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BEFORE THE CORPORATION COMMISSION OF THE STATE OF OKLAHOMA

APPLICATION OF **PUBLIC SERVICE COMPANY OF OKLAHOMA,** AN OKLAHOMA CORPORATION, FOR AN ADJUSTMENT IN ITS RATES AND CHARGES FOR ELECTRIC SERVICE IN THE STATE OF OKLAHOMA	)	CAUSE NO. **PUD 200600285** ORDER NO. **545168**

HEARING: May 1, 2, 3, 4, 7, 8 and 9, 2007
Before the Commission *en banc* with Referee Jacqueline T. Miller

APPEARANCES: David B. Dykeman and Lenora F. Burdine, Deputy General Counsels, James L. Myles and Teryl L. Williams, Assistant General Counsels for Public Utility Division, Oklahoma Corporation Commission
William L. Humes, Elizabeth Ryan and Whitney Weingartner, Assistant Attorneys General for the Office of the Attorney General
Jack P. Fite, Ann M. Coffin, James F. McNally, Jr., Bret J. Slocum, and Rhonda C. Ryan, Attorneys for Public Service Company of Oklahoma
Thomas P. Schroedter, James D. Satrom, G. Dean Luthey, Jr. and J. Fred Gist, Attorneys for Oklahoma Industrial Energy Consumers
Lee W. Paden, Attorney for Quality of Service Coalition
Glenn M. White, Robert A. Weishaar, Jr. and Vasiliki Karandrikas, Attorneys for Gerdau Ameristeel Corporation
Ron Comingdeer, Mary Kathryn Kunc and Kendall W. Parrish, Attorneys for Oklahoma Commercial Consumers Group
Cheryl A. Vaught and Scot A. Conner, Attorneys for Redbud Energy, LP
James W. George, Grace C. Wung and Gregory K. Lawrence, Attorneys for Wal-Mart Stores, Inc.
Nancy J. Siegel, General Counsel and Steve Cousparis, City Attorney, Office of the Mayor, The City of Tulsa

FINAL ORDER

PROCEDURAL HISTORY

On September 29, 2006, Public Service Company of Oklahoma ("PSO" or "Company") filed with the Corporation Commission of the State of Oklahoma ("Commission" or "OCC") 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 October 3, 2006, Oklahoma Industrial Energy Consumers ("OIEC") filed its Motion to Intervene. The Attorney General of Oklahoma ("AG") filed his Entry of Appearance on October 27, 2006. On November 2, 2006, the Commission issued Order No. 531708 granting the OIEC's Motion to Intervene.

On November 13, 2006, the Quality of Service Coalition ("QSC") filed a Motion to Intervene.

On November 21, 2006, PSO filed its Application and supporting documentation basing its request for a general rate change upon a test year ending June 30, 2006. PSO requested a general rate change of $49,495,296. Additionally, PSO requested the inclusion of construction work in progress ("CWIP") in rate base, requested the implementation of a Formula Based Rate Proposal, submitted a new depreciation rate study with a request for new depreciation rates, and requested the expansion of its Economic Development Program.

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 Stuart Solomon, David P. Sartin, Donald A. Murry, Susan D. Abbott, Julie M. Cannell, John O. Aaron, Michael S. Isenberg, Bernard M. Pasternack, Preston S. Kissman, E. Kevin Bethel, David A. Davis, Hugh E. McCoy, David A. Jolley, Donald R. Moncrief, and Kathy J. Champion.

On November 22, 2006, PSO filed a Motion for Protective Order. On November 27, 2006, the Commission issued Order No. 532594 granting the Motion to Intervene of QSC. On December 8, 2006, PSO filed a Motion for Procedural Schedule and on December 15, 2006, filed a Motion to Determine Notice. PSO filed an Amended Motion for Protective Order on December 15, 2006. On December 19, 2006, Staff's response regarding PSO's compliance with the minimum filing requirements was filed. Staff stated that the Application was in substantial compliance with the minimum filing requirements as set forth in OAC 165:70 *et seq.* for Class A or B utilities. On December 21, 2006, PSO filed a Motion for Hearing Before the Commission *En Banc*. On December 22, 2006, a Motion for Intervention was filed by the Oklahoma Commercial Consumer's Group ("OKCCG").

Gerdau Ameristeel Corporation ("Gerdau") filed a Motion to Intervene on January 3, 2007.

The Commission issued Order No. 533942 granting PSO's Motion for Protective Order on January 4, 2007. The Commission issued Order No. 534026 setting the cause before the Commission *en banc* on January 8, 2007. On January 10, 2007, the Commission granted the Motion for Intervention by OKCCG by Order No. 534115. On that same date the Commission issued Order No. 534116 determining the notice for this proceeding. On January 12, 2007, the Commission issued a Procedural Order, Order No. 534231.

On January 11, 2007, Gerdau filed a Motion to Associate Counsel. On January 17, 2007, a Motion to Intervene by Redbud Energy, L.P. ("Redbud") was filed. On January 19, 2007, Commission issued Order No. 534429 granting Gerdau's intervention. On January 26, 2007, this Commission issued Order No. 534742 granting Gerdau's Motion to Associate Counsel and finding that Robert A. Weishaar, Jr. and Vasiliki Karandrikas to be admitted as attorneys of record in the cause for Gerdau.

On January 31, 2007, Wal-Mart Stores, Inc. ("Wal-Mart") filed a Motion to Intervene. On February 2, 2007, OIEC filed a Motion to Compel and to Suspend Procedural Schedule, the Commission filed its Notice of Initial Screening Conference and this Commission issued Order No. 535074 granting Redbud's intervention. On February 15, 2007, this Commission issued Order No. 535570 amending the procedural schedule. On February 15, 2007, Wal-Mart filed a Motion to Associate Counsel.

On February 20, 2007, City of Tulsa, Oklahoma filed a Motion to Intervene. On that same date, the AG, OKCCG, PSO, Wal-Mart, OIEC, QSC, Gerdau, and the OCC Staff filed their Lists of Major Issues. On February 22, 2007, this Commission entered Order No. 535818 granting Motion to Intervene of Wal-Mart. On February 28, 2007, this Commission issued Orders Nos. 536047 and 536046 granting Wal-Mart's Motion to Associate Counsel and finding that Grace C. Wung and Gregory K. Lawrence to be admitted as attorneys of record in this cause for Wal-Mart. On March 9, 2007, this Commission issued Order No. 536556 granting the Motion to Intervene of the City of Tulsa. On March 9, 2007, PSO filed a Motion to Amend Procedural Schedule based upon an Errata filed on March 8, 2007. On March 20, 2007, Redbud filed a Statement of Position, as did the City of Tulsa on March 21, 2007.

On March 20, 2007, the parties filed responsive testimony. Brandy Loyd Wreath, Javad Seyedoff, George Mathai, Jason Thenmadathil, Robert C. Thompson, Marvin Vaughn, Karen Forbes, and Fairo Mitchell filed responsive testimony on behalf of the Staff of the Commission. Roya Soltani, Daniel J. Lawton and Jacob Pous filed responsive testimony on behalf of the AG. Scott Norwood, Mark Garrett, and J. Randall Woolridge filed testimony on behalf of the OIEC, James T. Selecky filed testimony on behalf of Walmart, and Joe Robson filed testimony on behalf of QSC.

On March 23, 2007, this Commission issued Order No. 537156 amending the Procedural Schedule. As a result of that Order, responsive testimony for Rate Design/Cost of Service was to be filed March 29, 2007 and rebuttal testimony regarding the same subject matter was due on April 18, 2007. On March 29, 2007 responsive testimony was filed by Mark Garrett for the OIEC, James Selecky for Wal-Mart, David Smith for Staff, Joe Robson for QSC, and Michael Sarafolean for Gerdau.

On April 9, 2007, rebuttal testimony was filed. OIEC filed the rebuttal testimony of Mark E. Garrett and Scott Norwood. PSO filed rebuttal testimony of John O. Aaron, Susan B. Abbott, Julie M. Cannell, David A. Davis, A. Naim Hakimi, Michael S. Isenberg, David A. Jolley, Preston S. Kissman, Donald A. Murry, David P. Sartin and Stuart Solomon. The AG filed the rebuttal testimony of J. Randall Woolridge.

On April 16, 2007, OIEC filed a Motion to Strike the Testimony of David Smith. OIEC's Motion was heard on April 26, 2007, by the Referee and the Commission *en banc.*

On April 17, 2007, PSO filed a Motion to Associate Counsel. On April 25, 2007, this Commission issued Order No. 538337 granting Motion to Associate Counsel and finding that Ann M. Coffin, James F. McNally, Jr., Bret J. Slocum, and Rhonda C. Ryan to be admitted as attorneys of record in the cause for Public Service Company of Oklahoma.

Rebuttal testimony regarding Rate Design was filed on April 18, 2007. PSO filed the rebuttal testimony of Kathy J. Champion, Donald R. Moncrief and A. Naim Hakimi. The Staff filed the rebuttal testimony of George Mathai. The OIEC filed the rebuttal testimony of Glen E. Gregory, Mark E. Garrett, and Edward C. Farrar. Wal-Mart filed the rebuttal testimony of James T. Selecky. Gerdau filed the rebuttal testimony of Michael Sarafolean.

Supplemental and/or amended testimonies were filed by Joe Robson on behalf of QSC, Karen Forbes, Brandy Loyd Wreath, Jason Thenmadathil on behalf of Staff, Roya Soltani on behalf of the AG and Mark E. Garrett on behalf of OIEC.

On April 18, 2007, a Settlement Conference was held, after which a Pre-Hearing Conference and the exchange of Exhibit Lists was held on April 20, 2007.

The Hearing on the Merits began on May 1, 2007 and continued on May 2, 3, 4, 7, 8, and 9, 2007.

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.

TESTIMONY SUMMARIES

PSO

John O. Aaron

DIRECT TESTIMONY
I. INTRODUCTION

My name is John O. Aaron. I am 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"). I am 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. I received a Bachelor of Science in Accounting from Louisiana State University in Shreveport in May 1980. I am 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 my direct testimony, I present and support 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 June 30, 2006. I describe 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, provides for the Commission to look beyond the six-month post test-year period if the Commission deems it appropriate.

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 $49,495,296 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	$1,189,422,564
Rate of Return	F-1	8.82%
Operating Income Requirement		$104,907,070
Pro Forma Operating Income	B-2	$74,857,059
Operating Income Deficiency		$30,050,012
Revenue Conversion Factor		1.647097
Revenue Deficiency		$49,495,296

IV. RATE BASE

The rate base components included on Schedule B-2, column 3, represent the test year unadjusted amounts for 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, accumulated deferred income taxes and pre-1971 investment tax credits. Exhibit JOA-2 lists the adjustments made to rate base in this filing.

My direct testimony described the four adjustments to plant in service that I make. The detail of each adjustment by FERC plant account is provided on Schedule C-2. I also describe asset retirement obligations. PSO recognized an ARO liability in December 2005. This ARO relates to the removal and disposal of asbestos in general buildings and generating plants. PSO recommends that the ARO cost of removal be removed from the depreciation rates and that the SFAS 143 depreciation and accretion be included in cost of service.

PSO made adjustments to the working capital portion of the rate base shown on Schedule B-2. The working capital adjustment shown on Schedule B-2 adjusts the fuel inventory component of working capital.

The Company is including a cash working capital ("CWC") allowance in this filing. AP Schedule E-1 presents a CWC allowance of a negative $123,632,537, which reduces the Company's rate base and resulting revenue requirement. The lead-lag study used by PSO as shown on AP Schedule E-1 in this filing is a "cash requirements" calculation.

PSO also included two adjustments to other additions and deductions to rate base in this filing. First, PSO included as a reduction to rate base the upfront funds paid to PSO by Independent Power Producer ("IPP") Interconnection Customers for transmission system upgrades. Second, accumulated deferred income taxes ("ADIT") are increased $601,705 from the June 30, 2006 test year unadjusted amount of $426,527,167 to a pro-forma amount of $427,128,872.

V. COMPONENTS OF CAPITAL

Schedule F-1 shows the components of PSO's capital per books at June 30, 2006, the pro-forma adjustments, and the adjusted capital amounts. After pro-forma adjustments, the Company's capitalization consists of 53.55% long-term debt, 0.43% preferred stock and 46.02% common equity. The overall weighted average cost of capital is 8.82%. Supplemental Package WP F-2 provides the cost of preferred stock and Supplemental Package WP F-3 provides the calculation of the cost of long-term debt. Adjustments were made to Schedule F-1 in calculating the weighted average cost of capital to reflect changes to the outstanding long-term debt balance and a change to common equity.

VI. OPERATING INCOME

Schedule H-1 provides 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 contains operating revenues, operating expenses, operating income before taxes, income taxes, and net operating income. The schedule also shows rate base and rate of return on rate base. Schedule H-2 provides 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 provide supporting information on each individual adjustment. Exhibit JOA-2 provides a list of pro-forma adjustments to operating income made in this filing along with the witness who sponsors the adjustment. Additionally, AP Schedule H-3 provides a brief description of each adjustment and the associated amount on a total company basis and an Oklahoma jurisdictional basis. My direct testimony described in detail the adjustments to operating income on a Total Company basis.

REBUTTAL TESTIMONY

Various adjustments proposed by the Staff and intervenors that I address in my Rebuttal Testimony focus on replacing test year amounts with amounts from outside the test year, for example December 31, 2006. This is improper. Not only are many of these adjustments contrary to the Commission's rule, they are internally inconsistent. It is improper to only adjust some cost of service items and not others. It is also improper to adjust some cost of service items on one basis and other items on an entirely different basis, and it is inconsistent to not apply the same principle for cost restatement equally to other items that may increase PSO's revenue requirement. In the context of a rate case, it is necessary to adjust all expenses, revenues, and rate base to have a consistent test year basis from which the revenue requirement is determined.

PSO's test year is the twelve month period ending June 30, 2006. Unlike Staff and intervenors, the Company 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. All of the Company's proposed adjustments adhere to this standard.

I. PRO-FORMA ADJUSTMENTS

I explain why I disagree with Staff and intervenors' reliance on 17 O.S. Section 284 in support of their pro-forma adjustments. The OCC Staff, the AG, and the OIEC appear to believe that the statute requires an update to reflect certain balances at the end of the six-month post test year period, or revenue and expense activity that has occurred in the six-month post test year period. I do not believe that this is an appropriate reading and application of the statute. To give effect to known and measurable changes occurring or reasonably certain to occur does not provide the parties freedom to simply substitute, on a selective basis, plant balances, and revenue and expense activity with amounts recorded by PSO six months later.

PSO's filing was based on the test year ending balances and activity at June 30, 2006. Given the test year, PSO was required to file its case prior to year end. It did so, and reflected all known and measurable adjustments at that time. PSO did not and, indeed, could not, file its case six months after the test year end to reflect the six month post test year amounts. In fact, the OCC's Minimum Filing Requirements do not allow this. It is improper to look back after year end and replace selective cost of service components. This would make a mockery of the matching principle as it applies to the Commission's test year concept.

II. RATE BASE

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

A. ELECTRIC PLANT

PSO's total electric plant requested in this filing is approximately $3.043 billion. All of the amounts are the actual balances at June 30, 2006. For CWIP, PSO included the test year-end amounts for only those projects that would be in service within 12 months after the end of the test year.

The OCC Staff and the intervenors recommend updating plant in service to December 31, 2006. The OCC Staff recommends a total electric plant balance of $3.035 billion. The AG and the OIEC both recommend a $3.031 billion total electric plant balance. The reduction from PSO's request would deny PSO the opportunity to earn a reasonable return on its investment that is used to provide service to its customers. All three parties erroneously rely on the statute discussed above.

In the event that the Commission determines that PSO is only allowed to look six months beyond the test year for CWIP that will be closed to plant in service, Exhibit JOA-3R shows $57,074,242 of CWIP that will be in-service at December 31, 2006. As indicated above, this reflects the known and measurable adjustment to PSO's June 30, 2006 test year consistent with the OCC's Minimum Filing Requirements.

B. TIME-OF-DAY METER INVESTMENT

The Staff, the AG, and the OIEC propose to eliminate PSO's $62,539 adjustment for Time-of-Day ("TOD") meter investment from plant in service. I disagree with the proposed adjustment. Mr. David Smith on behalf of the OCC Staff recommends in his March 29, 2007 cost of service and rate design testimony, on page 10, that PSO expand its TOD pilot program. Without this meter investment, PSO cannot implement the pilot program discussed in the direct testimony of Ms. Kathy Champion. I do not understand why one OCC Staff member recommends the expansion of a specific program and another OCC Staff member recommends that the cost needed to implement the program be disallowed.

C. ACCUMULATED DEPRECIATION

OCC Staff, the AG, and the OIEC recommended adjustments to PSO's accumulated depreciation. Ms. Soltani and Mr. Mathai recommend increasing PSO's accumulated depreciation by $47,744,686, which reduces PSO's rate base by a corresponding amount. Mr. Garrett recommends a $4,284,205 decrease to PSO's accumulated depreciation, which increases PSO's rate base.

Ms. Soltani's adjustment attempts to restate accumulated depreciation to the balance at December 31, 2006. This is not proper. PSO's test year is June 30, 2006. The Commission should also reject the accumulated depreciation adjustments proposed by Mr. Mathai on behalf of the OCC Staff. Mr. Mathai relied on the work of Ms. Soltani for his adjustment.

Mr. Garrett, on behalf of OIEC, recommends updating the accumulated depreciation and amortization balances to reflect the actual balance at December 31, 2006. Even if the update was proper, he excludes the accumulated amortization of plant acquisition adjustments from his balance since he also removes the plant acquisition asset. PSO included with accumulated depreciation the asset retirement obligations recorded in Account 230 pursuant to SFAS 143. I assume that Mr. Garrett mistakenly excluded this adjustment to his amount. The balance at

December 31, 2006 recorded in Account 230 is $6,436,874, which should be reflected as an increase to Mr. Garrett's accumulated depreciation balance.

D. PREPAID PENSION ASSET

PSO has included $82 million in prepaid pension assets, the thirteen month average balance at June 30, 2006, 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 claims that since PSO's contributions were discretionary, PSO should not earn a full rate of return on that contribution. I disagree. Mr. Hugh McCoy states in his direct testimony that the 2004 and 2005 contributions were necessary but discretionary in terms of ERISA-required minimum contributions. I am told that the pre-2004 contributions, however, were mandatory contributions under ERISA. Whether the pension contributions were either discretionary or mandatory should have no impact on the proper rate base treatment. The pension contributions produce 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.

As discussed in Mr. Hugh McCoy's direct testimony, the prepayment of pension cost results in benefits to PSO's customers. Exhibit JOA-6R, line 5, shows a $1.6 million net benefit to ratepayers with PSO's proposed rate base treatment of the prepaid pension asset, when compared to the savings in pension cost.

I do agree with Mr. Garrett that even if the pension contribution produces benefits, PSO should not be allowed to earn a return greater than the cost of making the contribution. That is exactly PSO's request in this case. Like any other prepayment, the pension contribution was financed by PSO's overall capital structure that includes a mix of long-term debt, preferred stock and common stock.

I disagree with Mr. Garrett that a long-term debt return is the proper return to apply to this prepaid asset. Mr. Garrett claims that PSO should not be able to earn a return greater than the cost incurred to make the contribution. As a result, he recommends that the asset earn PSO's long-term debt rate. However, there is absolutely no basis for this recommendation.

I disagree with the recommendations of Mr. Mathai to remove the prepaid pension asset from rate base and apply his recommended 8.5% return rate. This adjustment is wrong for the same reasons discussed above with regard to Mr. Garrett's recommendation. While Mr. Mathai does provide for a higher return, it is still not possible or logical to "paint" certain long-term assets with different returns.

Further, Mr. Mathai and Mr. Garrett do not otherwise correctly calculate their proposed treatment of this prepaid asset. Exhibit JOA-6R, line 14, shows that the recommendations proposed by Mr. Mathai and Mr. Garrett inappropriately reduces PSO's revenue requirement.

E. OTHER PREPAYMENTS

Mr. Thenmadathil recommends updating the balances to December 31, 2006, consistent with the OCC Staff's interpretation of 17 O.S. Section 284. He also removes prepaid credit line fees, the prepaid OCC Assessment Fee, and prepaid factoring costs from rate base for a $677,470 reduction to PSO's requested other prepayments. Ms. Soltani also recommends an updating of the balances to December 31, 2006 and excludes the $128,132 prepaid OCC Assessment Fee from rate base.

I disagree with Mr. Thenmadathil's recommendation. PSO has included in its filing the thirteen-month average balance at June 30, 2006, the end of the test year as required by the OCC. His recommendation to update the prepaid balances to December 31, 2006 recognizes reductions in the prepayment balances for expense amortization that has not been included in PSO's cost of service. Additionally, the items removed by Mr. Thenmadathil represent reasonable costs incurred by PSO in the normal course of its business.

I also disagree with Ms. Soltani's recommendation. PSO has included in its filing the thirteen-month average balance at June 30, 2006, the end of the test year as required by the OCC. Her recommendation to update the prepaid balances to December 31, 2006 recognizes reductions in the prepayment balances for expense amortization that has not been included in PSO's cost of service. Additionally, Ms. Soltani's adjustment to remove the OCC Assessment Fee is wrong for the same reason I discussed in response to Mr. Thenmadathil.

While Mr. Garrett does not make a direct recommendation regarding other prepayments, in his attempt to remove the prepaid pension asset from rate base, he mistakenly assumes that PSO's entire prepaid balance is related to the prepaid pension asset. Thus, he improperly removed all other valid prepaid expenses in the amount of $1.9 million, recorded on PSO's books at June 30, 2006.

F. MATERIALS AND SUPPLIES

Mr. Vaughn recommends updating the material and supplies balances to December 31, 2006. This results in a $3.4 million increase to the balance included in PSO's rate base. Ms. Soltani recommends an average balance based on the historical 2004 to 2006 time period instead of PSO's thirteen-month average balance at June 30, 2006. Her adjustment results in a $408,000 decrease to PSO's requested rate base.

I disagree with Mr. Vaughn's recommendation. PSO has included in its filing the thirteen-month average balance at June 30, 2006, the end of the test year as required by the OCC. Updating to December 31, 2006 as proposed is not the recognition of known and measurable adjustments to PSO's test year. Simply stated, it is introducing an updated test year.

I also disagree with Ms. Soltani. Ms. Soltani takes a three-year average of the thirteen-month average materials and supplies balances from 2004 to 2006 to arrive at her recommended adjustment. PSO has consistently requested a thirteen-month average balance for materials and supplies. Moreover, the OCC Minimum Standard Filing Requirements state that the schedule for materials and supplies should be the thirteen-month balances of materials and supplies for the test year.

G. FUEL INVENTORIES

Ms. Soltani recommends the use of the thirteen-month average balance at December 31, 2006 instead of PSO's adjustment to reflect target coal inventories. This would result in a $ 1.1 million reduction to PSO's request.

Ms. Soltani's recommendation is not practical for system reliability purposes and could lead to higher fuel costs if adequate levels of coal inventory are not maintained. PSO's adjustment is based on the target tons for Northeastern Units 3 and 4, and PSO's share of Oklaunion. The cost per ton used in PSO's adjustment is based on the average inventory cost per ton at June 30, 2006, the test year end.

H. CUSTOMER DEPOSITS

Mr. Javad Seyedoff recommends a $975,000 decrease to rate base to reflect the thirteen-month average balance of customer deposits at December 31, 2006. Ms. Soltani and Mr. Garrett recommend a decrease of $3.1 million to rate base to reflect the balance at December 31, 2006. I disagree with these recommendations. PSO has included in its filing the year end balance at June 30, 2006, the end of the test year as required by the OCC. Updating to December 31, 2006 as proposed is not the recognition of known and measurable adjustment to PSO's test year. The fact that customer deposits have increased at December 31, 2006, is not a measurable occurrence at the time PSO prepared its filing based on a June 30, 2006 test year.

I. OFF-SYSTEM SALES TRADING DEPOSITS

The rebuttal testimony of Mr. A. Naim Hakimi addresses this issue.

J. IPP SYSTEM UPGRADE CREDITS

The IPP System Upgrade Credit represents funds provided by PSO's IPP customers that are eventually refunded to the IPP customer. I disagree with Mr. Thenmadathil's recommendation to update this balance to December 31, 2006. PSO has reflected the amount of IPP System Upgrade credits recorded on its books at June 30, 2006, the test year end. Updating the balance to December 31, 2006, is not a known and measurable adjustment. It is improper to replace PSO's test year amount with an updated year end amount.

K. CASH WORKING CAPITAL

PSO has reduced its rate base by approximately $123.6 million to reflect the CWC allowance determined by a lead-lag study based on the twelve-month period ending June 30, 2006, the test year period.

Mr. Thompson takes issue with this calculation. He includes interest expense and preferred stock dividends, both components of return, in his CWC calculation. However, he excludes return on common equity since he does not recognize that a "cash" payment is made for this item. He did accept the revenue lag days and the expense lead days determined by PSO. The AG did not reflect any recommended O&M adjustments in the CWC calculation. The OIEC reflected their respective adjustments to O&M in the CWC calculation and accepted the lead-lag days determined by PSO.

I disagree with Mr. Thompson's calculation. Mr. Thompson recommends including the interest on long-term debt and dividends on preferred stock in the CWC calculation. PSO excluded the effect of interest on long-term debt and dividends on preferred stock by assigning these items zero lead and lag days in the CWC calculation.

Mr. Thompson states on page 13, "That Commissioners accepted Staff's CWC calculation methodology after deliberating the extensive testimony and cross-examination regarding this question." (emphasis added). Mr. Thompson is incorrect that the Commission deliberated the question of including interest on long-term debt and dividends on preferred stock in PUD 200500151. In PUD 200500151, the Oklahoma Gas and Electric ("OG&E") case, Mr. Thompson was the OCC Staff's witness on CWC. In that case, he challenged OG&E's inclusion of "non-cash" items in the CWC—depreciation expense, return on equity and investment tax credits. According to Mr. Thompson, OG&E used a full requirements approach to determine its CWC which includes all cash as well as non-cash items included in cost of service. The question in that case was not whether to include interest on long-term debt and dividends on preferred stock in the CWC calculation. The question was whether to include or exclude "non-cash" items such as depreciation, return on equity and investment tax credits in the CWC calculation.

This issue was not addressed in the final order in PUD 200500151. The portion of the final order pertaining to CWC is silent on the issue of interest on long-term debt and dividends on preferred stock.

PSO's proposed treatment of these items is correct. First, long-term debt and preferred stock simply do not represent a ratepayer-supplied source of working capital for PSO. Instead, these are investor-supplied sources of capital. The delay in payment of interest on long-term debt and dividends on preferred stock is already reflected in the cost of capital analysis. Although it is true that interest on long-term debt is typically paid semi-annually and preferred stock dividends are paid quarterly, the rates of returns that lenders and preferred stockholders demand reflect these payment conventions.

Second, the OCC's Minimum Filing Requirements define working capital as "the average investment required to fund daily operating expenditures" and includes the CWC calculation as a component of that item. In my opinion, daily operating expenditures draws a line on the income statement at operating income. Interest on long-term debt and preferred stock dividends are not a component of determining operating income. Operating income is the investor's earnings.

Even if the Commission decides that the recommendation of the OCC Staff is correct, the calculation is not correct. PSO did not calculate or provide the payment lead days for interest on long-term debt or preferred dividends. The values for these two components, according to

Mr. Thompson, were taken from an Exhibit provided in rebuttal testimony in PSO's rate case, PUD 960000214. These values should be updated for a proper calculation.

I do agree with Mr. Thompson that the final CWC amount will need to be recalculated with the level of expenses and methodology approved in this proceeding.

L. ACCUMULATED DEFERRED INCOME TAXES

Ms. Soltani and Mr. Garrett propose to update all Accumulated Deferred Income Taxes ("ADIT") balances recorded on PSO's books to the balance at December 31, 2006 to be consistent, they claim, with their other updates to PSO's rate base.

I disagree with their recommendations. PSO has reflected the proper level of ADIT, as adjusted, based on the test year ending balance at June 30, 2006. Updating to the December 31, 2006 balances is not a known and measurable adjustment. Instead, these adjustments reflect updated balances and attempt to introduce a new test year.

I also have further objections to the ADIT amounts recommended by Mr. Garrett and Mr. Mathai. As I discussed in the section on Prepaid Pension Assets, neither Mr. Mathai nor Mr. Garrett appropriately adjusted ADIT to reflect the removal of the prepaid pension asset from rate base. If the Commission adopts either of these recommendations and removes PSO's prepaid pension asset from rate base, a $31,719,987 million corresponding adjustment should be made to decrease ADIT at June 30, 2006.

M. NON-EXPENSE PAYROLL ADJUSTMENT

I disagree with the adjustment proposed by Mr. Brandy Wreath regarding the non-expenses portion of PSO's payroll. First, the adjustment to payroll recommended by Mr. Wreath is a prospective, not a retrospective, adjustment. PSO has recorded payroll costs in capital and O&M accounts as it was actually charged before and during the test year. To adjust that amount now is the equivalent of retroactive ratemaking. Second, I call this adjustment as proposed by the OCC Staff a "give to get" adjustment. Because the OCC Staff has calculated a payroll expense ratio that is not representative of PSO's actual test year base payroll expense, or the historical base payroll expense percentages, the OCC Staff attempts to right this wrong by including the reciprocal amount in rate base. It is more appropriate to have a payroll expense ratio that is representative of the underlying payroll costs recorded by PSO rather than this adjustment. The understated payroll expense ratio (the reciprocal of the percentage used by the OCC Staff in this adjustment) recommended by the OCC Staff is not supported by the facts presented by PSO and, as I discuss in the payroll section of this testimony, should be denied.

III. OPERATING INCOME

Exhibit JOA-9R provides a summary of the adjustments to operating income proposed by the OCC Staff, the AG, and the OIEC. Like the parties rate base adjustments, these adjustments include a mix of calendar year December 31, 2006 amounts, test year amounts, average amounts, and inaccurate calculations.

A. ENVIRONMENTAL EXPENSE

Both Mr. Thenmadathil and Ms. Soltani recommend removing $8,541 of environmental expense from PSO's filing. I can accept the adjustment to remove the environmental expense and have previously acknowledged this in my response to the AG's 6th Data Request, Question No. 25 and the OCC's 93rd Data Request, Question No. 1. Exhibit JOA-10R provides these data responses.

B. DUES AND MEMBERSHIPS

Mr. Brandy Wreath proposed removal of $354,407 of dues and memberships from PSO's filing. His adjustment removed the following: (1) $147,830 of payments to various chamber and civic organizations; (2) an additional $144,799 of Company dues (the largest three to the Oklahoma State Chamber for $50,000, the Nature Conservancy of Oklahoma for $10,000 and Edison Electric Institute for $83,102); and (3) $61,778 of dues allocated to PSO from AEPSC for various organizations. Ms. Soltani removes $426,642 of payments for all chambers of commerce, various civic organizations, as well as other miscellaneous dues and memberships.

I disagree with these proposals. PSO's dues and memberships are a reasonable and normal operating expense that should be included in cost of service. Professional dues and memberships have been included in cost of service as a reasonable and necessary business expense incurred to maintain qualified staff and should not be removed.

The OCC Staff's adjustment regarding many of the expenses removes one-half of the expense and yet for others the entire amount was excluded. Apparently the OCC Staff does give some value to PSO's dues and memberships. However, no justification was given for the inconsistency of this approach.

The adjustment recommended by the AG removes all non-professional dues and memberships from PSO's cost of service. If the Commission determines that the recommendation of the AG is appropriate, the adjustment is overstated by $1,088. This amount is identified as social dues on the AG's workpapers. This amount was not included in PSO's cost of service.

C. LEGISLATIVE EXPENSES

Mr. Garrett recommends excluding $635,159 of PSO's legislative monitoring and advocacy expenses recorded "above-the-line" or reclassified from "below-the-line" for purposes of PSO's revenue requirement calculation. Mr. Brandy Wreath and Ms. Roya Soltani also recommend excluding all of PSO's legislative monitoring and advocacy expenses from PSO's cost of service. Both Mr. Wreath's and Ms. Soltani's adjustment remove amounts greater than the amount PSO requested in its filing for legislative expenses.

Not all of PSO's legislative expenses are recorded "below-the-line." Supplemental Package WP H-14 provides the detail of PSO's legislative charges. PSO included $635,129 of legislative expenses in its cost of service, $326,112 charged to "above-the-line" accounts and $309,018 charged to "below-the-line" accounts. WP H-14 of the OCC's Minimum Filing

Requirements requires a "summarization of all payments to individuals registered to lobby in Oklahoma...during the test year." PSO has interpreted this requirement, possibly inaccurately, to include all charges incurred by PSO for participating in legislative activities, whether those charges are for monitoring legislative activities or advocating PSO's position.

Legislative monitoring expenses included in PSO's cost of service are normal, ordinary operating expenses providing benefits to PSO's customers. These activities and the corresponding expenses, allow PSO to adequately protect the company – and its ratepayers – from legislation that increases PSO's costs of doing business.

I disagree with the recommendations of the OCC Staff, the AG, and the OIEC. The recommendations of the OCC Staff, the AG and the OIEC are based on general arguments that expenses incurred by PSO's legislative monitoring activities are not necessary costs in providing electric service, and may not benefit customers. Quite possibly, the disallowance is based on PSO including all legislative activity expenses on WP H-14, whether legislative monitoring or legislative advocacy. PSO's legislative activities do in fact benefit ratepayers and therefore are appropriate costs to recover.

D. GENERATION PLANT MAINTENANCE EXPENSE

The rebuttal testimony of Mr. Michael Isenberg addresses the recommendations of other parties concerning the proper level of generation maintenance expense to include in PSO's cost of service.

E. TRADING DEPOSITS INTEREST EXPENSE

Mr. Thompson and Ms. Soltani exclude $3,902 of net trading deposit interest expense from PSO's filing. Mr. Thompson states that PSO customers currently receive no benefit from these deposits. Ms. Soltani claims that trading expenses are not necessary for providing electric service. I disagree with these recommendations. The net interest expense related to these deposits should be reflected in PSO's cost of service since the deposits are required for PSO to engage in both power purchasing and off-system sales markets. Since the benefits of PSO's trading activities are reflected in the fuel adjustment clause, a reasonable alternative is to allow recovery via that mechanism rather than recovery in base rates.

F. RATE CASE EXPENSES

PSO requested recovery of its estimated $410,000 in rate case expense over a two-year period, or $205,000 per year. Both Mr. Thenmadathil and Ms. Soltani recommend different recovery periods for the current rate case expenses. Mr. Thenmadathil recommends a five-year period or a reduction of $123,000 to PSO's requested rate case expense for this proceeding. He does, however, concede that a two-year recovery would be acceptable if the formula rate plan as proposed by PSO is not implemented in this case. Ms. Soltani recommends a three-year recovery period of $136,667 per year or a reduction to PSO's request of $68,333.

I disagree with this recommendation. The expense should be recovered over a reasonable period approximating no more than the time between rate proceedings. I believe that to be two years, three at the most. PSO has incurred approximately $249,000 through March 2007. Additional rate case expense will be incurred from April 2007 through the completion of hearings. PSO, therefore, requests the ability to update rate case expense incurred through the close of hearings and recover that expense over two years.

G. OTHER OUTSIDE SERVICES

I can accept Mr. Thenmadathil's recommendation to exclude $12,769 from outside services expense.

H. LEGAL EXPENSE

Mr. Jason Thenmadathil recommends reducing legal expenses by $195,741. The majority of this exclusion, $181,589, relates to an employee discrimination case. In addition, Mr. Thenmadathil excludes $14,173 of legal expenses associated with this current rate case. I can accept the adjustment to exclude the expenses related to the current rate case of $14,173. However, I do not accept the adjustment related to the employee discrimination case. The fact that the case was settled, should not affect recovery of legitimate and necessary legal expenses.

I. ADVERTISING EXPENSE

Mr. Thompson identified $475,990 of advertising costs as non-recoverable for ratemaking purposes. I can accept the adjustment in advertising expenses related to the expenses Mr. Thompson reviewed and disallowed which amount to a $475,990 reduction to PSO's revenue requirement.

Mr. Garrett recommends 100% disallowance of PSO's pro-forma advertising expenditures in the amount of $1,392,779. Mr. Garrett purports to base his recommendation on: (1) the Supreme Court's decision in *State v. Oklahoma Gas and Electric Co.,* (2) the Oklahoma Statutes at 17 O.S. 180.1; and (3) the Commission Rules at OAC 165:45-13.

I disagree with Mr. Garrett's proposal. The Supreme Court case relied upon by Mr. Garrett interpreted the Commission's ability to implement rules for electric companies. Those rules were repealed effective July 1, 1999. (16 OK REG 2237) The Commission has not promulgated rules to replace the ones revoked. I also disagree with how Mr. Garrett has applied Oklahoma Status at 17 O.S. 180.1. As Mr. Garrett has pointed out in his testimony, but seems to ignore, the statute exempts various types of communications from being classified as advertising and therefore makes them allowable for ratemaking purposes. All of these exempted types of advertising can be found in PSO's expenses requested in this filing.

J. MARKETING AND SALES EXPENSE

Mr. Thompson recommends a reduction of $35,319 related to expenses recorded as marketing and sales expense. His recommendation is simply based on the belief that these expenses should be shared between shareholders and ratepayers.

I disagree with this adjustment. The OCC Staff reviewed a sample of three invoices totaling approximately $7,500 (10% of the amount erroneously reported on WP H-21 as sales expense) and apparently determined that some of the charges were not reasonable. Based on this review, the OCC Staff concluded that PSO's marketing and sales expenses (which PSO stated in the response do not exist) "promote" PSO and should be shared equally between shareholders and ratepayers. This limited review should not be the basis for a 50/50 sharing of these expenses, which as stated by PSO, are not sales and marketing expenses.

K. AD VALOREM TAX EXPENSE

Mr. Vaughn recommends a $1.4 million reduction to the ad valorem tax expense included in PSO's filing. Ms. Soltani and Mr. Garrett recommend a $1.7 million reduction to PSO's requested ad valorem tax expense.

Mr. Vaughn's adjustment is based on the premise that only Oklahoma property taxes should be recovered from PSO's customers. His resulting effective ad valorem tax rate is flawed. Ms. Soltani and Mr. Garrett simply update the test year ad valorem tax expense to reflect the total for the calendar year 2006.

L. PURCHASED POWER CAPACITY EXPENSE

Mr. Vaughn recommends a $2.1 million reduction to PSO's requested purchased power capacity expense. Ms. Soltani recommends $4.8 million reduction to purchased power capacity expense. Mr. Scott Norwood recommends a $3.5 million reduction to PSO's purchased power capacity expense.

Mr. Vaughn calculated a three-year average of purchased power capacity expense for the period 2004 to 2006. This represents a $2.1 million reduction to PSO's requested amount. However, the use of a historical average level of purchased power capacity expense is not a known and measurable adjustment to PSO's test year ending expense.

Ms. Soltani states that "[t]he Company's adjustment is based on estimated cost." This is not true. PSO's adjustment is based on the known and measurable capacity purchases occurring in the test year. PSO annualized the purchased power capacity quantity based on the existing contracted purchased power capacity prices.

Mr. Norwood states on page 23 of his testimony that PSO's requested recovery of purchased power capacity expense "could lead to double recovery". What "could" transpire is not a basis for disallowing proper costs.

M. PAYROLL EXPENSE

Mr. Wreath recommends a $2.8 million reduction to PSO's pro-forma base payroll. His adjustment is based on PSO's December 2006 annualized base payroll and a three-year average payroll expense ratio. Ms. Soltani recommends a $2.0 million reduction to PSO's pro-forma payroll. Mr. Garrett recommends a $3.051 million reduction to PSO's payroll expense.

I disagree with Mr. Wreath's proposed adjustment. Most importantly, Mr. Wreath applied a three-year average payroll expense ratio to the December 2006 annualized level to arrive at his test year adjusted amount. His recommended $2.8 million reduction should be denied since the ratio underlying his calculation is a mismatch of components.

Ms. Soltani's payroll adjustment should also be rejected. First, her base payroll adjustment reflects actual calendar year 2006 base payroll. It is not an annualized amount that reflects a full year of base payroll for active employees at their December 31, 2006 pay level. In addition, as I stated earlier in my testimony, this is not a known and measurable adjustment. Instead, it attempts to selectively introduce a new test year. Second, her adjustment to reduce PSO's test year overtime payroll by $1.934 million is not correct. She incorrectly assumes that overtime payroll is charged entirely to expense; that is not the case. PSO's test year overtime payroll charged to expense is only 70.27%. The remainder would be charged to capital accounts. Third, Ms. Soltani's adjustment for AEPSC base payroll billed to PSO is based on the calendar year 2006 AEPSC base payroll billed to PSO. As I stated earlier in my testimony, this is not a known and measurable adjustment. Instead, it attempts to introduce a new test year.

I also disagree with Mr. Garrett's proposed adjustments. First, his payroll adjustment reflects December 31, 2006 payroll information. As I stated earlier in my testimony, this was not a known and measurable adjustment at the time PSO filed its rate case. Second, his calculation produces results for PSO's payroll expense that are not reasonable. His base payroll amount is $2.9 million lower even though the employee count increased between the end of the test year and December 31, 2006. However, the fact that Mr. Garrett missed two pay periods is an explanation for the difference in his calculation.

N. PRELIMINARY ENGINEERING EXPENSE

Mr. Mathai and Mr. Norwood recommend that PSO not recover preliminary engineering costs related to the evaluation of additional generating resources. PSO requested recovery of $2.2 million over five years or $442,403 per year.

Mr. Mathai recommends deferral of these costs until the time the new plants are constructed; then, amortizing these costs over the life of the new plants. However, the costs at issue in this adjustment relate to generation technologies that PSO will not pursue. Mr. Mathai's recommendation is correct for preliminary engineering costs incurred by PSO for the new generation plants that are being constructed; and, PSO is doing just that.

Mr. Norwood erroneously concludes that PSO has stated that it would not seek recovery for such costs if the related bids were not accepted. He bases the false conclusion on PSO's response to the OIEC's 4th Data Request, Question No. 21, in PUD 200600030, attached to my testimony as Exhibit JOA-16R. Mr. Norwood reads meaning into the response that simply does not exist.

O. FICA TAX EXPENSE

Mr. Wreath recommends a $227,111 decrease to payroll tax included in PSO's filing. Ms. Soltani recommends a $515,572 reduction to payroll tax included in PSO's filing.

Mr. Garrett recommends a $369,502 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.

These proposed adjustments should be rejected. The level of payroll tax included in PSO's filing is consistent with the level of payroll expense requested by PSO. To the extent the Commission changes the level of total payroll expense requested by PSO, there should be a corresponding change to payroll tax expense.

P. EMPLOYEE BENEFITS EXPENSE

Mr. Wreath recommends the following adjustments to PSO's employee benefits:

1) a $221,792 reduction for SFAS 87 pension expense,
2) a $360,184 reduction for SFAS 106 expense,
3) a $141,295 reduction for SFAS 112 expense,
4) a $449,528 reduction for employee group benefits expense, and;
5) a $204,763 reduction for employee savings plan expense.

Ms. Soltani recommends a $313,394 reduction to pension expense to reflect the elimination of Supplemental Executive Retirement Plan ("SERP") expense from PSO's cost of service. Mr. Garrett recommends a $596,081 decrease to pension expense to reflect the elimination of SERP expense from PSO's cost of service.

I disagree with Mr. Wreath's adjustments. His adjustment to SFAS 87 expense, SFAS 106 expense, and SFAS 112 expense is based on the flawed payroll O&M expense ratio I discussed in the Payroll Expense section of this testimony. The payroll O&M expense ratio as calculated by Mr. Wreath does not reflect the distribution of incentive payroll to capital accounts and O&M accounts and incorrectly assumes the incentive payroll is charged 100% to capital which is incorrect.

Mr. Wreath's adjustments to employee group benefits expense and PSO's matching retirement savings plan contributions are based on calendar year 2006 information and also used the flawed payroll O&M expense ratio. In addition to these reasons, the 2006 calendar year amounts do not represent annualized amounts reflective of annualized payroll dollars and employee counts.

Both Ms. Soltani and Mr. Garrett incorrectly state that SERP expense is not a necessary cost for PSO to provide electric service.

Q. INCENTIVE COMPENSATION EXPENSE

Mr. Garrett has overstated his proposed disallowance by incorrectly concluding that PSO "did not make a corresponding adjustment to the AEPSC payments." Supplemental Schedule WPP-07-2 (Affiliate Adjustments) provides the detail of the adjustment of AEPSC incentive compensation billed to PSO during the test year. Lines 93 through 188 detail the adjustment by account and totals to $4,813,079. Exhibit JOA-17R provides a corrected table similar to the table presented by Mr. Garrett on page 43 of his direct testimony should the Commission agree with the premise of the adjustment proposed by Mr. Garrett.

R. IPP SYSTEM UPGRADE CREDIT INTEREST EXPENSE

Mr. Thenmadathil proposes to update IPP System Upgrade Credits to the December 31, 2006 amount. Consistent with this rate base adjustment, the OCC Staff also updates the associated interest expense. This is not a known and measurable adjustment at the time PSO filed its rate case. Instead, it is a selective adjustment for a new test year.

S. CREDIT LINE FEE EXPENSE

Mr. Thompson and Ms. Soltani recommend reversing the company's adjustment that reclassifies $203,300 of credit line fees from "below-the-line" to "above-the-line." The proposed adjustment should be rejected. Credit line fees are a cost of doing business just as fuel expense and payroll expense are costs of doing business.

T. DEPRECIATION EXPENSE

The rebuttal testimony of Mr. David A. Davis addresses the adjustments to depreciation expense proposed by the OCC Staff, the AG, and the OIEC.

U. CUSTOMER DEPOSIT INTEREST EXPENSE

Mr. Seyedoff recommends an adjustment to reflect the thirteen-month average balance at December 31, 2006. Ms. Soltani on behalf of the AG recommended updating customer deposit interest to reflect the balance at December 31, 2006. I do not agree with either of the recommendations. PSO has included in its cost of service the appropriate level of interest expense using the OCC prescribed interest rates and the June 30, 2006 test year ending balance of customer deposits.

V. FACTORING EXPENSE

PSO sells its accounts receivable to AEP Credit, Inc., a wholly owned subsidiary of AEP. The factoring of PSO's receivables occurs daily with a discount (*i.e.,* factoring) expense consisting of a charge for carrying costs and a charge for bad debt expense.

Mr. Thompson and Ms. Soltani made recommendations on the amount of factoring expense to include in PSO's revenue requirement based on the respective return on equity recommended by the OCC Staff and the AG. 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 be calculated based on the return on equity ultimately approved by the Commission in this filing.

W. PENSION ASSET ALTERNATE RECOVERY

I disagree with the alternative recovery of prepaid pension asset recommended by Mr. Mathai and Mr. Garrett. I addressed the issue of the prepaid pension asset earlier in my testimony in the rate base section. The alternative recommendations of Mr. Mathai and Mr. Garrett to recover in cost of service a lesser return on an amount improperly limits PSO's recovery of the return on investments that provide current and future benefits to PSO's customers.

