | $ 35.00000 | |
| | Delivery Fee | $ 1.30580 | |
| Plan B | Service Charge | $ 90.00000 | |
| | Delivery Fee | $ 0.29040 | |

# News from the Oklahoma Corporation Commission

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**December 17, 2009**

## MEDIA ADVISORY – 918 AREA CODE

**The Oklahoma Corporation Commission is scheduled to vote Friday on what plan to institute in the 918 area code to deal with the predicted exhaust of available phone numbers.**

**The Commission has two choices: 1) Overlay or 2) Split.**

**In an overlay, all existing numbers would keep the old 918 area code. Eventually all new numbers would get a new area code.**

**In a split, the existing 918 area code's geographic area is split into two parts, with one part keeping the 918 area code and the other part getting a new area code.**

**Please see the attached document for the history and full information on this issue.**

**The Commission vote is scheduled for Friday 12-18, 9:30 a.m. in Room 301 of the Jim Thorpe Building, 2101 North Lincoln, Oklahoma City.**

**-OCC-**

# AREA CODE EXHAUST AND RELIEF

## *Questions and Answers*

**Area Code Exhaust and Relief**
**Questions and Answers**
## Table of Contents


| | Page: |
|---|---|
| Introduction | 4 |
| Why are we running out of numbers? | 4 |
| Why are we adding a new area code? | 4 |
| Will the cost of calls change because of a new area code? | 4 |
| How does a new area code affect other services? | 5 |
| How are numbers added ? | 5 |
| What is the planning process to establish a new area code? | 6 |
| Who decides who receives the new area code? | 6 |
| Why not assign a new area code to faxes / wireless services? | 6 |
| Why not add a digit or two to the telephone number instead of adding area codes? | 7 |
| What is a rate area? | 7 |
| What is a wire center? | 7 |
| Why don't area code boundaries conform to Municipal or County boundaries? | 8 |
| What are the methods of area code relief? | 8 |
| What are the attributes of geographic splits? | 8 |
| How is a new area code introduced in a geographic split? | 9 |
| How would an area code split impact home and business service? | 9 |

## Area Code Exhaust and Relief
## Questions and Answers
### Table Of Contents


| | |
|---|---|
| What is the overlay method of area code relief? | 10 |
| What are the attributes of overlays? | 11 |
| Why must an overlay apply to all services? | 11 |
| Why is it necessary to dial the area code + the seven digit number (10 digits) for overlays? | 11 |
| How is a new area code introduced in an overlay? | 11 |
| How would an overlay and 10 digit dialing impact home and business telephone service? | 12 |
| Who is the official source of area code information? | 13 |
| Whom to contact with your questions and comments? | 13 |
| Glossary Of Terms | 14-16 |

**Area Code Exhaust and Relief**
**Questions and Answers**

## Introduction

This guide is meant only as an information resource to help you in determining how you would be impacted by an area code split or an area code overlay, and to aid you in reaching a decision as to which you would prefer. It is not intended, nor should it be interpreted, as an argument for or against those options.

The information contained herein regarding the effects of an area code split or overlay is not exhaustive. The Corporation Commission wants to hear from you regarding how you think either option may impact you. You can submit your comment and opinions via the web (www.occeweb.com), or by phone: 1-800-522-8154.

If you have further questions, please email us (m.skinner@occeweb.com or j.palmer@occeweb.com) or call us, (405) 521-2211.

## Questions and Answers

### Why are we running out of numbers?

In recent years, a combination of new technologies and increased consumer demand for regular telephones in homes and offices, cellular and PCS phones, pagers, lines used for fax machines, modems, internet access, and other uses have strained existing telephone number resources. Also, new local telephone service providers need telephone numbers in order to provide service to their customers. All of these factors have resulted in an increased demand for numbers in the 918 area code. As a result, telephone number shortages have occurred at what's called the *prefix* level. A *prefix* is the three-digit number that is between the area code and your 4-digit line number.

### Why are we adding a new area code?

Due to the many choices in service providers, significant increases in products and additional lines, and the limit to the amount of resources in an area code that can be allocated to telecommunication providers, it has become necessary to add the new area code to the 918 area.