X. REVENUE ADJUSTMENTS

Mr. Don Moncrief will address the revenue adjustments proposed by the OCC Staff and the OIEC in his cost of service and rate design rebuttal testimony.

Y. TRANSMISSION EXPENSE

Ms. Soltani recommends a three-year recovery of the reversal of this non-recurring net credit. Her adjustment reduces PSO's requested transmission expense by $145,372. The OCC should reject Ms. Soltani's recommendation. There is absolutely no valid reason for a three-year recovery of PSO's adjustment that reverses a non-recurring credit. Her recommended treatment of the non-recurring credit is not appropriate and not consistent with the treatment of the non-recurring charge proposed by PSO.

Z. SOUTHWEST POWER POOL ("SPP") ADMINISTRATIVE FEES

Ms. Soltani recommends a $221,174 reduction to PSO's requested SPP administrative fees. Ms. Soltani's adjustment would improperly attempt to shift the test year to December 31, 2006. Further, Ms. Soltani makes no recommendation to adjust other transmission expenses, distribution expenses, customer expense, or general and administrative expenses to the December 31, 2006 level.

AA. COMMUNITY AFFAIRS EXPENSE

Ms. Soltani recommends disallowing PSO's request to increase its community affair staffing levels. The recommendation should not be granted. PSO has requested the $300,000 expense that would allow the addition of three additional community affairs managers. These additional employees are needed because of PSO's large geographical area and the number of customers served by PSO's existing community affairs managers. Ms. Soltani's recommended disallowance is based on a small portion of the activities the community affairs managers will perform.

AB. AEPSC TRADING ADMINISTRATIVE EXPENSE

Mr. A. Naim Hakimi addresses PSO's position regarding Mr. Norwood's recommendation to remove AEPSC trading administrative expense from the cost of service.

AC. INCOME TAX ADJUSTMENT

The OCC Staff, the AG, and the OIEC all made adjustments to PSO's tax calculation to reflect the appropriate changes to taxable income as a result of their respective adjustments. With the exception of an adjustment made by Ms. Soltani for permanent differences, it appears that the calculations reflect the adjustments proposed by the respective parties. PSO's income tax calculation is consistent with previous filings with the OCC. The inclusion of these permanent differences has been accepted by the FERC and accepted in filings in Arkansas, Louisiana, and Texas by PSO's sister utility companies. The OCC has not disallowed these permanent differences in previous PSO filings.

IV. CAPITAL STRUCTURE

Mr. Fairo Mitchell of the OCC Staff recommends an adjustment to reflect PSO's capital structure at December 31, 2006, consistent with other adjustments proposed by the OCC. This adjustment is based on the OCC Staff's interpretation of 17. O.S. Section 284. This recommendation should be rejected. As I have stated previously, PSO's test year in this filing is June 30, 2006. Simply replacing test year amounts with amounts at December 31, 2006 is not proper. This recommended adjustment should be rejected.

Susan D. Abbott

My name is Susan D. Abbott and have prefiled direct testimony in November 2006 and rebuttal testimony on April 9, 2007, in this proceeding. I am a Managing Director of New Harbor Incorporated.

I have a B.A. in literature from Syracuse University and a M.B.A. in finance from University of Connecticut. For over 25 years, I have been a securities analyst specializing in utility investments and for much of that time I was at Moody's.

My testimony provides an opinion as to the effect on Public Service Company of Oklahoma's ("PSO" or "the Company") creditworthiness, as viewed by the fixed income investor, of the planned construction program necessary to service the Company's growing customer base, including the effects of both the construction program and the regulatory treatment thereof. My point of view is that of a rating agency such as Moody's Investors Service ("Moody's"), Standard and Poor's ("S&P"), or Fitch Ratings ("Fitch").

I provide an overview of the role of credit agencies, how they evaluate a company, the factors they consider important, and the consequences of the ratings on the ability of the company to have access to capital from the market. I also discuss how a major construction program can raise concerns for rating agencies.

PSO currently enjoys senior unsecured ratings of Baa1 from Moody's, BBB from Standard & Poors, and A- from Fitch. All three rating agencies consider the ratings stable. Fitch views the Oklahoma statute that allows for fuel cost pass-through as positive, and states "the company...benefits from an annually adjusted pass-through clause that helps stabilize earnings and cash flow". In addition, Fitch also finds positive "rules allowing companies to obtain approvals before construction....as significantly increases the probability of adequate recovery of investments." It is clear that ratemaking procedures that provide for consistency and predictability are favored by the rating agencies. Therefore, a rate change plan such as the one being proposed by PSO would serve not only to stabilize cash flow, but also provide a positive foundation for maintenance of PSO's ratings throughout the five year term of the upcoming $2.0 billion construction program.

S&P, in its report on capital expenditures dated July 27, 2005, states that the "key consideration would be the regulatory treatment of capital expenditures. A utility's ratios will benefit to the extent that it can add CWIP to the rate base. Also, a jurisdiction that minimizes regulatory lag by adding assets to rate base earlier and by allowing for contemporaneous recovery of expenditures will benefit utility credit quality." This is a clear sign that a rate change plan that will stabilize and make more predictable cash flows will benefit the Company's rating and its customers.

Finally, I present an analysis of the impact that granting or denying the formula based rates requested by the company would have on three key financial factors used by rating agencies to evaluate utilities. I conclude that granting the requested formula based rates would allow the company to maintain its current credit rating, but denial would put PSO in jeopardy of a downgrade as early as 2009.

In my rebuttal testimony I respond to several points raised by Dr. J. Randall Woolridge on behalf of Oklahoma Industrial Energy Consumers, one point in Daniel J. Lawton's testimony on behalf of the Office of the Attorney General, and offer a general comment on the depreciation expense recommendations. In Mr. Woolridge's criticism of my analysis, he makes a number of claims that are simply without merit. For instance, Mr. Woolridge ignores the fact that the three financial measures I present are the only ones published by the rating agencies and recent statements by the rating agencies show that they are concerned about PSO's construction and the regulatory treatment of those costs. For instance, Moody's notes PSO's $2 billion construction program and comments that disallowance of appropriate rate recovery could weaken its credit profile.

With regard to Mr. Lawton's assertion that the pretax and after-tax coverage ratios show that his recommended return is adequate, I point out that rating agencies focus more on cash flow metrics and the coverage measures used by Mr. Lawton are no longer widely relied upon.

Finally, while I do not hold myself out as a depreciation expert, there are cash flow consequences to the depreciation expense allowance that the Oklahoma Corporation Commission should consider. Given the substantial construction program that PSO is about to embark upon, cash flow will be very important. So, to the extent there is a reasonable range of depreciation expense, I believe that the Commission should consider PSO's financial situation.

E. Kevin Bethel

<u>DIRECT TESTIMONY</u>

The purpose of my direct testimony is to support the $59,970,658 of affiliate charges included in cost of service. I explain that AEPSC provides various professional services primarily to AEP's utility companies, including PSO. Services provided include accounting and financial reporting, legal, engineering, customer operations, information services and telecommunications services. AEPSC also provides services related to generation, transmission and distribution management as well as other areas as summarized by Exhibit EKB-1 of my testimony. Those services are billed to PSO at cost with no profit or return component added. I discuss the five functional organizations of AEPSC that include Utility Operations, Generation, Finance, Accounting and Strategic Planning, Shared Services, and Office of the Chairman. I explain that AEPSC employees are located throughout the AEP footprint, including 507 in PSO's service territory. Providing services through a centralized service organization such as AEPSC provides savings through economies of scale by utilizing standard processes and technology systems where possible. Costs incurred by AEPSC and billed to PSO of $58,503,810 in cost of service are necessary to PSO's operations and provide benefits to customers in a cost effective and efficient manner.

I also discuss in my testimony that PSO has included $1,466,848 in cost of service related to affiliate transactions with affiliates other than AEPSC. I describe these types of costs as being either service payments, or convenience payments. Service payments are made where the affiliate provides a service such as storm restoration work, or provides equipment or professional expertise that PSO is in critical need of in order to expedite the work. Another example is where AEPTN is the operator of the HVDC transmission interconnect, which is jointly owned by PSO. PSO is billed their share of the services related to the operation of that facility by AEPTN. These types of costs are simply payment for services rendered and are billed at cost. Convenience payments are those where PSO does not receive the benefit directly from the affiliate, but the affiliate pays on behalf of multiple companies. A good example of this is where there would be legal work related to a SPP matter, and our other affiliate in the SPP region, SWEPCO, paid the invoice on behalf of both companies. PSO would then be billed their share of the work performed.

I explain that AEPSC, as well as the other affiliate costs, are accounted for using a work order system that was required by the SEC, and is now required by the FERC. Costs for services benefiting only one company are direct billed, while costs benefiting more than one company are allocated using SEC approved allocation factors. Allocation factors are chosen that best reflect the cost driver associated with the services provided. EKB-3 is included in my testimony to show the 38 allocation factors used to bill cost of service charges to PSO and the amounts billed by each factor. I discuss the use of a volume driven formula, for example number of invoices for billing services related to invoice processing. I also explain that where a volume driven factor is not readily available, we use the most representative factor, such as transmission pole miles for managing and dispatching the transmission system. Any allocation method should allocate costs on a basis that relates the cost to the activity generating the cost and should be applied consistently to all affiliate companies for similar services. I believe using the work order system we have in place to capture charges, and the use of the allocation factors approved by the SEC, we accomplish that. We have controls in place that ensure the proper billing of affiliate costs to all affiliates. These controls can be divided into areas of accounting systems controls, management oversight, and audit and reporting oversight. I have also included Exhibit EKB-4 that provides an overview of these controls utilized by AEPSC.

The Public Utility Holding Company Act of 1935 ("PUHCA 35") gave the SEC significant authority over operations of service companies such as AEPSC during much of the test year. We continue to use the SEC approved work order system and approved allocation factors subsequent to the repeal of PUHCA 35 to bill costs to affiliates. We used the SEC rules to ensure that we were providing services economically and efficiently for the benefit of the affiliate companies at cost, while being fairly and equitably allocated among the companies. I also explain that with the repeal of PUHCA 35, the FERC has been given the responsibility for oversight of service companies. The FERC issued FERC Order 684, "Financial Accounting, Reporting and Records Retention Requirements Under the Public Utility Holding Company Act of 2005" on October 19, 2006, and we continue to monitor the application of this order and any further requirements of FERC. In summary, I believe that the current processes used for accumulating costs and billing between affiliates is appropriate and operating effectively and efficiently.

Julie M. Cannell

My name is Julie M. Cannell. I prefiled testimony in November 2006 and rebuttal testimony on April 9, 2007.

I have an MBA in finance from Columbia University in addition to degrees from Emory University and Mary Baldwin College. Prior to forming my own advisory firm, J. M. Cannell, Inc. in 1997, I was a securities analyst specializing in the electric utility industry for approximately 20 years while employed by the investment management firm Lord Abbett & Company. I am a Chartered Financial Analyst. I have previously testified before this Commission.

My direct testimony discusses the probable impact of the Public Service Company of Oklahoma's proposed rate increase and formula based rate structure on investors' evaluation of the Company.

The Company is about to embark on a significant construction program that will require it to access the capital markets. The cost of that capital will have a direct impact on the rates paid by retail customers.

An adverse regulatory decision could be a key determinant on whether an investor invests or keeps his investment in a utility stock. Investors, who still look to utility stocks for stability and regular dividends even as the risk level in the industry has increased, place a high value on consistent and constructive regulation. Because of the major role that institutional investors and hedge funds now play in the market, there is likely to be a quick and potentially significant reaction to any unexpected negative ruling by a regulatory commission.

Both the credit rating agencies and security analysts are aware of the sizeable construction program PSO is about to undertake and are very cognizant of the crucial role that regulation must play in support of the construction initiative. Investors want utilities to receive timely and adequate recovery of their costs to enable them to pay dividends and have adequate cash flow to sustain credit ratings.

During a time of significant rate base additions, it is especially important that the utility be granted a return that maintains its credit rating and allows it access to capital markets. A higher ROE would be viewed as supportive and would allow PSO to raise capital on more favorable terms in both the equity and debt markets, which will benefit customers.

In my rebuttal testimony, I respond to the rate of return testimony filed by the intervening parties, as well as the Oklahoma Corporation Commission Staff ("Staff"). I also address comments of OIEC witness Dr. J. Randall Woolridge regarding my direct testimony.

The intervenors and staff base their recommendations on the calculation under various models, but such academic models are simply tools in an investor's decision-making kit. In the final analysis, judgment and experience often carry far more weight.

While the intervenors all are recommending a ROE below 10% in this proceeding, there was only a sprinkling of rulings issued in 2005 and 2006 incorporating ROEs below 10% and those included a number of decisions in a jurisdiction that employed a future test period. Since the filing of my direct testimony, Goldman Sachs has said that it expects an 11.0% ROE to be granted in this proceeding. Additionally, a recent study I conducted for EEI regarding investors' perceptions of state regulatory issues revealed, among other things, that: 1) investors consider 10% to be a minimum allowed return on equity threshold; 2) Investors are concerned with utilities' ability to actually earn their authorized return; and (3) the return on equity should adequately recognize the risks associated with a company's particular risks.

With regard to Dr. Woolridge's criticism that I did not perform empirical studies to support my direct testimony, the observations that I offer in this proceeding are founded on nearly thirty years of experience as an analyst of the electric utility industry, including almost two decades as an institutional investor.

Finally, in regard to Dr. Woolridge's criticism of my support for PSO's requested ROE, I point out in my rebuttal that investors require a return that is commensurate with the risk they assume in making an investment. PSO is preparing to undertake a significant capital spending program that will require them to access the capital markets on a regular basis. Investors' perception of the constructiveness of Oklahoma regulation is a key influence on what PSO's cost of capital will be.

Kathy J. Champion

My name is Kathy J. Champion and I filed direct testimony in this docket on November 21, 2006, and rebuttal testimony on April 18, 2007.

I have a Bachelor of Science degree in Business Administration from Bartlesville Wesleyan College. I have been with AEP, or its predecessor Central and South West Corporation ("CSW"), since joining Public Service Company of Oklahoma ("PSO") in 1983. I have previously testified before this Commission and my qualifications are contained within my direct testimony.

In my direct testimony of November 21, 2006, I support PSO's proposed revenue distribution, rate design changes, service fee changes, and proof of revenue.

For revenue distribution, PSO focused on obtaining full recovery of assigned costs by customer class as determined by the class cost-of-service study sponsored by witness Donald R. Moncrief, while attempting to mitigate customer impacts associated with moving a customer class to full recovery of its costs. PSO is requesting an 11.51% overall base rate increase and proposes to increase overall residential rates 12.96%, commercial rates 13.24%, and industrial rates 4.51%.

PSO's rate design balances several objectives: encouraging efficient use of resources; sending appropriate price signals; providing new demand-side management rate options; limiting rate impacts to the extent practicable; and improving customer satisfaction with PSO's rate structure.

The proposed rate structure in general increases the Basic Service Charge and reduces the variable energy charges for Residential and Commercial customers. This will decrease the dramatic shifts between on-peak and off-peak prices, while still sending appropriate price signals with declining block rates in off-peak winter months and inclining block rates in on-peak summer months.

To address the demand-side management objective, PSO proposes an optional Time of Day pilot program for Residential, Low Use General Service, and General Service Customers. During the pilot, PSO proposes including a "best rate" feature, which allows customers to try the Time of Day options while protecting them from paying more than they would under the standard tariff. PSO also proposes two new interruptible tariff options for Large Power and Light Customers, and a modification to the Energy Price Curtailable Service Pilot Rider approved in PSO's last general base rate case.

PSO also proposes to maintain a discount for schools.

PSO proposes to eliminate the Alternate Feed Service Rider, which has had no participation since it went into effect in June 2004, and to suspend the Non-Utility Generator Service tariff until the SPP imbalance market has been implemented and market prices have stabilized.

Regarding service fees, PSO proposes to eliminate the Service Call Fee and the Temporary Disconnect Fee to protect the physical safety of its customers.

PSO proposes changes to its electric service rules, regulations, and conditions of service to clarify a customer's obligation to provide PSO permission and access to a customers' premises and rights-of-way, to clarify PSO's ability to trim and remove trees near PSO's electric equipment, and to clarify the limitation of liability for fluctuations and interruptions in electric service over which PSO has no control.

PSO proposes to change its Deposit Plan to include automatic refunds of non-residential deposits, make deposit receipts non-assignable, ease deposit requirements for good-pay customers, eliminate certain options to cash deposits, and provide for early refunding of deposits to residential customers with satisfactory pay history.

In addition, my direct testimony supports the schedules that detail the proposed rate design for all of the tariffs.

In my rebuttal testimony of April 18, 2007, I address the recommendations made by Public Utility Commission Division Staff ("Staff") witness Mr. David Smith, Oklahoma Industrial Energy Consumers ("OIEC") witnesses Mr. Scott Norwood and Mr. Mark Garrett, Wal-Mart witness Mr. James Selecky, and Quality of Service Coalition ("QOSC") witness Mr. Joe Robson regarding the Company's proposed revenue distribution, proposed rate design changes, demand-side management, Miscellaneous Service Charges, and the amount and method of fuel recovery.

My rebuttal testimony explains that the revenue distributions proposed by OIEC, QOSC and Wal-Mart have significant negative impacts on the residential class, while PSO's proposal considers impacts on all customer classes, moves the classes toward full cost recovery, encourages demand-side management, and sends appropriate price signals.

I also address concerns raised by OIEC and Wal-Mart that implementing a Formula Base Rate ("FBR") Plan will exacerbate the existing disparity in class relative rates of return. Because the FBR uses the Total Rate Base allocator to determine the costs assigned to the classes, the FBR actually moves toward levelizing the rates of return and does not further the disparity.

My testimony points out the flaws in Staff's proposal to limit the increase to the Basic Service Charge to 25%, pointing out that Staff provided no justification for the 25% figure, did not dispute the appropriateness of matching fixed costs to fixed price recovery, did not dispute that the Company's cost-of-service study supports an even greater increase than the Company proposed, and did not show the effect of Staff's recommendation on customers.

I also refute QOSC's claim that PSO did not provide enough support for its proposed rate design changes. I describe the information provided in the Company's direct case, in data responses, hundreds of pages of cost and rate impact analyses, trend-of-use data, customer complaint trends, and proof of revenues, all of which more than amply support the Company's proposed rate design.

Next, I show that Staff incorrectly assumed that Miscellaneous Service Revenues should somehow compose the same percentage of total company revenue that occurred during the test year. I explain that those revenues are based on charges for the service times the number of occurrences and will not increase or decrease in direct proportion to the total Company revenue.

Finally, I refute OIEC's recommendation that the current fuel amount be embedded in base rates. I show that recovering fuel as a separate item allows customers to identify the costs attributable to fuel. I also show that the amount of fuel to be recovered should reflect the actual cost at the time of implementation, rather than some historical amount.

This concludes my testimony summary.

David A. Davis

Direct Testimony

Introduction

My name is David A. Davis and I filed direct testimony in this docket in November 2006 and rebuttal testimony on April 9, 2007.

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

In my testimony in November 2006, I discuss the revised depreciation accrual rates for PSO's electric plant in service and address how Financial Accounting Standards No. 143 ("SFAS 143"), Financial Accounting Standards Board ("FASB") Interpretation No. 47, and Federal Energy Regulatory Commission ("FERC") Order 631 affects PSO's depreciation study.

Depreciation Study Overview

My testimony includes a comparison of PSO's current rates and the study rates, shown below, which are based on December 31, 2005, depreciable plant balances as adjusted for study purposes:

Composite Rates and Accruals

Functional Plant Group	Existing Rates	Accruals	Study Rates	Accruals
Steam Production Plant	2.69%	$26,325,209	2.49%	$24,419,280
Other Production Plant	3.21%	1,007,511	2.76%	868,299
Rail Spur & Rail Cars	1.49%	778,548	1.53%	800,848
Transmission Plant	2.00%	9,555,413	2.49%	11,866,041
Distribution Plant	3.09%	35,075,605	3.63%	41,159,612

General Plant	5.15%	7,702,733	3.89%	5,815,548
Total	2.85%	$80,445,019	3.01%	$84,929,628

Based on the study results, I recommend an increase in the annual depreciation expense of $4,484,609 or 0.16% 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.

I made two adjustments to the recorded plant balances: (1) associated with Tulsa Generating Until 3 where the adjusted plant balances for steam production plant at December 31, 2005, included the cost for this unit; and (2) related to Northeastern Plant Units 1 and 2 where the accounting records show an investment balance of $96,117,346 for Account 316, Miscellaneous Power Plant Equipment, for December 31, 2005. The correct balance for Northeastern Plant Units 1 and 2 in Account 316 is $4,610,345.

Definition of Depreciation

In preparing the study, I 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 based on cost estimates made by other utilities for dismantling generating units. The depreciation rates were calculated by the Average Remaining Life Method.

Asset Retirement Obligations

SFAS 143 prescribes the accounting for Asset Retirement Obligations ("ARO") and was implemented by PSO effective January 1, 2003, as required by the FASB. SFAS 143 applies to legal obligations associated with the retirement of tangible, long-lived assets and requires that those legal obligations be recognized at fair value at the time the legal obligation was incurred.

The FASB issued FIN 47, which interprets the application of SFAS 143. FIN 47 clarifies that a conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. PSO has recognized AROs under FIN 47.

SFAS 143 does not change the accounting requirements for obligations that are not specific legal retirement obligations for cost based rate-regulated companies that meet the criteria for application of Statement No. 71. Cost based rate-regulated companies that meet the criteria for application of SFAS 71, such as PSO, can continue to collect asset retirement costs that are not within the scope of SFAS 143 through depreciation rates when authorized by a ratemaking authority. However, for SEC financial reporting purposes, the amounts of removal costs that have been collected for non-ARO assets through the Company's Commission-approved depreciation rates, and included in accumulated depreciation, must be reclassified to a regulated liability for SEC financial reporting purposes, but not for FERC reporting purposes.

FERC issued Order 631, which added new balance sheet and income statement accounts to be utilized for recording AROs. Order 631 also revised definitions of the general and plant accounting instructions contained in the Uniform System of Accounts. FERC specifically addressed accounting for the cost of removal that does not constitute a legal obligation in Section III, paragraph 36 of Order 631.

PSO's book depreciation study complies with the accounting requirements of SFAS 143, FIN 47, and FERC Order 631 for Production, Transmission, Distribution and General plant. For SEC financial reporting purposes the amount of gross removal costs included in depreciation rates and accruals and the actual removal cost charges to accumulated depreciation can readily be determined and reclassified to a regulatory liability account.

Study Results

For Steam Production Plant, the composite rate decreased from 2.69% to 2.49% and for Other Production Plant the rates decreased from 3.21% to 2.76%. The decreases were caused by a combination of the net effects of: (1) an increase in the estimated gas and combined cycle plant lives; (2) changes in the interim plant retirements; and (3) changes in removal costs. For Transmission Plant, the composite rate increased from 2.00% to 2.49%, which was caused by an increase in the net salvage ratio for four accounts, partially offset by a decrease in the net salvage ratio for one account and increases in the average service lives for three accounts. For Distribution Plant, the composite rate increased from 3.09% to 3.63%, 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 decreased from the current 5.15% to 3.89% and was mainly attributable to the actual book reserve being greater than the reserve that is indicated by the depreciation study analyses. The remaining life depreciation rate calculation causes the decrease in the composite rate.

Rebuttal Testimony

My rebuttal testimony of April 9, 2007, rebuts depreciation-related testimony from 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 current level of depreciation by amounts ranging from $19.4 million to $26 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 a settlement in the Company's last rate case and are reflected on Attachment 2 of a Joint Stipulation and Settlement Agreement in Cause No. PUD 200300076. Only the rates were specified in the settlement and, as a result, it is not possible to specifically determine existing useful plant life 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 existing lives and net salvage values can be calculated. This is how I determined the current useful life and net salvage percentage information contained in the depreciation study conducted for this case.

The depreciation study reflects changes in the useful lives of production plant from the lives embedded in the current depreciation rates. The Company's generation department performed an evaluation of plant lives and changes in lives are shown below:

Plant	**Life Span Current Study (Years)**	**Life Span Prior Study (Years)**	**Change in Life Span (Years)**
Steam Production Plant			
Northeastern Unit 3	42	42	0
Northeastern Unit 4	42	42	0
Rail Spur	27	41	-14
Oklaunion	42	42	0
Comanche	38	39	-1
Northeastern Unit 1	35	35	0
Northeastern Unit 2	65	39	26
Riverside Unit 1	60	39	21
Riverside Unit 2	60	39	21
Southwestern Unit 1	65	55	10
Southwestern Unit 2	65	55	10

Southwestern Unit 3	65	43	22
Tulsa Unit 2	62	50	12
Tulsa Unit 3 (re-started in 2006)	9	N/A	N/A
Tulsa Unit 4	62	50	12
Other Production Plant			
Weleetka 4	44	40	4
Weleetka 5 & 6	44	39	5
Weleetka	57	52	5
Comanche	62	51	11
Northeastern (1&2)	68	54	14
Northeastern (3&4)	42	42	0
Riverside	60	39	21
Southwestern	70	48	22
Tulsa	59	47	12

N/A = not applicable

The Company's evaluation of plant lives for this rate case, when considered with changes made in plant net salvage percentages, resulted in a decrease of $2 million in depreciation expense when the requested rates are compared to the current approved rates as applied to plant at December 2005.

Messrs. Pous, Garrett and Selecky take issue with the production plant depreciable lives in the depreciation study, and all recommend that the Company use a 60-year useful life for its coal production plants, instead of the 42-year life reflected in the depreciation study. However, the witnesses have accepted the Company's useful life assumptions for other types of production plant included in the depreciation study.

The useful lives for coal, gas and diesel plants were provided by the Company's generation department and for purposes of the depreciation study were determined in the same manner. Company witness Michael Isenberg provided testimony supporting the useful lives utilized by the Company.

I disagree with the intervenors' arguments that a 60-year life should be used for the company's coal plants instead of a 42-year life. The Company's generation department is staffed by people who are knowledgeable about the operating, environmental, economic, physical and technological conditions at the Company's generating stations. Although I did not make an independent determination that a 42-year life was appropriate, it is a common practice for accountants who conduct depreciation studies to rely on generation department personnel who are familiar with operating characteristics of production plant for useful life information.

I refute Mr. Pous' criticism of the Company for using "interim additions" as justification for its useful life assumptions. All cost amounts used for the Depreciation Study filed in this proceeding were reflected on the Company's books at December 31, 2005. In this context, "interim additions" are future major additions to generation plant that continue generating unit life, and no amounts of future "interim additions" were included. Interim additions can allow a generating unit to continue to operate beyond the time when it would otherwise cease operations if the interim additions were not made.

Production Plant Net Salvage Value

Messrs. Pous and Selecky criticize the Company's determination of production plant net salvage value and propose a sweeping recommendation that all production plant be assigned a negative 5% net salvage value. Mr. Pous also suggests an alternate proposal that reflects a positive 10% net salvage value, which he bases on his claims that many of the Company's plants could be sold in the future. I do not agree with these intervenor proposals. Unlike my analysis of net salvage values, which considers demolition studies of specific plants around the country, the intervenors' 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 and an incorrect assumption that future brown field sites should provide a benefit to current ratepayers. These assumptions 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 dollar per kilowatt hour capacity relationship ("$/KW").

The production plant net salvage value that I utilized in the depreciation study was the result of an engineering study performed by a Company depreciation consultant in connection with the Company's 1996 Oklahoma rate case (Cause No. PUD 960000214) updated to reflect more current information and assumptions.

The engineering study surveys a number of plant demolition and removal cost estimates to determine a comprehensive cost per kilowatt hour to demolish and remove gas and oil and coal production plants. This initial analysis considers the demolition cost studies of 27 utilities across the country and collects data related to 130 individual plants including some AEP plants. The initial study was prepared in 1996 and contained $/KW estimated removal cost data inflated at 4% from the date of each plant's demolition study through 1995.

In 2003, the Company's depreciation expert updated the study in connection with PSO's 2003 rate case, Cause No. PUD 200300076. In that case, the removal cost per KW estimates that were originally reflected in the 1996 coal study were used and no inflation factors were applied to the data past 1995. This was done in order to be conservative and reflect the fact that inflation was less than 4% during this period. At the same time, removal costs for the gas and oil units produced by the 1996 analysis were updated through 2000. These costs were then inflated using a reasonable 3% rate of inflation applied from the date of each individual plant's demolition study.

When conducting my depreciation study in connection with this case, I started with the results of the 1996 demolition analysis and the 2003 update done by the Company. I applied no inflation factors to any of the plant cost of removal. As a result, removal costs in my depreciation study reflect no inflation since 2000 for gas and oil plants and since 1995 for coal plants. In addition, I eliminated all removal costs associated with asbestos. It is important to note that the coal $/KW cost amount has not been inflated in over 10 years, since 1995, and the gas and oil $/KW cost amount (which was only inflated at 3% to begin with) has not been inflated in over 5 years, since 2000.

This is a reasonable method to determine production plant net salvage values for a depreciation study. Because there is not a large amount of data regarding the terminal cost for generating plants, it is very common in the industry to consider plant demolition studies in order to determine production plant net salvage values. Based on the results of the study, the Company has proposed an 11% negative net salvage for its coal generating stations, a 10% negative net salvage for un-depreciated rail spur investment and a negative 15% net salvage for its gas-fired steam generation.

Trying to compare these negative net salvage rates with the existing net salvage rates embedded in PSO's existing depreciation rates approved by the Commission in Cause PUD 200300076 is difficult because the Company's current depreciation rates were the product of a settlement. However, if one assumes that any difference between the settlement and requested depreciation rates are reflected in net salvage values rather than in asset useful lives (which is the assumption reflected in my depreciation study), existing settlement depreciation rates would include a 12% negative net salvage for its coal generating stations, a 10% negative net salvage for un-depreciated rail spur investment and a negative 20% net salvage for its gas-fired steam generation. This is a reasonable assumption to make and is also conservative in the case of net salvage values. The differences between requested and settlement depreciation rates have to be reflected in either useful lives or net salvage values.

The effect of the Company's request for lower negative production plant net salvage percentages in this rate proceeding decreased the Company's proposed book depreciation expense by $526,240. The proposed percentages are very comparable to the net salvage values approved by the Oklahoma Commission in an Oklahoma Gas and Electric ("OG&E") rate case (Cause No. PUD 200500151), in which the Oklahoma Commission approved negative net salvage percentages ranging from 10% to 15% for steam generating plants.

The intervenors do not call into question the age of the demolition studies the Company relied on in determining production plant net salvage value. Mr. Pous testifies that the age of the studies does not "negate their validity."

In my rebuttal testimony, I respond to several criticisms asserted by Mr. Pous. I disagree with all of his contentions.

Mr. Pous claims that the analysis ignores the Company's own experience with previously retired generating units. The sale of a small amount of used equipment associated with the units resulted in some minor positive net salvage value, yet there was no terminal retirement of these units and the Company's experience with their retirement is in no way representative of the Company's remaining units.

Mr. Pous claims that the results of the demolition study produce too wide a variation on removal costs. The demolition studies performed by the 27 utilities were completed at various points in time for the different utilities by several demolition companies, so one would naturally expect some variation in their calculations, but the variation does not negate the resulting amounts.

Mr. Pous claims that the wide variation in contingency costs represents a flaw in the study. Because contingency cost percents were calculated by different salvage companies for 27 utilities and 130 different generating stations, a range of contingency costs should be expected.

Mr. Pous claims the Company "arbitrarily" relied exclusively on inflation as the sole factor affecting demolition costs. This criticism is unfair and unreasonable. We know that any inflation will affect removal costs. However, there is no way to predict accurately how factors such as technology and productivity may affect future costs and it may be incorrect to assume that these factors were not considered by the demolition company estimates and incorporated in items such as the contingency estimate.

Mr. Pous criticizes the study's use of a 4% inflation rate on the basis that the Consumer Price Index ("CPI") from 1984 to 2006 was much lower. As mentioned above, the 4% rate was only applied to the coal plant removal cost amounts and only through 1995. A 3% rate was applied to gas and oil plant removal costs amounts and only through 2000. By not adding inflation for 1995 to 2005 for coal plants, the effective inflation rate was approximately 1.6%, which is a very conservative rate. Similarly, not adding inflation from 2000 to 2005 for the gas and oil plants yields a conservative inflation rate of approximately 2.1%.

Mr. Pous claims that the utilities contained in the Company's study all have production net salvage values ranging from a negative 3.4% to a negative 10%, based on FERC Form 1 information. I respond to this claim by pointing out that the detailed net salvage percentages shown in FERC Form 1 are only required every 5 years unless there are changes. The last detailed report was required in 2001 and the next one is due in 2006. AEP utilities represented in the removal cost study had no changes to report at December 2005 and last reported this information in 2001.

Mr. Pous criticizes the Company for not having the original data underlying the demolition studies available. The original data underlying the demolition studies for the AEP affiliated utilities listed in the study was provided in the Company's response to AG question 3-6. The data for the other companies in the study is the proprietary property of the consultant's company, Deloitte and Touche.

Mr. Pous claims that the demolition studies the Company relied on are not "market-tested" and do not contain contractor bid information for actual demolition activity. I disagree with this claim because it would be illogical for the Company to request a bidding process for the estimated cost of the demolition of generating stations 10 or more years in the future.

Mr. Pous also claims in his testimony that the increase in salvage price for copper has an impact on the demolition studies, yet he cites only one category of salvage value to make his point. While recent salvage values for copper have increased faster than the CPI, Mr. Pous' approach isolates this increase and ignores demolition costs that also may have increased faster than the CPI. In addition, in order to be conservative, the Company stopped inflating net salvage values in 1995 for coal plants and in 2000 for gas and oil plants. Mr. Pous makes no mention of this fact.

I also disagree with Messrs. Pous and Selecky when they argue that a potential sale of a generation station should be taken into account in considering salvage value. Generating station sales should be considered by the Commission only when they occur, not in determining a salvage value in a depreciation study.

I disagree 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 would benefit future customers by lowering the cost of developing the property for generating station use. Any benefits should be reflected in the cost of the new plant and associated rates.

The negative 5% rate for production plant net salvage value contention of Messes. Pous and Selecky is not reasonable. Neither witness offers any underlying documentation or support that would allow the Company or this Commission to test the validity of this percentage. The Company's broad-based study is reasonable and the Commission should reject the intervenors' arguments.

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 comprehensive plant demolition studies undertaken by utilities across the country. The negative salvage percentages requested by the Company are lower than those reflected in current depreciation rates approved by this Commission in the Company's last rate proceeding (Cause No. PUD 200300076). In addition, the negative net salvage percentages presented by the Company are comparable to OG&E's production plant net salvage rates as noted above.

Transmission and Distribution Property Net Salvage General

Mr. Pous criticizes my analysis of T&D property net salvage values and recommends altering the salvage values associated with 10 individual property accounts. Mr. Selecky proposes to simply reduce the net salvage ratios by 50% that I used to determine the depreciation rates. Mr. Garrett recommends that existing net salvage values be maintained but that the Company be directed to file a depreciation study in its next case that includes the "Pennsylvania Method" as an option for the Commission to consider with respect to determining net salvage values for T&D property. I do not agree with the intervenor proposals. They are unreasonable and do not present a true and accurate picture of the Company's actual T&D net salvage values. They should be rejected in favor of the net salvage rates that I propose.

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, I determined T&D net salvage values using twenty-one 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 as described above. 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.

Mr. Pous' criticism that my determination amounts to nothing more than a mathematical calculation and is not a depreciation study is unreasonable. 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 21 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 for large transactions that are obviously abnormal and distort results of the study. This was not the case, and therefore not necessary, in the analysis that I undertook.

A comparison of proposed T&D net salvage rates with those embedded in Cause No. PUD 200300076 is shown in Exhibit DAD-1, page 28 of the Depreciation Study.

The impact the Company's recommended net salvage percentages would have on current annual depreciation amounts is as follows: based on original cost investment at December 31, 2005, the net salvage percentages are approximately $4.4 million of the $11.9 million requested for Transmission accounts and approximately $15.7 million of the $41.1 million requested for Distribution accounts. However, the change in useful lives and net salvage values results in only a total recommended increase of $2.3 million for Transmission Plant, or 0.49% and $6.1 million for Distribution Plant or 0.54%. Combine these modest recommended increases with the decreases the Company has requested for Production and General Plant and the total increase requested by the Company is only $4.5 million or 0.16%.

OIEC witness Garrett is not correct in saying that the annual level of removal costs embedded in the Company's proposed depreciation rates is $37,741,355 based on plant in service at December 31, 2006. However, Mr. Garrett's testimony in this regard is based on the Company's incorrect initial response to OIEC question 11-13. The corrected amount is $27,465,615 and was included on a updated discovery response.

Mr. Pous claims that the Company fails 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. I also respond to Mr. Pous' claim that the Company inappropriately categorizes 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. Selecky claims that the depreciation rates contain an annual T&D net salvage component of $24.097 million, yet the Company's average actual annual net salvage expense over the last 5 and 10 years was $5.182 million and $6.019 million, respectively. The Company's revised response to OIEC question number 11-11 indicates that the net salvage component in the proposed T&D depreciation rates equals approximately, $22.8 million. Mr. Selecky's simple average of annual net salvage expense is much more likely to produce intergenerational inequities than the net salvage calculation reflected in the Company's depreciation study. Removal costs in any given year will vary greatly and, depending on the years used for the average, could allow a utility to collect much more or less than is actually required for the removal of property. Also, large assets such as substations don't normally require removal for many years. Therefore the cost to remove these assets will not be included in many five or ten year averages. As a result, an averaging over a period of time that happens not to include large infrequently removed assets such as these will require future customers to pay for the removal of assets that benefited customers in past periods.

Mr. Pous is not justified in his criticism of the Company's T&D net salvage data as it relates to his allegation that the Company cannot identify contractor costs, overtime costs, or the causes of retirements to analyze a depreciation study. In 2006 alone, the Company issued over 11,000 work orders for T&D accounts. Maintaining data of this type would be time consuming, costly and not normally useful in calculating the proper net salvage percentage to use in a Depreciation Study for T&D accounts.

Mr. Garrett contends that there is little support and virtually no explanation for the amounts that the Company is asking for in regards to negative salvage. I disagree 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. Garrett also incorrectly alleges there is a mathematical flaw in the calculation of the net salvage percentages. However, Mr. Garrett is correct that the calculation generally compares removal costs that are being incurred today with original installed costs that were sometimes originally booked 20 to 50 years ago. This comparison explains 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. Therefore, the mathematical relationship of current removal cost and older property cost is constant and does not add inflation.

Mr. Garrett advocates the "Pennsylvania Method," which, according to him, includes a normalized level of actual removal cost expenditures, based on a 5-year average, in the depreciation rate calculations rather than an estimated level of future expenditures. This methodology does not provide a better means of calculating a net salvage percentage. A five year average of salvage credits and removal costs is much more likely to produce intergenerational inequities than the net salvage calculation in the Company's Depreciation Study.

Mr. Garrett contends 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. This is incorrect. The removal cost factor doesn't 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.

Specific Property Accounts

For account 354, Towers & Fixtures, Mr. Pous recommends using a negative 20% 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. To respond to the criticisms, I agree that the retirement history for this account is not as frequent as for other accounts and noted this in my analysis for this account in the depreciation study. However, the amounts of removal cost and the retirement in 2003 that Mr. Pous cites were minor and did not have a profound effect on the average negative net salvage percentage for this account when calculated over the entire 21 years of history. My proposal for a negative 69% net salvage rate for this account is based on 21 years of the Company's history of costs and reimbursements related to this account. There are retirements in over half of these 21 years. As a result, the retirement data is sufficiently robust to calculate an accurate net salvage percentage.

Mr. Pous recommends using a negative 57% net salvage rate for transmission account 355, Poles & Fixtures, instead of the negative 108% 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 states that the Company's proposed negative net salvage rate is the most negative of any utility that he is aware. I respond to the criticisms by pointing out that the proposed negative 108% net salvage rate is only slightly more negative than the -90% rate that was calculated and proposed in Cause No. PUD 200300076. Mr. Pous provides no backup or source of his industry information for his statement that the negative net salvage rate is the most negative of any utility in the industry. His suggestion that contractor costs, overtime costs and emergency situations should be used to make adjustments to the Company's amounts is incorrect. Where these types of costs are typically required for removal of this type of property, they should be included in the analysis. My proposal for a negative 108% net salvage rate for this account is based on 21 years of the Company's history of costs and reimbursements related to this account.

For transmission account 356, Overhead Conductor & Devices, Mr. Pous recommends using a negative 38% net salvage rate instead of the negative 90% 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 claims that there is a lack of quality information maintained by the Company to support the recommended 90% rate. To respond to the criticisms, I point out that the proposed negative 90% net salvage rate is slightly less negative than the -93% rate that was calculated and proposed in Cause No. PUD 200300076. Mr. Pous again states that the negative net salvage rate is at the high end of values for utilities in the industry without providing any backup or source of his industry information. He again makes an incorrect assertion that adjustments should be made for contractor costs, overtime costs and emergency situations. These types of costs and situations should not be removed from the analysis if they are typically required for removal of this type of property. I base my proposal of a negative 90% net salvage rate for this account on 21 years of the Company's history of costs and reimbursements related to this account. This negative salvage rate is reasonable.

For distribution account 364, Poles, Towers, & Fixtures, Mr. Pous recommends using a negative 40% net salvage rate instead of the negative 124% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 78% embedded in the Company's current depreciation rates. Mr. Pous again criticizes the Company for using a mathematical average for its net salvage rate without adjusting the results for contractor costs, overtime costs and emergency situations. He also says that there will be an "economy of scale" for large retirements that will drive the cost down and points to 2003 retirements where a negative 36% rate was calculated. To respond to criticisms, I point out that the proposed negative 124% net salvage rate is less negative than the -152% rate that was calculated and proposed in Cause No. PUD 200300076. Mr. Pous again makes an incorrect assertion that adjustments should be made for contractor costs, overtime costs and emergency situations. These types of costs and situations should not be removed from the analysis if they are typically required for removal of this type of property. Further, poles and other types of equipment represented by this account are not typically removed in mass quantities as claimed by Mr. Pous. As a result, his "economies of scale" argument is invalid. I base my proposal of a negative 124% net salvage rate for this account on the fact that the poles and equipment represented in this account are of a low dollar value. When current day removal cost is compared to older original cost amounts a high negative net salvage rate is expected. The removal cost as compared to original cost retirements has trended downward (less negative) in recent years and as noted above was calculated at -152% in our last depreciation study. Also, as for other accounts in the study, the negative net salvage rate of 90% proposed for this account is based on 21 years of the Company's history of costs and reimbursements related to this account.

For distribution account 365, Overhead Conductor & Devices, Mr. Pous recommends using a negative 40% net salvage rate instead of the negative 115% 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 states that the negative net salvage value proposed by the Company is more negative than any electric utility that he is aware of in the industry. To respond to criticisms, I point to the fact that the proposed negative 115% net salvage rate is less negative than the -121% rate that was calculated and proposed in Cause No. PUD 200300076. Mr. Pous' suggestion that a review of activity in this account would yield adjustments to exclude unusual situations is incorrect and should be rejected. I base my proposal for a negative 115% 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, you would expect a high negative net salvage rate when comparing current day removal costs to older original costs. Additionally, there is a large activity in this account that makes the calculated average more reliable. The removal cost as compared to original cost retirements has trended downward (less negative) in recent years and as noted above was calculated at -121% in our last depreciation study. Also, as for other accounts in the study, the negative net salvage rate of 115% proposed for this account is based on 21 years of the Company's history of costs and reimbursements related to this account.

For distribution account 366, Underground Conduit, Mr. Pous recommends using a negative 15% net salvage rate instead of the negative 70% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 32% embedded in the Company's current depreciation rates. Mr. Pous indicates that the Company's recommended change in the net salvage percentage is significant and unrealistic. To respond to criticisms, I point out that Mr. Pous provides no backup or source of his industry information to support his claims. He again makes an incorrect assertion that contractor costs, overtime costs and costs related to emergency situations should be removed from the analysis. However, this is incorrect when these types of costs and situations are typically required for removal of this type of property. I base my proposal for a negative 70% net salvage rate for this account on the fact that the assertion that that contractor costs, overtime costs and emergency situations are typically used to make adjustments to the Company's amounts is incorrect since these types of costs and situations are normal for removal of this type of property. As with other accounts in the study, the negative net salvage rate of 70% proposed for this account is based on 21 years of the Company's history of costs and reimbursements related to this account.

For distribution account 367, Underground Conductor, Mr. Pous recommends 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 states that his recommendation is based on his analysis of historical data and supported by the Company's unwritten policy of abandonment in place for such investment. To respond to the criticisms, I point out that Mr. Pous' analysis of existing data concentrates on 2002 where he calculated that 45% of the retirement history for this account resides with only minimal removal cost and asks that the Commission consider this as proof that the requested rate is too high. He incorrectly ignores all other data. My proposal for a negative 21% net salvage rate for this account is based on the fact that it 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 21 years of the Company's history of costs and reimbursements related to this account.

For distribution account 368, Line Transformers, Mr. Pous recommends using a negative 10% net salvage rate instead of the negative 20% proposed by the Company. Mr. Pous' proposed negative net salvage rate is less than the negative 24% embedded in the Company's current depreciation rates. Mr. Pous criticizes the Company for using a simple arithmetic average for the proposed negative salvage rate. To respond to the criticisms with regard to this account, I point 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. Mr. Pous criticizes the Company for using a simple arithmetic average and then performs his own simple arithmetic average of the last 10 years to propose a lower negative salvage rate. I propose a negative 20% net salvage rate for this account based on the fact that it is less than (less negative) than the -24% rate embedded in PSO's current depreciation rates. The negative net salvage rate of 20% is based on 21 years of the Company's history of costs and reimbursements related to this account.

For distribution account 369, Services, Mr. Pous recommends using a negative 25% net salvage rate instead of the negative 84% 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 states 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, I point 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. I propose a negative 84% net salvage rate for this account based on the fact that it is based on the total historical activity for this account. Individual customer services are a relatively low dollar item on a per service basis and it is not surprising that today's removal cost would be a relatively large percentage of older original cost being removed.

For distribution account 371, Installations on Customers' Premises, Mr. Pous recommends using a negative 25% net salvage rate instead of the negative 68% 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. Mr. Pous indicates that the ranges of negative salvage for this account are of a high magnitude and require investigation. He again states 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, I point out that the Company is recommending a negative salvage 68% that is 17% less negative than the rate currently embedded in the Company's current depreciation rates. Mr. Pous provides no backup or source of his industry information to support his criticisms. I propose a negative 68% 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 21 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.

This concludes my testimony summary.

A. Naim Hakimi

My name is A. Naim Hakimi and I filed rebuttal testimony in this docket on April 9, 2007 and April 18, 2007.

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

My rebuttal testimony filed on April 9, 2007 responded to issues raised by Mr. Scott Norwood, testifying on behalf of the Oklahoma Industrial Energy Consumers ("OIEC"), Ms. Roya Soltani, testifying on behalf of the Office of the Oklahoma Attorney General ("AG"), and Commission Staff witnesses Messrs. Robert Thompson, Marvin Vaughn, and Jason Thenmadathil.

Mr. Norwood recommends that $4.4 million in "AEPSC Trading Expenses" should not be recovered in base rates. Mr. Norwood is wrong. These expenses are not variable out-of-pocket costs. Consequently, the AEP System Integration Agreement ("SIA") prohibits these expenses from being included as out-of-pocket costs that can be subtracted from trading and marketing revenues as proposed by Mr. Norwood. Moreover, the "trading" expenses referred to by Mr. Norwood cover PSO's share of expenses relate to various functions AEPSC performs for PSO as its Agent under the AEP West Operating Agreement and AEP System Integration Agreement. In addition, it is clear that PSO's customers benefited from AEPSC's trading and generation dispatch activities during the test year (fuel cost savings were in excess of $101 million) and that these benefits are significantly higher than the associated administrative expenses. Therefore, PSO should recover in base rates the requested $4.4 million in "trading" expenses and Mr. Norwood's proposed disallowance should be rejected.

Contrary to the representation made by Mr. Norwood, PSO did inform the Commission of the expected changes in the margin sharing methodology in the SIA prior to those changes going into effect. Furthermore, AEPSC was required to file a sharing methodology with the FERC in the year 2005 in accordance with the requirements of the SIA approved by FERC in the year 2000. The change in the SIA sharing methodology was subjected to regulatory review and approved by the FERC.

Mr. Norwood recommends that the current Commission-approved sharing of margins from off-system sales be modified from the present split of 75/25 (customer percentage of total margins/shareholder percentage of total margins) to 90/10. Given that the Company does not flow negative margins on a calendar year basis to customers, the Company is effectively allocating to customers an amount higher than 75 percent and a change to the current sharing percentages is not warranted.

Ms. Soltani recommends that actual rather than target coal inventory level costs be used in base rates. She claims that the Company can meet the shortfall with power purchases and fuel oil inventory. My rebuttal testimony demonstrates that it is neither practical nor cost effective for PSO to cover the inventory shortfall with power purchases or fuel oil inventory and that Ms. Soltani's proposal should be rejected.

Ms. Soltani and Messrs. Thenmadathil and Thompson recommend removal of off-system trading deposits from base rates. These deposits are necessary for AEPSC to engage in bulk power purchases and sales as Agent for PSO. PSO receives significant benefits from these purchase and sale transactions. These transactions are necessary in order for PSO to reliably and economically serve its native load customers, and the deposits should be included in base rates.

Ms. Soltani recommends removal of purchased power capacity costs from the pro-forma adjustment calling them "estimated." These costs are not estimated. Purchased power capacity costs are based on actual contracts for the purchase of capacity. The amounts of capacity under these contracts are fixed at levels used in the test year. These costs are known and measurable and are necessary for PSO to serve its native load obligation and should therefore be included in the pro-forma adjustment.

Mr. Vaughn claims that because the Company's purchased capacity contracts expire at the end of 2007, a lower level of capacity costs compared to the amounts reflected in the actual capacity contracts should be included in the pro-forma adjustment. The capacity costs of the contracts entered into by PSO are known and measurable and it is undisputed that PSO's capacity needs will continue beyond 2007, whether filled from capacity purchases from the market or PSO's newly built generation. Therefore, the Company's pro-forma adjustment to capture these capacity costs should be approved.

Mr. Norwood recommends that $3.4 million in PSO's capacity costs should be recovered through a capacity purchase rider rather than base rates. PSO is not opposed to recovering these costs through its Fuel Cost Adjustment ("FCA") Rider tariff provided that **all** purchased capacity costs are recovered through the Rider. If all purchased capacity costs are not recovered through the FCA Rider, then these costs must be recovered in base rates.

My rebuttal testimony filed on April 18, 2007 responded to the feasibility of demand-response proposals made by Mr. Michael Sarafolean on behalf of Gerdau Ameristeel Corporation. Mr. Sarafolean is proposing that PSO customers under the Real Time Pricing ("RTP") Schedule be provided with economic opportunities associated with sales of energy in the SPP Energy Imbalance Service ("EIS") Market, as well as provision of Ready Reserves under the Southwest Power Pool ("SPP") Open Access Transmission Service Tariff ("OATT").

My testimony showed that the RTP Schedule precludes customers from reselling the energy they are purchasing from PSO. My testimony also explains that Mr. Sarafolean's recommendation would, in effect, give such customers the ability to purchase energy from PSO under the RTP Schedule pricing structure and resell it at hourly market prices.

Mr. Sarafolean also suggests that the Commission should consider a demand response program in this docket. My rebuttal testimony makes clear that Mr. Sarafolean's proposal is premature. First, the FERC Order on Rehearing did not require SPP to institute a demand response program as Mr. Sarafolean suggests. Second, SPP has not developed or even completed a study associated with the implementation of demand-response programs in the EIS Market. Any Commission action based on Mr. Sarafolean's recommendations would therefore, require speculation as to the final outcome of such an SPP study and the associated implementation plan. Third, considerable time and effort will be needed by the SPP to develop market rules and the associated systems to implement a demand-response program as part of the EIS market. PSO will need to carefully review these rules, if implemented, and consider the practicality of appropriate tariffs that may permit customers with demand-response capability to participate in such SPP programs. Finally, it is clear that if customers are allowed to arbitrage the price PSO charges under the RTP Schedule versus the SPP EIS price, additional costs will be borne by other PSO customers. Therefore, these cost impacts should be considered in evaluating demand response programs when and if SPP institutes such a program.

Mr. Sarafolean incorrectly suggests that the maximum SPP EIS Locational Imbalance Prices ("LIPs") for the month of February 2007 exceeded $800/MWh on several occasions. In fact, the actual hourly maximum LIP used for settlement was $202.06/MWh during that month.

In order to provide the timely response needed to satisfy SPP Ready Reserve requirements, an interruptible customer needs to provide PSO with the ability to interrupt it within 15 minutes of a contingency event through supervisory control action by PSO. There is no indication in Mr. Sarafolean's testimony that his client is willing to operate under such specific timing and control criteria so development of a service rider for this application is premature.

This concludes my testimony summary.

Michael S. Isenberg

My name is Michael S. Isenberg and I have filed direct testimony in this docket on November 21, 2006 and rebuttal testimony on April 9, 2007.

I have a Bachelor of Arts degree in Bible and a minor in Mathematics. I completed the University of Chicago's Management Development Program in 1993. During my nearly 27 years of experience with AEP (more than fourteen of which were with PSO), I have held a number of different positions, many of which were related to the generation function. I have filed testimony in Oklahoma and Texas on a number of issues including, primarily in Texas, unit service lives and plant O&M expenses.

My direct testimony states that PSO owns and operates a generation fleet that is both fuel-diverse and flexible to help provide reliable low cost energy to its customers. PSO is able to provide this low cost energy by leveraging the system efficiencies gained through AEP Services and the System Integration Agreements. I also describe the activities that are required to operate and maintain the PSO generating fleet and testify that the level of O&M expense ($63.8 million) for PSO's generation activities is reasonable, necessary, and representative of on-going operations and maintenance activities.

In my testimony, I also support the proposed service lives of PSO's generating units, including the 42 year service lives for PSO coal-fired units. These service lives are used in the depreciation study sponsored by Mr. David Davis. As explained in my testimony, the service life determinations are based on an analysis of the specific individual units for whom the service life is being established. This analysis considered the condition of the unit, the unit vintage and fuel source, the type of service provided, ongoing equipment maintenance practices (including whether certain component replacements had been completed), the current state of power generation technology, and environmental requirements.

I conclude my direct testimony by providing support for PSO's new generating capacity at the Company's Riverside Station, the Company's Southwestern Station, and the Company's 50% ownership share through a joint venture agreement to build a new 950 MW coal-fueled baseload unit near Red Rock, Oklahoma. I also recommend that PSO be allowed to amortize over five (5) years approximately $2.2 million incurred in the development of the self-build baseload bids.

In rebuttal testimony, I respond to issues raised in the responsive testimony filed by Mr. Pous and Ms. Soltani on behalf of the Attorney General's Office of Oklahoma, Mr. Selecky on behalf of Wal-Mart Stores, Inc., Mr. Norwood and Mr. Garrett on behalf of the Oklahoma Industrial Energy Consumers, and Mr. Thenmadathil and Mr. Mathai on behalf of the Public Utility Division of the Oklahoma Corporation Commission.

While Mr. Pous, Mr. Selecky and Mr. Garrett all recommend a 60 year life for PSO coal-fired units instead of the Company proposed 42 year life, none of these intervenors base their recommendation on any internal or external unit conditions that will affect the life of these units. Rather, the intervenors' position is wholly dependent on a misguided reading of selected AEP emails that discuss both the factors that influence the PSO coal plant unit service lives and the 60 year service life that has been used for AEP's eastern coal fleet. My testimony demonstrates why a unit specific assessment is critical for determining unit lives and why I relied on these assessments in selecting a 42 year service life for the PSO coal plant units. The selection of the 42 year life for PSO's coal unit is further supported by my extensive experience with these units. As to the AEP eastern coal fleet, my testimony explains that there are major differences between the AEP's eastern coal-fired fleet and PSO's coal-fired units that renders invalid the intervenors' simplistic attempt to simply assign all AEP coal-fired units the same service life. The two major differences between the PSO coal-fired fleet and AEP's eastern fleet are vintage and the type of coal that is used. AEP's eastern coal-fired fleet is on average more than twenty years older than PSO's units. As a result, significant component part replacements have been made to the eastern coal-fired fleet that have not been made to PSO's coal-fired units. In addition, PSO's coal-fired units, unlike the eastern fleet, burns PRB coal, which is significantly different in terms of chemical composition than the Appalachian coal burned by AEP's eastern fleet. These factors, when coupled with the environmental uncertainty, the differences in the unit vintage and design, and the condition of the units based on individual engineering assessments, supports AEP's position that a 42 year life for PSO's coal-fired units is appropriate.

Ms. Soltani, Mr. Norwood and Mr. Thenmadathil each propose different adjustments based on historical averages to reduce PSO's test year level expense for Generation related O&M. My rebuttal testimony explains why the intervenors' proposals should be rejected. Briefly, the Commission should approve the Company's test year generation related O&M expense based on the following:

- The intervenor recommendations do not conform to ratemaking rules.
- None of the intervenors challenge any specific expense incurred in the test year as being imprudently incurred, unreasonable or non-recurring.
- The recent increases in O&M costs are primarily driven by increases in craft labor and material costs that represent the true cost of doing business. In particular, the evidence shows that PSO has experienced a 16% increase in craft labor rates in 2006 alone and expect another 10-40% increase in 2007. Material costs have increased in the range of 5%-15% a year depending on the item.
- The level of O&M expenses in the test year represents the level of costs required to maintain the plants in the future. This fact is evidenced by PSO's Plant Long Range Plans.

Finally, my rebuttal testimony responds to Mr. Norwood's and Mr. Mathai's recommendations related to PSO's request to amortize the approximate $2.2 million of developmental costs for PSO's self-build baseload bids. Mr. Mathai's recommendation is consistent with my position that PSO should begin to recover these costs in this proceeding. Mr. Norwood, however, argues that PSO should not be allowed to recover these reasonable and necessary expenses. In particular, Mr. Norwood's position ignores the fact that these were cost of service bids for which PSO could only receive recovery of costs plus a regulated return. Unless PSO is allowed to recover these costs in this proceeding, it will have no opportunity to recover these costs. My testimony explains why the self-bid process benefits PSO's customer. Mr. Norwood does not dispute this fact. Therefore, the costs associated with the self bid process should be recovered in base rates.

This concludes my summary testimony.

David A. Jolley

DIRECT TESTIMONY

INTRODUCTION

My name is David A. Jolley. I am 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"). I have filed direct testimony in this docket on November 21, 2006.

I received a Bachelor of Science degree in Production and Operations Management from The Ohio State University in 1976, and have 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, I was awarded a lifetime achievement award by the American Compensation Association. I 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 I continue to hold. In my current position, I am 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 develops and maintains compensation programs for PSO that are market competitive and aligned with AEP's various business strategies. It conducts ongoing research and recommends changes to compensation programs as necessary, and develops communications materials in support of compensation programs and monitors compliance with federal and state regulations related to compensation.

The purpose of my testimony is to show that the compensation levels for employees of PSO and AEPSC, are necessary, reasonable, and market competitive. I also support the reasonableness of the portion of AEPSC affiliate charges to PSO that include 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 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.

Incentive programs are 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.

In addition, we periodically conduct ad hoc inquiries of neighboring utilities to collect specific information on positions not found in published sources and to validate PSO's and AEPSC's pay levels relative to local market data.

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 is used to establish the midpoint of the salary range assigned to each position. The salary range extends 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 is 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 are also taken into consideration.

For existing employees, PSO and AEPSC use 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, which include quality and quantity of work, special projects, personal development, and in the case of managers and supervisors, development of subordinate staff. The amount of each employee's base salary increase, also known as a "merit" increase, is 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 is 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 2005, the total merit increase budget for both exempt[1] and nonexempt salaried employees at PSO, AEPSC, and the other AEP Operating Companies was 3.0%. For the year 2006, the total merit increase budget for both exempt and nonexempt salaried employees at PSO, AEPSC, and the other AEP Operating Companies was 3.5%. The Mercer 2005/2006 salary planning survey reported average merit increases granted by all companies at 3.6% for exempt salaried employees and 3.5% for nonexempt salaried employees for 2005, and 3.6% for exempt and nonexempt salaried employees projected for 2006. The 2005/2006 World at Work salary planning survey reported that average merit increases granted by all companies for exempt salaried employees were 3.4% and 3.3% for nonexempt salaried employees for 2005, and 3.5% for exempt and nonexempt salaried employees projected for 2006.

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 is 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 2.8% general increase in 2005, and 3.0% in 2006, which is less than the average rate of 3.5%

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[1] 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.

reported by the Bureau of National Affairs Daily Labor Reporter for 2005 and 3.4% for 2006. Ten of the sixteen electric utilities whose service territories surround PSO reported an average general increase of 3.58% for 2005 in the Southwest Personnel Group Annual Compensation Survey.

Based on the above described data, I believe that PSO's and AEPSC's base compensation by merit increases for salaried employees and general increases for hourly/craft employees are 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.

INCENTIVE COMPENSATION

Incentive compensation plans are formal plans that are fully described in written documents and approved by the Company's senior management. There are three incentive programs that relate to employee compensation amounts included in PSO's test year costs: The Energy Delivery Plan, the Information Technology ("IT") Plan, and the Business Logistics Plan. The plans applicable to AEPSC include the Energy Delivery Plan, the Generation Plan, the IT Plan, the Business Logistics Plan, the Human Resources 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, DAJ-9, DAJ-10 and DAJ-11 to my testimony.

The majority of PSO's incentive expenses (approximately 64%) during the test year were incurred through the Energy Delivery Plan. The Energy Delivery 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 340 PSO employees participated in the Generation Plan, 17 employees participated in the Information Technology Plan and 78 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-12 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 energy delivery 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 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). In each instance, these measures are consistent with the provision of quality utility service at reasonable cost.

The PSO and AEPSC incentive plans differ from the energy delivery 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 includes measures related to controlling the amount and cost of inventory, the Human Resources Plan includes measures related to diversity and employment, and the IT Plan includes measures related to availability of computer applications and support of computer equipment. All other incentive plans are similar to the Energy Delivery 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 are 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 are not designed as "bonuses" or additions to an already appropriate level of compensation. Instead, the Company designs an overall compensation package that includes an incentive compensation portion to reward employees for the achievement of strategic objectives that are both financial and operational in nature. It is the entirety of this compensation package that allows 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 is 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, $3,523,745, be included in cost of service, rather than the $10,822,038 in actual accruals made 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 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 witness John Aaron supports this pro-forma adjustment for the PSO rate case and PSO witness Kevin Bethel supports 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 2005 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 2005 Mercer US Compensation Planning Survey reported that 86% of the 1,350 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 2005 World at Work Salary Budget Survey reported that the number of companies using incentive pay programs continues to increase each year and that 76% of 2,836 responding companies were using incentive pay programs in 2005, up from 68% reported in 2002.

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 constitutes a competitive, market based total compensation package.

COMPETITIVENESS OF TOTAL COMPENSATION LEVELS

Exhibit DAJ-1 compares compensation data from the 2005 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 compares compensation data from the 2005 EAP Data Solutions Energy Technical, Craft & Clerical ("EPSO") Survey to that of key hourly/craft benchmark positions at PSO. This survey is the largest source of compensation data for positions of this type and includes data collected from 75 companies representing 99,450 incumbents nationally. The information included in Exhibit DAJ-2 represents data from the Mountains/Plains region. This exhibit also indicates that, with the exception of Meter Readers, PSO's compensation levels are 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 is below market median and the addition of incentive pay brings the total compensation package to a more competitive level overall.

Exhibit DAJ-3 compares exempt positions at PSO and AEPSC to compensation survey benchmarks covering a broad range of professional, management and supervisory positions for which survey data is 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 indicates 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 establishes salary ranges whose midpoints are approximately +/- 10% of the median base salary for comparable positions in compensation surveys. The entire salary range extends 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.

SENIOR MANAGEMENT COMPENSATION PROGRAM

AEP uses 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 includes long-term incentives. Approximately 525 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 2005, the compensation peer group consisted of 14 large and diversified energy services companies, plus 12 Fortune 500 companies, which, taken as a whole, approximately reflect the company's size, scale, business complexity and diversity.

The HR Committee generally uses median compensation information of the compensation peer group as its benchmark but does 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 maximize shareholder value by linking a portion of their compensation directly to shareholder return and 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 equals the 20-day average closing price of AEP Common stock for the last 20 days of the performance period. Exhibit DAJ-13 explains 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 $1,268,591. 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 2005 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.

REBUTTAL TESTIMONY

On April 9, 2007, I 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. I 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 intervenor 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 $2,671,085 to $12,371,104, or 3% to 16%, of this total compensation. 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 intervenor 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.

ANNUAL INCENTIVE COMPENSATION

Mr. Wreath has recommended that the company's proposed annual incentive costs be reduced by $1,402,494 (50%). Ms. Soltani has recommended that the company's proposed annual incentive costs be reduced by $986,649 (28%). Mr. Garrett has recommended that the company's proposed incentive costs be reduced by $11,102,513. As discussed by Mr. John Aaron in his rebuttal testimony, Mr. Garrett's recommendation actually exceeds the $6,908,434 in total annual incentive compensation requested by the Company.

Mr. Wreath contends 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. Ms. Soltani has taken a slightly different approach, contending that all "financial" measures contained in the various annual incentive compensation plans, which by her methodology amount to approximately 28% of annual incentive compensation only benefit shareholders, not ratepayers. As a result, she recommends that 28% of annual incentive compensation be removed from cost of service. Like Ms. Soltani, 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 argues 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 all 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 argue 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 is significant because it suggests that these witnesses are 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 my direct testimony I explain 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. Intervenors 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 I presented in my direct testimony showing the reasonableness of PSO's total compensation package, which includes 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 intervenor witnesses call into question various aspects of the design of PSO's and AEPSC's incentive compensation plans. Ms. Soltani questions the measures that she contends focus on corporate-wide financial results. Similarly, Mr. Garrett questions the inclusion of financial measures, but then ultimately concludes 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 criticizes the EPS modifier.

Mr. Wreath also questions the plans' use of financial measures but ultimately concludes that the cost of the plans should be evenly split between ratepayers and the Company.

I disagree 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 ensures that no incentive awards are paid unless AEP meets its targeted level of earnings per share. More importantly, from a customer benefit perspective, the portion of incentive awards above the target level are paid from additional earnings, not by ratepayers. This is the very reason why the amount requested in this case has been 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.

The intervenors maintain that amounts of incentive compensation should not be included in cost of service because their payment is uncertain, implying that these amounts are akin to some sort of annual bonus payment. This is not how these amounts should be characterized, as they are not bonuses. As explained earlier, a portion of employees' compensation package takes the form of incentive compensation in order to motivate and align employee efforts with performance measures that match overall Company objectives. They are not bonus payments to be paid only for extraordinary performance. In fact, the exact opposite is the case. Incentive payments are part of an overall compensation package that is market competitive and thus is *designed to be attainable.* The Company has, overall, been successful in reaching its compensation goals and paying out at least the target level of annual incentive compensation during the last 5 years.

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 $1,268,591 incentive expense, be denied. They contend 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. I disagree with the intervenors' recommendation and their reasoning for the same reasons I 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 is 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 concludes that the overall level of compensation is excessive. Given all of the testimony on this issue, including the intervenors', there is no basis for the Commission to conclude that those managers are excessively compensated.

The intervenors' recommended disallowance of all long-term incentive compensation is not consistent with their position on the annual incentive program. 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. Long-term incentive compensation for senior employees should be fully included in the Company's rates, but if there is a disallowance, it should be no more than the proportion of annual incentives subject to disallowance, if any.

Preston Kissman

My name is Preston Kissman and I filed testimony in this docket on November 21, 2006, and rebuttal testimony on April 9, 2007.

I 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. I also completed the Harvard University Program for Management Development and the University of Idaho Program for Public Utility Executives. I am a Registered Professional Engineer in the State of Texas and have been employed in various positions within CSW and AEP since 1971.

In my testimony of November 21, 2006, I provide an overview of the distribution services PSO provides to its customers, including engineering, construction or line services, and operation and maintenance of distribution lines. I also demonstrate that the adjusted test year level of distribution services expense ($46,363,544) is reasonable and necessary in order to continue to maintain a reliable and safe distribution system capable of meeting the demands of PSO's customers. No party to this case has recommended any disallowance to PSO's requested level of distribution service expense.

I also discuss 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 is 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 focuses 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. The success of these two programs is evidenced by the significant decline (27% from 2004-1005 and 36% from 2005-2006) in the total outage minutes experienced by PSO's customers in recent years, the steadily decreasing number of reliability related complaints that the Commission has received from PSO customers since 2003, and the continuing improvement in PSO's customer satisfaction studies.

Finally, my direct testimony describes PSO's plans to continue its proactive work to improve reliability and service to PSO's customers in the future. For example, PSO began in 2006, to install meter systems that will allow it monitor and record momentary electric service interruptions ("MAIFI"). This will enable PSO to better identify locations experiencing reliability incidents so that action can be taken before sustained outages occur. In addition, PSO plans to achieve a four-year vegetation management cycle and will continue its efforts to replace overhead services with new underground facilities. In all, PSO anticipates that it will invest more than $580 million in its distribution system over the next five years in order to further improve the level of service provided to our customers.

My rebuttal testimony was filed on April 9, 2007. In that testimony, I address the recommendations and comments of Joe J. Robson on behalf of the Quality of Service Coalition. Mr. Robson's testimony acknowledges both the operational and performance improvements PSO has made to its distribution system in recent years, but Mr. Robson also questions several aspects of PSO's service quality.

With respect to the reliability indices scores ("SADI" and "SAIFI") mentioned by Mr. Robson, it is clear that these results must be evaluated in light of the significant improvements that PSO has made to the distribution system. These system improvements have reduced the number of major storm related outages that, in the past, have had the effect of lowering the indices results. The SAIDI and SAIFI results have also been affected by the more accurate outage reporting system that PSO has implemented. For these reasons, the SAIDI and SAIFI results should not be viewed in a vacuum, but in conjunction with other factors. When these other factors, such as customer satisfaction studies and customer-minutes interrupted, are considered, it is clear that PSO's customers are receiving reliable, high quality electric service on a day-to-day basis and that Mr. Robson's concerns are unfounded.

This concludes my testimony summary.

Hugh E. McCoy

Hugh E. McCoy, a Director of Accounting Policy and Research for American Electric Power Service Corporation ("AEPSC"), supports the adjusted test year amount of $3,911,669 for pension cost and $6,352,454 for postretirement benefit cost which Public Service Company of Oklahoma ("PSO") is requesting to recover. The amounts requested by PSO are the expense amounts from the 2006 actuarial studies calculated in accordance with generally accepted accounting principles ("GAAP") under Statement of Financial Accounting Standards ("FAS") Nos. 87 and 106, respectively.

Mr. McCoy describes PSO's pension plans and the calculation of pension cost in accordance with FAS 87 (and where applicable, FAS 88). As required by FAS 87 and actuarial professional standards, Towers Perrin, the Company's independent actuary, performs annual actuarial valuations using reasonable actuarial methods and assumptions. Most of the Company's pension benefit cost is computed directly based on the demographics of the Company's actual employees and retirements, and the remainder of the cost is assigned equitably with no cross-subsidization between affiliates. All of the underlying actual economic and demographic data included in the 2006 actuarial study, which determined PSO's 2006 pension expense, was complete, known and measurable as of December 31, 2005.

Mr. McCoy describes PSO's postretirement benefit plan and how the cost amount is determined in accordance with FAS 106. He discusses the actuarial studies prepared by Towers Perrin for the plan in accordance with FAS 106. Postretirement benefit cost under FAS 106 includes the same components as FAS 87 pension cost. Except for minor differences necessitated by the slightly different nature of pension benefits and postretirement benefits, the requirements of FAS 106 are very similar to FAS 87.

Mr. McCoy supports the inclusion in rate base of $80,653,703 in additional pension contributions that PSO has made to ensure that its qualified pension plan pension obligations are fully funded under FAS 87. Mr. McCoy explains how investment return on these additional contributions provide a direct benefit to PSO's customers by reducing the current pension expense calculated in accordance with GAAP under FAS 87 that must be recovered through rates by $7.9 million. These additional contributions have been prudently incurred by PSO to provide service to its customers. Inclusion of these additional contributions in rate base will allow the Company to recover its cost of funds for these additional pension contributions. Mr. McCoy supports inclusion in rate base of these additional contributions because the customers benefit from the existence of appropriate pension funding for PSO's employees and from the lower pension cost under FAS 87 that results from PSO's having made these contributions.

Finally, Mr. McCoy discusses the appropriate treatment for regulatory accounting of certain effects of special pension and postretirement benefit accounting rules on the amount of equity in the Company's capital structure. In accordance with FAS 87, PSO recorded for financial reporting purposes a minimum pension liability related to its non-qualified pension plan, which was recorded as an after-tax equity deduction of $152,371 to Accumulated Other Comprehensive Income ("AOCI"). Mr. McCoy explains why this negative equity amount should not be recognized for regulatory accounting purposes. FAS 158, which was recently promulgated, will expand the use of special equity reductions and/or additions. Mr. McCoy, accordingly, requests the Commission to explicitly recognize in its final order in this case that the special adjustments to equity required by these special accounting requirements should be excluded from capital structure for ratemaking purposes. The Commission's concurrence on this point will allow the Company to defer on its books any such pension and postretirement benefit equity reduction or equity addition as a regulatory asset or liability, as applicable.

Donald R. Moncrief

My name is Donald R. Moncrief and I have filed direct testimony in this docket on November 21, 2006 and rebuttal testimony on April 18, 2007.

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

In my direct testimony of November 21, 2006, I present and support PSO's proposed jurisdictional and class cost-of-service studies and the development of the jurisdictional and class allocations and related schedules required by the Commission. I also present and support PSO's proposed tariff to implement its Formula Based Rate Proposal, as well as pro-forma adjustments made to test year customers, revenue, and sales volume data.

PSO's proposed Formula Based Rate tariff ("FBR") is contained in Exhibit DRM-2. This tariff will enable PSO to adjust its rates in a more efficient manner and allow for a more streamlined regulatory process, while allowing appropriate Commission oversight. Under the FBR tariff, the Commission will monitor PSO's earnings and adjust rates up or down based on changes to PSO's investment, expenses, and revenues. The FBR will use a test year of the 12 months ending December 31 of each year during the period the FBR is in effect, and will use FERC Form 1 data to calculate PSO's earned return. This earned return will be compared to a band of 100 basis points around the Company's Allowed Return, which will be set in this case. If the earned return falls below the band, rates will be changed by the amount necessary to increase earnings to the Allowed Return by adjusting the tariffed billing components. If earned return falls above the band, PSO initially proposed that earnings above the band would be shared through a credit 50/50 between the customers and PSO for the first 100 basis points, 75/25 for the next 100 basis points, and the customers would receive 100% of the earnings after that. The change in revenues will be allocated to the major rate classes using the Total Base Rate Allocator. Adjustments to Form 1 data would be limited to removal of Fuel Cost Adjustment Clause costs and revenues, recognition of regulatory accounting adjustments to reflect recovery of factoring and interest on customer deposits, and recognition of the effect of any statutorily-enacted tax charges.

I also sponsor the jurisdictional and class cost-of-service studies. The class cost-of-service study is a fully allocated, embedded study consistent with PSO's previous filings with the Commission, that assigns the retail total company costs to the retail classes. That study allocates demand-related production costs to the classes using the four coincident peak average and excess ("4CP A&E") methodology. This method recognizes that system demands are considered in planning and operating PSO's generation facilities through the 4CP component. The average demand component ensures that all customers who benefit from the use of the generation system are allocated a reasonable share of the cost of the system. Absent the average demand component, customer classes that do not take power at the time of the 4CPs, such as lighting classes, would receive no allocation of costs. Transmission costs are allocated using the 4CP method, because the Company's transmission facilities are designed to meet peak load and to maintain system reliability.

Distribution costs in Accounts 364-368, which include lines and poles, were allocated based on class maximum diversified demand and customer-related distribution costs such as meters and drop lines were allocated using the weighted number of customers' methodology. Customer-based allocators were used for customer accounting, customer information, and customer services expenses. Labor allocators were used for general plant and many A&G expenses.

My rebuttal testimony addresses issues raised concerning PSO's proposed FBR, adjustments to customer data, the class cost-of-service study, and Miscellaneous Revenue issues.

First, I discuss the FBR and Staff witness George Mathai's alternative Performance Based Rate Change ("PBRC") and New Generation and Transmission Expenditure Recovery ("NGTR") mechanisms. Mr. Mathai's alternative is workable, if modified as discussed by Company witness David Sartin. I agree that the mechanism should be modified so that if PSO's earned return is above the band, the sharing mechanism should be adjusted to reach all the way down to the Allowed Return instead of just to the upper band. I do not agree that the sharing mechanism should be accomplished through a change in the tariff, because only a portion of the excess is passed to the customers and a credit is appropriate and easier to administer in these circumstances. I have included alternative PBRC and NGTR tariffs incorporating PSO's modifications as exhibits in the event the Commission adopts Mr. Mathai's proposal.

Regarding adjustments to customer data, I refute OIEC witness Garrett's proposal to update the customer adjustment to December 31, 2006, which is six months after the test year. PSO adjusted the customer count to test year end, as it has in all previous cases. Further, customer counts six months after the end of the test year are not known and measurable at test year end. I do agree with Mr. Garrett and Staff witness Forbes that the weather adjustment should not have been applied to customer charge revenues. I have recalculated the weather adjustment using Ms. Forbes' methodology and correcting for errors.

Wal-Mart witness Selecky contends that an unquantified portion of Distribution Accounts 364-368 (e.g., poles and wires) should be allocated using a customer allocator instead of the demand allocator. I refute this position, showing that these costs do not vary with the number of customers, showing that Mr. Selecky's proposed minimum-system methodology involves significant use of judgment and is subject to significant disagreement, and showing that Mr. Selecky's proposal results in the shifting of costs onto residential customers.

Next, I address Staff witness Smith's proposed allocation. He criticizes the Company's cost-of-service study because in his opinion the 4CP A&E allocator produces preferences for some classes, notably lighting. I point out that the 4CP A&E methodology is only applied to production plant and that the "average" component assigns costs to customer classes, such as lighting, that are not using the system at the time of peak demand. Mr. Smith did not perform a cost-of-service study, nor did he allocate costs. Instead, he allocated revenues to the classes based on the percentage of revenues contributed by the classes during the test year. Further, he applied that same reasoning to calculate Miscellaneous Revenues, which are actually calculated by normalizing test year booked revenues. These revenues do not vary according to the Company's revenue requirement and cannot be calculated by applying a percentage to the revenue requirement. Mr. Smith's proposals are not supported and should be rejected.

This concludes my testimony summary.

Donald A. Murry

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

I have 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, I 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, I was a Professor of Economics at the University of Oklahoma and since 1998 I have been Professor Emeritus at the University of Oklahoma. In these positions, I directed and performed academic and applied research projects related to energy and regulatory policy. During this time, I 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, I served as Chief of the Economic Studies Division, Office of Economics of the Federal Power Commission.

I have appeared before numerous courts and state utility commissions.

In my testimony, I analyze the current cost of capital and recommend a rate of return in this proceeding. First, I reviewed the current economic environment that would influence the cost of capital of PSO, and noted the increasing inflationary pressures in the economy and the rising interest rates in recent years, plus the forecasted continued increase in inflation and interest rates. For my analysis of the cost of capital of PSO, I considered the appropriate capital structure, and in my rebuttal testimony, I agree that the appropriate capital structure is that recommended by Staff witness Fairo Mitchell.

To measure the cost of common stock, I used the commonly accepted Discounted Cash Flow "DCF" and the Capital Asset Pricing Model "CAPM" analyses and applied them to the common stock of both AEP and each utility in a group of comparable companies that were similar to AEP. Based on these results and my overall analysis of the comparable companies, I am recommending an allowed return for the Company in this proceeding in the range of 11.75 to 12.00 percent and believe that the return of 11.75 percent is adequate, unless interest rates rise.

The most important influence on my judgment of the appropriate recommended allowed return for PSO is the forecasted increase in interest rates. In addition, I recognized the relative volatility of the DCF method and the biases in the CAPM method in evaluating the results of my DCF and CAPM analyses.

Finally, in my direct testimony, I estimated the After-Tax Interest Coverage of PSO at my recommended return of 11.75 percent to be 2.60 times, which is slightly below the average interest coverage of the comparable companies, which is 2.85 times.

In my rebuttal testimony, I respond to the direct testimonies of Fairo Mitchell, J. Randall Woolridge, Daniel J. Lawton, Joe Robson, and George Mathai.

With regard to Mr. Mitchell, as mentioned above, I agree with his proposed capital structure. On the topic of return on equity, I note the similarity of his analysis to my own and correct some data errors, the largest of which is a mismatch concerning his risk premium in his CAPM analysis. With these corrections, Mr. Mitchell's recommended return on equity should be 10.33%. In addition, it would be appropriate to also adjust his return for flotation and for the relative size of the company, and with these adjustments, the return that results is 10.88%.

Dr. Woolridge's testimony presents a flawed analysis for a number of reasons. For instance, he completely fails in any meaningful way to account for the increase in interest rates. Another example is his market-to-book discussion, which compels the conclusion that he believes other comparable regulated utilities are earning above their cost of equity. He has incorporated an inadequate concept of risk that affects his testimony throughout and a number of his conclusions.

Furthermore, Dr. Woolridge used an incorrect standard for determining whether an allowed return is "reasonable". By determining that all of his comparable electric utilities earn returns exceeding their "equity cost rates," Dr. Woolridge appears to recommend a return for PSO that is in direct conflict with the concept of setting a return sufficient to attract capital. If he had calculated the Before-Tax and After-Tax Interest Coverages associated with his recommendation, it would have revealed his recommendation to be inadequate: 3.12 times for Before-Tax coverage compared to an average of 3.8 times for his comparable group, and 2.28 times for After-Tax compared to 2.85 times for his comparable group.

Finally, I noted a number of inconsistencies, internal contradictions, and mechanical mistakes that undermine the accuracy and validity of his testimony. This was the case especially in Dr. Woolridge's response to my direct testimony. For example, while Dr. Woolridge criticizes my use of analysts' forecasts, he uses analyst's forecasts in his own analysis.

With regard to Mr. Lawton, in my rebuttal I first respond to some mischaracterizations of my direct testimony. But more importantly, there are a number of significant problems with his analysis. He did not account for the issuance expenses of common stock, and his recommended return will result in an After-Tax Coverage Ratio of 2.33 times, which is significantly below that of the comparable group of 2.85 times. Finally, a comparison of his recommendations in other cases shows his methodologies are inconsistent from case-to-case. If Mr. Lawton had used the same cost of capital methods in this proceeding that he used in some previous regulatory proceedings, he would have calculated a range for return on equity of 10.19 percent to 10.64 percent.

Mr. Robson's testimony does not offer any new perspective or insight into the relationship of CWIP, FBRs, and investment risk, and his testimony does not justify any adjustment to return on equity.

Finally, in my rebuttal, I respond to Mr. Mathai's suggestion that the return on equity for his proposed regulatory asset should be reduced by "100 to 150 basis points less than the established benchmark ROE." No adjustment for risk is justified by the facts, and Mr. Mathai presents no justification for the size of his recommended adjustment.

Bernard M. Pasternack

My name is Bernard M. Pasternack and I filed direct testimony in this docket on November 21, 2006.

I have a B.S. degree in Electrical Engineering and a M.S. degree in Electric Power Engineering from Rensselaer Polytechnic Institute in Troy, New York. I also have an MBA degree from Fairleigh Dickinson University in Madison, New Jersey. I have been employed in various positions with AEP since 1968. I have previously testified before the Federal Energy Regulatory Commission and state regulatory commissions in Texas, Virginia, and West Virginia. A more detailed discussion of my qualifications is contained within my prefiled testimony.

My direct testimony, filed on November 21, 2006, describes the transmission services provided by PSO to its customers and demonstrates that the costs associated with operating PSO's transmission system are reasonable and necessary. My testimony also addresses 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 incurred during the test year ($17.4 million). Since 2003, PSO has invested approximately $61 million in capital in the transmission system 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. PSO has also invested approximately $13.9 million in Construction Work In Progress as of June 30, 2006 for transmission projects scheduled to be placed in service by June 30, 2007. The major capital projects undertaken by PSO since 2003 include the initial phases of the Tulsa area 345/138 kV project, the addition of a second autotransformer at the Lawton Eastside Station, rebuilding transmission facilities between the Riverside and Weleetka power plants, and interconnection of IPP generators at Oneta, Southwestern and Weatherford stations.

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. For example, PSO currently plans to make significant future transmission investments in 2007-2011, including completion of the $58.7 million Tulsa area project. While these projects are not included in this rate request, these future projects evidence PSO's continuing commitment toward accommodating generator interconnections and other transmission service requests while ensuring that the needs of PSO's customers continue to be met in a safe, reliable, and cost effective manner.

This concludes my testimony summary.

David P. Sartin

My name is David P. Sartin and I filed direct testimony in this docket on November 21, 2006, and filed rebuttal testimony on April 9, 2007.

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

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

My direct testimony provides financial information showing that the formula rate approach requested by PSO is the best alternative for placing significant amounts of new investment in rate base during the next six years. This is accomplished by providing and summarizing PSO's financial forecast under two different approaches to rate relief for the six-year period 2007 through 2012, which encompasses the period of construction and initial commercial operation of PSO's new base load and peaking generation units through the time when these assets are expected to be fully included in customers' base rates.

My direct testimony also discusses the benefits to customers and investors of a sound regulatory policy that permits recovery of financing costs during the construction period of new assets through inclusion of construction work in progress ("CWIP") in rate base. I also provide financial forecast information showing that without rate relief over the next six years, PSO cannot achieve reasonable rates of return and may not be able to sustain investment grade bond ratings. The financial forecast information and testimony I provide should be considered in conjunction with the testimony of PSO witnesses Julie M. Cannell and Susan D. Abbott who explain the views of equity investors and debt holders of companies like PSO during periods of substantial capital requirements.

My rebuttal testimony covers the topics of CWIP in rate base and formula rates. Specifically, I am responding to the testimonies of: Joe Robson, Quality of Service Coalition; James T. Selecky, Wal-Mart Stores, Inc.; Roya Soltani, Office of the Attorney General; Mark E. Garrett, Oklahoma Industrial Energy Consumers; and George Mathai, Public Utility Division of the Oklahoma Corporation Commission ("Commission" or "OCC"). I also comment on Redbud Energy, LP's statement of position. The primary topics I address in this testimony are the intervenors opposition to PSO's proposed formula based rate, the OCC Staff's alternative formula rate proposal, and the need for including CWIP in rate base.

OCC Staff witness George Mathai's proposal for formula rates is a workable solution to PSO's proposed formula rate approach. PSO believes, however, that there are certain enhancements and changes that should be made, which I discuss in this testimony. While other parties to the case offer various reasons why they believe formula rates will not work, under either PSO's proposal or Mr. Mathai's proposal, with the changes recommended herein, formula rates can work effectively and beneficially for both the Company and its customers.

Inclusion of CWIP in rate base is a public policy decision of the OCC that is in the best interests of customers and PSO, and one that this Commission has previously made. A policy of CWIP in rate base will lower overall costs to customers and permit a more gradual increase to customer's rates. It benefits PSO's customers by providing PSO improved cash flows during a construction period that will call for unprecedented investment in new electric facilities, which will permit PSO better access to capital markets at lower interest rates. The OCC has permitted CWIP in rate base in prior PSO cases (Order No. 134222, Cause No. 25897). All of the reasons cited by the OCC in that order as to why CWIP in rate base was appropriate remain valid today.

J. Stuart Solomon

PSO filed this case for two basic reasons.

First, PSO's current rates are not sufficient to allow the Company to recover costs necessary to provide reliable service to customers, and also provide an adequate return to PSO's investors. As a result, PSO has filed for a base rate increase of $47.9 million. PSO has not had a base rate increase since 1994, and the Company only earned 6.5% on its equity in 2006. This is an unreasonably low return and substantially below even the inappropriately low levels recommended by Staff and Intervenors.

Second, PSO is making significant levels of investment to serve customers and support the growth and development of the state and our communities. Specifically, PSO plans to invest over $2 billion over the next five years, primarily in new generating facilities to meet growth in customer needs. Given this extraordinary level of investment, PSO has proposed a formula-based rate ("FBR") plan as a fair and efficient regulatory mechanism to set rates, along with the recovery of the financing costs of Construction Work in Progress on a contemporaneous basis.

The FBR provides an annual, streamlined review of costs that assures appropriate rate levels for customers, and avoids the regulatory costs and burdens that would otherwise occur with traditional rate proceedings. The FBR will allow PSO to keep its earnings at adequate levels to support its investment program.

The contemporaneous recovery of financing costs on investments – CWIP – benefits both customers and the Company. It provides cash to help pay for construction costs and results in lower overall costs to customers than the traditional, AFUDC method. It also creates a more gradual rate path for placing large investments like generating plants into rates.

Given PSO's already low earnings, Staff and Intervenor rate decrease recommendations make no sense and instead would serve no purpose but to unreasonably weaken PSO. PSO cannot provide reliable service, meet its customers' needs, and satisfy customer and demand growth if reasonable expenses are disallowed and rates are decreased. Intervenor testimony rejecting PSO's proposed FBR and the recovery of CWIP prevent an efficient regulatory approach that benefits both customers and the Company.

PSO is encouraged by Staff's support of a FBR mechanism and the recovery of CWIP, and PSO would appreciate the opportunity to work with Staff to develop a workable FBR plan.

In short, there are three important aspects of PSO's filing:

1. A request for rate relief, so the Company can recover its reasonable costs to serve customers and earn a reasonable return on its invested capital;
2. The FBR proposal, which provides an efficient regulatory approach and ensures reasonable rate levels; and
3. The contemporaneous recovery of the financing costs of Construction Work in Progress, which lowers the costs of investments and provides a more gradual rate path for customers, while providing current year cash flow to help pay for the Company's customer investment program.

PSO is at a critical point in its history. The Company's rates are unreasonably low and significant rate relief through this case is essential so PSO can continue to provide reliable service. Moreover, PSO has embarked on an unprecedented investment program to serve customers, and a FBR mechanism with CWIP recovery allows PSO to make those investments, while also providing important benefits to customers.

OIEC

Edwin C. Farrar

My rebuttal testimony responds to issues raised in responsive testimony by David Smith of the Public Utility Division Staff.

I was previously employed by the Oklahoma Corporation Commission as a manager in the Public Utility Division and in that capacity I provided expert testimony on cost of service and rate design issues. I also provided direction and training to Mr. Smith prior to the filing of this rate case by PSO to prepare him for his assigned rate case responsibilities. I did not, however, have any assigned responsibilities in this proceeding as a Staff member. I stated in my testimony that I have not heard of the "straight cost allocation methodology". Based on my review of testimony, work papers and discovery responses, I concluded that the "straight cost allocation method" is not a legitimate cost of service methodology and it does not use "cost" as a basis for customer class allocations. I explained that Staff's recommendation would completely undermine the Commission's efforts to increase system efficiency through Demand-Side Management programs.

I testified that cost based rates represent a sound rate design policy that send accurate price signals to consumers so that they can control their use of electric power when the cost of electric power production exceeds the economic value they place upon it. I explained further that customers that use power for economic activities will decrease their production in PSO's territory if the power sold to them is priced above their actual cost of service. The concept of requiring subsidies to be provided by large industrial customer classes to other classes is seriously flawed for that reason. Those subsidies encourage waste by the subsidized class and cause harm to the customer classes that provide those subsidies.

I testified that the rate design for PSO should be based on the actual cost to provide service to customers and this would result in a significant reduction in rates for Service Level 1, 2 and 3 customers under every revenue requirement filed in this cause. I recommend that the rate design proposed by Staff be rejected by the Commission because it is not based on any accepted regulatory principle and because it will cause harm to all PSO ratepayers for decades.

I testified that Staff's "straight cost allocation method" was not a legitimate cost of service method, but it is based on the current revenues billed to each customer class. I provided evidence that Staff's rate design method is based on PSO's existing revenues. I presented the line items from PSO's cost of service study referenced by Staff and demonstrated that those lines are actually the revenues collected from PSO ratepayers and not the costs incurred by those ratepayers. I testified that the class rate of return is the best indicator of subsidization between classes and the rates of return for Service Level 1, 2 and 3 customer classes are not equal but in fact large subsidies are extracted from those classes. Staff has in fact admitted in discovery responses that their method is based on revenues rather that costs incurred to serve customers.

I testified that the 4CP Average and Excess allocation methodology used by PSO does not give preference to any customer class but instead is based on generally accepted cost allocation methodologies for utilities with significant summer peaks like PSO. Staff's rate allocation methodology on the other hand is heavily biased in favor of the subsidized classes and will <u>increase</u> the differences in the class rate of return contributions as shown on the table below.

STAFF'S RETURN ON RATE BASE	
Class	**Rate of Return**
RESIDENTIAL	**6.03%**
LIGHTING	**4.63%**
C&I SL5, SL4	**9.71%**
C&I SL3	**12.22%**
C&I SL2	**15.29%**
C&I SL1	**17.16%**

I recommended that the Commission adopt the cost allocation methodologies sponsored by PSO in its errata cost-of-service study and supported by the OIEC and Wal-Mart in responsive testimony in this Cause. I recommend that the rates for Service Level 1, 2, and 3 be reduced.