### Will the cost of calls change because of a new area code?

No. Calls that were local before the introduction of the new area code will remain local calls. Local calling areas do not change when a new area code is established.

## How does a new area code affect other services?

911 Services will NOT be affected by the introduction of a new area code. Emergency calls will continue to be handled just as they are today.

411 Services will NOT be affected by the introduction of a new area code. Directory assistance calls will continue to be handled just as they are today. There is no change in the cost of a directory assistance call because of an area code change.

211 Services will NOT be affected. Calls to 211 will continue to be handled just as they are today.

## How are numbers added?

An area code (technically called a Numbering Plan Area, or **NPA**) consists of 792 available prefixes, each in turn consisting of 10,000 numbers. A prefix (NXX) is the three-digit number that is between the area code and your 4-digit line number. An area code would consist of 1,000 prefixes (NXXs) **if** all of the numbers 0 through 9 were utilized. However, ***N*** is a number from 2 to 9 and ***X*** is a number from 0 to 9. Since no prefixes begin with 0 (0XX) or 1 (1XX) because these digits serve special functions in the network, this eliminates 200 prefixes. In addition, *N*11 prefixes are not available except as special use prefixes, such as 911 for Emergency Services. That eliminates 8 more prefixes from assignment to individual companies. This is why there are only 792 prefixes available in an area code.

Numbers are allocated to telecommunications service providers by prefix. As most of the numbers available in each of the 792 prefixes are assigned, the area code approaches what is called ***exhaust***. In other words, the supply of available numbers begins to shrink to a critically low level. Exhaust, in turn, creates the need for an additional area code for that particular geographic area. While the Oklahoma Corporation Commission has adopted number conservation measures which have been successful at delaying the onset of exhaust, one cannot change the fact that the telecommunications numbering system is finite.

Telecommunications service providers request prefixes from the NANPA (North American Number Plan Administrator). NANPA assigns new prefixes, monitors the usage of prefixes within an area code, and forecasts when an area code will most likely exhaust and a new area code will be required.

Area code forecast exhausts are determined by NANPA using the Numbering Resource Utilization and Forecast (NRUF) reports, which are 5-year forecasts of number demand provided semi-annually be each telecommunications service provider of demands submitted; the historical CO code demand, the current demand for codes, the number of rate centers within each area code and other factors pertaining to the individual area codes.

**Area Code Exhaust and Relief**
**Questions and Answers**

## What is the planning process to establish a new area code?

The North American Numbering Plan Administrator (NANPA) notifies the Oklahoma Corporation Commission (OCC) and the telecommunication industry 3 years in advance of when it is anticipated that a particular area code will run out of prefixes.

The area code planning process begins with NANPA and the telecommunications industry group meeting to identify viable solutions. When developing and evaluating area code relief plans, the industry is required to follow regulations established by the Federal Communications Commission (FCC) and the state commissions, as well as the telecommunications industry guidelines.

After feasible alternatives are developed the industry strives to reach consensus on the best plan for the area as a whole. That plan is then submitted to the OCC. If the Industry is unable to reach consensus on a relief plan, then the planning results are submitted to the OCC.

## Who decides who receives the new area code?

The OCC makes the final decision on all area code relief plans. If an area code split is approved, they decide which area will retain the existing area code or receives a new area code.

## Why not simply assign a new area code to faxes / wireless services as a way to provide more numbers?

Perhaps the most common suggestion from the public threatened with an unwelcome area code change is to create an area code that can be assigned to wireless services, fax machines, or other non-wire line, non-voice uses, e.g. credit card verification and Point of Sale. The reason we can't do that is because the federal government won't allow it. The FCC (Declaratory Ruling and Order, FCC Docket 95-19, IAD File No. 94-102, adopted January 12, 1995) has banned such a use of area codes. This Order specifically precludes area code plans that exclude a particular kind of telecommunications service from an area code or that segregate services and technologies into different area codes. The reasoning is that this prohibition is needed to protect new telecommunications services from discrimination or disadvantage. If a new area code were assigned to cellular services, for example, all calls between a cellular customer and a wire line customer would require 10 digits while a wire line-to-wire line call could be made with seven digits. Some would argue that this would favor wire line customers at the expense of cellular customers. Currently, with local number portability, wireline numbers are now being ported to wireless service providers and vice-versa. Therefore, there is a co-mingling between the technologies of numbers within the assigned blocks and codes of numbers that prevents them from being separated by area codes. Area code relief is done at the full prefix level and involves all numbers associated with each prefix.