I know of no authoritative text on economic regulation that supports the methodology recommended by Staff.

I recommend that the "straight cost allocation method" developed and proposed by Staff be rejected because it compounds the subsidies in PSO's current rates, it encourages waste, it will lead to increases in costs of all ratepayers, it causes harm to the classes providing the excessive subsidies, and Staff provided no evidence to support it.

I recommend that the errata cost of service study be accepted by the Commission. I further recommend that the rates be designed to bring the major rate classes close to equalized rates of return.

Glen E. Gregory

The purpose of my rebuttal testimony is to respond to the cost allocation and the rate design recommendations of Mr. David Smith of the Public Utility Division Staff.

The fundamental purpose behind a cost of service study is always to determine where individual class revenue levels should be set. The Staff "Straight Cost Allocation Method" completely negates that process by relying on the very numbers it is supposed to be evaluating and correcting. Staff's proposed approach is fundamentally flawed, unsupported by any recognized authority and it fails to address the goals of a legitimate class cost of service methodology. This method makes no effort to link the costs caused by any of the classes to the rates they are charged. Furthermore, it fails to correct (and even increases) the problem of subsidies in PSO's current rates.

Staff's "Straight Cost Allocation Method" is not a legitimate method. I recommend the Commission reject Staff's proposed method in favor of a credible, established method such as the one used in PSO's cost of service study.

Mark E. Garrett

Summary of Direct Testimony- Revenue Requirement Issues

Plant, Accumulated Depreciation and CWIP (Six-Month Post Test Year Update)
Instead of increasing rate base by including approximately $63,537,423 from CWIP projects in Plant in Service, I recommend that the Commission update both the Plant in Service and Accumulated Depreciation accounts through December 31, 2006. In Oklahoma, the Commission gives effect to known and measurable changes that occur within six months of test year end, in this application, December 31, 2006. The resulting adjustment is calculated by comparing PSO's requested level of Plant in Service and Accumulated Depreciation to the actual balances in these accounts at December 31, 2006. This treatment has the effect of including in rate base all CWIP projects actually complete and in service within six months of test year end. Also, all off-setting decreases in the plant investment levels – in effect, all changes in the Accumulated Depreciation accounts - are recognized as well. The statutory requirements to give effect to known and measurable changes occurring within six-months of test year end are satisfied when both the Plant in Service balances and the Accumulated Depreciation balances are updated to the end of the six month post test year period. And, when the increases and decreases to the investment levels in Plant in Service and Accumulated Depreciation are both updated, the undesirable effects of the piecemeal approach taken by PSO are avoided. This approach has been previously accepted by this Commission in ONG's last rate case PUD 04-610 and in OG&E's last rate case, PUD 05-151. Following the Commission's approach in OG&E's rate case, I included Completed Plant not Classified in PSO's plant balances. OIEC's adjustments to PSO's pro-forma rate base to update plant and accumulated depreciation to 12-31-06 is $7,826,928.

Accumulated Deferred Income Tax (Six-Month Post Test Year Update)
This adjustment updates PSO's Accumulated Deferred Income Tax ("ADIT") balances to the 12-31-06 levels. This adjustment is necessary to give effect to the known and measurable increase in the deferred tax balances that occurred within six months of test year end. This standard adjustment was recognized and accepted by the ALJ in her recommendations in the recent ONG rate case proceeding. The adjustment necessary to update the accumulated deferred income tax balances to December 31, 2006 levels is $5,610,494.

Prepaid Pension Asset
I am proposing an adjustment to reduce the pro-forma rate base by the balance in PSO's Prepaid Pension account, and increase operating expense by an amount equivalent to a cost of debt return on this balance. In general terms, PSO has been contributing more to the fund than its SFAS 87 calculated cost levels. These contributions are discretionary, not mandatory contributions. The minimum required contribution levels for PSO over the past five years have been zero. The question is whether this balance should receive a cost-of-money return rather than a full rate base return. A rate base return includes a substantial profit component while a cost-of-money, or

long-term debt return, does not. Since the contributions to the pension fund above the SFAS 87 levels have been discretionary contributions, PSO should not be allowed to earn a profit on the excess discretionary contributions it makes to the fund. However, since ratepayers receive a benefit from the contributions in the form of lower SFAS 87 expense levels, PSO should be allowed to recover the cost of making reasonable additional contributions. The adjustment should not be based on the benefit to ratepayers (as proposed by Staff) if the benefit received by the ratepayers is greater than the cost-of-money return to PSO. If PSO received a compensation level that was greater than the actual cost it incurred to make the contributions, then again, it would be making a profit off of the discretionary contributions. The correct answer is to allow PSO to recover only the actual cost of making the contribution, without earning an additional profit from doing so.

This treatment has been accepted by this Commission in the past. In PUD 05-151, the Commission removed OG&E's prepaid pension balance in the amount of $67.1 million from rate base and provided a cost of debt return of 6.03% on the 13-month average balance of $52.9 million. Also, in ONG's 1992 rate case, PUD 91-1190, the Commission allowed a cost of debt return on ONG's deferred pension balance. These are the only two occasions in Oklahoma, to my knowledge, where this particular question has been addressed by the Commission, and in both cases the Commission followed the same approach.

Customer Deposits (six-month post test year update)

As with Plant, Accumulated Depreciation, and Deferred Taxes, Customer Deposits should be updated to the 6-month post-test-year balance at 12-31-06. In the Customer Deposit account, the balance has been steadily increasing over the past several years, and it continued to increase during the 6-month period after the test year. My adjustment increases PSO's pro-forma balance in the Customer Deposits account by $3,060,948 to reflect the 12-31-06 balance.

Load Growth Adjustment (Six-Month Post Test Year Update)

PSO has proposed an adjustment to test year revenues based on customer counts at test year end, June 30, 2006. However, customer counts at 12-31-06 indicate that PSO's customer base has increased over the levels that existed at test year end. OIEC's Customer Growth adjustment annualizes PSO's revenue levels to reflect customer count at the end of the 6-month post test year period. PSO agrees that load is increasing within its service area. This calculation resulted in a revenue growth adjustment of $1,713,100.

Weather Adjustment

I accepted PSO's weather related kWh. However, PSO used total unadjusted non-fuel base test year revenues to price the weather-related kWh adjustment. The result is that the customer charge was inappropriately included in PSO's weather-related revenue adjustment. Weather kWh is variable and related only to energy consumed, therefore, only the non-fuel base energy charge should be used to develop the weather related revenue adjustment. To correct this mistake I developed a weather kWh revenue adjustment that did not contain the customer charge. The removal of the customer charge and other non kWh charges from the calculations results in an increase in current non-fuel base revenue of $1,083,514.

<u>Payroll Adjustment (Six-Month Post Test Year Update)</u>
PSO is proposing to increase test year payroll expense by $2,697,440 based on payroll levels at test year end. PSO's proposed adjustment results in a pro-forma payroll expense level of $56,765,130. I am recommending, instead, to compute the payroll annualization adjustment using payroll levels at December 31, 2006, six months after test year end. This results in an annualized payroll level of $54,230,475, which is $2,534,656 less than the level proposed by PSO. In general, I used the standard payroll annualization approach – also used by PSO – where the last payroll level for the period is multiplied by twelve. PSO used the payroll cost levels at June 30, 2006 to calculate its adjustment, and I used the cost levels at December 31, 2006. My adjustment also takes into account both base pay and overtime expenditures, while PSO's adjustment annualizes only base pay. Overtime payroll expenditures during the test year were unusually high. This adjustment results in a decrease to pro-forma operating expense of $2,534,656.

<u>AEPSC Payroll (Six-Month Post Test Year Update)</u>
PSO proposes to increase test year AEPSC payroll expense by $431,368 based on the expense levels in place at test year end. AEPSC payroll should be annualized at the end of the statutory 6-month post test year period. In response to AG 2-67, PSO provided the annualized AEPSC payroll expense level at 12-31-06. The annualized level at 12-31-06 is $517,217 less than the annualized level at test year end. Also, PSO indicates that the AEPSC employee count at 12-31-06 has decreased by 83 during the 6-month period after test year end.

<u>Incentive Compensation</u>
In most 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 to employees is uncertain; (2) factors that most significantly impact earnings for a utility (such as weather and rate cases) are outside the control of most employees and have limited value to customers; (3) incentive plans conditioned on earnings discourage conservation and demand-side management programs; (4) 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) incentive payments embedded in rates shelter the utility against the risk of earnings erosion through attrition, because, in those years when financial performance measures are not met, and incentive payments are not made, the amount embedded in rates for incentives acts as a financial hedge to shelter the poor financial performance of the utility.

Since utilities retain, between rate cases, all of the savings generated from increased efficiencies promoted by these incentives, payment to the employees for these plans should be made from a portion of the savings these plans help achieve. Thus, a properly designed incentive compensation plan will pay for itself and does not need to be subsidized by ratepayers.

I have participated in several proceedings in which the costs of incentive plans were disallowed based on the arguments set forth above. In **Oklahoma**, Cause No. PUD 91-1190, Cause No. PUD 200400610, and Cause No. PUD 200500151. In **Texas**, GUD No. 9670. In **Nevada**, Docket No. 03-1000.

Also, it should be pointed out that in Texas, in PUC Docket No. 28840, the Texas Commission disallowed **sixty-six percent (66%)** of AEP-Texas Central's test year incentive payments. This was the portion of the utility's incentive payments that was based on financial performance measures, in the opinion of the Texas Commission. AEP-Texas Central is a sister company of PSO and uses the same incentive plans.

In the analysis of incentive compensation plans it is important to distinguish between financial performance measures and quality of service measures. However, if the overriding goal of the incentive plan is to increase shareholder earnings, the entire incentive compensation should be funded out of the increased earnings that trigger the payments.

Analysis of PSO's Incentive Compensation Plans:
The *2006 Energy Delivery Companywide Incentive Plan,* which accounts for 64% of PSO's incentive compensation states that it is designed to encourage and reward the two following behaviors: (1) Contributing to corporate financial success with a focus on AEP's earnings per share ("EPS") – creating value for the AEP shareholder; (2) Rewarding employees for meeting or exceeding annual performance goals through focusing on customer service and satisfaction.

An analysis of the weight given to each of the plans performance measures reveals that 70% of the incentive compensation weight is given to company concerns while only 30% is devoted to customer satisfaction and reliability. In the section entitled *Award Calculation and Key Provisions,* the plan describes how the overall compensation payment calculation is subjected to an Earnings per Share modifier: "AEP management has committed to meeting its 2005 EPS target for the Board and shareholders. The EPS Modifier ensures that the aggregate level of incentive compensation paid is appropriate to AEP's overall performance and **<u>does not come at the expense of reaching the EPS objective</u>**." This description clearly states 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 employees will be compensated only to the extent additional earnings are available to do so.

Analysis of AEPSC Incentive Plans:
The AEP Shared Services Incentive Plans are even more focused on financial performance measures. These plans are all weighted heavily toward company goals and financial performance measures in particular, much like the plan at the operating company level discussed above. The *Corporate Incentive Plan* is weighted 100% toward improving earnings per share. Other AEPSC plans, like the *Human Resource Incentive Plan,* which shows a 30% weighting toward customer satisfaction, appear to have a customer focus, but the customers AEPSC serves are the <u>AEP affiliated companies</u> and the employees at these companies, not actual utility customers. A review of the stated goals for each AEP/PSO incentive plan clearly reveals that concerns about corporate earnings dominate the incentive plan objectives at both the corporate and operating company levels. A review of these goals shows the emphasis AEP places on increased earnings. This emphasis is made particularly clear when the first stated goal in each plan is the goal to increase shareholder value through a focus on earnings per share. Additionally, the EPS Modifier discussed above is included in each of the Plans.

For ratemaking purposes, all of the cost of the AEP/PSO incentive plans should be excluded, based on the fact that these plans are overwhelmingly weighted toward company rather than customer objectives. However, if from a from a policy perspective, the Commission wanted to encourage a focus on customer concerns, the Commission could include the limited portion of the plans designed to improve customer service and reliability. Because AEP does not track the cost of its incentive plans separately, it is difficult to estimate the amount of the aggregate payment associated with customer concerns. However, in PSO-Wide Energy Delivery Plan – the plan with the most weight given to customer concerns – the customer satisfaction and reliability weighting is 30%. In my opinion, 30% would be the upper limit of what could be attributed to customer satisfaction and reliability concerns in the PSO incentive plans. This would be consistent with the findings of the Texas Commission in the AEP-Texas Central case where 33% of the incentive payments were allowed in rates.

Long-Term Executive Stock Incentive Plan

Incentive compensation payments to officers, executives and key employees of a utility are generally excluded, and I agree with this treatment. Since officers of any corporation have a duty of loyalty to the corporation itself and not to the customers of PSO, these individuals typically put the interests of PSO first. Undoubtedly, the interests of PSO and the interests of the customer are not always the same, and at times, can be quite divergent. This natural divergence of interests creates a situation where not every cost associated with executive compensation is presumed to be a necessary cost of providing utility service. PSO's long-term executive incentive plan is specifically designed to tie executive compensation to the financial performance of AEP. 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 PSO'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. Further, a well designed incentive plan should pay for itself. Thus, there is no need to include in rates amounts that will be provided through higher earnings. PSO recorded test year executive incentive compensation of $1,268,591. OIEC removes this amount from the cost-of-service.

Supplemental Executive Retirement Plan ("SERP")

I recommend that the SERP Expense be removed from the revenue requirement in this proceeding. PSO provides supplemental retirement benefits to officers, and division presidents of PSO. Supplemental retirement plans for highly compensated individuals are provided because benefits under the general pension plans are subject to certain limitations under the Internal Revenue Code. Benefits payable under these supplemental plans are typically equivalent to the amounts that would have been paid but for the limitations imposed by the Code. The amount of Supplemental Executive Retirement Plan costs included in PSO's filed cost-of-service was $596,081. I recommend a sharing of the total executive benefits costs as follows: I recommend that ratepayers pay for all of the executive benefits included in PSO's regular pension plans and that shareholders pay for the additional executive benefits included in the supplemental plan.

Advertising Expense

The costs addressed in this adjustment are costs identified by PSO as "Advertising" costs which are statutorily excluded for ratemaking purposes. For those costs not specifically disallowed under the statute, the Commission may still exclude the cost if the cost is not shown by the utility to be "*beneficial to all customers.*" In this application PSO has made no such showing. I recommend the Commission exclude all of the costs identified by PSO as "Advertising" expenditures in the amount of $1,392,779, unless PSO can show in rebuttal testimony that these costs or a portion of these costs fall within one of the narrow statutory exceptions.

Legislative Advocacy

PSO seeks to include $635,129 in rates for the Oklahoma portion of costs associated with legislative advocacy. My adjustment removes these costs from operating expense for ratemaking purposes. Traditionally, the costs of legislative advocacy are not included in operating expense for ratemaking purposes because the political interests of a regulated utility that enjoys a monopoly franchise within the state can be quite different from the interests of PSO's captive ratepayers. It would be unfair to require ratepayers to fund the lobbying activities of corporate executives whose duty of loyalty is clearly owed to the corporation and its stockholders. The adjustment to remove legislative advocacy costs in the amount of $635,129 is set forth at Exhibit MG-2.9.

Property Taxes

PSO proposes an increase to test year property tax expense based on an estimated assessment of its pro-forma plant levels. However, property 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. Considering the way in which property tax is actually assessed, PSO's estimates based on projected book value are inappropriate. The amount of property tax actually assessed PSO for the year ending December 31, 2006, which includes the 6-month post test year period, was $32,312,415. This is the amount that should be included in pro-forma operating expense. OIEC's adjustment of $ 1,730,203 is the amount needed to restate PSO's pro-forma tax expense to actual levels at December 31, 2006.

Removal Cost Adjustment (Negative Salvage Value)

PSO is proposing to increase its depreciation expense by $9,652,894 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 increase rates by approximately $9.8 million annually.

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.

The <u>annual</u> level of removal costs embedded in PSO's <u>existing</u> depreciation rates was $18,782,313, based on Plant in Service at December 31, 2006.

The <u>annual</u> level of removal costs embedded in PSO's <u>proposed</u> depreciation rates is $37,741,355, based on Plant in Service at December 31, 2006.

PSO's actual removal costs are much lower than the estimated costs included in rates. In 2006, PSO incurred actual removal costs of $10,649,332. This data shows that the estimated removal costs requested by PSO in this proceeding are nearly than **<u>four times higher</u>** than the level of costs PSO actually incurs to remove assets.

I recommend 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. This would result in an adjustment of $18,959,043, which is the difference between the removal cost accrual under proposed rates of $37,741,355 compared with the removal accrual under existing rates of $18,782,312.

The Commission should also consider adopting 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.

- **Pennsylvania** has used the approach for many years.

- **New Jersey** adopted the approach in 2004 in the Jersey Central Power and Light ("JCP&L") rate case. The New Jersey Board continues to use this approach.

- **Delaware,** in the past five years, has switched to using the Pennsylvania method for most of its regulated utilities.

- **Oklahoma** addressed the Pennsylvania approach in ONG's most recent rate case. In that case, the OCC rejected ONG's request for higher depreciation rates related to increased negative salvage estimates and instead instructed the utility to file a depreciation study in its next rate case that considered implementing the Pennsylvania approach.

- **Georgia** requires an approach for calculating negative salvage that strips the inflation element from the calculation and recognizes removal costs at current values.

- **Kansas** staff recently recommended the Pennsylvania approach in a KGS case. That case, however, was settled and not tried on the merits.

- **Texas** Railroad Commission examiners, in the recent Atmos Mid-Tex rate case, rejected the utility's proposed increase in removal cost accruals, and found that my recommendations with respect to the Pennsylvania method were reasonable and should be considered in the next Atmos proceeding.

If the Commission decided to include a level for removal costs based on actual expenditures rather than projected future costs, I recommend the Commission use the actual expenditure levels for the test year. PSO identified this amount as $10,649,332. This would result in a decrease adjustment of $27,092,032 to the proposed PSO level of $37,741,355.

Production Plant Life Spans (Depreciation Expense)
In a depreciation study, rates are set to recover the original cost of an asset over its expected useful life. If the expected remaining life is set too short, the resulting depreciation rates will be higher than necessary, and current ratepayers will be forced to bear costs now that should borne by future generations of ratepayers. For its coal plants, PSO selected a life span of 42 years. The actual life span for these units, however, is 60 years or more, according to PSO's own personnel. Numerous examples of the expected 60-year life span for the coal units can be found in PSO's responses to AG 10-10, AG 10-44 and OIEC 11-17. Further, the 60-year life span for coal units is used by AEP in other states. In prefiled testimony in another jurisdiction, Mr. Mazzone states that the "AEP System experience is proving that unit useful lives of 60 years and greater are reasonable and necessary." Moreover, at least one AEP unit is currently operating beyond the 60-year life expectancy. According to the testimony of Mr. Mazzone, the Appalachian Power Company's Glen Lyn Unit 5 is presently operating in its 61st year. The impact of this change reduces annual depreciation expense by $7,055,000.

Adjustments Proposed By Other OIEC Witnesses
I have included the following recommendations in the revenue requirement calculations:

Recommendations of Mr. Scott Norwood

Production Plant Maintenance Expense Normalization	$ 15,027,077
Purchased Power Capacity Cost Normalization	$ 3,456,000
AEPSC Trading Administration Cost Removal	$ 4,396,675
New Generation Engineering Cost Amortization	$ 422,403

Recommendations of Mr. Randal Woolridge Cost of Capital Ratio

Return on Common Equity	9.25%	46.02%

Cost of Long-Term Debt	6.32%	53.55%
Cost of Preferred Stock	4.02%	0.43%

Conclusion

The impact of OIEC's adjustments on PSO's requested revenue requirement are set forth below:

Rate Increase Proposed by PSO	$ 49.5 Million
OIEC Adjustments	$101.4 Million
Rate Decrease Proposed by OIEC	$ 51.9 Million

Summary of Rate Design Testimony

Formula Based Rate Approach Overview

The Company is proposing a formula-based approach to ratemaking that would replace the traditional rate case review with annual filings of FERC Form I data that would dictate when, and to what extent, rates would need to increase from year to year in order for the utility to earn its authorized return.[2]

Mr. Solomon sets forth the Company's justification for the new proposed approach. He states that over the next several years PSO will be making unprecedented levels of investment in generation, transmission and distribution assets. He states that the Company is planning to invest $2 billion in new assets over the next five years, and that these new investments will more than double PSO's rate base. Mr. Solomon also states that the formula approach will help avoid the numerous rate cases and associated costs of these cases that would be required under the traditional approach over the next few years.

These statements, however, are merely conclusions without support. Mr. Solomon provides no examples, no analysis, no authority, nor any other form of support for his conclusion that the additional time and effort required under the traditional regulatory model during a period of unprecedented capital expansion would not be necessary or beneficial to ratepayers. In fact, the statement itself is counterintuitive from a ratepayer's perspective. During a period of unprecedented capital expansion, ratepayers would want more regulatory oversight, not less.

The additional costs to PSO, and eventually to ratepayers, to process the current cause will be about $400,000. PSO's planned increase in capital investment over the next five years is $2 billion. Even if PSO has a rate case every year during this period, the additional cost of these five cases would be $2 million. When compared to the planned $2 billion capital spending level, the additional regulatory oversight cost to PSO's ratepayers would only be .1%, one tenth of one percent. However, if these rate cases resulted in even a 5% reduction in the Company's overall spending level – in other words, if the additional regulatory scrutiny caused the spending level to be $1.9 billion rather than $2 billion – the return to ratepayers would be 50 to 1.

[2] Rates would increase whenever the Company's earned return for the previous year fell more than 50 basis points below the return authorized in this proceeding. Rates would increase by an amount sufficient to restore Company earnings to the level of its full authorized return.

Mr. Solomon claims that to include the Company's planned unprecedented $2 billion investment in rates in a timely manner would require "long, expensive, and contentious regulatory proceedings." In my experience, contentious regulatory proceedings tend to result in significant reductions in the utility's proposed recoveries. For example, in PUD 90-898, the Commission disallowed approximately $91 million, or 69%, of the Company's requested increase. Also, in PUD 03-226, the Commission disallowed approximately $9.2 million of the requested annual contract costs. Similar significant savings to ratepayers resulted from the Commission's review of ONG's Dynamic Energy contract, the review of ONG's legal expenses, and the review of several litigated rate cases. Based on these results, I believe the Commission would want to provide ample opportunity for contested hearings during a period when a utility is planning to more than double its rate base.

Mr. Moncrief states that the proposed FBR is similar to the Performance Based Rate Change Plan ("PBRC") approved in CenterPoint Energy Arkla's last rate case. In that proceeding, the Commission approved a stipulated agreement among the parties that contained a formula approach similar to the approach now recommended by PSO.

However, the CenterPoint case was different in many respects.

(1) The CenterPoint formula was the result of a stipulated agreement among the parties to that case. Here we have no such agreement. In fact, those parties representing PSO's ratepayers in this proceeding are unanimously against the FBR approach.

(2) The CenterPoint approach was a pilot program authorized for a 5-year trial period. The trial period is not over and the results of this pilot program are not yet known.

(3) The impact on Oklahoma from a change in regulatory approach for PSO is much greater than the CenterPoint change. CenterPoint's revenue requirement in that case was $110,300,960. PSO's revenues in the test year were $1,464,153,000. Based on revenues, PSO is 13½ times larger than Arkla.

(4) CenterPoint's customer base and revenues were declining. In fact, this was the stated basis for approving the new approach in the CenterPoint case. This natural, steady <u>decline</u> in revenues was something that was outside the control of CenterPoint personnel. By contrast, PSO's customer base and revenues are both increasing. Where less regulatory oversight might be justified in the case of a small utility with a naturally declining customer base, more oversight would be required for a large utility with an expanding base that has decided to spend at unprecedented levels over the next few years.

In its last general rate case, ONG requested that the Commission allow the utility to recover capital invested between rate cases through a proposed System Investment Rider ("SI Rider"). ONG's requested rider for interim capital investment recovery was rejected by the Commission.

There are various significant flaws and problems with the Company's proposed approach.

<u>Due Process</u> – I believe there could be significant due process concerns with any approach that imposes a rate increase on captive customers without providing a reasonable opportunity for the customers to review and challenge the proposed increase.

<u>Symmetry</u> – The FBR is asymmetrical in its design. When utility earnings fall below the dead-band, ratepayers absorb 100% of the costs to restore the utility's return to its authorized level. However, when earnings exceed the dead-band, only 50% of the excess is shared with ratepayers.

Aside from these two overarching areas dealing with fairness, there is a general ratemaking weakness in the formula in that it fails to provide the customary cost-control incentives provided under the traditional model.

The formula approach is susceptible to various potential manipulations:

<u>Capital Structure Manipulation</u> – The rate of return under the formula could be significantly decreased in any year by changes made to PSO's capital structure. These changes would be made at the corporate level with no input from PSO or its ratepayers. Since AEP is PSO's only shareholder, AEP could significantly increase PSO's equity levels with an equity infusion to ostensibly pay for new capital investments.

<u>Cost Level Manipulation</u> – Under the Company's proposed approach there is not adequate opportunity to review the reasonableness of the actual cost levels included in the rate of return determination. The formula simply looks at the balances contained in the FERC Form 1 filing. These balances could be easily manipulated to affect the formula results. In my testimony I include several examples.

<u>Formula Manipulation</u> – The Company could increase its earnings on a long-term basis by intentionally decreasing earnings in one year. For example, the Company could intentionally decrease its ROE in one year by increasing incentive payments, or by accelerating a plant maintenance project.

Moreover, rates calculated under the FBR would include the cost of unfinished construction projects. This would have the effect of forcing current ratepayers to pay the costs of projects not yet in service, assets not yet used and useful. This violates the long-held ratemaking principle that investors are allowed to earn a return only on that portion of their invested capital used and useful in providing utility service.

According to the Company, the FBR proposal in Oklahoma is AEP's first attempt at establishing such an approach. Further, although the Company identified several cases where commissions implemented formula based rates as part of restructuring efforts and the transition to deregulation, it appears that only Louisiana uses a formula-based approach for its regulated utilities to any noticeable degree.

Mr. Solomon provides three reasons for including CWIP costs in rates during the construction period. First, he indicates that by including CWIP in rates PSO will be better able to "maintain a reasonable level of earnings and attract the capital it needs on more reasonable terms." He also states that including CWIP in rates as the investment is made provides a lower total cost to ratepayers. Finally, he indicates that this approach will provide a more gradual and reasonable increase for customers.

However, confidential Exhibit MG-2 attached to my testimony compares the Company's own load growth projections with the revenue increase shown for the Red Rock plant. This comparison shows that the revenue increase from the Red Rock project is virtually eliminated with the Company's own anticipated load growth.

Moreover, PSO's claim that ratepayers will save money by paying for the plant under construction is simply wrong. In any financial analysis where the value of future payments is assessed, the time value of money must be considered. This fundamental principle of financial analysis is completely absent from the Company's calculations. When the cumulative value of the money saved by ratepayers during the construction period is taken into consideration, the more economic choice for ratepayers is the choice that excludes CWIP from rates until the project is complete. In my testimony, I compare the total cash outlays for ratepayers over an assumed 50-year life for the coal plant under two scenarios: one with CWIP included in rates during the construction period, and the other with CWIP not included. This comparison shows that the savings ratepayers retain during the construction period by not paying CWIP are never overcome by the lower annual payments made over the life of the project.

A final problem with PSO's FBR approach is that the rate structure established in this case will not be altered during the tenure of the FBR. This poses significant problems for those classes, such as the industrial class, that are paying rates substantially higher than cost of service based rates. Unless the subsidies embedded in the industrial rates are eliminated in this proceeding, there will be no opportunity in the future under the Company's proposed annual filings to eliminate these subsidies.

Class Cost Of Service Allocations

Utility rate design consists of two broad phases: cost allocation and rate design. In the cost allocation phase, the cost of service study assigns to each customer class its proportional share of the total costs incurred to provide service. When costs are correctly allocated to the individual classes, rates can be developed to recover the actual cost of providing service to each class. Cost-based rates are fair and more efficient. They are efficient in that they ultimately tend to reduce the overall cost to the electric provider. Rates that are not cost-based tend to promote inefficiencies.

The function of a price signal is to establish the level of production at which supply and demand will match. In competitive energy markets, there is a continual dialogue between energy producers and consumers, where energy producers send cost production signals to consumers, and consumers in turn signal back to producers the prices at which they are willing or able to purchase energy.

Like most energy commodities, energy usage is somewhat elastic. As prices increase, consumers typically seek options to reduce usage or demand. Demand on PSO's system has grown to the point that PSO is proposing to add both new peaking and base load capacity. This current growth in demand, however, may tend to be overstated for the subsidized classes and understated for classes currently providing the subsidy. These distortions occur because subsidized customers are less likely to aggressively control their power costs through the use of more efficient equipment or by adding insulation to their houses for example.

PSO also should increase the use of DSM programs to reduce peak demand and encourage conservation. However, the most effective demand side tool available to any utility is pricing.

PSO's revised ECCOS study appropriately assigns costs to the various customer classes. However, as discussed in more detail below, although PSO's cost allocation methodology is accurate, its proposed rate design fails to implement cost-based rates. Current rates of return collected from the various classes range from 14% from Industrials to 4% from Residentials.

Analysis of PSO's errata class cost of service which shows that even if rates were increased by the full $49.5 million proposed by PSO in this application, SL1 rates should be reduced by $1,175,466, SL2 rates should be reduced by $4,623,061 and SL3 rates should be reduced by $1,662,348 to reflect the true cost of service to these classes. These reductions are required to bring the rates of these customers to actual cost according to PSO's own study. Please note that these reductions to the industrial customers are needed even if PSO's requested increase were approved.

Rate Design And Allocation Of Rate Decrease

For the same Industrial and Residential classes, PSO is proposing return rates of 15% and 7% respectively. The Company's proposed rate design ignores basic cost causation principles and fails to send accurate price signals important to demand side management goals.

I recommend that the rate reduction ultimately ordered by the Commission be allocated to the customer classes in a manner that brings the classes significantly closer to equal rates of return. This recommendation would correct the rate structure such that it more closely recovers from each customer class the actual cost of providing service to that class.

If the overall rate reduction ordered by the Commission is within the range of that recommended by Staff or the Attorney General, I recommend allocating the reduction proportionately to bring the customer classes to within 95% and 105% of an equal rate of return. This would mean the residential class and the lighting class would need to be increased to improve their rate of return to 95% of an equal rate of return. It would also mean that the other classes with greater than average rates of return would still be decreased. Any decrease to the classes with a greater than the average rate of return would be limited by reducing the class to only 105% of an equal rate of return. This is the method that was supported by PSO in determining allocation of rate increases or reductions in several cases in the past.

Interruptible Service Options

I recommend approval of the Interruptible Service Pilot Rider ("ISPR"). I also support the implementation of the Emergency Curtailable Service Rider ("ECS") and PSO's proposed Emergency Price Curtailable Pilot Service Rider ("EPCS"). These interruptible service options could provide cost savings to PSO customers and should be implemented.

I further recommend that the interruptible tariff proposed by Mr. Sarafolean for Gerdau Ameristeel, if designed and implemented in such a way as to be beneficial to all ratepayers, should be adopted by this Commission on a trial basis to determine its over-all potential as a demand-side management tool. The Commission's renewed focus on demand-side management ("DSM") programs is manifested in the Commission's recent DSM technical conferences. These efforts by the Commission are important to the resource planning of Oklahoma's investor-owned electric utilities, especially during this period when both PSO and OG&E allege the need to expand rate base investment to unprecedented levels.

Summary of Rebuttal Testimony

Rebuttal to Mathai's new NGTR and PBRC

In its Application, PSO proposed a formula-based rate ("FBR") approach that would replace the traditional rate case review with annual filings of FERC Form I data. These filings would dictate when, and to what extent, rates would need to increase from year to year in order for the utility to earn its authorized return.

The OIEC strongly opposes a formula-based approach to ratemaking. In direct testimony, I showed how a streamlined approach to setting rates is ill-advised especially during a period of significant capital expansion where more, not less, regulatory oversight is needed. I also showed how including CWIP in rates before projects are completed actually results in substantially higher costs to ratepayers. And, I pointed out how the formula approach cannot be justified with rate-shock concerns, when additional revenues from load growth will offset much of the projected cost increases.[3]

In his direct testimony, Staff witness Mathai proposes an alternative approach to PSO's FBR he calls the New Generation and Transmission Expenditure Recovery rider ("NGTR"). This rider would allow the utility to recover a *return on* and a *return of* investment in new plant during the construction period through the amortization of a regulatory asset account with a pending true-up in some future regulatory proceeding. Even the utilities do not go this far. Neither PSO in this application nor OG&E in its base load case have gone so far as to request premature *recovery of* construction costs. This is tantamount to depreciating an asset before it is even built. So it is surprising to me that Staff would make such a recommendation.

A partial list of why Mathai's NGTR recommendation is inappropriate is provided below.

(1) Violates depreciation rules. Depreciation rules require that the cost of an asset be amortized over the useful life of the asset. The useful life of an asset begins when the asset is placed in service. Here, the amortization would begin before the asset is placed in service.

(2) Violates cost/causation principles. A fundamental ratemaking principle followed in virtually every jurisdiction is that costs should be recovered from those who cause the costs to be incurred. When new generation plants are built in anticipation of future load growth, the cost of these plants should be borne by those future ratepayers that create the need to build the plants. Here, Mathai recommends charging current ratepayers to whom the assets are not yet available.

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[3] If rate-shock were truly a concern, the Commission would want to examine the Company's current resource plan and the resource plans over the past several years to determine how the Company got to a point where enough additional capital expenditures were needed over a short enough time frame to result in rate shock.

(3) Violates the matching principle. The *matching principle* requires that costs be matched with the benefits they provide. In this case, the "cost" would be the recovery of the plant through depreciation expense, and the "benefit" would be the electricity produced from the plant. Here, ratepayers would be forced to begin paying the "cost" of the plant before the plant is producing any "benefits" to the ratepayers.

(4) Violates the rule against intergenerational inequity. Sound ratemaking policy requires that each generation of ratepayers pay its own way. Here, current ratepayers would be required to subsidize a future generation of ratepayers.

(5) Violates the Used and Useful Doctrine. This long-held ratemaking rule requires that ratepayers pay for only those assets that are *used and useful* for the provision of utility service. The origins of this fundamental doctrine are grounded in the constitutional *prudent investment* rule. This rule is applicable in every jurisdiction, including Oklahoma. Here, Staff's recommended rider runs afoul of the *used and useful* standard because it requires ratepayers to pay for assets not yet used and useful for the provision of service.

Further, Mathai's proposed NGTR rider is not consistent with the position he took in ONG's last rate case. In PUD 04-610, ONG requested a new System Investment Rider to recover anticipated future capital expenditures without a rate case, much like Mathai's current NGTR rider. In the ONG case, Staff opposed the proposed rider. Mathai's opposition to the rider was based upon sound ratemaking principles and good public policy arguments. He correctly pointed out that the proposed rider was a form of objectionable piecemeal ratemaking and that it would help the utility reduce risk and avoid regulatory oversight.

A basic ratemaking principle followed in substantially every jurisdiction is that utility rates are set to recover the cost levels that exist at a given point in time, a test year. Regulators use a test year to provide a "snap-shot" of the utility's investment level, operating revenue and expense, depreciation and taxes. As time passes after the test period, these revenue and cost levels change. Investment levels may increase with the addition of new plant, but these increases are generally offset with decreases in investment levels through depreciation recoveries or with increases in revenues from new load. If, after rates are set, the utility earns more than its authorized return because revenues increase and/or cost levels decline, the utility is allowed to keep the difference. If the utility earns less than its authorized return because revenue decline and/or cost levels increase, the utility suffers the loss. This is the ratemaking paradigm utilized in virtually every jurisdiction.

An important part of this paradigm is the risk element, the risk the utility assumes is that it will not earn more, and perhaps will earn less, than its authorized return. It is this element of risk embedded in the paradigm that allows the utility's return on equity to be set at levels above that of risk-free capital. If, during the period new rates are in effect, a utility wants to earn its authorized return, or more than its authorized return, it will have to operate its business in an efficient manner. If a commission were to approve the recovery of one of these "at risk" costs through a rider mechanism, it would need to also make a downward adjustment to the utility's return on equity to reflect the reduced amount of risk now assumed by the utility.

There are other reasons that riders are objectionable. When a particular type of expenditure is provided recovery treatment through a rider mechanism it tends to remove the utility's incentives to efficiently manage and control this cost. Riders also tend to bias managements' decisions toward costs that are tracked. Thus, the rider mechanism is poor public policy because it can actually create artificial disincentives for managements' cost-control and decision-making functions.

Mathai's proposed rider isolates one type of cost PSO anticipates will increase after new rates are in effect and allows PSO to recover these costs through a pass-through to ratepayers. In Oklahoma, the legislative intent with respect to post-test-year changes is set forth in Title 17 §284, where the Commission, in its review of a utility's application to change rates, is directed to give effect to all known and measurable changes that occur within six months of test year end. This provision provides a reasonable cut-off for post-test-year considerations.

Mr. Mathai proposes the NGTR rider based on the faulty premise that the rider will benefit ratepayers by (1) reducing the overall rate increase associated with PSO's capital expansion plans and by (2) decreasing the impact of rate shock. Both of these perceived benefits are illusory.

PSO and Mr. Mathai both claim that by paying early, ratepayers pay less. This simply is not the case. The calculations of PSO and Mathai both ignore the time value of money – the fact that a dollar received today is much more valuable than a dollar received one year from now. The isolated fact that annual rates would be marginally lower the first year a plant is operational if the return component during the construction period is recovered through a rider rather than accrued and added to the overall plant balance is only part of the total picture. The complete picture takes into account the total value of all payments made during the useful life of the plant and the construction period as well. And the value of these payments will depend in large part on when the payments are made, since payments made early are more costly than payments delayed.

At Exhibit MG-1, I compare the traditional ratemaking model with the new proposed rider approach. Under the traditional model, CWIP is accrued and added to the overall plant balance during the construction period. Payments begin when the plant is completed and placed in service. Under the rider approach, the return component is collected each year, so that at the end of the construction period the plant balance includes only the cost of the plant with no additional amounts for accrued return. This analysis shows that the cost to ratepayers is higher when ratepayers begin paying for an asset before it is placed in service. This analysis also shows that the premise upon which Staff's proposed rider is based – that providing a current return on new generation and transmission expenditures saves customers money in the end – is a **false premise**. Without this premise, there is no justification for the NGTR rider. Because this analysis shows a negative financial impact to ratepayers from premature recoveries of invested capital, I recommend the Commission not approve Staff's recommended NGTR rider.

Further, in my direct testimony, I showed how the total revenue increase associated with PSO's Red Rock (coal base load) project is virtually eliminated with PSO's anticipated load growth. In other words, the increase in the revenue requirement associated with the Red Rock project will be absorbed by new load on PSO's system rather than by existing customers. Thus, PSO's and Mathai's rate shock threats are not a legitimate excuse for implementing premature plant recoveries.

As part of its two-part alternative ratemaking approach, Staff recommended implementing what Mr. Mathai calls the *Performance Based Rate Change* plan ("PBRC") along with his NGTR rider. The PBRC is a 15-part filing that would dictate when, and to what extent, rates would need to increase from year to year in order for the utility to earn its authorized return.

There are several aspects of Mr. Mathai's PBRC plan that make the plan unworkable:

(1) Mr. Mathai wants *contentious issues* resolved before the plan is implemented so that these issues would not need to be addressed in the streamlined annual proceedings. The problem with this approach is that this Commission cannot limit the authority of future commissioners by deciding now how certain issues will be treated in the future, except through a rulemaking.

(2) Under Mathai's proposed PBRC, rate design would remain the same year after year. This part of Mathai's PBRC is completely unacceptable to commercial and industrial customers. Under this approach, the substantial subsidies embedded in current rates would remain intact throughout the years covered by the PBRC. The gradualism approach now being utilized to reduce these subsidies would be put on hold as long as the PBRC was in effect.

(3) I believe there could be significant *due process* concerns with any approach that imposes a rate increase on captive customers without providing a reasonable opportunity for the customers to review and challenge the proposed increase. The scrutiny provided through the existing traditional regulatory process provides important protections for ratepayers that should be carefully preserved by this Commission.

(4) Staff provides <u>no</u> showing of need for a streamlined ratemaking process, especially during a period when significant new levels of capital expenditure are expected to be added to the Company's rate base. During a period of significant expansion, the Commission should provide a heightened level of regulatory scrutiny, not a new streamlined approach that provides less opportunity for ratepayer intervention and general regulatory oversight.

(5) The current situation with PSO is a sharp contrast to the situation that existed with CenterPoint where Staff's alternative PBRC plan was approved through an agreement of the parties on a 5-year trial basis. In that case, CenterPoint's customer base and revenues were declining. In fact, this was the stated basis for approving the new approach in the Commission's order. By contrast, PSO's customer base and revenues are both increasing.

Moreover, formula-based ratemaking is far more susceptible to potential manipulation than the traditional approach. I discussed various examples in my rate design testimony. Because of the numerous significant weaknesses in both the PBRC and the NGTR rider, and because the interim recovery of investment can be decided in an application after a used and useful determination has been made for PSO's new investment, I recommend the Commission <u>not approve</u> either the PBRC or the NGTR rider.

<u>Rebuttal to Staff's Incentive Pay Adjustment</u>

Staff reduced PSO's incentive compensation by 50% to reflect an equal sharing of these expenses between shareholders and ratepayers, on a belief that PSO's incentive compensation plans produce comparable benefits to both groups. Staff's treatment is similar to the approach used by commissions throughout the western states, and closely follows the approach taken in California, where compensation costs are shared 50/50 between the utility and its customers. A recent survey conducted by our firm of the commissions of western states shows that most states disallow all or part of finance-based incentive payments and nearly all states exclude executive plan costs. This survey also shows that most states include only that portion of incentive compensation expense that can be shown to relate directly to ratepayer benefits. Although Staff's approach to the incentive compensation issues is, in general, an acceptable approach, the amount of Staff's proposed adjustment is too low. Staff's adjustment addresses only the PSO incentives, and overlooks the AEP incentive costs allocated to PSO. For consistency, the AEP incentive costs should be treated in the same manner as the PSO incentives. That is, Staff should also adjust the AEP costs by 50%.

Scott Norwood

My name is Scott Norwood. I am an electrical engineer with over 26 years of electric utility industry experience in the areas of energy regulation, planning and procurement. I am here today testifying on behalf of the Oklahoma Industrial Energy Consumers. My testimony addresses 4 issues underlying PSO's base rate increase request in this proceeding.

First, my testimony addresses the unreasonableness of PSO's request to recover $63.8 million for test year non-fuel production O&M costs. This request is more than $18 million per year (40%) higher than the average level of production O&M expenditures incurred by the Company over the five calendar years prior to the test year. My investigation demonstrates that a significant factor contributing to the abnormally high level of test year production O&M expenses was extraordinary level of outages at PSO's generating facilities during this period. For the test year, the number of days of forced outages at PSO's plants was 57% higher than the average over the previous 3 years, while the days of planned outages was 124% higher than normal. This higher level of plant outages contribute to higher contract labor and materials costs in the test year O&M. PSO made no adjustments to reflect this abnormal level of costs.

Staff witness Thenmadathil and AG witness Soltani also are proposing adjustments to the abnormal level of PSO's production O&M expenses; however, their adjustments do not fully account for the extraordinary expenses during the test year and therefore do not produce a reasonably normalized level of production O&M expenses for setting PSO's base rates.

I recommend an adjustment of $15.0 million to PSO's test year production O&M expenses, based on actual expenditures by the Company over the previous 5 years, with adjustments for inflation. My recommendation would allow PSO to recover $48.7 million per year in its base rates for production O&M. This amount is 12.8% higher than the average expense incurred by PSO during the four calendar years immediately preceding the test year.

The second issue addressed by my testimony is PSO's request to recover in base rates approximately $4.4 million of charges from its affiliate AEPSC related to the administration of energy trading activities on behalf of PSO during the test year. During May of 2006 AEP modified the AEP System Integration Agreement in a manner that will effectively allocate most of the benefits of AEP energy trading away from PSO and to its affiliates in the AEP East Zone. In fact, in the first 10 months since this change was implemented, AEP West's share of energy trading margins under the SIA was negative $13.6 million. In light of this change and serious questions which exist regarding the future benefits, if any, to Oklahoma consumers of AEP's energy trading activities, I am recommending that the $4.4 million of trading administration costs be removed from PSO's base rates and recovered through the calculation of margins that are credited to the fuel clause. My recommendation provides a more accurate calculation of the net profits of energy trading since it includes the administrative costs incurred by AEP to make such trades. Under my proposal, in the event PSO's share of future AEP trading margins exceed the level of trading administration costs, which PSO suggests in its rebuttal will be the case, the Company would continue to fully recover these costs. In the alternative, if trading benefits to Oklahoma decrease in the future due to AEP's modification of the SIA, the net losses arising from these trading activities will not be automatically passed on to PSO's customers as would occur under the Company's proposal to embed such costs in its base rates.

The third issue addressed by my testimony is PSO's request to recover $2.2 million in costs it incurred in the development of self-build bids provided in response to the Company's baseload request for proposals, which it proposes to amortize over a 5-year period. I recommend that the Commission disallow PSO's request to recover these bid preparation costs since nearly 60% of the requested costs were incurred outside of the test year period, because the Company previously had indicated that it would seek to recover only costs associated with successful bids and because a majority of the costs involved IGCC and CFB baseload bids which were clearly not cost effective alternatives.

Fourth, my testimony addresses PSO's request to recover $3.5 million in base rates for short-term capacity purchases from Tenaska and Merrill Lynch that will expire at the end of 2007 and be replaced by capacity supplied from the Company's new combustion turbine peaking units. To ensure that there is no double recovery of capacity costs, I recommend that the capacity costs for these two short-term contracts be removed from PSO's rates and recovered through a purchased capacity rider. I further recommend that the capacity costs of these contracts be allocated on a demand basis consistent with the manner they would otherwise be treated if recovered through base rates.

Finally, my testimony addresses PSO's proposed adjustments to its base rate fuel charges. In its original rate application, PSO requested that it be allowed to increase its base rate fuel charge by more than 40% from the existing rate of $0.034 per kWh to $0.0477 per kWh. After investigating this proposal, I found it to be unreasonable and unsupported and therefore recommended that OIEC's existing base rate fuel charge be maintained. In its March 8th errata filing, PSO proposed to eliminate its base rate fuel charge and to instead recover all fuel costs through its Fuel Cost Adjustment ("FA") Rider. As of the date I filed this summary, OIEC has not completed its review of PSO's amended fuel cost recovery proposal. Until OIEC has completed its analysis of PSO's amended fuel cost recovery proposal, I recommend that the Company be required to maintain its current base rate fuel charge of $0.034 per kWh.