## Why not add a digit or two to the telephone number instead of adding area codes?

People have also suggested various means of expanding the current dialing plan which permits seven-digit dialing within an area code and require 10-digit dialing between area codes. The most frequent suggestion was adding an 8th digit to the customer line number. However, this state is an integral part of the North American Numbering Plan Administration and cannot unilaterally make changes in the dialing protocol that other regions and countries rely upon. National planners are studying means of expanding the numbering system. Such changes will almost certainly require years to implement in a coordinated manner, and therefore will not eliminate the need for area code relief in the immediate future.

## What is a rate area?

A **rate area**, also known as a **rate center**, is that geographic area containing one or more wire centers, used as the basis to define the local and long distance areas. When communities were smaller, the rate area was the center of each community's greatest concentration of population, such as the post office or other centrally located points. As communities grew and population centers changed, planners connected large population centers by drawing vertical and horizontal lines across a map of the United States. When the vertical and horizontal lines intersected, a rate center was identified, and the distance between rate centers (which became the basis of what constitute a long distance call) was measured in airline miles. Local and long distance telephone companies in the United States use rate areas to calculate the rates that are charged for telephone calls.

## What is a wire center?

A ***wire center*** is a building in which local switching systems are installed and where the outside lines, or wire, leading to customer premises is connected to the central office equipment. A ***wire center boundary*** is the perimeter of the area surrounding a wire center containing all customers whose lines are physically connected to a switching system at that wire center. There may be one or more wire centers within each rate center.

## Why don't area code boundaries conform to Municipal or County boundaries?

**Area Code Exhaust and Relief**
**Questions and Answers**

When the telecommunications industry considers new area code boundaries it is obliged to follow rate area boundaries which reflect the physical infrastructure that enables telecommunications service. The alternative to following these boundaries would be to rip out in-ground facilities and re-wire affected customers at a tremendous cost.

The grid of telephone wires was, in most cases, laid down prior to municipal boundaries, which tend to change more frequently.

## What are the methods of area code relief?

The most common methods of relief are:

1) Splitting the present area served by the area code, and assigning a new area code to part of the region, while the other part would keep the old area code. This technique is called a **split**.
2) Adding another area code to the entire geographic area currently served by one area code, This technique is called an **overlay**.

## What are the attributes of geographic splits?

- Splits provide a single area code for each geographic area. This may minimize confusion for customers outside the area. Future splits will reduce the geographic size of the area code.

- Splits require an area code change for approximately one half of customer's numbers in a two way split. Stationery, business cards and advertising will need to be revised by customers receiving the new area code.

- Geographic splits permit seven digit dialing within an area code.

## How is a new area code introduced in a geographic split?

**Area Code Exhaust and Relief**
**Questions and Answers**

A new area code is introduced in two steps. These steps are designed to guide consumers, familiarize them with the new area code and facilitate the correct use of that code.

- ***Permissive Dialing:***

  The *permissive dialing* period begins with the introduction of the new area code and generally lasts approximately six months*. It provides a 'get acquainted' transition period for the new area code.

  *Permissive dialing* allows the old and new area code customers to call between the two area codes using seven-digit dialing. Customers from outside the area can call the new area code by dialing either the old or the new area code + the telephone number; the call will complete during the *permissive period*.

  (* The permissive dialing period varies in length per commission decision)

- ***Mandatory Dialing:***

  Approximately six months after the introduction of the new area code, an *intercept recording* period* will begin. At this time, callers **must use the appropriate area code** plus the telephone number. Calls incorrectly dialed will be referred to a recording throughout the recording period. It will inform the calling party that the new area code must be used to complete the call.

  After the completion of the *recorded announcement* period, if customers do not use the correct area code they may reach a wrong number or a recording.

  (* The recording period varies in length per commission decision)

## How would an area code split impact home and business telephone service?

If your area code changes, you would need to notify family, friends and business associates of the change. You may also need to change stationery, business card and other printed material or reprogram your equipment to reflect the change.

Other changes that may be required include: address books, advertisements, alarm equipment, automatic dialers, bill statements, business cards, checks, computer lists, electronic banking information, emergency contact lists, identification

bracelets, fax machines, health provider cards, the number plate on your telephone, pet ID tags, and speed dial lists.

Additionally, business customers should check for:

**Impacts with PBX and other business equipment**
Some business customers may need to upgrade or adjust their equipment to handle the new area code. Not all business equipment would require upgrading. Call routing lists may also need to be changed.

**Impacts to Integrated Service Digital Network (ISDN) Customers:**
Some ISDN equipment may have the area code included in the Service Profile Identifier (SPID). If so, that equipment would have to be reprogrammed to accommodate a new area code. ISDN customers would be notified of the specific date that they need to reprogram their SPID. If the SPID is not reprogrammed on that date, the ISDN equipment won't work.

**Impacts to Least Cost Routing:**
Customers with PBXs who use the Least Cost Routing feature may require upgrades to their PBX or they can eliminate the Least Cost Routing feature and allow the local exchange carrier to route the traffic.

**Test number available for new area code:**
Once the new area code has been determined, a test number is established at least 30 days prior to the start of permissive dialing. This allows business customers to verify that their equipment can complete calls to the new area code. The test number may be obtained from the associated planning letter for each area code on the NANPA web site. Their web address is www.nanpa.com.

## What is the overlay method of area code relief?

An area code overlay occurs when more than one area code serves the same geographic area. In an area code overlay, relief is provided by opening up a new area code within the same geographic area as the area code requiring relief. With an overlay, all current customers keep their area code and telephone number. Numbers using the new area code are assigned to new telephone customers or those adding additional lines. Because two area codes reside in the same geography, all local calls would require ten digit dialing, the area code + the seven-digit telephone number (10 digits).

## What are the attributes of overlays?

- With an overlay there would be multiple area codes for each geographic area and it will end further shrinking of the geographic size of the area code. Subsequent relief would likely be another overlay.

- An overlay would not require existing customers to change their area code.

- An overlay would require customers to dial 10 digits (or 1+10 digits) for all calls within the geographic area.

## Why must an overlay apply to all services?

The FCC has decided that an overlay must apply to all services to mitigate any anti-competitive effects that would advantage incumbent telecommunication providers and disadvantage new providers and their customers.

## Why is it necessary to dial the area code + the seven digit number (10 digits) for overlays?

10 digit dialing is a regulatory requirement established for an overlay area code by the FCC in its Second Report and Order (FCC 96-333) to mitigate any anti-competitive effects that would advantage incumbent providers and disadvantage new providers and their customers and to ensure dialing parity between the two area codes.

This dialing requirement results from a concern that customers in the original area code and customers with the overlay area code would have different dialing arrangements for the same geographic area. Those in the original area code could reach a party in their same geographic area with a seven digit call, while those in the overlay area code would have to dial 10 digits to reach the same party.

## How is a new area code introduced in an overlay?

An Overlay area code is introduced in three steps.

- ***Formal 10 Digit Permissive Dialing:***

During a determined formal *permissive 10 digit dialing* period, customers are encouraged to begin using the area code + the seven-digit number to place all calls within the area code, although calls will still complete if only the seven-digit number is dialed. During this time, life safety systems, alarms, PBX's, fax machine calling lists, speed dialers, private entry access systems, auto-dialers and out-dialing lists on personal computers should be reprogrammed.