Dr. J. Randall Woolridge

My name is J. Randall Woolridge. I am a professor of finance and a consultant and have testified on the cost of capital in public utility rate cases for twenty-five years. In addition to my public utility work, I have consulted with major corporations, investment banks, and government agencies in twenty-five countries around the world. I am here today on behalf of the Oklahoma Industrial Energy Consumers. My testimony addresses the appropriate cost of capital for PSO. In developing my recommendation, I have reviewed the testimony and recommendations of PSO witnesses Dr. Donald A. Murry, Ms. Susan D. Abbott, and Ms. Julie M. Cannell as well as the testimonies of Staff witness Mr. Fairo A. Mitchell and the Attorney General's witness Mr. Daniel J. Lawton.

Dr. Murry is the primary cost of capital witness for PSO. To arrive at an equity cost rate for the Company, Dr. Murry and I have both applied the Discounted Cash Flow Model ("DCF") and the Capital Asset Pricing Model ("CAPM") to the same group of six publicly-held electric utility companies as well as PSO's parent company, American Electric Power ("AEP"). I have adopted the Company's proposed capital structure and senior capital cost rates. This is quite fair to the Company since I have elected to not include short-term debt in the capital structure in the ratemaking capitalization despite the fact that PSO has consistently used short-term debt as a source of capital. Consequently, the major area of contention in this case is the proposed equity cost rate for PSO. Dr. Murry's equity cost rate estimate is 11.75%, while my analysis indicates an equity cost rate of 9.25% is appropriate for the Company. Using these inputs, I am recommending an overall fair rate of return of 7.66% for PSO.

In terms of the DCF approach, the two major areas of disagreement between Dr. Murry and myself are (1) the relevance of DCF equity cost rate results and (2) the estimation of the expected growth rate. With respect to (1), Dr Murry argues that the DCF model produces unreliable results in estimating an equity cost rate for a public utility. As a result, he ignores the vast majority of his own DCF results for the proxy group and AEP in estimating a DCF equity cost rate range of 10.59% to 11.16% for PSO. With respect to (2), Dr. Murry has relied exclusively on the forecasted EPS growth rates of Wall Street analysts and *Value Line* in estimating a DCF equity cost rate. I have used both historic and projected growth rate measures, and have evaluated growth in dividends, book value, and earnings per share. One important factor that I consider and highlight is the upwardly-biased expected earnings growth rates of Wall Street analysts and *Value Line*.

The CAPM approach requires an estimate of the risk-free interest rate, beta, and the equity risk premium. Whereas there is general agreement on the beta and risk-free interest rate, we have significantly different views on the alternative approaches to measuring the equity risk premium as well as the magnitude of equity risk premium. We also disagree on the need for a size premium adjustment to the CAPM. As I highlight in my testimony, there are three procedures for estimating an equity risk premium – historic returns, surveys, and expected return models. Dr. Murry relies solely on historic measures of the equity risk premium and has used equity risk premiums of 7.10% and 8.65% in his two versions of the CAPM. I provide evidence that risk premiums based on historic returns series are upwardly biased measures of expected risk premiums. I use an equity risk premium of 4.17% which (1) uses all three approaches to estimating an equity premium and (2) employs the results of many studies of the equity risk premium. As I note, my equity risk premium is consistent with the equity risk premiums (1) discovered in recent academic studies by leading finance scholars, (2) employed by leading investment banks and management consulting firms, and (3) that result from surveys of financial forecasters and corporate CFOs. Dr. Murry justifies his size premium using historical returns. As discussed in my testimony, there are a number of errors in using historical market returns to compute risk premiums. In addition, I argue that any equity cost rate adjustment based on the relative size of a public utility is inappropriate. One study noted in my testimony tested for a size premium in utilities and concluded that, unlike industrial stocks, utility stocks do not exhibit a significant size premium. The primary reason that a size premium is not required for utilities is that utilities are regulated closely by state and federal agencies and commissions and hence their financial performance is monitored on an on-going basis by agencies of both the state and federal governments.

Dr. Murry's testimony is supported by the Company-sponsored testimonies of Ms. Julie M. Cannell and Ms. Susan D. Abbott. Ms. Cannell's testimony claims to review the authorized return from the perspective of investors and Ms. Abbott's testimony purports to review the regulatory treatment of the Company's construction program from the view point of the rating agency and fixed income investor. Ms. Cannell's testimony is very general in nature and is not supported by any empirical studies, which support Dr. Murry's ROE recommendation. Ms. Abbott's concludes that the Company' requested rate increase and formula rates are necessary to support the Company's bond ratings. However, her testimony does not support this conclusion. Her study of comparative bond rating metrics is flawed. She makes no comparisons of PSO's construction program to those of other electric utilities, and she makes no mention of other elements of regulatory ratemaking in Oklahoma. Furthermore, her conclusions are not consistent with the recent reports on PSO of the major bond rating agencies. One of these reports indicates that PSO has "one of the stronger credit profiles among the AEP subsidiaries."

Staff witness Mr. Fairo A. Mitchell and Attorney General witness Mr. Daniel J. Lawton both provide equity cost rate estimates for PSO which are excessive but not as extreme as Dr. Murry's. There are several problems in the DCF analyses of the two witnesses. First, both of the Company witnesses rely exclusively on the forecasted earning per share ("EPS") of Wall Street analysts and/or the *Value Line Investment Survey* in determining a growth rate measure for their DCF models. I have provided evidence in my testimony that there is a positive bias to the EPS growth rate projections of both Wall Street analysts and *Value Line* for not only companies in general, but also for electric utilities. Second, both of the witnesses have relied solely on EPS growth, and have ignored growth in dividends and book value per share. According to the DCF model, EPS, DPS, and BVPS should all grow at the same rate. Furthermore, the cash flows in the DCF model are dividends and not earnings. Any growth rate indictor other than projected EPS growth has been ignored by the two witnesses.

There are also some specific errors in the DCF analyses of the two witnesses. Mr. Mitchell results are inflated since he has misrepresented his results by not accounting for some obvious growth rate outliers for companies in his group. In addition, in his two-stage DCF analysis, Mr. Lawton uses the average of the high-end projected EPS growth rates of Wall Street analysts as compiled by Zacks and First Call for the comparable companies. Thus, he has ignored or is not aware of the research on the well-known upward bias in analysts' EPS growth rate forecasts, and has exaggerated this bias by using the high-end of the estimates for the second-stage growth rate for all of his comparable companies.

Mr. Mitchell also uses the CAPM approach. The primary error in this analysis is the risk premium, which is measured as the difference between arithmetic historical mean stock returns and bond returns as compiled by Ibbotson Associates. As discussed in my testimony, using the historic relationship between stock and bond returns to measure an ex ante equity risk premium is subject to a myriad of empirical errors and overstates the equity risk premium. Mr. Mitchell and Mr. Lawton also employ Comparable Earnings and Risk Premium approaches which use projected returns on common equity ("ROEs") for electric utility companies as the measure of return. The primary issue in both approaches is that neither Mr. Mitchell nor Mr. Lawton has evaluated the market-to-book ratios for these companies. Therefore, they cannot indicate whether the past and projected returns on common equity are above or below investors' requirements. These returns on common equity are excessive if the market-to-book ratios for these companies are above 1.0.

In summary, my recommended equity cost rate of 9.25% for PSO is consistent with the current economic environment. Long-term capital costs are at historical low levels. The yields on long-term Treasury bonds have been in the 4-5 percent range for several years. Prior to this cyclical decline in rates, these yields had not been this low over an extended period of time since the 1960s. Long-term capital costs are also low due to the decline in the equity risk premium and the *Jobs and Growth Tax Relief Reconciliation Act of 2003,* which reduced the tax rates on dividend income and capital gains.

Furthermore, my recommendation presumes that the Oklahoma Corporation Commission ("OCC") does not adopt PSO's Formula Based Rate ("FBR") tariff plan. Despite the fact that Dr. Murry acknowledges that the FBR tariff would decrease the volatility of the Company's common equity earnings, he does not believe that the FBR affects the Company's degree of riskiness and therefore it's required rate of return on common equity.

QOSC

Joe Robson

The testimony presented in this cause by Joe Robson, Chairman, Quality of Service Coalition addresses of vital concern to our members. Quality of Service Coalition is an unincorporated association of individuals, businesses, trade associations, and communities primarily located in Eastern Oklahoma. All members are customers of Public Service Company of Oklahoma.

The testimony addresses the concerns of the Coalition and its members related to operations and performance. Our members want reliable, safe and affordable electric service. We review and comment on PSO's testimony related to performance and recommend the Commission consider requiring utilize additional reporting requirements to monitor performance and hopefully give additional information that can help reduce outages.

Our basic concerns in PSO's rate case, PUD 200300076, are still valid concerns of our members. Responding to requests for service from builders is a continuing concern. Street lights that are the responsibility of PSO to maintain but are not working properly are a continuing concern. We would support more aggressive demand side management programs for PSO customers to reduce demand for energy during peak periods and thus reduce or delay the need for additional generation but also provide customers information, programs and energy management processes that will also reduce the amount of energy they consume and by doing so provide lower bills each month.

Finally, our members are concerned about the way rates are designed and the disparity that currently exists between various customer classes. We would support any effort to redesign rates that would provide an equalization, which probably will take some time, of rates among various customer classes.

PSO is a business that has costs and expenses that it incurs to provide service to customers. Those costs should be reviewed in this case and a reasonable revenue requirement fixed to allow the company to provide reliable, safe and affordable electricity to PSO's customers.

GERDAU

Michael Sarafolean

<u>Responsive Testimony</u>

The Responsive Testimony presented in this cause by Michael Sarafolean, Energy Manager for Gerdau Ameristeel Corporation ("Gerdau Ameristeel"), provides a brief overview of Gerdau Ameristeel' operations in Oklahoma and addresses two demand response-related issues. Gerdau Ameristeel recently purchased and now operates a steel manufacturing facility in Sand Springs, Oklahoma, which is located in the service territory of Public Service Company of Oklahoma ("PSO").

Mr. Sarafolean makes two recommendations. First, the Commission should direct PSO to make available to appropriately qualified customers an interruptible service rider that allows the customer to interrupt voluntarily during hours when Energy Imbalance Service ("EIS") Market locational imbalance prices ("LIPs") for the area in which they are located exceed a mutually agreed price, and be paid a portion of that LIP for the hours of interruption. Second, the Commission should direct PSO to make available to appropriately qualified customers an interruptible service rider that provides compensation to customers that make their loads available for short-notice, short-duration interruptions that PSO could use to satisfy Contingency Reserve requirements in the Southwest Power Pool ("SPP"). Mr. Sarafolean provides background information, recommends implementation details, and explains the potential benefits of these additional offerings.

Apart from tangible financial benefits, these procedures will add value to PSO's system in terms of efficiency, and will promote certain Commission goals. A reduction of Gerdau

Ameristeel's demand will place no burden on PSO and will require PSO to take only minimal physical or administrative steps to accommodate the change. PSO will realize the inherent benefit of an automatic increase in output for the period required to either compensate for insufficient output or to provide additional energy to the SPP system. Additionally, Gerdau Ameristeel's participation in such a process is, by nature, a demand-side response. Rather than requiring or promoting the purchase of additional energy by PSO, these procedures will optimize usage of "capacity" - in this case, demand response capacity - already located within PSO's system. Recognizing the definite value to itself, PSO, and the SPP system, Gerdau Ameristeel views both of these procedures as realistic business opportunities with identifiable benefits for PSO, Gerdau Ameristeel, and other PSO ratepayers.

Rebuttal Testimony

Mr. Sarafolean testifies that PSO's use of FBR is not justified and that the use of FBR would be adverse to PSO customers. Based on his experience, Mr. Sarafolean testifies that an FBR may adversely affect Gerdau Ameristeel and other industrial ratepayers. Accordingly, Mr. Sarafolean agrees with OIEC witness Garrett that the Commission should reject this aspect of PSO's rate case.

Mr. Sarafolean is concerned that the FBR does not provide sufficient protections for ratepayers through appropriate means for challenging rate increases that will automatically occur through the proposed FBR. Because of this lack of ratepayer review and oversight, Mr. Sarafolean believes that this approach will present opportunities for the Company to assess improper charges on customers, without also providing the necessary incentives for the Company to efficiently manage its resources.

Mr. Sarafolean recommends that the Commission reject the FBR and require PSO to implement a rate design that provides ratepayer protection through formal opportunities to participate in regular rate proceedings.

WAL-MART

James T. Selecky

Mr. Selecky filed testimony on behalf of Wal-Mart Stores that addressed the following issues:

1. Book depreciation rates.
2. Excluding construction work in progress from rate base.
3. Cost of service and allocation of any revenue responsibility changes.
4. Opposition to PSO's proposed Formula Based Rate rider.
5. Response to the Staffs proposed cost of service/allocation method.

Depreciation

Mr. Selecky testified that PSO's proposed book depreciation expense is excessive because the proposed depreciation rates understate the life span of the coal-fired units and overstate net salvage component of the depreciation rates.

PSO is proposing a life span for its coal-fired units of 42 years. PSO's proposed life for its coal-fired rates results in accelerated recovery of its investment and violates cost causation principles. Industry data clearly indicates that a life span of 60 years is appropriate and is utilized by other utilities to depreciate their coal-fired units. The Commission should develop PSO's proposed depreciation rates utilizing a life span of 60 years for the coal-fired units.

PSO has also overstated the net salvage associated with the steam production plants. PSO's proposed net salvage value for its steam production plants does not properly reflect the value that these sites will have as future generating sites. The access that these sites have to the transmission system, roads, railroads and water make the existing generating sites valuable for future generating plants. Current ratepayers should benefit from the value that these sites will provide for the next generation of ratepayers. Therefore, Mr. Selecky recommends that the Commission reduce the consideration given to the terminal net salvage component of the steam production depreciation rates.

Mr. Selecky's proposed changes to PSO's steam production depreciation parameters reduce PSO's proposed steam production depreciation expense by $9.678 million.

PSO's transmission, distribution and general ("TD&G") plant net salvage components of its proposed depreciation rates reflect estimates of future inflation, which unnecessarily raise rates for today's ratepayers and can produce intergenerational inequities. PSO's proposed transmission, distribution and general depreciation rates include an estimate of future inflation based on historic inflation rates. The use of a historic inflation rate to develop the net salvage component from the depreciation rates results in excessive depreciation rates and expense.

PSO's TD&G depreciation rates contain an annual net salvage expense component of $24.1 million. However, PSO's actual TD&G net salvage expense over the last five years has been $5.2 million annually and over the last 10 years, the average annual net salvage expense has been $6.0 million. If the Commission determines that it wants to continue to reflect future inflation in the net salvage component of the depreciation rates, it should rely on forecasts of future inflation as opposed to historic levels of inflation. Over the last 49 years, which is the average life of PSO's TD&G assets, the annual rate of inflation as measured by the CPI has been approximately 4.1%. Over this same period, the Gross National Product Price Deflator has been 3.6% per year. The Annual Energy Outlook of 2007 published by the US Department of Energy indicates that the Consumer Price Index ("CPI") for the next 25 years will be approximately 1.8% per year. In addition, the Survey of Professional Forecasters projects that the annual CPI is expected to be 2.35% from 2007 through 2016.

Mr. Selecky recommends that the Commission replace the historic levels of inflation that are built into the TD&G rates with forecasted inflation rates. As a result, Mr. Selecky is recommending that the net salvage ratios that PSO used to develop its depreciation rates be reduced by 50%. The 50% is developed by looking at the difference over the 49-year period utilizing a 2.3% annual escalation rate as opposed to a 3.8% escalation rate. This reduction in cost escalation reduces the net salvage percentages by 50%. The reduction in the inflation rate reduces PSO's proposed TD&G depreciation rates by $12.048 million for a total recommended reduction in depreciation rates of $21.726 million.

Construction Work in Progress

The Commission should not include any construction work in progress ("CWIP") in rate base. PSO's proposed CWIP is not used and useful in providing service to today's ratepayers. Including CWIP puts a burden on current ratepayers while not providing them with any benefits. The only time CWIP should be included in rate base is if the utility indicates that it needs CWIP in rate base for financial integrity reasons. Mr. Selecky testifies that PSO has not made such a claim in this case.

Finally, excluding CWIP from rate base is consistent with the Commission's recent ruling in the Oklahoma Gas & Electric Company case in Cause No. PUD 200500151. In that proceeding, the Commission accepted the Staff's recommendation to remove all projects that were not completed and included in plant in service for the known and measurable period.

Cost of Service and Rate Design

Cost of service is a basic and fundamental ingredient in the ratemaking process. A cost of service study should reflect cost causation. The results of a properly performed cost of service study should be utilized to allocate any rate changes. It is important to utilize the results of a properly conducted cost of service study to assign revenue responsibility and design rates. As indicated in Mr. Selecky's direct testimony, all rates should be moved to cost of service.

Although Ms. Selecky has not performed a specific analysis of the various allocation factors utilized by PSO, Mr. Selecky supports the classification and the allocation methods employed by PSO with one exception. Mr. Selecky supports an allocation of fixed production and transmission cost using average and excess method.

However, Mr. Selecky recommends that the Commission instruct PSO to perform a cost of service study allocating certain distribution costs on both a customer and demand component. PSO has allocated distribution line costs using a demand allocator. Distribution line costs should be allocated using both a customer and demand allocators. Mr. Selecky suggests that this revision be made to the cost of service study in this case, or alternatively that PSO be directed to reflect the customer-related portion of distribution plant in its cost of service filed in its next general rate case.

Mr. Selecky also supports utilizing the results of the PSO cost of service study to allocate any rate change in this proceeding. Mr. Selecky recommends that if the Commission determines that the total increase is less than PSO's requested amount, any reduction from the requested amount should be allocated to those rate classes whose rates are above cost of service or who have a rate of return in excess of the overall rate of return.

Mr. Selecky opposes PSO's proposed Formula Based Rate. The Formula Based Rate should be rejected because it does not provide sufficient ratepayer protection or appropriate incentives for efficient utility investment or operations. However, if the Commission decides to accept a formula based rate proposal, such a proposal should be constructed that all intervenors can participate in review of any filing that PSO makes in connection with a Formula Based Rate. Also, there should be sufficient time to have all parties review the utility filings and request additional information. Finally, any disputes should be resolved by the Commission on an accelerated basis.

Finally, Mr. Selecky opposes the Staff's cost of service method for allocating any increase in this proceeding. The Staff's cost of service method is not recognized and does not reflect cost causation principles. Any cost of service study needs to look at cost and why the costs were incurred. The Staff's proposal fails to examine well established cost of service principles. Therefore, no weight should be given to the results of the Staff's cost of service study.

ATTORNEY GENERAL

Daniel Lawton

My name is Daniel J. Lawton and I am a principal in the firm of Diversified Utility Consultants, Inc., located at 12113 Roxie Drive, Suite 110, Austin, Texas. I am testifying on behalf of the Oklahoma Attorney General's Office. In my prefiled responsive testimony, I make the following conclusions and recommendations:

(i) The Company's proposed 8.82% overall return on investment is overstated and should not be adopted as representative of the Company's cost of capital requirements;

(ii) The Company's requested 11.75% return on equity is an overstatement of the required return on equity for PSO;

(iii) The Company's required return on equity is in the range of 9.3% to 10.2%, a point estimate of 9.75% is reasonable for the Company; and

(iv) The Company's overall cost of capital for this case should be at 7.90%.

Jacob Pous

Mr. Pous addresses the Company's depreciation expense request. In particular, Mr. Pous demonstrates that PSO's failure to perform appropriate analyses in the areas of production plant life and net salvage, and mass property net salvage results in a significant level of excessive depreciation expense related revenue requirements.

In the area of production plant life spans the Company proposes to retain the existing 42-year life span for its coal-fired generating units. The Company's proposal reflects unusual and unacceptable practices that do not reflect the underlying beliefs or expectations of its Engineering Department or its depreciation experts, nor does it comply with standard industry expectation, or what is testified to in other jurisdictions for affiliates of the Company. The Company's proposed life span for coal-fired generating units reflects the Company's inappropriate manipulation of its witnesses and data in order to create a "straw man" negotiating lever. Relying on a 60-year life span for coal-fired generating units is not only appropriate, but is in line with how the Company expects to operate these units. The impact of this adjustment in a reduction of $7,055,111 based on plant as of end of December 2005.

In the area of 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 performed between 1984 and 1994 for other utilities. The information was obtained and developed by an outside consultant who testified on behalf of the Company in 1997 in Cause No. PUD 960000214. PSO has elected to utilize the unsubstantiated information from its prior consultant as a basis to project the recovery of approximately $130 million over the life of its units. A review and comparison of the data with actual values utilized by many of those other utilities demonstrates the complete disconnect between such values and reality. Based on available information, application of a -5% net salvage more closely reflects the values actually utilized by the other utilities reflected in the Company's sample. In addition, a -5% level of net salvage was utilized by many of PSO's sister-operating companies, prior to deregulation in Texas. Use of a -5% net salvage results in a $3,931,864 reduction to the depreciation expense based on a plant as of end of 2005. In addition, Mr. Pous also recommends an alternative recommendation that reflects a +10% net salvage. This recommendation reflects the 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.

In the area of 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 21 years of historical data. 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 states is mandatory. The Company's blind reliance on historical averages yields results that in many instances are by far the most negative net salvage values of any utility that can be identified in the industry. This fact, significant variation from the industry, has gone unnoticed and unexplained by the Company. Correction of the net salvage value proposed for 10 mass property accounts results in $13,795,525 reduction to depreciation expense based on plant as of the end of 2005.

The combined impact of the various recommendations is not the summation of the individual components. The life span and net salvage adjustments for production plant interact with one another. Therefore the combined impact of Mr. Pous' recommendations results in a $23,890,895 reduction to depreciation expense based on plant as of the end of 2005.

Roya Z. Soltani, CPA

My testimony is responsive to the asserted revenue requirement and proposed rate design of Public Service Company of Oklahoma. The Attorney General's revenue requirement recommendations are summarized in the Accounting Schedules of the Office of the Attorney General. I sponsor rate base adjustments, income statements adjustments and a certain rate design recommendation in my testimony. I have limited my 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.

I support the elimination of test year end construction work in progress ("CWIP") that is not completed by six-month post-test-year. I also propose to increase accumulated depreciation to synchronize the additional growth in the depreciation reserve with plant in service additions through December 31, 2006.

I recommend an update to prepayments average to the actual 13-month total average balance at December 31, 2006, and to remove prepayments amount for the OCC quarterly assessment fee that is collected monthly by the Company through customer billing. I propose to update the Company's requested level of Customer Deposits and Accumulated Deferred Income Taxes to the actual end month balance at December 31, 2006. These adjustments are necessary to reflect the final known and measurable amounts in the rate base. My testimony supports a reduction in fuel inventory necessary to eliminate excessive fuel inventory from the Company's pro-forma adjustment. I also recommend normalizing Materials and Supplies balance by averaging 2004 to 2006 balances and to amortize PSO's cost of current rate case over a three-year period. I propose to include the Company's actual SPP administration fee and SPP FERC assessment expenses for 2006.

My testimony reflects PSO's direct payroll and AEPSC payroll allocation to PSO for calendar year 2006. I also propose to eliminate some costs attributed to the financial performance component 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. On average 28% of the incentive plan targets focus on the corporate-wide financial results of AEP. This corporate component closely links business unit rewards to overall corporate performance in creating value for AEP shareholders. The consolidated financial targets are not linked to customer service, employee safety, cost reductions or operational efficiencies. I recommend 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.

Legislative advocacy, memberships in local and state chambers of commerce, civic and social dues and memberships, credit line fees, environmental activities that are not included in the net operating income under FERC Uniform System of Accounts should be disallowed. Ratepayers should not support costs that are not necessary to provide electric utility services.

PSO's test year request for non-fuel production O&M is substantially higher than the historical average expenditures in this area. I recommend a reduction to the test year amount of non-fuel production O&M cost based on the three year 2004-2006 average amount. I propose to disallow inclusion of the Company's estimated purchased capacity costs in base rates.

PSO is proposing a Formula Based Rate ("FBR") tariff in this filing. This tariff will enable PSO to adjust its rates every year based on the changes to PSO's investment, expenses, and revenues. The proposed FBR tariff is similar to the tariff approved for CenterPoint Energy in a five-year pilot program by the Commission in Order No. 499253. The CenterPoint Energy pilot program ensures that the Company's earnings fall within an approved range by allowing annual adjustments to its rates. The pilot program is not completed; any approval of future similar plans should be considered only after the completion of the CenterPoint Energy pilot program.

STAFF

Karen Forbes

Weather Normalization: Staff proposed an initial weather adjustment of ($2,323,237) to remove fixed customer charges for the test year period from PSO's non-fuel base revenue weather adjustment of ($7,157,364), which resulted in a recalculated weather related kwh revenue of ($4,834,147) for a revenue difference of ($2,323,237). The fixed customer charges had been included in the variable and energy weather related kWh revenue adjustment. Only the non-fuel base energy charge should be used to develop the weather related revenue adjustment.

Pre-Filed Responsive Testimony Reference:
Forbes, 3/20/07, page 6, ($2,232,327)

Staff's amended weather adjustment for ($775,625) replaced Staff's initial weather adjustment for ($2,323,237), resulting in an increase to test year revenues. Staff's amended adjustment did not alter Staff's methodology, only adjusted the weather factors applied to the June 2006 weather kwh calculation as well as adjusted the customer charges for the commercial and industrial classes (SL4 & SL5) to be consistent with current tariff charges. Staff's initial weather adjustment utilized customer charges shown in the Company's Workpaper M-4-1 that were rounded-up, resulting in some pricing differences to the commercial and industrial classes (SL4 & SL5).

Amended Testimony reference
Forbes, 4/4/07, page 2, ($775,625)

Javad Seyedoff

The following issues are the focus of the testimony of Javad Seyedoff, Customer Deposits (FERC account 235), Interest on Customer Deposits (FERC account 431), and Customer Advances (FERC account 252). Another area of my review involves the Utility Assessment Expense (FERC account 928), specifically OCC and FERC Assessment Fees.

Customer Deposits (R-11): Staff proposes an adjustment of $(974,637) over the Company's adjustment on schedules B-2 and corresponding WP B-6, in the amount of $(35,440,000).

Staff's adjustment is	
Company's adjustment on Schedule B-2	$(35,440,000)
Staff adjustment, thirteen (13) month average	$(36,414,637)
Adjustment Number R-11	$(974,637)

due to the continuous upward trend of balances of six months post test year period. Staff used thirteen (13) month average, six-month post test year end period. Staff's position with respect to out-of-period adjustments is based on 17 O.S. §284, which states in 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." Staff looked at the monthly balances from January 2004 to December 2006.

Interest on the Customer Deposits (H-22): Staff is proposing an adjustment of $21,967, since split balances of monthly short and long term interest on the customer Deposits prior to February 2006 were not available (per data request PUD-PSO- 24(1-2), 95(1-2), and 102(1)). By applying OCC rule 165:35-19-10 governing how the rate of interest is applied on Customer Deposits, along with short and long-term interest, Staff determines the appropriate interest on the customer deposits balance to be included in the cost of service. Using the thirteen (13) month average post-test year ending December 2006, Staff calculated Customer Deposits to be $36,414,637, and Interest on the Customer Deposits to be $120,042. Staff used the thirteen (13) month average in determining the effective rate to be 3.96%. Then, Staff applied the effective rate by multiplying it by the thirteen (13) month average of Customer Deposits ending December 2006, which is $36,414,637. Total Staff Pro-Forma Interest on the Customer Deposits Expense equaled $21,967. This amount is just, fair, and reasonable.

Staff Total Pro Forma	$1,440,500
Test Year End Balance (B-6-2)	$1,418,533
Adjustment Number H-22	$21,967

Customer Advances: Staff did not propose any adjustment, because Company balances were zero. Company used a balance of $0.00 in Schedule B-2 and WP B-6. The balance was $294,691 in January 2004, but has been zero since that time.

FERC Assessment Fees: Staff proposed no adjustment to Test Year End total FERC Assessment Fee of $595,709.45. Company Pro-Forma adjustment WP H-2-13 page 3 of Schedule H-2 for removal of $305,829 for 2004 FERC true up for Assessment fee will increase O& M expenses. Staff accepts the company's proposed Pro-Forma adjustment. Based on the information reviewed and the balances above, the differences are immaterial.

Utility Assessment Fees ("OCC"): Staff is proposing no adjustment because of the immateriality of the difference between PSO's OCC Assessment Fee Revenue and Expenses in the amount of $2,942. Utility Assessment fees are collected through tariff mechanisms by the Company, which was invoiced by OCC for payment. Staff accepts the company's proposed Pro-Forma adjustment.

PSO, OCC Assessment Fee Revenue	$741,557
PSO, OCC Assessment Fee Expense	$738,615
Total Staff Adjustment	$ 2,942

Staff had addressed several other issues during the audit. However, we are not proposing any specific adjustment at this time on any of those issues.

George Mathai, CPA

My name is George Mathai. My business address is Jim Thorpe Office Building, Suite 580, Oklahoma City, Oklahoma 73105. I am CPA/Chief of the Accounting and Financial Analysis ("AFA") Department in the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "the Commission").

It was my responsibility to oversee the field investigation related to this filing, to supervise the preparation of schedules, work papers, the Staff Revenue Requirement Exhibit, and accounting issue testimony to support the AFA Staff's quantification of PSO's current revenue requirement based upon a test year ended June 30, 2006. I am sponsoring the overall Staff Accounting Exhibit explaining Staff's recommended Revenue Requirement for PSO. I am also specifically testifying on issues related to Formula Based Rate/PBRC, Treatment of New Generation and Transmission Capital Expenditure Recovery Mechanism ("NGTR Mechanism"), New Preliminary Engineering Costs, Regular Construction Work in Progress (CWIP), Prepaid Pension Obligations, Depreciation and Accumulated Depreciation issues and AEP Service Company ("AEPSC") issues.

Section A, Schedule -1 of Staff's Accounting Exhibit provides a computation of PSO's Revenue Requirement. In this Cause, Staff initially filed testimony on March 20, 2007, that the Company's jurisdictional Revenue Excess is $17,705,731 as shown on Line 7 of Schedule A. This finding of Revenue Excess for PSO incorporates Staff's recommended rate base of $1,043,608,352, adjusted operating income of $ 95,076,490, and a rate of return of 8.07%. However, based on the review of the rebuttal testimony, Staff's revised Revenue Excess is $12,107,433. The revised Total Company Revenue Requirement is $456,389,060. The changes are explained in Staff's supplemental testimony filed on April 23, 2007.

Staff used the six months post test year as the cut-off period as it is consistent with the language in 17 O.S.§ 284 which states in part that, "[T]he 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."

<u>PSO's FORMULA BASED RATE ("FBR")</u>

The proposed FBR tariff is similar to the Performance Based Rate Change ("PBRC") approved December 28, 2004, for CenterPoint Energy Arkla by this Commission. PSO wants to include the New Generation and Transmission Capital Expenditures ("NGTE") in the rate base as a part of the FBR. The FBR is designed to enable PSO's earnings to remain within an approved range by allowing adjustments to rates between rate cases.

PSO wants to use FERC Form 1 data to determine if the Test Year's earnings are above or below the Authorized Return on Equity ("AR") and calculates a revenue deficiency (a charge) or revenue excess (a credit). PSO is proposing that to determine if a rate adjustment is necessary, the Earned Return on Equity ("ER") for each year be compared to a band of 100 basis points around the AR determined from the current case.

However, Staff has concerns regarding the FBR approach. Our concerns are in the areas of including CWIP in the Rate Base, Sharing Mechanism Band and its application, reliance on FERC Form 1 as the source for annual FBR review, limitations on pro-forma adjustments, lack of new proposals by PSO regarding performance improvements or productivity improvements or cost saving measures, and certain filing requirements and timing issues. Therefore, Staff is unable to support the FBR in the current form as proposed by the Company.

STAFF'S ALTERNATIVE PROPOSALS TO PSO'S FBR

Staff would like to modify the PSO proposed FBR into two-parts. We would propose a Performance Based Rate Change ("**PBRC**") Plan and a New Generation and Transmission Capital Expenditures Recovery ("**NGTR**") Mechanism.

Under the **first** proposal, **PBRC**, the Company shall file the Plan each year to assess the earnings of the Company without regard to the investments in New Generation and Transmission Expenditures (NGTE projects). The filing should include the following requirements/elements:

- It should meet the format of a Minimum Filing Requirements of a Streamlined Rate Case. The MFR filing should be based on the actual books and records of the Company rather than limited to the FERC Form 1 report as suggested by PSO.
- Benchmarks should be established in the following ratemaking issues normally considered contentious as follows:
  - ROE will remain the same as established in this rate case until the Commission has a subsequent full rate case.
  - The Depreciation Methodology will remain the same based on the Study/Position accepted by the Commission in this Cause.
  - Cash Working Capital will continue to be calculated using the same Lead/Lag days determined by Commission in this Cause.
  - Regular CWIP will be treated as determined in this Cause.
  - Completed But Not Classified Construction that is in the books less than 60 days shall be included in rate base.
  - No Weather Normalization Adjustment will be made since the actual revenue will be used each year.
  - Rate Design shall remain the same, and the charges or credits due to PBRC Plan will be distributed accordingly to all classes affected by PBRC.
- Company should establish Goals and Standards of Performance improvements, Productivity improvements and Cost saving measures as a part of PBRC.

- Under the sharing mechanism, once the 100 basis point band is established, whenever the ER falls below the 50 basis point of the AR or goes above the 50 basis point of the AR, the charge or the credit should be calculated the same way as described in Staff's above testimony.
- The Pro-forma adjustments should be limited to Labor, Benefits, and Tax changes due to government actions.
- The Commission should maintain its authority to review the books and records of PSO, including requiring PSO to file a full rate application at any time.

Since FBR/PBRC is a Rate Base/Rate of Return methodology of ratemaking, the Revenue Requirement is calculated in ***total*** considering all issues at a given time. Therefore, it is judicially imprudent to implement any ***partial*** charges or partial credits *before* the Commission issues its final order as to the ***total revenue requirement*** of the Company in each of the FBR/PBRC filings.

Each FBR/PBRC filing is a stand-alone rate case, except these are processed in a streamlined manner. Each case would have its own issues and it is more transparent and efficient to file a *new cause* for each year rather than the same cause number as suggested by PSO.

New Generation and Transmission Expenditure Recovery Mechanism ("NGTR Mechanism")

The **second** Staff proposal is to set up an Interim Rider called **NGTR Mechanism** to recover the return on and return of the **New Generation and Transmission Expenditures** while such Plant is still under construction.

PSO requested to include the New Generation and Transmission Expenditures in the **rate base** before these are actually in service. (Please see the November 21, 2006, testimony of PSO Witness David Sartin, page 5, line 6, thru page 9, line 15, and Donald R. Moncrief's November 21, 2006, testimony, page 8, lines 19-22.) Staff does not agree with this approach. Instead, Staff believes that there should be a **NGTR Mechanism** Rider established to recover a return ***on*** the investment and a return ***of*** the investment once the Commission approves the used and useful concept on such investments. Please see Staff Exhibit GM- 1 and 2 for the calculation illustrations.

Let me explain the difference between the **return on** the investment and the **return of** the investment. A *return **on** the investment* is the remuneration to the investors for the use of their money, such as cost of debt and preferred stock, and a return on the equity. All these costs put together is known as Rate of Return.

The *return **of** the investment* is returning the capital amount back to the investors on a periodic basis, such as depreciation expense and amortization expense amounts. Staff is recommending a *return **of** the investment* through the **NGTR** rider mechanism, which is a Regulatory Asset, rather than a Rate Base item. **Staff is also recommending a 100 to 150 basis point reduction to the ROE on these regulatory assets, compared to the ROE to be authorized in this instant Cause.**

Staff's NGTR proposal Mechanism is an approach that allows setting up of a Regulatory Asset Account with an amortization provision during the Construction period on an **interim** basis. The company's proposal by its witness Mr. David Sartin to include the New Generation and Transmission Expenditures as CWIP in rate base has a **permanent** rate effect, before the prudency of the total plant investment is determined.

The **Staff's NGTR Mechanism** requires less regulatory or accounting consequences while allowing mutual benefits to all stakeholders of the utility. This provides the Commission an opportunity to look at the prudency of the Capital Expenditures on a comprehensive basis at the completion of the project. This approach will also minimize the "rate shock" effect of a two (2) billion dollar investment raising the rates at the end of five years on Oklahoma customers. Another advantage to this policy is that it provides a more gradual increase in customer rates.

The **Company's FBR proposal** to include the CWIP in rate base has several far-reaching consequences from a ratemaking standpoint, since it is a ***permanent*** rate recovery method. During the time this asset is under construction, if the cost of the plant is recorded in a CWIP account and allowed in the rate base as a part of the FBR/PBRC calculation, new rates could be set by different Commission orders. A prudent and comprehensive review of the total investment in such a plant could only be done at the end of the completion of the construction of the facility. If such review reveals that certain imprudently incurred investments should be disallowed, the Commission would have to overcome at least **three hurdles** based on sound ratemaking principles and legal precedents, as described below, if those NGTE are already in the rate base. The three hurdles are **retroactive rate changes**, **Collateral attack**, and the **Filed Rate Doctrine**.

Staff's NGTR Mechanism proposal is consistent with the intent of the recently enacted provisions of House Bill 1910, codified at 17 O.S. § 286, which allows the Commission to provide certain Rate of Return ("ROR") on the new generation CWIP once the "used and useful" determination is made by the Commission. Staff proposes that PSO set up Regulatory Asset Accounts for New Generation and Transmission Capital Expenditures subject to certain refund protection in case of no-performance by the Company. The company should be allowed to earn a return on the investment that is specifically calculated taking into account two special situations. (Please ***See*** **Exhibit GM-1** for illustration purposes.) **First**, current customers are asked to pay a return on an investment that will not produce any actual kWh or any actual transmission until it is fully in service a few years in the future. **Secondly,** the customers are taking the risk through their current payments. Therefore, the investors have less risk and the risk premium should be reduced. **Staff, in its proposed PBRC plan, suggests that the Return on Equity ("ROE") established on this type of Regulatory Asset be an ROE of 100 to 150 basis points less than the established benchmark ROE.**

I believe providing a current return on NGTE saves money in the long run to the customers by avoiding the compounding effect of paying carrying costs on top of carrying costs incurred by recording Allowance for Funds Used During Construction ("AFUDC").

Staff is proposing an amortization of the investment balances, which is booked as a Regulatory Asset or Regulatory Liability, based on the life of the asset during the Construction period. This is actually facilitating the **return of the investment** starting from a period earlier than when it is fully become Plant in Service. Please see Exhibit GM-2, attached to Mr. Mathai's responsive testimony, as an illustration of the possible financial impact.

FASB 71 gives the Commission flexibility to make regulatory decisions to enable sound public policy. Staff's proposal allows the Company greater cash flow and lesser need for capital from investors at a higher cost, and minimizes the **"rate shock"** effect of a two (2) billion dollar investment at the end of five years. Thus, Staff's NGTR Mechanism provides a more **gradual increase** in customers' rates.

REGULAR TEST YEAR CWIP

Adjustment B-9 will decrease Construction Work in Progress by $29,560,676 while Adjustment B-1 will increase Plant in Service by $20,940,266 to reflect the updated Plant balance at December 31, 2006.

Staff continues to stand by its opinion that it is not fair for **current** ratepayers to fund the **future** cost that may or may not benefit the current ratepayers, unless it is in the public interest.

RETURN ON PREPAID PENSION ASSET

Staff does not believe that inclusion of the $81,973,283 prepaid pension assets in the rate base is the appropriate ratemaking treatment of prepaid pensions. The pre-paid balance was generated when PSO funded more than the annual expense booked for cost of service purposes, to build up the fund assets to equal the accumulated benefit obligation.

Customers are already paying for the current pension expense level of $2,528,894 as proposed by Staff in the cost of service. However, PSO's funding of the under-funded benefit obligation provided benefit security to members, and prevented participant notices by funding to certain targets. Since PSO finances the pre-paid pension funding, Staff recommends that PSO be allowed to recover the expected long term return on the asset, which is 8.5 percent. Based on this, Staff has allowed a 13-month average balance ending December 31, 2006 of $80,670,521 at an 8.5 percent carrying cost to recover $6,856,994 annually in the cost of service (*See* Staff Accounting Exhibit Schedule H-2A, Line 1).

NEW PRELIMINARY ENGINEERING COSTS - The Company has requested to collect all costs associated with preliminary engineering for new generation from the test year and previous years, which total to $2,212,016. The Company proposed to amortize this total for 5 years. Company made a test year expense decrease $516,348. However, Staff recommends that all preliminary engineering costs associated with new generation be deferred until construction begins for those new plants. Staff recommends recording all preliminary engineering costs of PSO as intangible plant during the initial constructing of the new plants be able to collect amortization expense during the life of the new plants. Staff Adjustment H-15 reduces operating expenses by $442,403 to remove the amortization of these costs from the test year.

DEPRECIATION STUDY

Staff included in its Revenue Requirement calculation an adjustment for depreciation expense reduction of $24,509,130. This adjustment is reflected under Staff Adjustment H-21. The depreciation adjustment is based on the review results of the Attorney General's witness Jacob Pous.

In addition, Staff proposes to increase accumulated depreciation balance by $47,744,686. (Adjustment B-14) This adjustment has the effect of decreasing net plant and increasing the accumulated depreciation by the same amount.

AEP SERVICE COMPANY ISSUES

Staff reviewed the adjustments proposed by AEPSC and accepted them. Staff has conducted only a limited review of the Allocation methodology used by AEPSC to spread its expenses between the AEP affiliates. Staff recommends that OCC Staff should conduct a detailed audit of the AEPSC in the future since SEC will not be conducting any affiliate allocation study since the repeal of PUCHA.

SUMMARY OF REBUTTAL TESTIMONY OF GEORGE MATHAI REGARDING MARK GARRETT'S REBUTTAL TESTIMONY FILED ON FBR/PBRC AND NGTR PROPOSALS

In Staff's opinion, Mr. Garrett is neither addressing the complex regulatory issues nor taking into consideration the challenges in the utility regulation necessitated by the changing investment climate and legislative initiatives. In fact, Mr. Garrett's testimony reminds me of the old country doctor who prescribes the same antibiotic for every disease. The result is if the patient is lucky, he or she may stay alive, but will be suffering for a long time from the wrong medicine's effect. Mr. Garrett's recommendation was to reject the financial diagnosis and treatment proposals made by both Staff and Company in the case for both New Generation and Transmission Capital Expenditures ("NGTE") and PBRC/FBR.

Staff's proposal of the NGTR Mechanism is consistent with the legislative intent of Title 17 O.S. Section 286(C)(5) which states, "The Commission shall also consider rules which may permit an electric utility to begin to recover **return on** or **return of** Construction-Work-In Progress expenses prior to commercial operation of a newly constructed electric generation facility subject to the provisions of this subsection." I have explained Staff's reasons and related benefits to all stakeholders in my direct testimony, page 16, line 8, thru page 21, line 4.

Mr. Garrett erroneously asserted in his rebuttal testimony that Staff had proposed "to allow a utility to begin recovering the cost of an asset before the asset is actually dedicated to the public service, as proposed in the NGTR". (Pg. 6, line 9, thru page 7, line 22.) Staff has not done so. Staff's NGTR is a mechanism to recover the major new generation or transmission projects dedicated to the public service, which are different from the regular everyday CWIP. Additionally, Staff's proposal requires that the shareholders receive a lower return in exchange for the higher risk the ratepayers are sharing.

Mr. Garrett opposes the Staff's NGTR Mechanism for reasons, which are not meritorious. Mr. Garrett claims that Staff's recommendation violates depreciation rules. Staff disagrees with his contention. Staff is recommending that if the Commission determines the NGTE projects, such as the Red Rock Generating Plant, are considered used and useful, the Company should be allowed to amortize the NGTE balance at the end of each year as a regulatory asset, based on the life of the asset. The Commission has the discretion to make regulatory policies that are in public interest under FASB 71. Another accusation Mr. Garrett makes in opposition to the NGTR Mechanism is that it violates cost/causation principles. He stated, "One of the most fundamental ratemaking principles followed in virtually every jurisdiction is that costs should be assessed to and recovered from those ratepayers who cause the costs to be incurred." (Page 6, line 20, thru Page 7, line 2.)

Mr. Garrett's argument reminds me of the kid who refuses to share his portion of the cake after sharing first from the friend's cake. Mr. Garrett fails to address the fact that previous customers paid for portions of the current cost of the generation plants presently in service since current customers are paying a **return on** a *net book value* and a **return of (depreciation)** based on cost of the generation construction, which in some cases occurred 20 or 30 years ago. His "cost/causation" argument does not hold water since most jurisdictions do not set rates based on today's replacement cost. It should further be noted that all new generation plants are not built for future load growth, but instead to replace aging plants providing service to today's customers.

Mr. Garrett also stated in his testimony that "The *matching principle* requires that costs be matched with the benefits they provide." Staff's proposal provides several benefits including the avoidance of compounding of return on return that happens under the AFUDC method suggested by Mr. Garrett. Additionally, due to the amortization of the regulatory asset, the return is calculated on a lower rate base amount than otherwise required. Further, Staff's approach helps to reduce the rate shock at the end of the completion of the generating plant. (*See* Exhibits GM Rebuttal-1, and GM 1 and GM 2 in filed testimony of March 20, 2007.)

Mr. Garrett claims that Staff's NGTR testimony is inconsistent with its testimony regarding interim recovery of invested capital in ONG Cause No. PUD 200400610. In Cause No. PUD 200400610, ONG requested four new riders to recover anticipated future expenditures including two riders to recover future capital expenditures. However, those capital expenditures had more of the normal plant additions unlike the NGTR Mechanism proposed by Staff in this Cause. Staff's opposition to the riders in the ONG case was based upon sound ratemaking principles and good public policy arguments. However, when he compares those arguments against the NGTE projects, it is like trying to mix water and oil together. The NGTE of PSO is entirely a different type of investment in nature and magnitude, which could not be compared with ONG's then proposed System Investment Rider. ONG's Riders were minor everyday construction work in progress. ONG's request was indeed a piecemeal ratemaking request without looking at the overall revenue requirement of the Company each year. ONG did not propose a CenterPoint Energy PBRC model or a model similar to PSO's FBR, which mandates an overall rate review each year. This way, Staff is avoiding the possibility of piecemeal ratemaking.

The implementation of the combination Programs of Staff's proposed PBRC Plan and the NGTR Mechanism provides for an annual streamlined rate review by the Commission with input from all interested parties. Staff takes strong exception to Mr. Garrett's assertion that, "ONG's System Investment Rider is very similar to the NGTR rider now proposed by Mr. Mathai." (April 9 2007, Rebuttal Testimony of Garrett, page 12, lines 8 & 9.) Staff's position remains the same as it was in the above referenced ONG cause, opposing any Riders that do not take into account the overall benefit to all stakeholders and those that are designed simply to reduce stockholder risks and avoid regulatory oversight. However, one of the reasons for Staff's proposed NGTR Mechanism instead of PSO's FBR is to assure that proper regulatory oversight is maintained to determine the prudence of the expenditure at the end of the completion of the construction of the Plant. Additionally, the NGTR Mechanism and PBRC Plan balance the interests of all stakeholders of PSO.

Please see Staff's Comparison of AFUDC Versus Return on Investment Versus Return on and Return of Investment, **Exhibit GM Rebuttal-1 and 2,** for a better understanding of the issues under discussion. Mr. Garrett claimed that Staff's NGTR proposal is based on "the faulty premise that the rider will benefit ratepayers". (Garrett Rebuttal of April 9, 2007, page 16, lines 12 &13). Mr. Garrett's Exhibit is incorrect. It appears that he has not taken into account all the components of the equation and assembled them as well as Staff did.

CONCLUSION

Staff requests that the Commission accept Staff's recommendation regarding Company's total Revenue Requirement based on the individual Rate Base and Income Statement adjustment treatments. Additionally, Staff recommends that the Commission accept Staff's two-part alternative proposals of PBRC and NGTR Mechanism modifying PSO's FBR proposal, as outlined in my testimony.

Fairo Mitchell

This cause is for the application of Public Service Company of Oklahoma ("PSO" or "Company") for an adjustment in its rates and charges for electric service in the state of Oklahoma. I am presenting Staff's recommendations regarding:

1. Return on Equity ("ROE");
2. Long-Term Debt Cost;
3. Preferred Stock Cost;
4. Capital Structure; and
5. Overall Rate of Return.

In preparing the recommendation, Staff used the following analyses: the cost of common equity; the discounted cash flow ("DCF"); Capital Asset Pricing Model ("CAPM") and Comparable Earnings methodologies. The results from the various analyses are summarized below.

Table 1: Staff's Proposed ROE on Common Equity

DCF Comparative Companies MSN Money	9.49%
CAPM Comparative Companies	9.87%
Comparable Earnings	10.84%
Average ROE	10.08%

The results of the DCF, CAPM and comparable earnings models establish a return on equity for PSO of 10.08%. The criteria used to determine a fair and reasonable rate of return included the economic guidelines and standards known as the comparable earnings and capital attraction standards established in the *Bluefield* (1923) and *Hope* (1944) decisions. The utility has the opportunity to earn this return on the Commission allowed rate base. Current and projected economic conditions and projected industry information as well as the returns on investments of comparable risk were considered. The DCF model is derived from present value theory and rests on the assumption that the value of a financial asset is determined by its ability to generate future earnings. The results of the constant growth DCF analyses are shown on Exhibits FAM-3, FAM-4 and FAM-9. The ROE mean of the two DCF calculations is 9.49%.

The theory supporting the Capital Asset Pricing Model ("CAPM") method of estimating capital costs rests on the premise that investors require a rate of return commensurate with the risk of the investment. The interest rate on a current 30-year U.S. Treasury Bond is used as a proxy for risk free investment. Added to this premise is an estimate of the particular investment's risk relative to the market as a whole. The results of the average of the CAPM analyses indicate a ROE estimate of 9.87% for the comparable group, as shown in Exhibits FAM-5 through FAM-7 and FAM-9.

The comparable earnings test examines realized returns on common equity. This approach indicates whether an investor accepts a company's return on equity based on the company's market to book stock price. Utilities with market-to-book ratios greater than one are able to attract new equity capital without dilution. Staff used historical realized returns and forecast returns to show that returns on common equity in the range of 10.84% can support market-to-book ratios of 1.71, as shown on Exhibit FAM-8.

Staff found PSO's recommended cost of long-term debt of 6.32 and preferred stock of 4.02% to be acceptable. These cost rates were developed from the actual cost rates of the Applicant's cost of money. The support for these two cost rates are shown in Exhibits FAM-10 and FAM-11.

PSO's request for a capital structure consisting of 53.55% long-term debt, 0.43% preferred stock and 46.02% common equity was modified to consider the book value of preferred stock and common equity six months after the test year, as stated in 17 O.S. § 284[4].

[4] 17 O.S. § 284 states that "the 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."

Staff reviewed and compared the average capital structure from the proxy group of electric utility companies and the average of the total electric industry utilities to PSO's capital structure. Staff determined that PSO's capital structure at December 31, 2006 should be 53.15% long-term debt, 0.41% preferred stock, and 46.44% common equity for the instant cause. Staff has recommended the following capital structure and overall rate of return.

<u>Table 2</u>: Staff's Proposed Capital Structure

	Ratio	**Rate**	**Rate of Return**
Long-term Debt	53.15%	6.32%	3.36%
Preferred Stock	0.41%	4.02%	0.02%
Common Equity	46.44%	10.09%	4.69%
Total	100.0%		**8.07%**

The proposed capital structure achieves a balance between investors' preference for lower risk and greater returns and the consumer's preference for lower prices. It is not suggested that PSO must adjust its capital structure to conform to Staff's proposed capital structure. Such a change would be a matter of internal management discretion.

David W. Smith

The purpose of Staff's testimony is to address class allocation in the following areas: Class Cost-of-Service Cost allocation, Rate design, and Demand Side Management ("DSM"). Staff reviewed testimonies of PSO's staff witnesses Moncrief and Champion. Staff reviewed PSO's Cost of Service study. Staff used a straight cost allocation method. Straight cost allocation takes the Company's actual cost of service per sub-class divided by the total cost of service to determine a factor which is applied to Staff's Revenue Requirement number, as stated on Staff's accounting Schedule A. Staff does not recommend PSO's proposed Basic Service Charge. Staff has no data or historical trends to show that PSO's proposed Basic Service Charge benefits the consumer. Staff is recommending a 25% increase to the Basic Service Charge to non-lighting classes. Staff recommends further participation of PSO's TOD pilot program. Staff further recommends, the expanded use of the Interruptible tariff option for industrial customers.

Jason Thenmadathil

My name is Jason Thenmadathil. My business address is The Oklahoma Corporation Commission located at 580 Jim Thorpe Building, Oklahoma City, Oklahoma 73105. I am a Public Utility Regulatory Analyst, employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "the Commission"). I have been employed as a Regulatory Analyst for the Public Utilities Division since December 2004. In this cause I have filed Responsive Testimony on March 20, 2007 and Supplemental Responsive Testimony on

April 23, 2007. The information shown below in this summary incorporates the recommendations made by Staff taking both of those testimonies into account. The following is a summary of my issue areas:

Plant-in-Service – Staff Adjustment B-1 increases rate base by $20,940,266 to allow a level of plant investment calculated at December 31, 2006. Staff is proposing a level of plant investment that is based on known and measurable data at the end of the six months post test year period.

Electric Plant Acquisition Premium – Staff Adjustment B-2 decreases the rate base by ($3,490,722) to remove the Electric Plant Acquisition Premium. These acquisition premiums were included in PSO's Cause Nos. PUD 2003-76 and 96-214, two cases that were settled. The PUD Staff recommended removing the acquisition adjustments from rate base and other operations in both cases. It is Staff's opinion that the Company has been unable to demonstrate a cost savings, operational efficiencies, or quantifications of additional revenues that would offset the price paid over net original cost.

Accumulated Amortization on Electric Plant Acquisition Premium – Staff Adjustment B-8 increases rate base by $3,398,515 to remove the related accumulated amortization of the electric plant acquisition referred to in adjustment B-2. This adjustment is necessary to remove the related amortization associated with the electric plant acquisition premium.

TOD Metering Pilot Program investment – Staff Adjustment B-3 decreases the rate base by ($62,539) to remove the estimated investment in the Time-of-Day ("TOD") metering pilot program. The actual cost of the investment in the TOD pilot program should be recorded. This will be recorded during the Company's first FBR filing (if approved) or the Company's next rate case. An estimate is not necessary.

Other Prepayments – Staff Adjustment B-13 decreases rate base by ($397,968) to allow a certain level of prepayments in the rate base. First, Staff is recommending a 13-month average updated to December 31, 2006, be used for prepayments, rather than PSO's 13 month average ending at test year-end. This part of the adjustment totaled to an increase in prepayments of $279,502. Second, Staff is proposing to remove ($128,132) of the OCC Assessment Fee Accrual, which is recorded as a prepayment. PSO is already allowed to collect monthly expenses for OCC Assessment Fees. The removal of ($172,037) associated with prepaid credit line fees and ($377,301) associated with prepaid carrying cost on factored accounts receivable will be addressed by Staff witness Bob Thompson.

Off System Sales Trading Deposits – Staff Adjustment B-5 decreases the rate base by ($5,268,984) to remove off system sales trading deposits. It is Staff's opinion that the off system sales trading deposits should not be reflected in the rate base until PSO can demonstrate that current customers can benefit from the associated off system sales under the current System Integration Agreement ("SIA").

IPP System Upgrade Credits ("Rate Base") – Staff Adjustment B-10 updates IPP System Upgrade Credits in the rate base by ($674,566) to match the updated transmission plant balance at December 31, 2006.

Maintenance Expenses – Staff Adjustment H-4 normalizes maintenance expenses by ($4,075,441). Staff's proposal normalizes Boiler Plant Maintenance Account 512, which depicted wide annual swings when reviewing previous test year amounts. Based on the trend seen using calendar year information versus test year information, it is Staff's opinion that using totals on a calendar year basis to develop a pro-forma level would be more fair than the use of a test year level. For Staff's 3-year average approach, Staff used the data from the calendar years following the test year of PSO's 2003 rate review. Staff also took into account known and measurable changes by using the calendar year 2006, which includes information through the six months after the test year.

Rate Case Expenses – Staff Adjustment H-6 decreases rate case expenses by ($123,000) to account for a 5-year amortization rate. If the Commission approves some form of an earnings-sharing mechanism (such as the FBR), PSO will not have another major rate case in 5 years. If the Commission does approve an earnings-sharing mechanism, the 2-year amortization period proposed by the Company would appear reasonable.

Non-Utility Outside Services – Staff Adjustment H-7 decreases outside services by ($12,769) for non-utility expenses.

Legal Expenses – Staff Supplemental Adjustment H-8 removes certain legal expenses amounting to ($104,957). Staff had originally proposed disallowance of an additional $181,569 related to a certain legal case regarding discrimination. However, Staff has supplemented this position and has recommended a 50/50 sharing of this cost between ratepayers and shareholders. The remaining portion of Staff's adjustment removes ($14,173) associated with rate case expenses from PSO's requested legal expenses. Since rate case expenses are being treated separately via an amortization expense adjustment, this cost should not be allowed as a legal expense.

Electric Plant Acquisition Amortization Expense – Staff Adjustment H-10 removes the electric plant acquisition amortization expense of ($31,641). This adjustment coincides with Staff Adjustment B-2.

IPP System Upgrade Credits (Interest Expense) – Staff Adjustment H-19 increases interest expense associated with IPP System Upgrade Credits by $49,243. An update of interest expense is necessary to match Staff Adjustment B-10 to update IPP System Upgrade credits in the rate base.

Robert C. Thompson, CPA

On behalf of the Oklahoma Corporation Commission ("OCC"), the following issues are focused on in the testimony of Robert C. Thompson, CPA:

Cash Working Capital:
Commission Staff recommends an adjustment to the cash working capital, which includes all of Staff's proposed changes to those accounts included within the cash working capital calculation. Staff is also 1) proposing an adjustment to the cash working capital to exclude non-cash items

such as depreciation, investment tax credit and common equity, and 2) removing cash working capital from rate base while providing alternative financing recovery for PSO's costs. Staff's adjustment will decrease cash working capital included in rate base by $7,891,077 and include a negative $131,523,614 in Rate base.

Environmental Adjustment:
Commission Staff recommends an adjustment because the company originally included this adjustment in proforma and later withdrew the adjustment after the application was filed. Staff is removing the $8,541 since the adjustment was withdrawn by PSO and therefore should not be included in the cost of service.

Trading Deposit interest expense:
Commission Staff recommends an adjustment is to reduce the cost of service operations expense in the amount of $3,902. Staff is disallowing the net test-year expense to be consistent with the rate base treatment of trade deposits, as presented by Staff Witness Jason Thenmadathil.

Write-off of obsolete inventory:
Commission Staff has accepted the company's adjustment for the removal of the write-off of obsolete inventory from the cost of service. Staff reviewed the entries and supporting documentation made by the company to set up the reserve, make the actual write-offs and reverse the balance in the reserve account at the end of December 2006. Staff has determined that these costs are one time in nature and non-reoccurring. It is Staff's opinion that these costs should not be borne by the ratepayers.

Marketing and Sales Expenses:
Commission Staff recommends that the marketing and sales expenses included in cost of service primarily promote the Company. Staff's position is that Company's marketing and sales expenses should be shared between shareholders and ratepayers resulting in the above adjustment.

Advertising Expense:
Commission Staff recommends that an adjustment is necessary to eliminate certain test year advertising expenses that in Staff's opinion should not be recoverable for ratemaking purposes. Staff eliminated advertising costs that promote the Company for the purpose of improving its public image.

Factoring and Bad Debts Expense:
Commission Staff recommends an adjustment is to recalculate the Factoring and Bad Debts Expense adjustment proposed by the company to reflect Staff's proposed Return on Equity and Revenue requirement.

Trading Deposit Interest:
Commission Staff Recommends proposing to remove trading deposit interest expense as customers are currently no receiving any benefit from off-system sales and this will be looked at further in the annual fuel audit.

Credit Line Fees:
Commission Staff recommends adjustment H-20 reverses PSO's adjustment H-2-15 to reclassify expenses associated with interest from credit line fees from a below the line account to the cost of service.

Interest Synchronization:
Commission Staff recommends 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 ratepayer's contribution to PSO for interest expense coverage. Staff's Adjustment for interest synchronization will increase the net income before income tax by $5,242,142.

Current Tax Expense:
Commission Staff recommends an adjustment to current income taxes to reflect Staff's adjustments to the operating income statement, resulting in a net increase to PSO's operating income of $16,063,772.

Marvin D. Vaughn

Introduction

My name is Marvin Vaughn. My business address is The Oklahoma Corporation Commission at 580 Jim Thorpe Building, Oklahoma City, Oklahoma 73105. I am employed as a Public Utility Regulatory Analyst in the Accounting and Financial Analysis ("AFA") Department of the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("OCC" or "the Commission"). In this position, I am under the direct supervision of PUD's Chief of AFA, George Mathai, CPA.

Purpose

The purpose of my testimony is to clarify Staff's position and to propose any adjustment necessary in the areas assigned to me for the audit in this cause, which were Materials & Supplies, Ad Valorem Taxes and Purchased Power Capacity Costs.

Issues

The following nine issues were addressed as issues in my testimony:

Ad Valorem Taxes: PSO proposes Ad Valorem taxes be included as an operating expense based on a pro-forma adjustment of the total PSO property tax obligation. This amount includes the tax obligation for all states in which the Company does business. Staff found that the level of Ad Valorem taxes included in the Company's filing was not reasonable and therefore proposes a decrease of $1,443,177 to the Company's pro-forma adjustment based on the actual tax obligation to Oklahoma.

Research and Development Expense: Staff analyzed the projects in R & D expense and compared the test year amount to the calendar year amounts in 2004, 2005, and 2006. Although Staff identified an immaterial difference between the test year and calendar year 2006, Staff proposes no adjustment to the Research and Development Expense.

Fuel Expense: PSO's fuel expenses consist of expenses related to the consumption of Coal, Natural Gas, and Fuel Oil. The Company proposed a pro-forma adjustment based on the amount of expenses not recoverable through the Fuel Adjustment Clause. Staff's analysis resulted in no differences and therefore Staff accepts the fuel expense pro-forma adjustment as proposed by PSO in its filing at this time. Staff will be conducting additional review of fuel issues in its Annual Fuel Audit.

Purchased Power: Staff reviewed the purchased power expenses and tied them to the monthly fuel adjustment clause filings. Staff analyzed the Company's pro-forma adjustment for the recovery of Calpine reactive power and proposes no adjustment, since these costs represent a *known and measurable* expense of the Company. In Staff's analysis of the Company's pro-forma purchased power capacity adjustment, Staff recognizes that the Company entered into contracts for capacity during the test year. However, these contracts expire in 2007 and the level of the Company's purchased power capacity decreases in the following years. Therefore, Staff is proposing to reduce the Company's pro-forma by $2,150,486 to reflect the Company's actual experience because the rates going forward should be based on the known and measurable data.

Line-Loss: Staff reviewed the Line-Loss study provided by the Company and did not identify any differences. This report is completed annually in April and incorporated into the fuel adjustment clause filing in June. Therefore, Staff proposes no adjustment to the line-loss levels proposed by PSO in this cause at this time.

Materials and Supplies: Staff proposes to increase the Total company level of materials and supplies included within PSO's rate base by $3,454,520. Staff's 13-month average is based on December 2005 - December 2006 time period versus PSO's June 2005-June 2006 time period. Staff's calculation is based on known and measurable 13-month average balance, and more accurately reflects the materials and supplies levels on a going forward basis.

Fuel Inventories: Staff reviewed the fuel inventory proposed by the Company to be included in the rate base. The Company's calculation is based on a 35-target day for Northeast 3&4 and a 40-target day for Oklaunion. The Company used the 13-month average of coal based on the June 2005-June 2006 period with the inclusion of a pro-forma adjustment level based on the target days for each plant. Although at the time of the filing the Company was not maintaining that level, the Company has maintained or exceeded that level presently. Therefore, Staff proposes no adjustment to the fuel inventory levels proposed by PSO in this cause at this time.

Miscellaneous General Expense: Staff reviewed the miscellaneous general expenses proposed by the Company in the test year and found no discrepancies. The Company removed the Associated Business Development ("ABD") expenses from the miscellaneous general expense account. Therefore, Staff proposes no adjustment to the miscellaneous general expense levels proposed by PSO in this cause at this time.

Transmission Expense: Although the Transmission Expense operation accounts fluctuate from test year to test year, Staff found that the account is showing a decreasing trend based on calendar year data. Staff found in its analysis that the test year represents a reasonable level. Staff is accepting the Company's adjustment for the Midwest Independent System Operator ("MISO") transmission service increase and the prior year adjustment.

Brandy Loyd Wreath

My name is Brandy Wreath and my business address is Jim Thorpe Office Building, Suite 580, Oklahoma City, Oklahoma 73105. I am employed by the Public Utility Division ("PUD") of the Oklahoma Corporation Commission ("Commission") as an Auditor. In this position, I am under the direct supervision of CPA/Audit Coordinator of Accounting and Financial Analysis ("AFA") Bob Thompson, CPA and Chief of AFA, George Mathai, CPA.

My Purpose in this cause is to present Staff's findings for the areas of Payroll, Taxes Related to Payroll, Community Affairs, Employee Benefits, Incentive Compensation, Legislative advocacy, Postage, Dues and Memberships, and Contributions, Service Company adjustments, and Rate Base for Payroll and Benefits.

In this cause I have filed Responsive Testimony on March 20, 2007 and Supplemental Responsive Testimony on April 23, 2007. The information shown below in this summary incorporates the recommendations made by Staff taking both of those testimonies into account.

Payroll: Staff proposes to adjust Base Payroll Operations and Maintenance ("O&M") Expense to $49,920,294 to account for annualization of the December 31, 2006 employee levels and payroll. This payroll adjustment calculates the O&M portion of Base Payroll based on the Company supplied 12-31-2006 levels. This is an increase of **$889,378** over the Company's filed pro-forma adjustment for Base Payroll. Staff has also adopted the Attorney General's ("AG") adjustment to Overtime Payroll. However, Staff only included the amount of the AG's adjustment that related to O&M expenses. The portion of this adjustment as it relates to Overtime Payroll will reduce payroll by **$(1,401,501)**. All adjustments referenced above equate to Staff's proposed Adjustment H-14 to reduce PSO's requested payroll O&M expense by **$(512,123).**

AEPSC Payroll: Staff finds the Company's calculation to be reasonable. Anticipated changes cannot be fully reviewed until such time as all transfers between the affiliates are complete. Staff's opinion is that the test year-end level of employees is the most appropriate level to use at this time. Staff also suggests that this area of payroll be part of the annual formula base rate review. Staff's proposed adjustment is $0.

Employee Incentives: While the Company reduced the amount for incentives to reflect a 100% percent payout, they still left the entire 100% payout portion to the ratepayers. Staff's opinion is that it is more appropriate that the 100% payout level, less executive incentives, be shared equally between the ratepayer and the stockholder as both can benefit from the increased operational and financial performances.

Therefore, Staff has reduced PSO's requested amount for employee incentives by 50% to reflect an equal share to be borne between the ratepayer and shareholder. Staff also based the calculation on the 3-year average for payroll O&M percentage allocations. Staff's proposed adjustment H-18 is **$(1,402,494).**

Community Affairs: The Company included an adjustment to payroll for additional Community Affairs employees. Staff accepts the company adjustment to increase O&M Expense by $300,000 to account for the additional Community Affairs employees requested by the company. Staff's proposed adjustment is $0.

Legislative Advocacy: The Company included in the cost of service $635,129 of expenses associated with Lobbying. Since ratepayers do not have any input as to the decision process to determine which issues are presented by the Company in its lobbying efforts, such expenditures should not be included in the cost of service. Staff's adjustment H-3 is **$(635,129).**

Taxes Related to Payroll: Staff calculated the change in FICA tax as a result of Staff's updated adjustments to payroll and special pay amounts. Staff utilized the Company's filed payroll and tax information to calculate the effective FICA rate. The reductions in payroll expense resulted in a lower tax burden for FICA. Staff's updated adjustment H-16 is **$(117,840).**

Employee Benefits: Staff has accepted the actuarial levels for employee benefits. The prior adjustments were based on the calculated 3-year O&M percentages. Staff has removed its adjustment H-17. Staff's Updated Adjustment is **$0.**

Dues and Membership: Staff proposes to disallow $354,407 of Dues and Memberships that the Company has included in the cost of service. Staff recommends sharing those costs that are beneficial to ratepayers and stockholders. Staff further recommends removing costs that are paid to various social clubs, service clubs, and Chamber of Commerce Organizations that Staff believes are expenditures that are not a necessary cost of providing electric service to PSO's customers. Staff's Adjustment H-2 is **$(354,407).**

Donations and Contributions: The Company's Donations and Contributions total of $2,849,256 was not included in the cost of service and the amount of $5,970 of additional contributions was removed from cost of service. The Company did not record any Donations and Contributions expenses in the cost of service.

Postage Expenses: The Company has included $ 70,586 for Postage Expense in the cost of service. Staff reviewed the number of mailed items from January 2006 to June 2006 and calculated the potential impact of the $0.02 postage increase that totaled $65,607. The company adjustment was based on estimated number of mailings rather than actuals, as in the staff calculation. Staff did not make any adjustment, based on the small calculated difference and the reasonableness of the requested Postage Expense.

Service Company Adjustments: Upon reviewing the information provided, Staff's opinion is that the PSO/AEPSC cost allocation methodology is appropriate and reasonable. The company direct bills most costs that occur. Each employee of the service company, and the affiliates, tracks their time by job and billing factor. This enables the service company and all affiliates to track billings to the source. This allocation process is used from the field all the way up to the highest executive levels.

When allocations are not made directly, they are made using known and measurable factors. The allocations are based on factors in the areas to be billed such as headcount for HR related issues. Staff feels that methodology is not only appropriate, but should serve as an example to other companies.

Rate Base for Payroll and Benefits: Staff's prior adjustment to Rate Base for Payroll Capitalization was based on Staff's 3-year average percentage. Staff has adjusted its levels and is no longer using the 3-year average. Therefore, Staff withdraws its proposed adjustment B-7 to increase Rate Base by **$4,431,623**. Staff's Updated Adjustment is $0.

STATEMENTS OF POSITION

Redbud

Redbud Energy, LP ("Redbud") hereby offers this Statement of Position in response to Public Service Company's ("PSO") application in this Cause. This Statement of Position addresses only Redbud's position regarding PSO's request for the approval of formula-based rates, and is not intended to address all issues which Redbud may address during the course of this Cause.

In this Cause PSO is requesting a change in its general rates to allow for recovery of an additional $50 million in revenues. In addition, and more importantly, PSO is also requesting the Commission to adopt a floating rate concept it calls Formula Based Rates (or "FBR"). Hand-in-hand with this floating rate concept, PSO is also requesting to modify the traditional treatment of Construction Work in Progress funds, requesting the inclusion of such funds in its rate base, which would include return of and return on such funds, contrary to traditional treatment of such funds. Moreover, PSO is seeking to "decouple," as it calls it, its rates from customer use or generating production levels.

In these comments Redbud will address the prudence of the utility requesting modification of PSO's rate recovery mechanism, particularly at a time when the utility itself has indicated it intends to invest more than $2 billion and "more than double its rate base" in the next five years.[5]

PSO has stated within this Cause and within other pending cases[6] before the Commission that it is about to embark on a significant spending spree that will entail "unprecedented levels of investment in new generation, transmission and distribution assets."[7] This is reason alone to

[5] Solomon Direct Testimony, page 5.
[6] For example, *see* Cause Nos. PUD 200500516 and PUD 200600030.
[7] Solomon Direct Testimony, page 5. This may imply that there has been inadequate investment in distribution, transmission and generation improvements in the past such that a tremendous amount of improvements must be made to continue to provide reliable service by the utility.

reject floating rates as the Commission's role in reviewing rates and general oversight will be even more important-not less so-during a period of massive investment by the utility.

First, PSO's analysis provided in support of its proposed formula-based rates includes investment in generation that is pending Commission review.[8] It would be inappropriate to set up a mechanism that would allow for automatic recovery/adjustment in rates to cover investment that is pending approval and may ultimately be disapproved by this Commission. The Commission has yet to determine the capacity need for the two additional peaking generation units and one base load coal unit PSO is attempting to have approved for its system.

Secondly, PSO claims that the Commission previously adopted formula based rates in Order No. 499253 issued in Cause No. PUD 200400187 with regard to CenterPoint Energy Arkla ("CenterPoint"), and asserts that since its proposal is similar in nature, the Commission should therefore approve it. PSO fails to point out several significant differences between its proposal and the CenterPoint order: CenterPoint is a natural gas utility, not an electric utility; the CenterPoint order was based on a settlement agreed to by the parties; the rates are considered by the parties to be a pilot program and are applicable only for the years 2005-2009; CenterPoint received a rate increase of only $3.4 million dollars and a return on equity of 10.25% (as opposed to PSO's $50 million increase and requested return on equity of 11.25%). Most importantly, the parties in the CenterPoint case did not implement formula rates in the face of utility-planned expenditures of vast amounts of capital in a short period of time. According to PSO, it plans to more than double its current rate base[9] over the period in which such formula rates would be in place, spending more than $2 billion, thereby substantially reducing the likelihood of any decreases being passed along to customers during this period. Other than stating that the Commission approved one formula rate in the past, PSO provides no evidence to show how it compares or is similarly situated to the application of test formula rates for CenterPoint. As shown above, PSO's factual position differs tremendously from that of CenterPoint, and as such, PSO's reliance on the CenterPoint order as the basis for approving its proposed formula rates has no merit. Moreover, PSO's formula rate proposal is wholly one-sided. In PSO's request to move from historical rate-of-return regulation to rates based PSO's proposed formula, PSO puts itself in a better position that it does the customer. For example, under PSO's proposal, if PSO earns too little, it files with the Commission and implements new rate schedules to make up for the difference. These rate schedules stay in place until modified. On the other hand, if PSO earns too much, it proposes only to "share" these over earnings by way of temporary credits to customers – not modified rate schedules.[10]

PSO claims a significant benefit of its formula rate proposal is to "ensure PSO's earnings fall within an appropriate approve range by allowing adjustments to rates between rate cases,"[11] which will be more efficient and "reduce regulatory costs and burdens."[12] Under Oklahoma law, the Commission processes rate cases in a timely manner – 180 days. If an order is not issued, the utility has statutory authority to implement rates subject to refund. Therefore, the Oklahoma Commission already has a timely and efficient process in place without the need to implement

[8] Sartin Direct Testimony, page 5.
[9] Solomon Direct Testimony, page 5.
[10] *See* Moncrief Direct Testimony, page 10 and Exhibit DRM-2.
[11] Moncrief Direct Testimony, page 9.
[12] Solomon Direct Testimony, page 6.

PSO's requested formula-based rates. PSO's own testimony supports this fact. For example, PSO's testimony discusses the fact that the Regulatory Research Associates ("RRA") ranks the *current* Oklahoma regulatory environment as "relatively balanced."[13] Moreover, Lehman Brother's ranks Oklahoma's *current* regulatory environment as "being responsible and constructive, and fairly balancing the interests of consumers and investors in a way that maximized the interests of both."[14] As noted by PSO, both of these assessments are evaluated from an *investor perspective,*[15] not a consumer or competitor perspective. Clearly, investors view the current Oklahoma regulatory climate satisfactory without the need for substantial changes in its rate regulation scheme.[16] The ultimate basic issue is adequate recovery through rates, not whether PSO is provided formula-based rates, including recovery of CWIP, in this Cause.

As a last note, PSO's investment over the next five years is estimated to be $2 billion, while AEP has capital expenditures planned of more than $10.6 billion in just the next two years alone.[17] As PSO relies on AEP almost entirely for access to the markets,[18] its concerns regarding cash flow and access to the markets appear to be more heavily impacted by AEP's corporate actions that by this proceeding itself.

City of Tulsa

The CITY OF TULSA ("COT"), an intervenor in this cause, respectfully proffers to the Oklahoma Corporation Commission a Statement of Position concerning Public Service Company of Oklahoma's ("PSO") Application for an adjustment in its rates and charges for electric service in the State of Oklahoma. COT hereby offers this Statement of Position in response to PSO's request for the approval of formula-based rates, and is not intended to address all issues, which COT may address during the course of this Cause.

COT, hereby adopts the Statement of Position filed on behalf of Redbud Energy, LP on March 20, 2007, as if set forth verbatim herein.

FINDINGS OF FACT AND CONCLUSIONS OF LAW WITH RESPECT TO 17 O.S. §284

17 O.S. Section 284, provides:

> In its review and examination of an application by a utility to change its rates and charges pursuant to Sections 137, 152 and 158.27 of Title 17 of the Oklahoma Statutes, and in any order resulting therefrom, the Corporation Commission shall

[13] Abbott Direct Testimony, Page 8.
[14] Cannell Direct Testimony, page 33.
[15] Cannell Direct Testimony, page 33.
[16] In fact, PSO recognizes Fitch's positive comments about the Commission's new competitive procurement rules in which they describe the requirement for RFPs and pre-approval of requests, "subject to review upon completion" and that such "significantly increases the probability of adequate recovery of investments." Cannell Direct Testimony, page 24, *quoting* Fitch Ratings.
[17] Solomon Direct Testimony, page 5.
[18] Cannell Direct Testimony, page 21.

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.

After consideration of the briefs filed by the parties in this Cause, the Commission finds for the interpretation of 17 O.S. Section 284 which requires ("shall") 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. 17 O.S. Section 284 is not inconsistent with the Article IX of the Oklahoma Constitution, Oklahoma statute or Commission rules. This interpretation would allow the Commission to adopt proposed adjustments of the parties within six (6) months of the end of the test period upon which the rate review is based. It is not necessary for the Commission to look beyond this period in this Cause, because the Commission has not recommended adjustments beyond the period set forth in 17 O.S Section 284. The Commission finds that the Commission's Order in this Cause be determined in accordance with the provisions of 17 O.S. Section 284.

Constitution, Statutes, Commission Rules.

Constitution.

The Oklahoma Corporation Commission was established pursuant to provisions of the Oklahoma Constitution. The Commission is empowered by Article IX, Section 18, of the Oklahoma Constitution to supervise, regulate and control public utility companies doing business within the state in all matters relating to the performance of their public duties. Article IX, Sections 15-35 detail the powers and duties of the Commission. The Corporation Commission is a body of limited jurisdiction and its jurisdiction is derived expressly or impliedly from the Constitution and statutes. *See Samson Resource Co. v. Oklahoma Corp. Comm'n,* 859 P.2d 118, 1120 (Okla. 1993) The Commission has the power and duty to prescribe and enforce rates, charges, classifications of service, and rules and regulations for public utilities. Pursuant to Section 19 of Article IX of the Oklahoma Constitution, the Commission may be "vested with such additional powers, and charged with such other duties as may be prescribed by law, in connection with the visitation, regulation, or control of corporations, or with the prescribing and enforcing of rates and charges to be observed in the conduct of any business where the State has the right to prescribe the rates and charges in connection therewith…"

Statutes.

A fundamental rule of statutory construction is to ascertain and give effect to legislative intent and that intent is first sought in the language of the statute. *See, eg., YDF, Inc. v. Shlumar, Inc., 136 P.3d 656, 658 (Okla. 2006)* It is only in cases where the legislative intent cannot be determined from the express language of the statute that the rules of statutory construction are applied.

Further Title 17, Section 152, of the Oklahoma Statues provides that this Commission shall have general supervision over all public utilities, with the power to fix and establish rates and to prescribe and promulgate rules, requirements and regulations, affecting their services, operation, and the management and conduct of their business; shall inquire into the management of the business thereof, and the method in which the same is conducted.

17 O.S. Section 284, originally a section of Senate Bill 1160, was adopted by the Oklahoma Legislature in 1994. The bill was a comprehensive bill containing a variety of provisions. The Act contained both an emergency clause section and an effective date section. The Act became effective on July 1, 1994.

17 O.S. Section 284, provides:

> In its review and examination of an application by a utility to change its rates and charges pursuant to Sections 137, 152 and 158.27 of Title 17 of the Oklahoma Statutes, and in any order resulting therefrom, the 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.

Section 284 appears to be a legislative enactment which grants powers to the Commission in connection with the prescribing and enforcing rates and charges for utilities. The primary goal of statutory construction is to determine legislative intent and that intent is to be ascertained from the statute in light of its general purpose and objective. *TXO Production Corp. v. Oklahoma Corp. Commission* 1992 OK 39 ¶7, 829 P.2nd 964. Thus, the language of Section 284 must be read to determine what the Legislature intended.

The language used by the Legislature prescribes a length of time, six (6) months, as the standard for making adjustments to items considered in a rate proceeding.

In the history of the Commission prior to the enactment of Section 284, there had been instances where adjustments were made to provide both the utility company, subject to an examination of rates, and the customers of those companies appropriate treatment for certain activities. For instance, in Cause 25346, Order No. 112286, the Commission found that "construction projects in progress which will be on line or in use no later than December 31, 1975, should be and are thus allowed in the current rate base." (The test year in that case ended on December 31, 1974.)

The enactment of 17 O.S. Section 284 imposed guidelines for the Commission in these circumstances. First, it is clear that the time period is a period of six (6) months following the end of the test period upon which the rate review is based. Second, the changes contemplated must be ones that are known and measurable changes occurring or reasonably certain to occur. Finally, in the review and examination of an application by a utility to change its rates and charges pursuant to certain sections, in this case, Section 152 of Title 17, the Commission must give effect to those changes.

Commission's Minimum Filing Rules ("MFRs").

OAC 165:70-3-2(a) states in part that "the utility shall file as the test year a recent historical 12-month test period . . . no more than (6) months old at the time the application package is filed with the OCC Court Clerk." Based on this requirement, PSO used the test year period ending June 30, 2006, and made its filing in November, 2006. Also, OAC 165:70-3-2(b) states that "the pro forma test year shall reflect normalized operations, including pro forma adjustments." The MFRs go on to define the term "test year" at OAC 165:70-1-2 as "the (12) month period used in determining rate base, operating income, and rate of return." "Pro forma adjustment" is defined in the same rule as "adjustments made to test year results and balances for known and measurable changes to obtain a normal and representative relationship between revenues, expenses, and rate base."

What Does "Shall" Mean?

> "The use of "shall" by the Legislature is normally considered as a legislative mandate equivalent to the term "must," requiring interpretation as a command." *Heirschberg*, Id, at 450.[19]

OCC Staff must "give effect" to all "known and measurable changes" occurring, or reasonably certain to occur, within six (6) months of the end of the test year.

What Does "Give Effect" Mean?

OCC Staff must consider all known and measurable changes occurring, or reasonably certain to occur, within six (6) months of the end of the test year, making pro forma adjustments,[20] where necessary, in order to properly account for the effects of said changes. This language does not require adjustments of test year component values (*i.e.*, revenues, expenses and rate base) if OCC Staff determines such adjustments would not reflect an ongoing normative or representative relationship between revenues, expenses, and rate base.

What Does "Known And Measurable" Mean?

As with the phrase "give effect," there is no statutory definition for "known and measurable", therefore it should also be read and understood according to its common usage. OCC Staff must consider only those changes occurring, or reasonably certain to occur, within six (6) months of the end of the test year. If a change is unknown then clearly OCC Staff cannot account for it within its review of a utility's application; likewise, if a change is known but its impact upon revenues, expenses or rate base cannot be reasonably measured then it cannot be accounted for by OCC Staff either.

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[19] *See McDonalds v. Groves*, 652 P.2d 281, 82 (Okla. 1982), *quoting* from *T.I.B. Corp. v. Edmondson*, 630 P.2d 1296) (Okla. 1981) and *Sneed v. Sneed*, 585 P.2d 1363 (Okla. 1978) stating:

" 'Shall' is generally indicative of a legislatively mandated imperative."

[20] Oklahoma Administrative Code (OAC) 165:70-1-2 "Pro forma adjustments" means adjustments made to test year results and balances for known and measurable changes to obtain a normal or representative relationship between revenues, expenses, and rate base.

What Does "Within Six (6) Months Of End Of The Test Period"[21] Mean?

"Within six (6) months" requires OCC Staff to consider any measurable changes occurring, or reasonably certain to occur, no later than six (6) months after the end of an applicant's submitted test year.

17 O.S. § 284 speaks only to the six (6) months immediately following the end of the test year and neither requires additional review by OCC Staff—which might prove impractical, or at least pressing, under the time constraints set forth in 17 O.S. § 152(3) and OAC 165:70-1-5[22]—nor does it prohibit such review by OCC Staff or this Commission as noted within the report and recommendation of the Honorable Administrative Law Judge Maribeth D. Snapp as accepted by this Commission in interlocutory order, Order No. 492407, in Cause No. PUD 200300076.[23] As a practical matter, OCC Staff has generally limited its review to those changes occurring, or reasonably expected to occur, within six (6) months of the end of the test year but it may, if determined to be in the public's best interest, extend its review beyond those six (6) months.

It has been suggested that OAC 165:70-3-3(a) negates the OCC Staff's six (6) month, post-test year review of known and measurable changes to revenues, expenses and rate base, however, OAC 165:70-3-3(a) is specific to utilities not OCC Staff.

OAC 165:70-3-3(a) simply requires rate case applicants to submit their application packages with data which is no more than six (6) months old. OAC 165:70-3-3(a) reads, in pertinent part:

> **As a minimum,** the utility **shall file as the test year a recent historical twelve-month test period** which shall be no more than six (6) months old at the time the application package is filed with the OCC Court Clerk. (Emphasis added.)

There appears to be nothing within OAC 165:70-3-3(a) which nullifies, restricts, or in any manner conditions OCC Staff's review authority under 17 O.S. § 284; to interpret OAC 165:70-3-3(a) as placing such restriction upon OCC Staff would be counter to recognized

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[21] OAC 165:70-1-2 "Test Year" means the twelve (12) month period used in determining rate base, operating income and rate of return.

[22] 17 O.S. §152(3):

> Public hearings on such matter must commence within forty-five (45) days of the end of such examination and be conducted by the Commission **and in no event shall the conclusion of such examination of the rate and changes and the hearing conducted by the Commission exceed one hundred eighty (180) days from the date the request was filed.** (Emphasis added.)

OAC 165:70-1-5(b)(2):

> Public hearings on such application shall commence within thirty (30) days of the end of the Commission's examination of such application and in no event shall the conclusion of the Commission's examination of the application and the hearing conducted by the Commission exceed one hundred eighty (180) days from the date the application was filed.

[23] "The ALJ advised counsel that although the Oklahoma statutes mandated that the Commission give consideration to known and measurable changes that are within six months outside of the test year, there is no legal prohibition against considering changes which occur beyond that time frame if the Commission finds it appropriate to do so." *ALJ Snapp, Order No. 492407, Findings of Fact, Para. 5, Ln. 1-4.*

statutory construction requiring all statutory language to be understood and applied so as to assure compatibility with other, differing statutory language, unless impractical.

Although intervenors apply *expressio uninus est exclusio alterius,* the maxim meaning the expression of one thing is the exclusion of another, this maxim should not be interpreted to allow a specific statute to take precedence over the general supervisory powers bestowed upon the Commission by the Oklahoma Constitution, Article IX Section 18.

FINDINGS OF FACT AND CONCLUSIONS OF LAW

A. Jurisdiction

The Commission finds that the Applicant is a public utility with plant, property, and other assets dedicated to the generation, production, transmission, distribution, and sale of electricity, power and energy at wholesale and retail levels within the State of Oklahoma. This Commission has jurisdiction over the Cause by virtue of the provisions of Article IX, Sections 18 of the Constitution of the State of Oklahoma, Okla. Stat. tit. 17 (2001), §§ 151 *et seq.,* and the rules and regulations of the Commission, including the Commission's Minimum Standard Filing Requirements as set forth in OAC 165:70. Due and proper notice of these proceedings was given as required by law and the orders of the Commission, and PSO is in substantial compliance therewith.

B. Test Year

The test year in this case is the twelve-month period ending June 30, 2006. The Commission finds that Okla. Stat. tit. 17, § 284 requires the Commission to give effect to known and measurable changes occurring or reasonably certain to occur within six months of 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 December 31, 2006, which is six months after test year end. PSO was critical of this approach, asserting that it was inappropriate to update some accounts and not others, and that if the Commission were going to update the test year it should update all accounts. The Commission finds that this position is not consistent with Okla. Stat. tit. 17, § 284, nor is this position consistent with prior Commission practices as it relates to previous rate cases (Cause Nos. PUD 200400610 and 200500151), which were litigated subsequent to the enactment of 17 O.S. Section 284.

C. Rate Base

1. Plant in Service

a. Utility Plant. The Commission adopts Staff's Adjustment B-1, which increases the utility plant in service by $20,940,266 as detailed by Mr. Thenmadathil. Staff updated the plant in service balances based on the known and measurable changes occurring or reasonably certain to occur within the six-month post test year period, December 31, 2006. Total plant proposed by Staff is $3,030,602,569. [Transcript of Proceedings, May 7, 2007, pg. CH-120, Testimony of George Mathai] The Commission finds that based on this final rate order, PSO's total Company plant in service is $3,030,727,646. [See Accounting Exhibits, Attachment 1, Application Package Schedules, Schedule B-2, pg. 1of 2]

b. Electric Plant Acquisition Premium-Clinton Sherman Industrial Air Park. The Commission adopts Staff's Adjustment B-2, which decreases the rate base by ($3,490,722) to remove the Electric Plant Acquisition Premium. These acquisition premiums were included in PSO's Cause Nos. PUD 200300076 and 960000214, two cases that were settled. The PUD Staff recommended removing the acquisition premium in both cases. The Commission agrees with Staff that the Company has been unable to demonstrate a cost savings, operational efficiencies, or quantifications of additional revenues sufficient to justify this acquisition premium remaining in rate base.

c. Time-of-Day ("TOD") Metering Investment. The Company included in its plant in service request $62,539, which is the cost of time-of-day metering investment that will be necessary to implement a time-of-day pilot program for residential and small commercial customers. Staff, the AG, and OIEC all proposed to eliminate this amount from plant in service. Aaron Rebuttal at pp. 20-21.

The Commission declines to make the adjustment proposed by Staff, the AG, and OIEC. The investment is necessary to incent the Company to continue its time-of-day pilot program. The Commission affirmatively supports the implementation of DSM type programs and does so by allowing the Company to recover this investment in its plant in service request.

d. Non-Expense Payroll Adjustment. Staff originally proposed an increase to Rate Base of $4,431,623 for Payroll Capitalization, which adjustment B-7 was based on a 3-year average percentage for O&M Expenses and Capitalization. Staff filed supplemental testimony asserting that Staff had adjusted its levels and was no longer using the 3-year average. The Commission agrees with the final analysis of Staff and agrees with Staff's withdrawal of its proposed adjustment B-7. Therefore, the Commission adopts Staff's assertion that no adjustment be made to the Company's filed position in this area. Staff ultimately adopted the Company's calculation of the payroll expense ratio. May 7, 2007 Tr. at pp. 160-161, l. 16 (Wreath Cross); Exhibit 266, Staff Supplemental Accounting Exhibit. As a result, the Commission finds that no non-expense payroll adjustment to rate base is proper.

e. Accumulated Amortization on Electric Plant Acquisition. The Commission adopts Staff's Adjustment B-8 which increases rate base by $3,398,515 to remove the related accumulated amortization of the electric plant acquisition referred to in adjustment B-2. This adjustment is necessary to remove the related amortization associated with the electric plant acquisition premium.

f. Construction Work in Progress ("CWIP"). The Commission adopts Staff's Adjustment B-9 to decrease CWIP by $29,560,676. By including the Plant-in-Service balance at December 31, 2006, all completed plant investments that are known and measurable occurring or reasonably certain to occur are included in the rate base; therefore, an amount for CWIP is not necessary. Staff additionally included $87,164,808 of Plant- in Service which was completed but not classified. Under this methodology, most of the CWIP that PSO has requested is included in rate base. Any CWIP, which is to be completed after December 31, 2006, is excluded.

g. Accumulated Depreciation. The Commission adopts Staff's Adjustment B-14 to increase PSO's accumulated depreciation by $5,550,184 which reduces PSO's rate base by a corresponding amount. Staff accepted the testimony of the AG witness Roya Soltani in Cause No. PUD 200600285, filed March 20, 2007.

2. Prepaid Pension Asset and Associated Accumulated Deferred Income Tax ("ADIT")

The Commission adopts Staff and OIEC's proposal to reduce the pro forma rate base by the balance in PSO's Prepaid Pension account, and to increase operating expense by an amount equivalent to the Company's cost of debt return on this balance. PSO included a 13-month average of Prepaid Pension costs in its pro forma rate base in the amount of $81,973,283, as reflected in HE-17 at page 22 of 24. The Commission finds that this amount should be removed from rate base consistent with the recommendations of Staff and OIEC, and a cost-of-debt adjustment should be made at the rate of 6.32% (as recommended by OIEC), for a total of $3,176,008, as reflected in HE-17 at page 22 of 24. The Commission finds that since the contributions to the pension fund above the SFAS 87 levels have been discretionary contributions, since ratepayers receive a benefit from the contributions in the form of lower SFAS 87 expense levels, PSO should be allowed to recover the cost of making reasonable additional contributions. PSO should be allowed to recover only the actual cost of making the contribution without earning a profit from doing so.

The Commission finds that this treatment of Prepaid Pension contributions is consistent with the Commission's prior order in Cause No. PUD 200500151 [Final Order, pg. 87]. The Commission further finds that the ADIT, in the amount of $31,719,987, associated with the Prepaid Pension contributions should be removed from the ADIT balance at December 31, 2006, as reflected in HE-17 at page 22 of 24. This additional adjustment was proposed by PSO witness Mr. Aaron in his rebuttal testimony, and accepted by OIEC witness Mr. Garrett at the hearing on the merits.