- ***Mandatory 10 Digit Dialing:***

  *Mandatory10 digit* dialing* begins at the end of the formal permissive dialing period. Callers must use the area code + the seven digit number for all calls within the area code. Calls incorrectly dialed using only seven digits are referred to a recording which will inform the calling party it is necessary to dial the area code + the seven-digit telephone number to complete the call. This recorded announcement will remain indefinitely.
  *Some states require 1+10-digit dialing

- ***Introduction of New Overlay Area Code:***

  Numbers in the Overlay Area Code are introduced at the beginning or shortly after the Mandatory 10 digit dialing begins.

## How would an overlay and 10 digit dialing impact home and business telephone service?

- All local calls would require use of the area code + the seven-digit number (10 digits).

- Equipment or services that are programmed to dial out using only seven digits would have to be reprogrammed to use 10 digits.

- Items such as stationery, checks, business cards would have to be changed to include the 10-digit number.

**Additionally business customers would:**

- Update life safety systems, fax machines, private dial access entry and PBXs.

- Update other sophisticated services and equipment such as message detail recording equipment, alternate route or least-cost routing systems, toll restriction, mobile telephone service, cellular telephone service, alarm circuits and PC modems.

- Include 10-digit numbers on all printed materials, such as stationery, checks, business cards, advertisements, promotional items, brochures, and catalogs.

- Notify alarm service providers of 10 digit dialing requirement so alarm service records and equipment can be updated as needed.

- Test telephone equipment to determine if it can dial and accept 10-digit dialed calls.

## Who is the official source of area code information?

NeuStar, Inc., is the North American Numbering Plan Administrator (NANPA). It can be found at: **http://www.nanpa.com**

## Whom do I contact with my questions and comments?

Oklahoma Corporation Commission
2101 North Lincoln
Oklahoma City, OK 73135
405-521-4180 or 405-521-4018
You can also get more information and submit comments/opinions via the web: www.occeweb.com

NANPA (North American Numbering Plan Administration)
46000 Center Oak Plaza
Sterling, VA 20166
Web site address: **http://www.NANPA.com**

**GLOSSARY OF TERMS**

**Code** (Central Office Code) Central Office Codes may also be referred to as prefixes or NXXs.

**Community of Interest:** Many items can be considered as "Community of Interest". These would include a city, closely located cities, a neighborhood, a business with multiple locations, government agencies that serve a wide area (not must one entity, i.e., county sheriff department) or other agencies/businesses with multiple locations.

**Cut Date** The date (Effective Date) by which routing changes must be completed of the assigned area code. Also, the date by which the area code becomes active.

**Exhaust** A point in time at which the quantity of telephone numbers at the prefix level within an existing area code equals zero.

**FCC** Federal Communications Commission

**Geographic Split:** The exhausting area code is split into two or more geographic areas, leaving the existing area code to serve one side of the geographic area and assigning new area codes to the remaining areas.

**Growth** Growth and demand for telephone numbers are not specifically tied to population. With the technology explosion and the advent of local competition in the telecommunications industry (to provide local service), more and more telephone numbers are needed. Growth is measured in the demand for telephone numbers.

**INC** Industry Numbering Committee, a standing committee of the Alliance for Telecommunications Industry Solutions (ATIS) that provides an open forum to address and resolve industry-wide issues associated with the planning, administrations, allocation, assignment and use of numbering resources and related dialing considerations for public telecommunications with the North American Numbering Plan (NANP) area.

**INPA** Interchangeable Numbering Plan Area - ("2" through "9" as second digit instead of the traditional "0" or "1")

**LNP** Local Number Portability

**MSAG** Master Street Address Guide (Data base for 911)

**NANC** North American Numbering Council

**NANP** North American Numbering Plan

**NANPA** North American Numbering Plan Administration

**NPA** Numbering Plan Area (Area Code)

**NXX** An NXX (prefix) is the three-digit number that is between the area code and the 4-digit line number, where <u>*N*</u> is a number from 2 to 9 and X is a number from 0 to 9.

**Overlay** An area code overlay occurs when more than one area code serves the same geographic area.

**PCS** Personal Communications Services

**Pooling Administrator** The term Pooling Administrator refers to the entity or entities responsible for administering a thousands-block number pool

**Prefix** See description of CODE or NXX

**PSAP** Public Service Access Point - "For 9-1-1 Services"

**Relief** (NPA Code Relief) Relief refers to an activity that must be performed when an area code nears exhaust of the 792 prefix capacity.