Based on the Commission's finding to remove the Prepaid Pension Asset and Associated ADIT from PSO's rate base and award it a debt return of 6.32%, *the Commission finds that* an additional adjustment must be made to reflect the removal of an equivalent amount of debt, $50,253,296 ($81,973,283-$31,719,987), from PSO's capital structure. Since the Prepaid Pension Asset and Associated ADIT will be financed entirely by debt, that level of debt is no longer available to finance PSO's remaining rate base and must be excluded when calculating the overall rate of return (ROR). Removal of $50,253,296 of debt from PSO's capital structure produces an adjusted ROR grossed up for income taxes of 11.120%. This adjusted ROR, when compared to the unadjusted ROR of 10.924% produces a differential of .196%. Applying the .196% differential to PSO's rate base of $1,121,719,668, as adjusted by the Commission's finding, produces an additional revenue requirement of $2,220,297. The Commission further finds that the additional adjustment made hereto to reflect the removal of debt from PSO's capital structure is based solely on the rebuttal testimony of PSO witness John Aaron filed in this proceeding and therefore, the additional adjustment above is made as a result of the evidence produced in this proceeding and sets no precedent for any future causes that the Applicant or others may file with this Commission.

3. Other Prepayments

a. Total Prepayments. The Commission adopts Staff's Adjustment B-13, which decreases rate base by ($397,968) to allow a certain level of prepayments in the rate base.

b. Update. The Commission agrees with Staff's recommendation of a 13-month average updated to December 31, 2006 to be used for prepayments, rather than PSO's 13-month average ending at test year-end. This results in an increase in prepayments of $279,502.

c. OCC Assessment Fee. The Commission also agrees with Staff's removal of ($128,132) of the OCC Assessment Fee Accrual, which is recorded as a prepayment. PSO is already allowed to collect monthly expenses for OCC Assessment Fees.

d. Credit Line Fees and Prepaid Carrying Cost for Factored Accounts Receivable. The Commission agrees with Staff that PSO has adequate funding to meet its short-term capital needs or requirements through the cash working capital allowed herein and with Staff's removal of ($172,037) associated with prepaid credit line fees and ($377,301) associated with prepaid carrying cost on factored accounts receivable, adequate funding is in place as addressed by Bob Thompson on Pages 18 and 19 of his pre-filed testimony.

e. Oklahoma Capital Investment Board. Staff did not include this prepayment in the balance used for the thirteen (13) month average ending December 31, 2006 since the associated tax credit for this prepayment is not reflected in PSO's cost of service.

f. FAS 158 Quail Contra Account. Staff and PSO agree that there is a zero effect due to an associated decrease in regulatory assets for the same amount.

4. Materials and Supplies

The Commission adopts Staff's Adjustment B-6 where Staff proposes to increase rate base for Materials & Supplies by $3,454,520. The Commission agrees with Staff's incorporating the known and measurable changes in the Materials & Supplies account occurring or reasonably certain to occur within six-months post-test year and their use of the 13-month average of actual inventory levels ending December 31, 2006, which produced a balance of $44,645,668. The Commission also agrees with Staff's assertion that the 13-month average is typically used if balances are volatile, and that forecasted amounts are used when the test year is based on projected data. The six month post test year approach was adopted by the Commission in Cause No. PUD 200500151, [Final Order, pg. 88].

5. Fuel Inventories

The Commission finds that the Company's 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 and should be adopted.

The pro forma adjustment made by the Company is necessary in order to correct the anomalous coal inventory levels experienced during the test year despite the Company's operational practice to achieve its target coal inventory levels. Exhibit 18, Aaron Direct. at p.15. The cost per ton used in PSO's adjustment is based on the average inventory cost per ton at June 30, 2006, the test year end. Aaron Rebuttal at p. 35. The Commission finds the Company's treatment of this item to be proper. Reliance on the test year-ending cost per ton properly incorporates the adjusted amount into the test year.

In contrast, the AG proposed to eliminate the pro forma adjustment from rate base. The record contains no studies to support a finding that a reduction in the Company's inventory target would not place customers at greater risk of high costs in the case of coal transportation disruption. Exhibit 163, Hakimi Rebuttal at p.16. There is no evidence in the record to rebut PSO's testimony that the use of a target to manage fuel inventory is an appropriate operational practice and does not justify the exclusion of these costs from base rates.

Unpersuasive is the argument that any interruptions that occur as a result of the use of the 13-month average for fuel inventories could be cured through a combination of off-system power purchases and the availability of fuel oil inventory. To the contrary, the evidence establishes that PSO's coal-fired power plants do not burn oil for generation and that a coal shortage would result in a loss of approximately 1,018 MW of low-cost coal generation for use by PSO's customers. *Id.* at pp.16-17. The evidence further demonstrates that power purchases are not a reasonable substitute for coal generation since any shortage in coal supply will likely affect other utilities as well. *Id.* at p.17. This, in turn, will increase the demand for and price of purchased power and result in significant cost increases for PSO's customers. *Id.*

Moreover, the AG's proposed removal of PSO's pro forma adjustment implies that PSO should reduce its inventory target by a corresponding amount. This would place the Company's customers at greater risk of high costs in the case of a coal transportation disruption. The Commission finds the Company's treatment of this item to be proper.

6. Customer Deposits

The Commission adopts Staff's Adjustment B-11, which reduced rate base by ($974,637) for the $35.4 million of customer deposits using a 13-month average ending December 31, 2006. The Commission agrees with the Staff position that an updated 13-month average is the appropriate on-going level for customer deposits. In Cause No. PUD 200400610 [p. 91-92 of 134] the Commission adopted a customer deposit level based upon a thirteen month average occurring six month post test year.

7. Customer Advances

The Company utilized a balance of zero and Staff had no adjustment.

8. Off System Sales-Sales Trading Deposits

PSO included $5.3 million in rate base to reflect the 13-month average of PSO's net off-system sales trading deposits recorded on its books for the test year ending June 30, 2006. This treatment would allow recovery of carrying costs on the net of the funds provided and held by PSO for off-system trading activities. The treatment is similar to other deposits made by PSO or received by PSO. Aaron Rebuttal at p. 37. The Commission finds that the Company's treatment of this item is proper.

Trading deposits serve as security for trading activities and provide benefits to customers by limiting credit risk exposure and protecting against the possibility of a loss occurring when a counterparty fails to meet the terms of a contractual debt obligation. Hakimi Rebuttal at p.18. Trading deposits are required for American Electric Power Service Corporation ("AEPSC") to engage in both power purchase and sale transactions in the market on behalf of PSO and are an industry standard for any corporation entering into purchasing, trading, and marketing contracts. *Id.* The fuel cost savings associated with PSO's energy purchases in the test year was in excess of $101 million. *Id.* at Exhibit ANH-1R. May 7, 2007 Tr. at p. 148, l. 2 through p. 149, l. 10 (Thenmadathil Cross). The evidence further establishes that the trading deposit amount included in the test year is only the net amount by which deposits posted exceed deposits required. The Commission finds that inclusion of these net deposits in rate base is reasonable and appropriate in light of the evidence demonstrating these expenses are necessary to enable PSO to buy and sell energy in the market in an effort to lower fuel costs to native load customers. Inclusion of these net deposits in rate base is appropriate.

9. <u>IPP ("Independent Power Producer") System Upgrade Credits</u>

The IPP credit represents a portion of funds provided by PSO's IPP customers. It is the portion that is eventually refunded to the IPP customer. The IPP customer makes two payments to PSO when executing an interconnection agreement. One payment is for the actual physical assets required to interconnect the customer with PSO's system. That payment is treated like a contribution in aid of construction and reduces PSO's plant investment. The customer pays for the assets and the payment is not refundable. The second payment is for upgrades PSO must make to its transmission system as a result of the customer's interconnection and the impact that interconnection may have on PSO's transmission system. FERC Order 2003-A, 106 FERC 61,220, issued March 5, 2004 requires that this upgrade payment be refunded. Aaron Rebuttal at p. 38. The Staff Adjustment B-10, updates IPP System Credits in the rate base by ($674,566) in order to match the updated transmission plant balance at December 31, 2006. *See also* Staff Adjustment H-19 in the amount of $47,243 updating the amount of interest expense for this item. PSO has reflected the amount of IPP System Upgrade credits recorded on its books at June 30, 2006, the test year end. The Commission adopts the position of PSO in the amount of ($8,664,432).

10. <u>Cash Working Capital ("CWC")</u>

The Commission finds that the Commission adopt Staff's adjustment No. B-12, which reduces CWC by $4,250,695. Although Staff accepted Company's expense lead-times and the CWC requirement offsets in the lead-lag study, Staff had differences with the Company's CWC allowance calculation. Staff's recommendation was to include interest on long-term debt and dividends on preferred stock within the CWC calculation. This calculation method was previously accepted by the Commission in Cause Nos. PUD 910001190, 200400610 and 200500151 and the Commission should continue to accept this calculation method. Finally, the Commission agrees with the Staff recommendation that the CWC should be updated upon final resolution of all other issues in this cause. The Commission finds that based on this final rate order, CWC is reduced by $5,331,253 [See Accounting Exhibits, Attachment 1, Application Package Schedules, Schedule B-2, pg. 1of 2]

11. Accumulated Deferred Income Tax ("ADIT") Generally

The Commission adopts the Staff's position regarding general ADIT taking into account the ADIT adjustment for prepaid pension asset as set forth in 2. above.

12. Excess Deferred Taxes

No adjustment.

13. Deferred Investment Credits (pre-1971)

PSO, Staff, AG and OIEC are in agreement as to the Total Company amount of $238,673 and the PSO Jurisdictional amount of $237, 931.

D. Rate of Return

1. Capital Structure

The Commission finds that the appropriate capital structure for PSO is 53.55% long term debt, 0.43% preferred stock, and 46.02% common stock. *See* Exhibit 15, Murry Direct at p. 7, l. 8-10. The appropriate capital structure for PSO in this proceeding includes $650,464,963 in long-term debt, $5,261,700 preferred stock, and $559,036,505 in common stock equity, resulting in a total capital of $1,214,763,168. *See* Exhibit 15, Murry Direct at p. 18, l. 8-11. These amounts represent the test year-end levels, June 30, 2006, for these components.

The capital structure of PSO is fundamentally similar to that of other electric utilities. The common stock equity of PSO is slightly higher than American Electric Power Company's ("AEP"), but is in line with the equity ratios of other comparable electric utilities. *See* Exhibit 151, Murry Direct at p. 18, l. 15-19.

While the Commission does not specifically adopt the recommendation of Fairo Mitchell of the OCC Staff, Mr. Mitchell's recommendation was utilized in the Commission's review of this issue. Mr. Mitchell recommended an adjustment to reflect PSO's capital structure as of December 31, 2006, consistent with other adjustments proposed by the OCC Staff that substitute later amounts.

PSO's capital structure at June 30, 2006, includes a special negative equity charge related to Statement of Financial Accounting Standards No. 87 , *Employers' Accounting for Pensions* ("FAS 87") minimum pension liability that was reversed for ratemaking purposes. Additionally, Statement of Financial Accounting Standards No. 158, *Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans* ("FAS 158") expanded the use of FAS 87 minimum pension liability and requires the recording of additional special accumulated other comprehensive income equity reductions or equity additions for items that have not yet been included in PSO's benefits cost or cost of service. Since these additional special equity reductions or equity additions apply to the balance sheet but not the income statement and therefore will not be included in current pension and postretirement benefit costs for book accounting and ratemaking purposes, such future pension and postretirement special equity reductions or equity additions should be eliminated from the capital structure when they occur. The Commission finds that these types of accumulated other comprehensive income adjustments to equity related to pensions and post-retirement benefits should be excluded from capital structure for ratemaking purposes. This will allow PSO to defer on its books any such pension and postretirement special equity reductions or equity additions as a regulatory asset or liability, as appropriate.

2. Cost of Capital

a. Cost of Debt and Preferred Stock. The Commission finds that PSO's embedded cost of long-term debt was 6.32% and the cost of preferred stock was 4.02%. Both costs are appropriate. *See* Exhibit 151, Murry Direct at p. 7, l. 11-12; *see also* Exhibits DAM-7 and DAM-8 and Mitchell Direct at pp. 25-26, Exhibit 125.

b. Return on Equity. The Commission finds that a return on equity of 10% is reasonable.

The Commission finds *Southwestern Public Service Company v. State of Oklahoma*, 637 P2d 92 relevant to its determination herein. In its opinion in that case, the Oklahoma Supreme Court stated:

> "The constitutional safeguard afforded to a utility is summarized in *Alabama Public Service Com. v. South Cent. Bell Tel. Co., (Ala., 348 So.2d 443)* as follows: 'The just compensation safeguarded to a utility by the 14th Am. to the U.S. Const. is a reasonable return on the value of the property used at the time that is being used for the public service, and rates not sufficient to yield that return are confiscatory. The determination of a fair rate of return is governed by the following legal principles: **(1)** it cannot be developed by a rule of thumb calculation, but must be determined in the exercise of a fair, enlightened and independent judgment in light of all relevant facts; **(2)** it must be equal to that generally being earned by others in the same general locality in business undertakings attended by corresponding risks, and uncertainties; **(3)** it must be sufficient to insure the investor's confidence in the financial soundness of the utility enterprise and enough to maintain and support its credit so that it will be able to raise the money necessary to improve and expand its service to the discharge of all its public duties; **(4)** in determining the reasonableness of its rates it is necessary to consider effect of the rates imposed in the light of the utility's present situation and in light of its requirements and opportunities.''

On the first point, cited in the above court decision, the record in the instant case before the Commission is voluminous and there is more than ample evidence and relevant facts on which to make a determination of a just and reasonable rate of return. As previously noted, witnesses recommended ROEs ranging from 9.25% to 11.75%.

As to the second point, the court indicates that the Commission should examine the level of earnings of other electric utilities "in the same general locality."

In Oklahoma, the two investor-owned electric utilities that serve areas closest to

PSO are Oklahoma Gas and Electric Company (OG&E), which in late 2005 was granted an authorized ROE of up to 10.75% by Commission order, and Empire District Electric Company, which through a settlement approved by this Commission in 2003 today remains authorized to earn an ROE of up to 11.27%. The average of those two returns is 11.01%.

Concerning the final two points in the aforementioned principles cited by the court, the Commission agrees with the Referee's belief stated at Page 136 of her report "that in determining a fair return for PSO, judgment is also required."

The Oklahoma Supreme Court has also stated in Turpen v. Okla. Corp. Comm'n, 769 P2d 1309, "There is no requirement that the Commission follow a specific plan in setting rates. Ratemaking is not an exact science involving precise mathematical calculation. The Commission is not limited to any particular theory or method in fixing rates. On the contrary, the Commission has wide discretion in the performance of its duties."

Witnesses for four of the parties to the instant Cause testified at length concerning the issue of ROE. No two expert witnesses agreed in their recommendations of an appropriate ROE. Other witnesses offered additional testimony pertinent to determining an appropriate return. After careful consideration of all of that testimony and based upon an analysis and comparison of the various positions asserted by the parties at the hearing on the merits and after applying judgment to the determination, this Commission finds that an ROE of 10% would be appropriate in this proceeding. An ROE of 10% would result in an overall 8.01% rate of return.

Expert witnesses that testified at hearing recommended ROEs ranging from a low of 9.25% (Dr. J. Randall Woolridge, witness for Oklahoma Industrial Energy Consumers); to a "middle ground" (Daniel Lawton, witness for Attorney General - who suggested an appropriate range from 9.3% to 10.2%; and Mr. Mitchell, who recommended the 10.17% adopted by the Commission Staff); to a high of 11.75% (Dr. Donald A. Murray, witness for PSO). The Commission has carefully considered all the testimony of the various experts and determined that 10% is a reasonable ROE based on the evidence received. That 10% ROE falls within the range of the expert recommendations, and adequately balances risk and return.

Staff witness Fairo Mitchell testified that in arriving at his recommendation regarding the Cost of Common Equity, which became the position adopted by PUD Staff, the Discounted Cash Flow ("DCF"), and Capital Asset Pricing Model ("CAPM") methodologies were used. He further testified that Staff also considered the risk associated with PSO's construction program. Mr. Mitchell presented the Commission and the parties with what was admitted into the record as Hearing Exhibit No. 4 ("HE-4"). HE-4 included a table, labeled Exhibit FAM-9, which detailed Staff's analysis of the average ROE when utilizing the DCF and CAPM methodologies, resulting in the recommended 10.17% ROE. It was further explained by Mr. Mitchell that the criteria used to determine his recommended ROE, which he considered to be fair and reasonable, included the economic guidelines and standards known as the Comparable Earnings and Capital Attraction Standards established in the *Bluefield* (1923) and *Hope* (1944) decisions; that a public utility has the opportunity to earn this return on the Commission's allowed rate base; and that current economic conditions and projected industry information as well as the Return on Investments of Comparable Risk were considered.

While cross-examination tended to focus on Staff's use of the median over an average and historic data that was used to calculate ROE, Staff supported its position by reiterating that the use of an average of Staff's calculations is accepted in the financial community as a reasonable estimate to calculate ROE. We agree.

Regarding the intervenors who suggested ROEs below 10%, Ms. Julie Cannell testified that there were only a "sprinkling of rulings" issued in 2005 and 2006 that awarded ROEs below the 10% level and that those included a number of decisions in a jurisdiction that employed a future test period, as opposed to the historic test period used in Oklahoma. She further stated that she had performed a recent study for Edison Electric Institute regarding investors' perceptions of state regulatory issues and that, among other things, that study revealed that investors considered 10% to be a minimum allowed ROE threshold and that the ROE should adequately recognize both industry risks and a company's particular risks. This witness also pointed out that PSO was preparing to undertake a significant capital spending program requiring it to access capital markets on a regular basis and that investors' perception of the constructiveness of Oklahoma regulation would be a key influence on PSO's cost of capital. Thus, the Commission found in her testimony additional support for the 10% ROE proposed by Staff and agrees that the current investment climate does not support a lower ROE than that adopted herein.

The Attorney General's witness, Mr. Lawton, testified that he recommended the appropriate ROE for PSO be determined to be 9.75%, which is the mid-point of a range for a reasonable authorized ROE for the company from 9.3% to 10.2%. Mr. Mitchell's recommended 10.17% is also within that range. The Commission's adoption of a 10% ROE for PSO is within that range.

There are a number of factors that argue for setting a return higher than the 9.25% recommended by the OIEC witness Dr. Woolridge or the 9.75% recommended by the Attorney General's witness Mr. Lawton. As stated in testimony, such factors include the outlook for higher interest rates and inflation and PSO's construction needs and programs. Further, the record is consistent that comparable utilities have been achieving returns at levels higher than even the 10.17% ROE recommended by PUD Staff witness Mr. Mitchell. *Mitchell Responsive, Exhibit FAM-8, Exhibit 125; Murry Direct, Exhibit DAM-12, Exhibit 15; Woolridge Responsive, Exhibit JRW-4, p. 3 of 3, Exhibit 127; Transcript at pages 134-135 (May 2, 2007).*

Besides the higher ROEs authorized in Oklahoma for OG&E and Empire District, PSO witness Ms. Cannell testified that electric utility ROEs authorized by state regulators around the country have gone down from an average of 11.16% in 2002 to 10.30% for the first quarter of this year. She also verified in her testimony that the Oregon Public Utility Commission on January 12, 2007 allowed a 10.10% ROE for Portland General Electric Company, and on January 11, 2007, the Pennsylvania Public Utility Commission authorized a 10.10% ROE for Pennsylvania Electric Company.

During cross-examination, PSO witness Mr. Stuart Solomon agreed that total return for stockholders of PSO parent American Electric Power Company last year was about 18% or more, which included stock price appreciation and dividends. *Transcript at pages 173-175 (May 1, 2007).* In consideration of the appropriate treatment of rate of return in this proceeding, the Commission references Commission Order No. 432267 in Cause No. PUD 980000444, issued May 17, 1999 wherein the Stipulation attached to the order provided at page 9, Section 11, Capital Costs:

"The Applicants commit and agree that the cost of capital as reflected in PSO's rates shall not be adversely affected by the result of AEP's acquisition of CSW. The Applicants also agree that subsequent to the completion of the merger, the cost of capital from PSO should be set commensurate with the risk of PSO and should not be affected by the merger. Applicants agree that they will not oppose, in either a regulatory proceeding or an appeal of a decision by the OCC, the application of the principal that the determination of the cost of capital can be based on the risk attendant to the regulated operations of PSO."

In conclusion, after reviewing the record and evidence in this case and the risk attendant to the regulated operations of PSO and after applying judgment, the Commission determines that a just and reasonable ROE of 10% is authorized.

3. Overall Rate of Return

The overall rate of return that results from the capital structure and cost of capital determined above is 8.01% as shown on Attachment 1, Schedule F-1, of the Accounting Exhibit [See Accounting Exhibits, Attachment 1, Application Package Schedules]

E. Revenue Adjustments

1. Adjustments to Customer Data Issues

a. Customer Data. OIEC witness Garrett proposes that an upward adjustment to test year revenues in the amount of $1,713,000 based on residential load growth is needed to reflect changes in the Company's non-fuel revenue levels over the six-month post-test year period. In fact, Mr. Garrett did not use year-end actual residential revenues, he projected year-end revenues using year-end customers. May 8, 2007 Tr. at p. 79. In response, PSO performed a similar projection, making some weather adjustments and customer adjustments as is the case with test year-end adjustments, and this produced projected revenues lower than those projected by Mr. Garrett. May 8, 2007 Tr. at pp. 79-80.

The Commission adopts the recommendation of PSO.

b. Weather Adjustment. PSO proposes a weather adjustment of ($6,381,756) and OIEC witness Garrett proposes a weather adjustment of ($6,073,850), while Staff witness Karen Forbes also proposed a modification of PSO's weather adjustment. Both Mr. Garrett and Ms. Forbes pointed out that PSO had applied the weather adjustment to the customer charge, which should not have been done, but Mr. Garrett and Ms. Forbes applied different methodologies to make the correction. Moncrief Rebuttal at p. 8, l. 17-18. PSO calculated its revised weather adjustment using Staff's methodology. Moncrief Rebuttal at p. 9, line 19. The Commission agrees with PSO's use of Staff's methodology, which has been used in the past and is the preferred method for calculating the weather adjustment. Accordingly, the Commission finds that Commission adopt PSO's revised weather adjustment.

c. 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. May 8, 2007 Tr. at p. 71. 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. Exhibit 027, Moncrief Direct at p. 27, lines 7-10. Staff witness David Smith recommends that PSO reduce the Miscellaneous Revenues amounts based on the ratio of those revenues to total Company revenues during the test year. The Commission declines to make the adjustments proposed by Staff because Miscellaneous Revenues are calculated independently of base rate revenues. May 8, 2007 Tr. at pp. 71-72. The Commission accepts the Company's calculation of Miscellaneous Revenues.

2. Expenses

a. Environmental. The Company accepted the recommendation of both the OCC Staff and the AG to remove ($8,541) of environmental expense from its filing. The Commission finds the adjustment to be appropriate.

b. Dues and Memberships. The Commission adopts the AG's proposal to decrease PSO's adjustment by ($425,554) to eliminate that portion of the adjustment not related to professional dues and memberships. The AG's revised adjustment removes dues and memberships in local and state chambers of commerce, civic and social dues and memberships, and incidental miscellaneous dues and memberships. The Adjustment does not eliminate professional dues and memberships.

c. Donations and Contributions. The Commission finds ($5,970) as proposed by PSO. The treatment of dues and donations is consistent with the Commission's findings in Cause Nos. PUD 200400610 [Final Order, pg. 121 and 122 of ALJ Report] and 200500151 [Final Order, pg. 97]

d. Legislative Expense. Supplemental Package WP H-14 provides the detail of PSO's requested legislative charges. PSO included $635,129 of test year legislative expenses in its cost of service, $326,112 charged to "above-the-line" accounts and $309,018 charged to "below-the-line" accounts.[24] Mr. Garrett, Mr. Wreath, and Ms. Soltani recommend excluding ($635,159) of PSO's legislative monitoring and advocacy expenses recorded "above-the-line" or reclassified from "below-the-line" for purposes of PSO's revenue requirement calculation.

The Commission adopts the adjustments of the Staff, AG and OIEC in the amount of ($635,159). *See* Cause Nos. PUD 200400610 [Final Order, pg. 106, ALJ Report] and 200500151 [Final Order, pg. 101]

e. Generation–Related O&M Expenses. The Commission finds that PSO should be permitted to recover its requested $63.8 million of generation-related O&M costs. The costs incurred during the test year were prudently incurred, are reasonable, and are recurring in nature. As evidenced by the testimony of PSO witness Mr. Isenberg and the Company's Plant Long Range Plans, the level of O&M expense incurred during the test year for generation-related

[24] WP H-14 of the OCC's Minimum Filing Requirements requires a "summarization of all payments to individuals registered to lobby in Oklahoma...during the test year." PSO has interpreted this requirement, possibly inaccurately, to include all charges incurred by PSO for participating in legislative activities, whether those charges are for monitoring legislative activities or advocating PSO's position.

services is representative of the future costs that will be required to continue the operation of the PSO generating assets. Exhibits 164/165/166, Isenberg Rebuttal, Exhibit MSI-6R.

While OIEC, the AG, and the Staff each proposed adjustments to the Company's requested generation-related O&M derived from different historical averages, the evidence demonstrates that those proposals are not representative of the test year or of ongoing level of O&M expense that will be required by PSO to operate and maintain its generating fleet. First, the intervenors' proposals are contradicted by PSO's Plant Long Range Plans, which establish that the test year level of generation-related O&M expense is representative of the level of expense that will be required during the period that the rates established in this case are in effect. *Id.* Second, reliance on a historic average to establish O&M expense in this case is not appropriate given the continued and sustained trend in increased levels of generation-related O&M expense that PSO has experienced every year since 2002. *Id.* at p. 25. Specifically, the evidence establishes that PSO's expenses increased from $41.4 million in 2002 to $43.4 million in 2003 to $46.4 million in 2004 to $54.1 million in 2005 to $60.1 million for calendar year 2006. *Id.*

Additionally, the evidence does not support OIEC witness Mr. Norwood's contention that the test year level of forced and planned outage hours resulted in an abnormally high level of test year O&M expense. The evidence shows that while the level of forced outages for Tulsa 2 and Oklaunion were the primary drivers of the increase in forced outage hours during the test year there was not a corresponding increase in the level of generation-related O&M expense for these units during the test year. For example, with respect to forced outage hours, the evidence shows that even though PSO's Tulsa 2 unit experienced a 2000% increase in forced outage hours during the first six months of 2006 as compared to all of calendar year 2005, there was less than a 10% difference in O&M expense for the Tulsa 2 unit between 2005 and 2006. Norwood Direct at Exhibit SN-3; HE-9; May 4, 2007 Tr. at pp. 65-70. The evidence further establishes that despite a significant increase in level of forced outage hours in 2006 as compared to 2005, the actual O&M expense for PSO's Oklaunion unit decreased during 2006. Norwood Direct at Exhibit SN-3; HE-10; May 4, 2007 Tr. at pp. 71-74. With respect to planned outages, the evidence also does not support Mr. Norwood's position given that the level of planned outages experienced during the test year is comparable to what the Company expects to experience during the period the rates established in this proceeding are in effect. Exhibit 126, Norwood Direct at Exhibit SN-3; Isenberg Rebuttal at Exhibit MSI-6R.

Finally, the evidence establishes that the actual level of inflation experienced by PSO should be considered in establishing an appropriate level of O&M expense. While Mr. Norwood included a 3% inflation rate in his adjustment to account for cost increases, Mr. Norwood offered no justification or basis for the use of this escalation rate. Mr. Norwood testified that his 3% inflation rate was not tied to any market index. May 4, 2007 Tr. at pp. 56-57. Mr. Norwood further testified that he did not conduct any study to identify the actual inflation rate that PSO experienced during the test year. In contrast, PSO offered evidence to demonstrate that it has experienced an actual compounded annual rate of growth in its generation-related O&M expenses of 7.52% for the period 2001 through 2006. Isenberg Rebuttal at p.26, Exhibit MSI-6R. This far exceeds the 3% included in Mr. Norwood's proposed adjustment. The evidence also reflects that for the six-year period 2005 through 2010, PSO's generation-related

O&M expense is projected to increase from $54.1 million to $78.1 million, a compound annual rate of growth of 7.60%. *Id.*

The Commission finds the unrebutted evidence offered by PSO regarding increases in the cost of contract labor and materials to be persuasive evidence that the test year level of generation-related O&M expenses is a reasonable and representative level of expense required to operate and maintain PSO's generation units. For example, the evidence establishes that the AEP Regional Services Organization ("RSO") that supports PSO's generating units experienced a rate increase in 2006 of approximately 16% for the skilled crafts and supervision that is direct billed to PSO. *Id.* Similarly, materials expense has increased by as much as 16% during 2006. *Id.* at pp. 28-30. The evidence also shows that as of December 2006, the RSO experienced an additional 41% increase in skilled labor rates for crafts such as Welders, Boiler Makers, and Supervision. *Id.* at p. 27. Contractors that perform work for PSO's plants have also experienced similar increases in skilled labor and supervision rates. *Id.* at pp. 27-28. This evidence supports a finding that O&M costs are not expected to decrease below the levels experienced by PSO during the test year.

Consistent with the above discussion, the Commission finds that the costs incurred during the test year were reasonable, necessary, and representative of the future costs that will be required by PSO to continue the operation of the PSO generating assets. Accordingly, the Commission approves the Company's requested $63.8 million in generation-related O&M costs.

The Staff and Attorney General also proposed adjustments to Generation Plant Maintenance Expense. The AG's adjustment compares the test year amount with the average of the three most recent plant O&M expenses, and normalizes the adjustment in the amount of ($8,517,672). [Responsive Testimony of Roya Soltani, pg. 29, lines 1-6]. The Staff's adjustment normalizes FERC account 512 for Boiler Plant Maintenance using a 3 year average ending at the six months post-test year. The resulting normalization adjustment (Staff Adjustment H-4) is a reduction to Boiler Plant maintenance expense of ($4,075, 441). [Prefiled Testimony of Jason Thenmadathil, beginning at pg. 15, lines 6-19]

Based on the foregoing, the Commission finds that PSO is permitted to recover generation related O&M expense in its cost of service. [Cause No. PUD 200500151, pg. 102 and 103]

f. Recovery of Baseload Bid Development Costs/New Generation Costs/Preliminary Engineering Expenses. PSO has awarded three proposals to build new generating capacity. Exhibits 19/20, Isenberg Direct at p. 27. The Riverside Station facility in Jenks, Oklahoma will add 170 MW of peaking capacity. *Id.* The Southwestern Station facility in Anadarko, Oklahoma will add 170 MW of peaking capacity. *Id.* PSO has also entered into a joint venture agreement to build a new 950 MW coal-fueled baseload unit near Red Rock, Oklahoma. *Id.* Under this agreement, PSO will own 50% or 450MW of the Red Rock unit. *Id.*

As part of the Request for Proposal ("RFP") process, AEPSC submitted self-build bids, on behalf of PSO. *Id.* at p. 28. The winning baseload bid was submitted by Oklahoma Gas & Electric Company (OG&E). *Id.* The two peaking bids selected by PSO were self-bid bids.

The Company seeks to amortize over five (5) years $2,212,016 in baseload bid development costs it incurred to participate in the RFP process. Isenberg Direct at p. 29. The Commission adopts Staff's Adjustment H-15 to remove preliminary engineering costs from operating expenses. The Commission agrees that all preliminary engineering costs associated with new generation be deferred until construction begins for those new plants, if constructed. The Commission further finds recording all engineering costs of PSO as intangible plant during the initial construction of the new plants if constructed; as intangible plant, the Company will receive rate base treatment for these new costs and be able to collect amortization expense during the life of the new plants, if any constructed. Staff Adjustment H-15 reduces operating expenses by $442, 403 to remove the amortization of these costs from the test year and defer those costs until initial construction of the new plants begins, if constructed. [Prefiled Testimony of George Mathai, March 20, 2007, pgs 24-25] The OIEC alleged that PSO in response to OIEC discovery (Cause No. PUD 200600030) indicated it would not seek recovery of the costs of preparing the bids. PSO refutes this proposition. Mr. Norwood proposes the same dollar adjustment as Staff stating that if the Commission were to allow recovery, the 5 year recovery period was not reasonable and such costs should be capitalized and recovered over the life of the baseload plant if any is constructed. [Direct Testimony of Scott Norwood on behalf of the OIEC, pgs 21-22]. The Commission finds the Staff's treatment of this issue as reasonable under the facts.

g. Trading Deposits Interest Expense. The Company requested to include $3,903 of net test year trading deposit interest expense in its cost of service. This is interest expense associated with the trading deposits discussed above. Aaron Rebuttal at p. 49. Both OCC staff and the AG recommended excluding this amount from PSO's cost of service.

Because the Commission has determined, above, that the trading deposits are properly included in PSO's rate base, the Commission likewise finds that the test year net interest expense related to these deposits, as proposed by the Company, should be reflected in PSO's cost of service. The deposits are required for PSO to engage in both power purchasing and off-system sales markets.

h. Regulatory/Rate Case Expense. PSO has requested to recover its estimated $410,000 in rate case expense over a two-year period, or $205,000 per year. Aaron Rebuttal at p. 50. Neither Mr. Thenmadathil nor Ms. Soltani disputed the amount. However, both recommend different recovery periods for the current rate case expenses. Mr. Thenmadathil recommends a five-year period, or a reduction of $123,000, to PSO's requested annual amortization of rate case expense for this proceeding. He does, however, concede that a two-year recovery would be acceptable if the formula rate plan as proposed by PSO is not implemented in this case. Ms. Soltani recommends a three-year recovery period of $136,667 per year or a reduction to PSO's request of $68,333.

According to the rebuttal position of the Company, the amount of rate case expenses should be recovered over a reasonable period approximating no more than the time between rate proceedings. That time is expected to be two years, three at the most. Aaron Rebuttal at pp. 50-51. According to the rebuttal position of the Company, PSO requested the ability to update rate case expense incurred through the close of hearings and recover that expense over two years. Prior to the close of hearings, PSO withdrew that request. Aaron Rebuttal at pp. 51.

Accordingly, the Commission finds that PSO's estimated $410,000 in rate case expenses should be recovered over a three-year period, as the AG has proposed.

i. Outside Services. OCC Staff recommended exclusion of ($12,769) of expenses charged to outside services for an AEP museum and exhibit located in its lobby. The Company accepted the proposed disallowance. The Commission adopts the Staff's proposed reduction to expenses.

j. Legal Expense. The Commission adopts Staff's Adjustment H-8, which removes certain legal expenses amounting to ($104,957). Staff had originally proposed disallowance of a total amount of ($195,741) related to legal expenses. This included legal expenses of ($181,568) associated with a case regarding discrimination. However, Staff has supplemented this position and as a result, has allowed 50% of this expense indicating that this should be shared on a 50/50 basis between ratepayers and shareholders rather than being completely removed. It is Staff's opinion that legal costs are a normal cost of doing business, but that these discrimination cases can be held to a minimum with proper management decision-making, and the Commission agrees. Staff's supplemental adjustment also removes ($14,173) associated with rate case expenses from PSO's requested legal expenses. Since rate case expenses are being treated separately via an amortization expense adjustment, this cost should not be allowed as a legal expense. The Company has agreed to this portion of the adjustment in rebuttal testimony.

k. Advertising Expense. The Company included in its cost of service test year-end advertising expense of $1,393,840. However, it subsequently accepted a proposed adjustment in advertising expenses related to the expenses Staff reviewed that amounts to a $475,990 reduction to PSO's revenue requirement. Aaron Rebuttal at p. 54. OIEC witness Garrett also accepted this adjustment. The Commission determines that this adjustment is proper.

l. Marketing and Sales Expense. The Company included in its cost of service test year end marketing and sales expense of $70,637. OCC Staff recommended a reduction of ($35,319) related to expenses recorded as marketing and sales expense based on the position that these expenses should be shared between shareholders and ratepayers. However, PSO explained that the Company has no retail marketing programs. The charges were recorded in FERC Account 912, Sales Expense, as a result of transposition errors. The amounts related to reimbursed employee expenses were included in expense reports. The charges should have been recorded in FERC Account 921. Aaron Rebuttal at pp. 54-55. Given the explanation of the Company and Staff's reliance thereon, the Commission finds the Company's request for its marketing expenses proper.

m. Ad Valorem Taxes. The Company included in its cost of service ad valorem tax expense of $34,049,988. This amount was based on test year ad valorem tax payments to applicable jurisdictions and test year end plant balances. OCC Staff witness Mr. Vaughn recommended a $1.4 million reduction to the ad valorem tax expense included in PSO's filing. Ms. Soltani and Mr. Garrett recommend a $1.7 million reduction to PSO's requested ad valorem tax expense.

Mr. Vaughn's initial adjustment was based on the premise that retail customers should only pay Oklahoma property taxes, and not property taxes paid to other jurisdictions. Exhibit 131, Vaughn Responsive at p. 11, l. 2-5. Nonetheless, at hearing, he indicated that he was not opposed to including ad valorem taxes paid to other jurisdictions in cost of service. He still supported his disallowance, however, stating he did not believe that PSO had property in any other jurisdictions besides Oklahoma and Texas and he was unable to confirm the ad valorem expense amounts for Texas that the Company reported. May 7, 2007 Tr. at pp. 174-176 (Vaughn Surrebuttal). Ms. Soltani and Mr. Garrett simply updated the test year ad valorem tax expense to reflect the total for the calendar year 2006.

Due to the varying understandings of PSO's tax process by the parties, the Commission finds that the OCC Staff and intervenor adjustments should not be allowed in this Cause. Mr. Aaron testified that all of the amounts of ad valorem taxes paid to the various jurisdictions where PSO owned property were proper. In addition, Mr. Aaron offered an exhibit and a detailed explanation of all the various jurisdictions in which the Company paid ad valorem taxes. Hearing Exhibit 20; May 9, 2007 Tr. at pp. 186-194 (Aaron Cross). This exhibit contains a summary of all ad valorem taxes paid and although the Company states this information was provided in discovery, the Staff made clear during the hearing that this information could have been provided in a more descriptive manner, given Mr. Vaughn's diligent efforts to review this issue. The Company should take into account Staff's concerns in the next rate review and make discovery process changes accordingly. The Commission finds that the amount of ad valorem taxes the Company requested is proper and all proposed adjustments to that amount are denied.

n. Purchased Power Capacity. PSO purchases capacity to have sufficient generation resources in place to serve its customers in a reliable and cost effective manner. Hakimi Rebuttal at p. 21. As a member of the Southwest Power Pool ("SPP"), PSO is required to meet the Capacity Margin Criteria (Criteria) of SPP. *Id.* Under the Criteria, PSO is required to own or purchase sufficient generating capacity resources to meet is forecasted peak load requirement plus a minimum capacity margin of 12%. *Id.*

Because PSO does not recover any portion of its capacity costs through its fuel cost adjustment ("FCA") Rider, PSO seeks recovery of its purchased capacity costs through base rates. *Id.* PSO made a pro forma adjustment to test year expenses to reflect the known and measurable change in the costs of this capacity. *Id.* at pp. 21-22. PSO made this adjustment because the capacity prices of capacity purchase contracts utilized by PSO during the test year changed on December 31, 2006. The evidence reflects that PSO will require additional capacity beyond December of 2007. May 8, 2007 Tr. at pp. 126-127. PSO's pro forma adjustment is based on the capacity costs from the contracts that were in effect during the test year with known capacity costs going into effect on December 31, 2006. Hakimi Rebuttal at p. 22.

While OIEC recommended that $3.4 million in purchased power capacity costs be recovered by PSO, OIEC proposes that this recovery occur through a newly created capacity purchase rider rather than base rates. PSO stated that it was receptive to recovering capacity purchase costs through its FCA Rider provided that all capacity purchase costs are recovered through the Rider. *Id.* at p. 24. It is not, however, clear based on a review of the evidentiary record whether OIEC's proposal contemplates the recovery of all costs of PSO's capacity purchases, which may vary from year to year or whether OIEC seeks to limit PSO's recovery of capacity purchase costs to $3.4 million. Accordingly, the Commission finds PSO's treatment of purchased power capacity costs to be appropriate.

The Staff proposed an adjustment in the amount of ($2,150,486); the AG proposed an adjustment of ($4,789,397).

As referenced above, while PSO's position is adopted in this report, on the basis of the testimony of Messr. Norwood (OIEC), the Commission finds that the Commission Staff conduct technical conference(s) to consider the OIEC's proposal of placing purchase power capacity costs through a purchase capacity rider and related issues. The technical conference should commence no later than November 15, 2007.

o. Payroll Expense. PSO determined the annualized base payroll for active employees on the payroll at June 30, 2006, the test year end. The result of this calculation was approximately $69.7 million total base payroll at June 30, 2006 for PSO. For the test year, PSO expensed 70.32% 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 70.32% to PSO's $69.7 million annualized payroll results in approximately $49.0 million of base payroll expense. When compared to the test year expensed level of $46.3 million, a $2.7 million increase is required. Only base payroll was annualized; overtime payroll was not. Test year overtime payroll charged to expense was $8,428,897. In summary, PSO's total requested pro forma payroll expense (annualized base payroll plus test year overtime payroll) was $57,459,813 for the test year ending June 30, 2006. Aaron Rebuttal at pp. 59-60.

OCC Staff witness Mr. Wreath originally recommended a $2.8 million reduction to PSO's pro forma base payroll. His adjustment was based on PSO's December, 2006 annualized base payroll and a three-year average payroll expense ratio. However, Mr. Wreath ultimately adopted the Company's payroll expense ratio, which changed his proposed payroll adjustment to a reduction of $512,123. Exhibit 266 (Staff Revised Accounting Exhibit); May 7, 2006 Tr. at p. 160, l. 19 through p. 161, l. 16 (Wreath Cross). AG witness Ms. Soltani recommended a $1.4 million reduction to PSO's proforma payroll based on PSO's December 2006 annualized base payroll and a three-year average for overtime payroll. Mr. Garrett recommended a $1.435 million reduction to PSO's payroll expense also based on December 2006 annualized amount. Hearing Exhibit 17.

The Commission adopts the Company's payroll proposal as being representative of payroll expense.

p. FICA Payroll Tax Expense. 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. OCC Staff witness Mr. Wreath recommended a $210,228 decrease to payroll tax included in PSO's filing. Ms. Soltani recommended a $515,572 reduction to payroll tax included in PSO's filing. Mr. Garrett recommended a $143,935 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. Aaron Rebuttal at p. 67.

These proposed adjustments should be denied. The level of payroll tax included in PSO's filing is consistent with the level of payroll expense found reasonable by the Commission above. As a result, the Commission accepts PSO's proposed level of payroll tax expense.

q. Employee Benefits-Supplemental Executive Retirement Plan ("SERP"). PSO included $596,081 as Supplemental Executive Retirement Plan ("SERP") in its cost-of-service. The Commission adopts OIEC's proposal to remove the SERP Expense from the revenue requirement in this proceeding. The Commission adopts OIEC's recommendation that ratepayers pay for all of the executive benefits included in PSO's regular pension plans and that shareholders pay for the additional executive benefits included in the supplemental plan.

r. Incentive Compensation. In most jurisdictions, including Oklahoma, the cost of incentive plans tied to financial performance measures are excluded for ratemaking purposes based on one or more of several reasons. Since utilities retain, between rate cases, all of the savings generated from increased efficiencies promoted by these incentives, payment to the employees for these plans should be made from a portion of the savings these plans help achieve. Thus, a properly designed incentive compensation plan will pay for itself and does not need to be subsidized by ratepayers. In the analysis of incentive compensation plans it is important to distinguish between financial performance measures and quality of service measures. However, if the overriding goal of the incentive plan is to increase shareholder earnings, the entire incentive compensation should be funded out of the increased earnings that trigger the payments. Cost of incentive plans were disallowed in Oklahoma in Cause No. PUD 91-1190, Cause No. PUD 200400610, and Cause No. PUD 200500151. Also, in Texas PUC Docket No. 28840, the Texas Commission disallowed sixty-six percent (66%) of AEP-Texas Central's test year incentive payments, which was the portion the Texas Public Utility Commission found was based on financial performance measures. AEP-Texas Central is a sister company of PSO and uses the same incentive plans.

The Commission finds that 50% of PSO's incentive costs should be excluded for ratemaking purposes, as recommended by OIEC. The amount of those incentive costs is $3,454,217 as referenced in HE-17 at page 16 of 24, OIEC Adjustment No. H-4. All of the costs of the plans should be excluded for the reason that the plans are overwhelmingly weighted toward the Company, rather than customer, objectives.

s. Long-Term Executive Stock Incentive Plan. The Commission adopts Staff and OIEC's proposal to remove $1,268,591 from PSO's cost-of-service. This amount is reflected on HE-17 at page 16 of 24, OIEC Adjustment No. H-5. The Commission finds that the FICA tax expense associated with the long term executive stock incentive payments should be removed for ratemaking purposes in the amount of $225,567, as proposed by OIEC. PSO's long-term executive incentive plan is specifically designed to tie executive compensation to the financial performance of AEP. 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. Further, a well designed incentive plan should pay for itself. Thus, there is no need to include in rates amounts that will be provided through higher earnings.

t. IPP System Upgrade Credit Interest. The Commission adopts the Company's proposed level of IPP upgrade credit interest expense of $632,504 as a corresponding finding to the Commission's determination regarding IPP System Upgrade Credits.

u. Credit Line Fees.

When the Company filed its case, it reclassified $203,300 in test year credit line fee expense from "below the line" to "above the line." Aaron Rebuttal at p. 72. AEP issues commercial paper that provides low-cost short-term borrowing rates for its affiliated companies, including PSO. In order to issue the commercial paper, AEP must guarantee the availability of funds to pay off maturing series of commercial paper. To do so, AEP obtains bank credit line support for that purpose. Aaron Rebuttal at p. 72.

OCC Staff witness Mr. Thompson and AG witness Ms. Soltani recommend reversal of this adjustment. Mr. Thompson states that PSO has adequate cash working capital and AFUDC to fund its construction activities without including this short-term debt cost in cost of service. Ms. Soltani states that PSO's overall rate of return is sufficient for these purposes and this short-term debt is not included in PSO's capital structure.

The Commission adopts the AG's proposal to reverse PSO's credit line fee adjustment in the amount of $203,300 to reflect that these fees are not included in PSO's net operating income under the FERC Uniform System of Accounts. These fees represent part of the cost of borrowing money in the form of short-term debt and thus are part of interest expense. Regulators provide for the recovery of capital costs including the cost of debt and equity financing through the overall rate of return and not by including interest costs in the income statement.

v. Depreciation Expense.