**Service Provider Number Portability** The ability to keep your current telephone number and have service from any telecommunications service providers within the same rate area.

**Thousands-Block Number Pooling** The process by which the 10,000 numbers in a central office code (NXX) are separated into ten sequential blocks of 1,000 numbers each (thousands-block) and allocated separately within a rate center.

**Wireless** Cellular, Paging, Specialized Mobile Radio (SMR) and Personal Communications Service (PCS) services

###

# News from the Oklahoma Corporation Commission

**Matt Skinner, Public Information**
**Phone: (405) 521-4180  m.skinner@occemail.com**

**December 18, 2009**

## MEDIA ADVISORY

**The Oklahoma Corporation Commission today decided to postpone a vote on a new area code plan for the area currently served by the 918 area code, pending public deliberations on the matter. A date for the deliberations has not been set.**

**-occ-**

BOB ANTHONY
Commissioner

JEFF CLOUD
Commissioner

DANA MURPHY
Commissioner

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April 16, 2009

President Barack Obama
The White House
1600 Pennsylvania Avenue NW
Washington, DC 20500

RE: The Proposed 2010 Budget

Dear President Obama:

Energy tax increases proposed in your budget and that are expected to come before the Senate Finance Committee would have disastrous effects on Oklahoma's efforts to educate its children, clean its environment, and create jobs. Any such new taxes will reduce investment in new oil and natural gas projects in a sector that provides energy to America and revenues to our state.

Oil and natural gas gross production taxes provide 10 percent of state-appropriated dollars for **education** in Oklahoma. The petroleum industry contributes a larger portion of education expenditures when direct income and property taxes are added, and provides an even larger percentage when similar taxes and sales tax revenues from spillover economic activity are considered. The oil and natural gas industry is the largest single contributor to our state's education budget.

Oklahoma is plagued by thousands of dangerous and unsightly abandoned oil and natural gas drilling sites from the freewheeling days of the 1910s and 1920s. A voluntary assessment on the petroleum industry pays to clean up these sites and return the land to pristine condition. This program remediates two to three sites every day. In these tight economic times, no funds are available for this critical **environmental** project other than monies obtained from the oil and natural gas industry.

Without considering spillover effects, the petroleum industry accounts directly for 16 percent of Oklahoma's gross state product (GSP). It is a fundamental part of our state's economic engine. When spillover effects are added, as much as half of the state's GSP is impacted by oil and natural gas. In human terms, the industry accounts directly for 76,000 jobs and indirectly for 245,000 more jobs, out of a total employment of some 1.6 million.

Starting in 1982, Oklahoma endured one of the most severe **economic** stresses of any state in the nation, as we lived through a depression the likes of which had not been seen since the Dust Bowl period. Oil and natural gas only recently helped to bring us out of these dire conditions. If the proposed tax increases are adopted, Oklahoma will suffer not just a recession, but will return to economic depression.

Attempts to repeal expensing of intangible drilling costs, the percentage depletion allowance, the marginal well tax credit, and the enhanced oil recovery credit, as well as increasing geological and geophysical amortization will cause a range of serious consequences—forcing the petroleum industry to stop producing from stripper wells (wells that produce less than 10 barrels of oil or 75 mcf of natural gas per day) that make up much of Oklahoma's production to halting or strictly curtailing drilling activities in the state. Such consequences translate to an end to major economic activity within our borders and reduced energy supplies resulting in higher prices for consumers.

Adoption of such policies will ravage our state budget—destroying progress we have made in education, in cleaning up the environment, and in returning our citizens to meaningful work. As the state-wide elected officials who regulate the oil and natural gas industry in Oklahoma and know its full impact on our people, we ask that you reconsider proposals that will devastate our economy.

Respectfully,

Bob Anthony
Commissioner

Jeff Cloud
Commissioner

Dana L. Murphy
Commissioner

DLM/at

cc: The Honorable Jim Inhofe
United States Senate

The Honorable Tom Coburn
United States Senate