(1) Production plant life spans. AG Witness Pous testified that the Company's proposal to retain the existing 42-year life span for its coal-fired generating units does not reflect the actual beliefs or expectations of its engineering department or its depreciation experts, nor does it comply with standard industry expectations or what has been testified to in other jurisdictions for affiliates of the Company. The Commission adopts the AG's position that a 60-year life span for coal-fired generation is not only appropriate, but is consonant with how the Company actually expects to operate these units. The Commission takes note of testimony received during the hearing in Cause No. PUD 200600285, that OG&E, also an electric utility serving Oklahoma, uses a 55-year life span for its coal-fired units. The effect of this adjustment is a reduction of $7,055,111, based upon plant as of the end of December 2005.

(2) Production plant net salvage. Messrs. Pous and Selecky also criticize the Company's determination of production plant net salvage value and propose a sweeping recommendation that all production plant be assigned a negative 5% net salvage value. Mr. Pous also suggests an alternate proposal that reflects a positive 10% net salvage value, which he bases on his claims that many of the Company's plants could be sold in the future.

The Commission does not agree with these intervenor proposals, which are based on speculation regarding possible future events. Unlike the Company's analysis of net salvage values, which considers demolition studies of specific plants around the country, the intervenors' proposals are not based on actual plant data. Davis Rebuttal at pp. 8-9. The Commission adopts the position of PSO on this issue.

(3) Mass property net salvage. Based on the record in this Cause, the Commission finds that PSO should make no changes to its existing mass property net salvage adopted in Cause No. PUD200300076 and set forth in PSO's depreciation study filed in this Cause.

PSO determined T&D net salvage values using 21 years of Company data to calculate, on an account-by-account basis, a mathematical relationship between original cost, retirements, salvage and removal costs. Davis Rebuttal at pp. 20-21. The resulting mathematical relationship was then used to either increase or decrease the amount to be depreciated over time.

Mr. Garrett testified that PSO's cost of removal calculations embed extreme levels of estimated future inflationary increases in current rates, through a mathematical approach that may no longer be characterized as just and reasonable for ratemaking purposes. The challenge 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 may result 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 may be 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 now for future inflation that has not yet occurred. 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. Mr. Garrett recommends that existing net salvage values be maintained but that the Company be directed to file a depreciation study in its next rate case that includes the "Pennsylvania Method" [see Responsive Testimony of Mark E. Garrett, Cause No. PUD200600285, pgs. 65-69] as an option for the Commission to consider with respect to determining net salvage values for T&D property.

Mr. Pous testified that PSO performed only a simplistic mathematical averaging to arrive at its recommended negative salvage rates in the mass property accounts (i.e. transmission, distribution and general plant). He further testified that there was no evaluation of the historical data. The Company's reliance solely on historical averages yields results that may seem to render very negative salvage values. Specifically, Mr. Pous recommends altering the salvage values associated with ten individual property accounts.

Mr. Selecky testified that PSO's mass property depreciation rates are excessive because they include a provision for negative salvage that significantly exceeds actual experience. In addition, PSO's negative salvage percentages rely on estimates of historic inflation to project future inflation. Mr. Selecky further testified that historic inflation rates are in excess of current projections for future inflation. Mr. Selecky finally proposes to reduce the Company's net salvage ratios by 50%.

The Commission agrees that PSO's requested increases in the negative salvage rates for the mass property accounts needs further evaluation. The Commission further finds that some level of evaluation that considers actual salvage and removal costs should be further performed. The Commission also finds that PSO's formula for calculating the removal cost component of the salvage values may embed significant levels of estimated future inflationary increases in current rates by assuming that past levels of inflation will be sustained into the future. As a result, the Commission does not adopt the Company's requested increases in negative salvage value rates in the mass property accounts in this proceeding. Instead, the Commission finds that the Company must continue to use the existing mass property net salvage. The Commission directs PSO to file a depreciation study in its next rate case that includes the "Pennsylvania Method" [see Responsive Testimony of Mark E. Garrett, Cause No. PUD200600285, pgs. 65-69] as an option for the Commission to consider with respect to determining net salvage values for T&D property.

(4) Updated to 2006. Depreciation expense and amortization expense for intangible plant should reflect updated plant balances as of December 31, 2006. An adjustment of $2,665,867 is therefore required for intangible plant.

(5) Depreciation Rates. As a reasonable resolution, the Commission finds that the new depreciation rates as set forth on Attachment 2 of Accounting Exhibit, Depreciation Rates, shall be implemented by PSO effective June 1, 2007.

w. Interest on Customer Deposits. The Commission adopts Staff's Adjustment H-22 amounting to an increase in expense of $21,967. This result was determined by Staff calculating the effective interest rate times a 13-month average balance ending December 31, 2006.

x. Pension Asset Recovery. *See* Prepaid Pension Asset and Associated Deferred Income Tax ("ADIT") section 2. above adopting position of the OIEC.

y. Transmission Expense-Transmission Credit. PSO reversed a non-recurring credit that was recorded in its test year transmission expense with the result being cost of service was increased. Aaron Rebuttal at p. 76. It is consistent with the Commission's post-test year adjustment policy to recognize that the ongoing level of transmission expense will not reflect this non-recurring credit. AG witness Soltani does not dispute the non-recurring nature of the credit, but would amortize the amount to cost of service prospectively. Her proposed adjustment would reduce the Company's proposed transmission expense by $145,372. Aaron Rebuttal at p. 76. The Commission adopts PSO's position on this issue because PSO's adjustment reverses a non-recurring credit. A three (3) year recovery period is not warranted under the facts presented herein.

z. Plant Acquisition Amortization Expense. Consistent with the Commission's determination regarding electric plant acquisition and accumulated amortization on electric plant, the Commission adopts the Staff's adjustment of ($31,641).

aa. AEPSC Trading Administration Costs. The Company's \$4.4 million AEPSC trading administration costs cover other services provided by AEPSC in addition to trading activities. These services are required to enable PSO to function and transact with other market participants in the SPP region. The costs borne by PSO are also compensating AEPSC for performing other functions such as power settlements for activities under the AEP West Operating Agreement and System Integration Agreement ("SIA"), SPP coordination and market activities, and many other functions that are essential to serving PSO's customer demand in a reliable and cost-effective manner. The fuel cost savings during the test year from purchases arranged by the AEPSC commercial organization under the AEP West Operating Agreement and SIA were in excess of \$101 million. Absent the AEPSC commercial organization, which is necessary to survey the market and arrange the power purchase transactions, this level of fuel cost savings could not be achieved. OIEC's recommendation to remove these administrative costs from base rates appears to be inconsistent with the SIA. The Commission adopts the Company's proposed trading expense.

bb. SPP (Southwest Power Pool) Administrative Fees. The Company included in its cost of service the June 30, 2006 test year-end amount of \$5,506,395 in SPP administrative fees and SPP FERC assessment fees. AG witness Ms. Soltani took issue with this amount and recommended a \$221,174 reduction to PSO's request for these fees to reflect the December 31, 2006 calendar year-end level of expense. The Commission finds that test year end level of SPP administrative fees as proposed by PSO to be accepted, as such fees are integral to PSO's participation in the SPP.

cc. Community Affairs Expense. PSO has requested an additional \$300,000 in community affairs expense over test year levels. Aaron Rebuttal at p. 78. As explained by Company witness Mr. Aaron, this additional expense represents the annual cost of three additional community affairs managers. PSO asserts that these additional employees are needed because of the Company's large geographical area and the relative large number of customers served by PSO's existing community affairs managers. *Id.* AG witness Soltani takes issue with the Company's request claiming that the costs are not necessary to provide electric utility service.

The Commission finds that PSO's requested level of community affairs expense is proper. The activities that these employees will conduct include: providing a point of community contact for the Company, facilitating the customer complaint resolution process, providing operational support for PSO's distribution facilities and infrastructure, providing operational support during outages by serving as the primary community and public emergency management contact, serving as the contact point for customer releases between the Company and rural electric cooperatives, and coordinating activities between local government agencies, local community organizations and the various functions within PSO. *Id.*

The Commission finds that these activities are proper and the cost of these additional employees should be included in PSO's cost of service.

The Commission finds the Company initiate informal meetings with the Staff, Attorney General and customers of PSO to continue to provide information regarding the functions of these employees. Meetings should commence no later than November 14, 2007.

dd. Income Tax Adjustment. The Company calculates its income tax expense to reflect the tax treatment allowed PSO, through IRS Regulations, for rate base and cost of service items included in the rate filing. The Company is allowed a tax deduction of only 50% of its meal and entertainment expenditures. In order to calculate the proper income tax expense for ratemaking purposes, taxable income from the accounting books has to be adjusted to recognize that 50% of the meals expenditures are not tax deductible. The Company adds back this non-deductible amount to book income to properly reflect taxable income. This add-back is the "permanent difference" that AG witness Soltani originally sought to eliminate. Aaron Rebuttal at p. 79. In the Supplemental Testimony of Roya Soltani of April 26, 2007, pg. 2, lines 9-13, Ms. Soltani stated that she had reversed the adjustment to the 50% meal disallowance and the preferred dividend credit in her calculations.

These costs are, however, reasonable and necessary. Therefore, the Commission adopts the Company's position that the income tax expense should be calculated in the proper manner that reflects the inclusion of these expenditures in cost of service and the fact that only 50% of these costs are deductible for determining income tax expense.

ee. Distribution Service and Reliability. Mr. Robson, testifying for the QSC, challenged the quality of service PSO provides to its customers and questioned PSO's reliability and service delivery. Kissman Rebuttal at p. 4, l. 3 and 5-17. PSO demonstrated, however, that increased SAIFI and SAIDI measures are not likely due to deteriorating service, but instead are the result of enhanced tracking systems. This outcome is similar to other utilities that have implemented outage automation systems. Kissman Rebuttal at p. 5, l. 4-15, p. 6, l. 3-4. PSO also showed that its service quality and reliability has improved based on total customer-minutes interrupted, customer satisfaction studies, and street light maintenance.

The Commission finds that the quality of service concerns expressed by Mr. Robson be submitted to the Public Utility Division and the Consumer Services Division of the Corporation Commission and that each such division develop a timeline for filing periodic (every 6 months) quality of service reports with the Commission. The Commission finds that a timeline be submitted to the Commission on November 14, 2007, and that the periodic report filings continue until such time as the Commission orders otherwise. It is the Commission's finding that PSO's utilization of CAIDI and MAIFI should also be addressed as set forth by Messr. Robson on behalf of the QSC.

F. Findings Regarding FBR (Formula Based Rates), PBRC AND NGTR

1. Conclusion of Findings

For the reasons explained below, the Commission declines to adopt Staff's proposal of the Performance Based Rate Change ("PBRC"), PSO's Formula Based Rate proposal or general CWIP recovery through NGTR. Although it is declining to approve PSO's FBR, Staff's PBRC or general CWIP recovery through NGTR in this proceeding, the Commission finds that formula-based rate mechanisms have merit, and the Commission will re-examine this issue should any party wish to file such proposals in subsequent proceedings. Because the

Commission finds that in this Cause, recovery mechanisms should be adopted on a project by project basis, it declines to adopt a general approach to CWIP recovery through the NGTR.

2. <u>PSO's Proposed FBR and Staff's PBRC and NGTR</u>

In light of its substantial construction program, PSO proposed that instead of filing multiple rate proceedings over the next five or six years, it be authorized to put into effect an FBR mechanism that would allow an expedited annual true-up of its costs. The proposed mechanism would allow recognition of changing costs and the inclusion of a return on CWIP in a regular and timely manner and would be based on audited FERC Form 1 filings with limited pro forma adjustments. Exhibits 13 and 14, Sartin Direct at p. 9; Exhibit 27, Moncrief Direct at p. 8, l. 21-23 through p. 9, l. 2, Exhibit DRM-2. PSO's proposed rate plan is similar to the tariff approved for CenterPoint Energy Arkla (CenterPoint) by this Commission in Order No. 499253 in Cause No. PUD 200400187. PSO's proposed FBR was designed to use a formula for developing PSO's Earned Return based on actual financial performance during the test year. This would be used to adjust the rates that would be applied to the months July through June following the test year.

In response to PSO's proposal, Staff proposed a two-part formula rate. One part, named the PBRC would allow the regular adjustment of rates for certain costs but would not include any CWIP in rate base. Exhibit 135, Mathai Direct at pp. 14-15. The second part, the NGTR, would create a regulatory asset that would correspond with the amount of CWIP the Company incurred for new generation and transmission that the Commission approved under the used and useful concept and then provide for the interim recovery of, and on, the regulatory asset through amortization. Exhibit 135, Mathai Direct at pp. 16-21

3. <u>FBR/PBRC</u>

PSO is embarking on a significant capital spending program in generation, transmission, and distribution. The parties to this proceeding, other than the Staff and PSO, oppose any form of formula based rates. In general, the parties maintain that the normal rate process is adequately efficient, and that the sharing mechanism associated with FBR is not fair. *See* Exhibits 124 and 157, Garrett; Exhibits 137 and 142, Robson; Exhibits 147 and 187, Selecky; and Exhibit 121, Soltani. The intervenors also maintain that the CenterPoint case [Cause No. PUD200400187] is distinguishable. The Commission finds the FBR may be a workable solution to problems created by large construction projects, but the parties have raised concerns that would need to be addressed before implementing as broad a FBR as the ones proposed by PSO or the Staff. [Transcript of Proceedings and Prefiled Testimony in Cause No. PUD200600285]

4. <u>CWIP Rider-Red Rock Related Cost Recovery</u>

In the PSO rate case, a record was taken concerning the issues of PSO's Formula-Based Rates (FBR) proposal, the Public Utility Division (PUD) Staff's proposed PBRC and NGTR and the general issue of CWIP (including "Red Rock"), that was extensive enough under normal circumstances to allow the Commission to decide how to proceed. Concurrent with consideration of the merits of these particular issues in the PSO rate case, though, a separate

Commission record was also being taken during the hearing in consolidated Cause Nos. PUD 200500516, 200600030 and 200700012, "Red Rock". Because an extensive record also exists on the subject of Red Rock related cost recovery within the Red Rock case, the Commission has determined that its decision on Red Rock-related cost recovery will be addressed in Cause Nos. PUD200500516, 200600030, 200700000012.

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 revenue requirement for the services it offers and to determine the costs that different classes of customers impose on the PSO system. The result is a fully allocated embedded cost-of-service study that establishes class cost responsibility to be used as an input in designing rates. To determine the necessary recovery from the different rate classes, the total revenue requirement is attributed to the classes of customers in a way that reflects the costs of providing service, using a three-step process: functionalization, classification, and allocation. Moncrief Direct at pp. 15-16.

1. Jurisdictional Cost-of-Service Study

PSO witness Donald Moncrief testified that the jurisdictional cost-of-service study serves to divide costs between the retail and wholesale (FERC jurisdictional) customers. Moncrief Direct at p. 22, l. 3-4. 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 Moncrief 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. Moncrief Direct at p. 32, l. 13-16. 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 whereby present and proposed relative rates of return by customer class can be compared and reviewed, and to comply with OCC filing requirements. Moncrief Direct at p. 36, l. 12-16.

a. Staff's Proposal. For the allocation of production-related costs to the retail customer classes in the class cost-of-service study, PSO used a four coincident peak average and excess (4CP A&E) methodology because that methodology recognizes customer class responsibility for the system peaks and also ensures that all customers who benefit from the use of the Company's generation system will be allocated a reasonable share of the cost of developing and operating the system. Moncrief Rebuttal at p. 18, l. 26 through p. 19, l. 7.

Staff witness Smith rejects PSO's cost-of-service study in its entirety because PSO used the 4CP A&E allocator for production plant, and proposes a "Straight Cost Allocation Method." Exhibit 146, Smith Prefiled at p. 6, l. 2. Mr. Smith did not in fact perform a cost-of-service study. Hearing Exhibit 15, Staff Response to OIEC's Second Data Request, Question 5; May 9, 2007 Tr. at p. 127. Mr. Smith acknowledged that his method is more accurately called a "Straight Allocation Method." May 9, 2007 Tr. at p. 113. His methodology does not in fact allocate costs, but instead allocates the revenue requirement to the customer classes based on the percentage of revenue generated by the customer classes during the test year. Hearing Exhibit 15, Staff Response to OIEC's Second Data Request, Questions 5, 16(e); Moncrief Rebuttal at p. 19, l.17 through p. 20, l. 2; Exhibit 187, Selecky Rebuttal at p. 3, l.1-16; Exhibit 186, Farrar Rate Design Rebuttal at p. 6, l. 14 through p. 7, l. 8, p. 10, l. 13 through p. 11, l. 13; Exhibit 184, Gregory Rate Design Rebuttal at p. 4, l. 13 through p. 5, l.10; May 8, 2007 Tr. at pp. 214, 234-238; May 9, 2007 Tr. at pp. 99-100, 126. While Mr. Smith argued that his methodology used the Company's cost-of-service study, in fact he relied on only one line from the cost-of-service study and that line contained only test year revenues and not costs. HE 15, Staff Response to OIEC's Second Data Request, Questions 6(b),(c); Farrar Rate Design Rebuttal at p. 11, l. 4-13. Further, Mr. Smith did not appear to take into account the Company's calculation of Miscellaneous Revenues, which was based on prices charged for rent from electric property, pole contact charges, and miscellaneous service fees and the number of occurrences for each service, and is unrelated to the Company's base rate revenue requirement, although he did not propose to change any of those fees and did not dispute the Company's calculation of the number of occurrences. May 8, 2007 Tr. at pp. 71-72. Mr. Smith applied a ratio of Miscellaneous Revenues to total test year revenues. As a result, his methodology underestimates Miscellaneous Revenues that are deducted from the revenue requirement and overstates the revenues that must be recovered from base rates.

The Commission finds that PSO's class cost-of-service study is reasonable and should be adopted by the Commission.

b. PSO's Demand-Only Methodology for Distribution System Costs. PSO uses a demand-only allocator for distribution costs in Accounts 364-368 because the distribution system poles, wires, and conduit are sized to meet the maximum local 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 on the basis of customers. Moncrief Rebuttal at p. 12, l. 17-19; May 9, 2007 Tr. at p. 89. Wal-Mart witness Mr. Selecky argues that PSO's cost-of-service study overstates the portion of distribution plant investment that should be classified and allocated as demand-related and understates the customer-related portion, and therefore recommends that PSO be ordered to perform a minimum system study to allocate a portion of Accounts 364-368 on the basis of customers instead of demand. Exhibit 136, Selecky Direct at p. 7, l. 16-18.

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 Rebuttal at pp. 11-14; May 9, 2007 Tr. at pp. 92-94. Further, changing the allocation from demand-only to a combination of demand and customer-related will result in shifting costs from commercial to residential customers. Moncrief Rebuttal at p. 14, l.14 through p. 15, l. 9; May 9, 2007 Tr. at pp. 89-90, 92. Finally, PSO has used the demand-only allocator for Accounts 364-368 in all its rate cases since the 1980's. Moncrief Rebuttal at p. 11, l. 2-3; May 9, 2007 Tr. at pp. 86-87.

The Commission adopts as reasonable PSO's demand-only methodology for classifying distribution system costs in Accounts 364-368, however, the Commission adopts the recommendation of Mr. Selecky in part and directs PSO to prepare a minimum system study to be filed in PSO's next rate review.

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. PSO proposed a revenue distribution to the customer classes that maintains some movement toward the goal of equalized class rates of return as shown in the class cost-of-service study, while attempting to mitigate customer impacts associated with that movement. May 8, 2007 Tr. at p. 137. The cost-of-service study shows that the residential class is currently producing a .65 relative rate of return, the commercial class is producing a 1.21 relative rate of return, and the industrial class is producing relative rates of return ranging from 1.63 to 2.30. Exhibit 111, Champion Direct at Exhibit KJC-1 Errata. At PSO's requested overall base rate increase of 11.49%, PSO's proposal increases overall residential rates 13.12% to a relative rate of return of .78, commercial rates 13.35% to a relative rate of return of 1.25, and industrial rates 3.69% to relative rates of return ranging from 1.28 to 1.76. Champion Direct at p. 5, l. 5-23; Exhibit KJC-1 Errata. See also Transcript of Proceedings, May 8, 2007, p. 121, Testimony of Kathy Champion.

Several intervenors recommended a more rapid movement to equalized rates of return. OIEC witness Garrett, representing certain customers in the industrial class, proposed a 95 to 105% bandwidth around the rate of return, not fully considering the impacts to the residential class. May 8, 2007 Tr. at pp. 181-182. Similarly, QSC witness Robson, who acknowledged he was not an expert witness, recommended a 90 to 110% bandwidth, also without fully considering the impacts to the residential class. Wal-Mart witness Selecky recommended reductions to the relative rates of return of those classes under which Wal-Mart takes service and an increase to residential rates, even if PSO's overall rates are decreased. May 9, 2007 Tr. at p. 96. Staff witness Smith did not address relative rates of return because relative rates of return are generated by cost-of-service studies, he rejected PSO's cost-of-service study, and he did not perform one of his own. Exhibit 180, Champion Rebuttal at p. 6, l.12-22.

PSO's proposed revenue distribution should be used in this cause. PSO is the only party that attempted to move the classes to equalized rates of return while also appropriately recognizing the impacts of such movement on the customer classes, specifically the residential class. May 8, 2007 Tr. at pp. 119-120. The intervenors' proposals, using PSO's proposed revenue requirement, would produce increases in residential revenues ranging from 18.64% to 24.71%, compared to PSO's proposed residential rate increase of 13.12%. Champion Rebuttal at p. 9, l. 1 through p. 10, l. 12; Exhibit KJC-2R. Such residential customer impacts are unacceptable to this Commission.

The Commission adopts PSO's proposal that customer classes be moved towards equalized rates of return while considering the impacts on all customer classes. However, the Commission finds that in this Cause, the Company proposed a rate design specifically applicable to a $47.9 million increase. The Commission further finds that the Company must specifically identify the rate design methodology (revenue distribution) to be applied to the customer classes including the resulting rate impact on a class-by-class basis. [See Attachment 3, Revenue Distribution]

I. Rate Design

1. Terms and Conditions

PSO proposed changes to its Electric Service Rules, Regulations, and Conditions of Service and to its Deposit Plan. The changes include clarifying the customer's obligation in return for taking electric service to provide PSO with permission and access to a customer's premises and rights-of-way, PSO's ability to trim and remove trees near PSO's electric equipment, and the limitation of liability for fluctuations and interruptions of electric service over which the Company has no control. Champion Direct at p. 30, l. 16 through p. 31, l. 5. PSO's proposed change to the Deposit Plan would include a new policy to comply with OCC Rule OAC 165:35-19-10(m), requiring automatic refunds of non-residential deposits. Champion Direct at p. 31, l. 9-11.

No party contested the proposed changes to Terms and Conditions, and the Commission adopts PSO's proposed changes as reasonable.

2. Service Fees

PSO proposes to update the prices of its service fees to reflect current costs. Champion Direct at p. 30, l. 3-10; workpapers M-2. No party disputed the proposed charges and the Commission finds them to be reasonable.

3. Residential Service

a. Basic Service Charge. PSO provides service to residential customers under four tariffs. The Company proposes to increase the Basic Service Charge from $6.57 to $13.00 per month for the RS and GCRS tariffs and from $5.67 to $10.00 for the LURS and GCLURS tariffs to reduce, to some extent, the variability of monthly customer bills; to be more reflective of the cost incurrence associated with PSO's costs and investments; to reduce customer dissatisfaction; and to reflect cost elements that do not vary with consumption. Champion Direct at p. 12, l. 8-12; May 8, 2007 Tr. at pp. 171-172. Recovery of all fixed costs would have resulted in a Basic Service Charge of $25.00 per month, so PSO recommended $13.00 and $10.00 charges in recognition of customer impacts that would result from moving that rate element to full cost recovery. Champion Direct at p.12, l. 6 through p. 13, l. 5.

Staff witness Smith recommends that any Basic Service Charge increase be limited to 25%. He did not dispute the appropriateness of matching fixed costs to fixed price recovery or that the cost-of-service study indicates a much higher level of recovery than PSO proposes. Champion Rebuttal at p.13, l. 11 through p. 14, l. 2.

QSC witness Robson criticizes PSO for providing no studies or other data relied on to support its rate design recommendations. Exhibit 152, Robson Addendum to Testimony at p. 4. In fact, PSO provided ample evidence supporting its proposals, including cost analyses in

Schedule L, workpapers, and discovery responses; rate impact analyses in discovery responses; a 10-year historical use trend and a customer complaint trend analysis in Ms. Champion's direct testimony; and the proof of revenues in Schedule M and the associated workpapers. Champion Rebuttal at p. 14, l. 14 through p. 15, l. 16. PSO's proposed Basic Service Charges for the residential classes are fully supported by the evidence, move toward full recovery of fixed costs through fixed charges, and mitigate the impact on customers. Therefore, the Commission finds that they should be approved.

b. On-Peak/Off-Peak Pricing. PSO's current residential rates have inclining block energy charges in the on-peak summer months and declining block energy charges in the off-peak winter months. The Company proposes to reduce the variable energy charges in the RS and GCRS tariffs, which will decrease the dramatic shift between on-peak and off-peak prices. Customer complaints spike during the summer months, due to higher consumption as well as to the significant seasonal rate differential. Champion Direct at p. 10, l. 6 through p. 11, l. 2. Further, even with the higher summer price signals, customers continue to use more kWhs during the summer. Champion Direct at p. 9, l. 13 through p. 10, l. 5. Despite the significant price signal, summer usage appears to be fairly inelastic. Champion Direct at p. 11, l. 9 through p. 12, l. 5. Therefore, PSO proposes to reduce the summer/ winter differential, which now recovers 60% of all costs in the summer months, to a level that recovers 56% in the summer months. This more closely matches the 52% of kWhs consumed during the summer months, while continuing to encourage conservation, send appropriate price signals, and encourage efficient use of PSO's generation system. Champion Direct at p. 13, l. 6-20.

QSC witness Robson proposes that, rather than changing the summer/winter differential, the Company promote the Average Monthly Payment Plan ("AMP"). However, approximately half of the residential customers either presently participate in the AMP program or are not eligible to participate. Further, PSO has promoted the AMP program in newspapers in both Spring and Fall, provides AMP information in the customer newsletter, and promotes AMP at community events and through targeted customer mailings. Champion Rebuttal at p. 15, l.17 through p. 16, l. 9. Therefore, it is not clear that Mr. Robson's proposal would have a significant impact.

The Commission adopts PSO's proposed reduction of the summer/winter differential and also Witness Robson's recommendation. Therefore, PSO is directed to continue to promote the Average Monthly Payment Plan and to monitor and track participation levels.

c. Time-of-Day Pilot. PSO proposes to introduce a Time-of-Day ("TOD") pilot tariff for 100 members of the residential class, which uses a higher price during the hours of 2 p.m. to 7 p.m. during the summer months to encourage customers to consider and make wise use of energy during that higher-use period. The pilot will allow the participants to test their ability to respond to price signals without penalty by allowing them to be billed on the "best rate" (*i.e.*, the lower of their standard tariff or the TOD rate). Champion Direct at p. 13, l. 21 through p. 14, l. 6. The Company has requested inclusion in its revenue requirement of the cost of the meters for the residential and commercial TOD pilots, however, the Company did not provide actual metering investment costs to the Commission. According to the Company witness, if the cost is not included in PSO's revenue requirement, it must be recovered from pilot participants, which will discourage participation. Champion Direct at p. 14, l. 7-14.

QSC witness Robson recommends that the number of pilot participants be expanded. However, PSO's proposed number of participants was chosen to allow the Company to build the support system needed for a successful TOD offering, which includes customer solicitation, customer billing, meter installation, customer response, and customer retention. This will enable the Company to successfully manage the implementation of the pilot and facilitate a successful review to determine any changes required to transition from a pilot to a permanent offering. Champion Rebuttal at p. 17, l. 11-20; May 8, 2007 Tr. at pp. 173-174. Further, an expansion of the number of participants would require additional investment in meters, the cost of which should be included in the revenue requirement for the reasons discussed in the preceding paragraph. Mr. Robson also recommends that the number of on-peak hours be reduced. While the limited number of on-peak hours he proposes may be beneficial to some customers, it does not give PSO the load reduction response it is seeking. Limiting those hours could merely cause customers to delay their consumption and if projected on a large population would delay the peak usage but would not avoid it. Champion Rebuttal at p. 17, l. 23 through p. 18, l. 5.

The Commission finds that PSO's proposed TOD pilot should be approved as proposed.

4. Commercial Service

a. Basic Service Charge. PSO provides service to commercial customers under several tariffs, including reduced rates for schools. The Company proposes to retain the schools' reduced rates. May 8, 2007 Tr. at p. 162. As was the case for residential service, PSO proposes to increase the Basic Service Charges of the LUGS, GCLUGS, GS, and PL tariffs to recover more of the fixed costs through the fixed Basic Service Charges. May 8, 2007 Tr. at pp. 171-172. The Basic Service Charges of the LUGS and GCLUGS tariffs would increase from the current $15.56 to $31.00 per month, the Basic Service Charge of the GS tariff would rise from $24.08 to $49.00 per month, and the PL Basic Service Charge would increase from $32.30 to $65.00 per month. Even at these levels, the Basic Service Charges will not fully recover fixed costs. Champion Direct at p. 19, l. 3-13.

As was also the case for residential service, Staff witness Smith proposes to limit the increase in Basic Service Charges to 25%. Again, he did not dispute the appropriateness of matching fixed costs to fixed price recovery or that the cost-of-service study indicates a much higher level of recovery than PSO proposes. Champion Rebuttal at p.13, l. 11 through p. 14, l. 2.

QSC witness Robson also criticizes PSO's proposed commercial rate design, again citing an alleged lack of studies or data to support PSO's proposals. Robson Addendum to Testimony at p. 4. As noted in the discussion pertaining to the residential rate design, PSO provided ample evidence supporting its proposals, including cost analyses in Schedule L, workpapers, and discovery responses; rate impact analyses in discovery responses; a 10-year historical use trend and a customer complaint trend analysis in Ms. Champion's direct testimony; and the proof of revenues in Schedule M and the associated workpapers. Champion Rebuttal at p. 14, l. 14 through p. 15, l. 16. Mr. Robson also suggested that PSO offer rate options with lower Basic Service Charges for smaller commercial customers and higher Basic Service Charges for larger commercial customers. PSO's LUGS rate in fact does contain a lower Basic Service Charge than the GS rate. To the extent Mr. Robson is advocating different Basic Service Charges within a tariffed class, no evidence supports such different treatment.

PSO's proposed Basic Service Charges for the commercial classes are fully supported by the evidence, move toward full recovery of fixed costs through fixed charges, and mitigate the impact on customers. Therefore, the Commission finds that they should be approved.

b. On-Peak/Off-Peak Pricing. As is the case for its residential rates, PSO's current GS commercial rate has inclining block energy charges in the on-peak summer months and declining block energy charges in the off-peak winter months. The Company proposes to reduce the variable energy charges in the GS tariff, which will decrease the dramatic shift between on-peak and off-peak prices. Even with the higher summer price signals, customers continue to use more kWhs during the summer. Champion Direct at p. 17, l. 17 through p. 18, l. 1. PSO proposes to reduce the summer/ winter differential, which now recovers 65% of all costs in the summer months, to a level that recovers 55% in the summer months. This more closely matches the 47% of kWhs consumed during the summer months, while continuing to encourage conservation, send appropriate price signals, and encourage efficient use of PSO's generation system. Champion Direct at p. 18, l. 2-6.

The Commission finds that PSO's proposed reduction in the summer/winter differential should be approved.

c. TOD Pilots. PSO proposes two commercial TOD pilots—one for LUGS customers and one for GS customers. Like the residential pilot, the commercial pilots will be available to 100 members of the LUGS and 100 members of the GS classes, and will use a higher price during the hours of 2:00 p.m. to 7:00 p.m. during the summer months to encourage customers to consider and make wise use of energy during that higher-use period. The pilots will allow the participants to test their ability to respond to price signals without penalty by allowing them to be billed on the "best rate" (*i.e.*, the lower their standard tariff or the TOD rate). Champion Direct at p. 20, l. 5-13. The Company has requested inclusion in its revenue requirement of the cost of the meters for the residential and commercial TOD pilots. If the cost is not included in PSO's revenue requirement, it must be recovered from pilot participants, which will discourage participation. Champion Direct at p. 14, l. 7-14.

QSC witness Robson again recommends that the number of pilot participants be expanded. However, PSO's proposed number of participants were chosen to allow the Company to build the support system needed for a successful TOD offering, which includes customer solicitation, customer billing, meter installation, customer response, and customer retention. This will enable the Company to successfully manage the implementation of the pilot and facilitate a successful review to determine any changes required to transition from a pilot to a permanent offering. Champion Rebuttal at p. 17, l. 11-20. Further, an expansion of the number of participants would require additional investment in meters, the cost of which should be included in revenue requirement for the reasons discussed in the residential TOD section. Mr. Robson also recommends that number of on-peak hours be reduced. While the limited number of on-peak hours he proposes may be beneficial to some customers, it does not give PSO the load reduction response it is seeking. Limiting those hours could merely cause customers to delay their consumption and if projected on a large population would delay the peak usage but would not avoid it. Champion Rebuttal at p. 17, l. 23 through p. 18, l. 5.

The Commission finds that PSO shall continue to participate in the TOD Pilot program. The Commission finds that PSO's proposed TOD pilot should be approved as proposed.

5. Industrial Service

a. Basic Service Charge. PSO proposes to increase the Basic Service Charge from $120 to $250 per month to include more of the fixed costs of customer service and billings in this charge. Champion Direct at p. 22, l. 2-4.

As was also the case for residential and commercial service, Staff witness Smith proposes to limit the increase in Basic Service Charges to 25%. Again, he did not dispute the appropriateness of matching fixed costs to fixed price recovery or that the cost-of-service study indicates a much higher level of recovery than PSO proposes. Champion Rebuttal at p.13, l. 11 through p. 14, l. 2.

PSO's proposed Basic Service Charges for the industrial classes are fully supported by the evidence, move toward full recovery of fixed costs through fixed charges, and mitigate the impact on customers. Therefore, the Commission finds that they should be approved.

b. Interruptible Tariffs. PSO proposes two new interruptible tariffs and a modification to the existing Energy Price Curtailable Service ("EPCS") Rider. PSO offers these proposals to provide the Company with a known level of load that could be shed when load curtailment is necessary, to help avoid the purchase of expensive market power when loads are peaking, and to meet customers' requirements for participation in interruptible offerings. Champion Direct at p. 22, l. 11-18.

Under the new Interruptible Power Service ("IPS") Rider, customers can nominate load for a certain number of hours and receive a credit in advance in exchange for their willingness to be interrupted for a fixed number of hours. The credit was developed using the current value of 100 or 200 hours of interruptible load and the bid price for capacity purchases in 2006. The tariff contains penalties for non-compliance. Champion Direct at p. 23, l. 7-14.

The new Emergency Curtailable Service ("ECS") Rider will be offered to a limited number of customers and is intended to be used during emergency capacity or transmission situations. The tariff will allow PSO to contact identified customers and quote them a market price, based on the prevailing market price, the SPP imbalance market, or a higher price if power and energy could not be imported to relieve the situation, for their nominated interruptible load. Customers must be ready, willing, and able to reduce load with limited notice and will receive payment only for load that is actually reduced in response to an interruption request. Champion Direct at p. 23, l. 15 through p. 24, l. 2.

PSO proposes to modify the current EPCS tariff by lowering the threshold for participating and by decreasing the duration of the curtailment periods. Champion Direct at p. 22, l. 21 through p. 23, l. 6.

No party opposes PSO's proposed new interruptible services or the modifications to the existing EPCS tariff. The Commission finds that these proposals are reasonable and should be approved. The Commission finds that PSO should study the Staff's proposal to expand the use of the Interruptible tariff option for industrial customers. [See Referee Report, Staff Draft, filed May 22, 2007, pg. 56 of 56]

c. Non-Utility Generator Service ("NUGS"). The NUGS rider was introduced to provide a market price to non-utility generators assuming the SPP imbalance market was going to be implemented and those market prices would be used to develop contract prices for these customers. While four customers currently qualify for this service, none are taking service under this tariff. Champion Direct at p.24, l. 5-7. Due to the delay in the SPP imbalance market, PSO requests that the NUGS tariff be suspended until the SPP imbalance market has been implemented and market prices have been stabilized. Champion Direct at p. 24, l. 3-18.

No party opposed PSO's proposal. The Commission finds that the NUGS tariff should be suspended until PSO applies to offer the service and the Commission approves that offering.

6. Lighting Service

PSO proposes to include a 110,000-lumen metal halide offering under the directional flood lighting option in the Non-Roadway Lighting tariff. Champion Direct at p. 27, l. 2-5.

PSO also proposes that the MSL and GSL rates be increased by 10% to mitigate the impact on cities, Security Lighting rates be increased by 4.5%, and ODL and Recreational Lighting rates be increased by 14%. Champion Direct at p. 27, l. 6-12.

No party opposed PSO's proposals, which provide an additional lighting option and move the lighting classes towards full cost recovery while mitigating customer impacts. The Commission finds that PSO's proposals are reasonable and should be approved.

7. Reliability Cost Adjustment Rider and Fuel Cost Adjustment Rider

a. Reliability Cost Adjustment Rider. PSO proposes to leave the Reliability Cost Adjustment ("RCA") Rider in place. The capital investment currently being recovered in the Undergrounding of Overhead Facilities ("UG") component is being rolled into rate base in this proceeding and the UG component will be set back to zero until new investment is placed in service and the associated costs are submitted with the quarterly true-ups, reviewed, and approved. Champion Direct at p. 27, l. 17-23. This proposal was unopposed. The Commission finds this proposal is reasonable and consistent with prior Commission orders, and should be approved.

b. Fuel Cost Adjustment Rider. In its initial application, PSO proposed that the current language found on Sheet Number 70-3 of the Fuel Cost Adjustment ("FCA") Rider regarding successor accounts and subaccounts be moved to a separate section and proposed no other changes. Champion Direct at p. 28, l. 3-4. This proposal is unrefuted and should be approved.

PSO also requested that the fuel in base rates be adjusted to reflect test year fuel. With its Errata filing, PSO recognized that the test year fuel was higher than current fuel costs and proposed that fuel costs currently recovered in base rates be removed from base rates and recovered through the FCA Rider. May 8, 2007 Tr. at pp. 150-151. In his rebuttal testimony, OIEC witness Norwood recommended that PSO continue to recover $0.034 per kWh of fuel through base rates based on the need for more information to support or explain removing fuel from base rates to be provided by PSO. Exhibit 158, Norwood Rebuttal at p. 10, l. 2-21. However, in rebuttal testimony, PSO witness Champion testified that recovering all fuel through the FCA produces no change to the amount a customer pays for fuel and will clearly distinguish fuel costs from base rate costs, which will facilitate customer understanding about how much of the energy charge is related to non-fuel costs and how much is related to fuel costs. Champion Rebuttal at p. 21, l. 6-15. The Commission finds that PSO's proposal to recover all fuel costs through the FCA Rider is not adopted. The Commission further finds that the base rate approach should continue to be utilized in the area of fuel costs as it has proven to be a workable treatment of fuel costs and PSO should continue to recover $0.34 per kWh of fuel through base rates.

In his direct testimony, OIEC witness Norwood advocated that purchased capacity costs be recovered through a rider to eliminate the potential for over-recovery of such costs. Exhibit 126, Norwood Direct at p. 23, l. 19 through p. 24, l. 3. Ms. Champion proposed an adjustment to the FCA Rider to allow recovery of purchased capacity costs if the Commission approves the alternative recommendation of PSO witness Hakimi that all purchased capacity costs be recovered outside of base rates. Champion Rebuttal at p. 22, l. 1-4; Exhibit KJC-3R. As discussed above, the Commission finds that PSO's proposed amount of capacity costs should be recovered through base rates and therefore there is no need for the adjustment to the FCA Rider.

8. Discontinued Services

PSO proposes to eliminate its Alternate Feed Service ("AFS") Rider, which has had no participation since it went into effect in June 2004. Customers who request alternate feed service will pay for the installation of local facilities required to extend the redundant distribution line to the location of the transfer switch, as well as the cost of that transfer switch. With the elimination of the AFS Rider, customers will take and pay for alternate feed service when they use it, if there is capacity available on the Station transformer or distribution circuit. Champion Direct at p. 20, l. 15 through p. 21, l.16. No party opposed the elimination of this tariff, and the Commission finds it reasonable to do so.

PSO also proposes to eliminate the Service Call Fee and the Temporary Disconnect Fee to ensure the safety of its customers, the Company's equipment, and its employees. The existence of these fees could encourage customers to engage in actions designed to circumvent the assessment of the fees and thereby create hazardous conditions. Champion Direct at p. 29, l. 6 through p. 30, l. 2. Again, no party opposed the termination of these fees, and the Commission approves PSO's proposal.

J. Intervenors' Demand-Side Management (DSM) Proposals

1. Gerdau

The Commission adopts PSO's proposed Interruptible Service Pilot Rider ("ISPR"). The Commission also adopts the Emergency Curtailable Service Rider ("ECS") and PSO's proposed Emergency Price Curtailable Pilot Service Rider ("EPCS"). These interruptible service options could provide cost savings to PSO customers and should be implemented.

The Commission further finds that PSO shall develop a tariff consistent with the recommendations of Gerdau Ameristeel in this proceeding. Such tariff shall be provided to the Public Utility Division for administrative tariff approval in accordance with Commission rules and procedure no later than November 1, 2007.

2. QSC

QSC witness Robson provided comments on DSM. He stated that there are ways to encourage DSM in addition to rate options, such as encouraging customers to use compact fluorescent light bulbs and providing programs, conferences, and educational materials on environmental, conservation, and energy programs for homebuilders. He noted that QSC participated in a discussion of integrated resource plans submitted by Oklahoma utilities and submitted a proposed action plan for a pilot program for DSM, which he attached to his testimony. Robson Testimony at pp.13-15.

PSO agrees with Mr. Robson that the marketplace provides the best DSM remedies for customers and encourages QSC to continue participation in the Commission's current workshop on DSM, which is a better forum to address Mr. Robson's proposal. Champion Rebuttal at p.18, l. 10-16; May 8, 2007 Tr. at pp. 93, 96. The Commission agrees that QSC's DSM plan should be considered in the Commission's current DSM proceeding.

The Commission finds that PSO initiate a collaborative process with the QSC and other interested customers to address the reporting of street lighting maintenance and related issues through utilization of neighborhood associations and other methods.

K. Demand Programs; Demand Side Management ("DSM"); Demand Response ("DR"); Energy Efficiency ("EE")

The record in this Cause and in Cause No. PUD 200600030 [consolidated Cause Nos. PUD200500516, 200600030, 200700012] demonstrate a significant difficulty in optimizing the cost structure of a public utility's operations. In Cause No. PUD200600030, the Commission has before it a request to build a new coal power plant in the near future. At the same time, significant reservoirs of demand reduction resources might well have avoided or significantly delayed construction of this plant and at a much lower cost. It is the responsibility of PSO to build and operate its utility system in a manner that minimizes its long-term cost to customers, including the deployment of all cost-effective energy efficiency. Achieving these benefits requires a long-term and extensive energy efficiency effort. To avoid repeating the current situation in which it is, for practical purposes, too late to use DSM and EE to potentially defer or avoid the construction of new power plants, the Commission finds that it is reasonable and appropriate to require the Company to implement new Demand Programs designed, in the long-run, to capture all achievable cost-effective energy efficiency and to do so as a high priority resource. Because they represent energy not consumed, these resources are cleaner and almost always cheaper, than traditional supply-side resources. In addition, energy wasted through inefficiency operates as a hidden cost in rates because of the additional plant, in the form of generation, transmission and distribution, required to serve wasteful consumption. It is in the public interest and in the interest of customers to avoid those additional costs and we find it appropriate to enlist the cooperation of customers through energy efficiency to accomplish this.

Accordingly, the Commission orders PSO to, within 60 days of the effective date of this order, file an application with the Commission seeking approval of comprehensive and cost effective Demand Programs to begin in 2008. PSO's filing shall include a proposed business plan for ultimately expanding its DSM, DR and EE programs including conservation, consumer education and consumer communication, to move towards the goal of garnering all cost-effective achievable savings, recognizing that it may take some time to build the program capacity required to meet this goal. As a part of this filing, PSO shall also submit a robust budget for DSM, DR and EE programs including progressive budget increases each calendar year. PSO's program plan should be designed to achieve a broad mix of savings based upon these budgets. Future budgets shall be based on achievable cost-effective programs and program capacity.

PSO's filing may incorporate existing DSM, DR and EE programs, and shall include additional proposed new or additional DSM, DR and EE measures. Among other things, PSO's DSM, DR and EE program shall include, at a minimum: (1) education and information for customers and trade allies, such as energy service providers, builders and, appliance retailers, (2) energy efficiency assistance for low-income customers; (3) incentives for heating, ventilation and cooling systems (HVAC), high efficiency appliances, motors, and lighting and (4) load interruption mechanisms or tariffs.

L. Statements of Position and Public Comment

The Commission considers the comments and filings of Redbud Energy LP and the City of Tulsa in its determination of the merits of this Cause.

M. Pending Motion

On April 16, 2007, the OIEC filed a Motion to Strike the Testimony of Staff Witness David Smith. The matter was heard by the Commission and the Commission allowed Mr. Smith to testify subject to a final ruling of the Commission pursuant to OAC 165:5-13-3(e). The Commission has weighed and considered the testimony in its determination of Rate Design. Therefore, the Motion to Strike has been addressed by the Commission.

N. Uncontested Issues

Expenses

SFAS 87 Pension Expense $1,500,658

SFAS 112 $1,629,646
Employee Benefits Group Insurance $1,318,927
FERC Assessment Fee $305,829
AEPSC Billing Adjustment ($5,157,315)
Other Tax Adjustment ($382,349)
Fuel Expense Adjustment($715,316,617)
Associated Business Development Expense ($1,377,888)
Reliability Cost Rider ($11,825,328)
OCC Assessment Fee($738,614)
Inventory Write Off ($1,781,629)
Postage Rate Adjustment $70,586
Calpine Reactive Power $2,204,460

Revenue Adjustments

Retail-Base-Reliability Rider ($11,825,329)
Retail Base-OCC Assessment ($741,557)
Retail-Base-Other ($4,699,412)
Retail-Fuel ($843,902,839)
Wholesale-Base $1,326,156
Wholesale-Fuel ($524,449)
Off-System Sales ($128,497,583)
Other Revenue ($4,683,554)

O. Revenue Requirement

The Commission finds that PSO will cause to be filed with the PUD a revised cost of service that incorporates each of the adjustments approved by the Commission including rate design, revenue distribution and proof of revenue.

The Commission finds that the above findings and recommendations are reflected in the revised Revenue Requirement Exhibit, ("Accounting Exhibit") attached hereto. [See Accounting Exhibits, Attachment 1, Application Package Schedules]

ORDER

IT IS THEREFORE THE ORDER OF THE CORPORATION COMMISSION of the State of Oklahoma that based on the evidence herein, the above Findings of Fact and Conclusions of Law are hereby adopted as the Order of the Commission.

IT IS FURTHER THE ORDER OF THE OKLAHOMA CORPORATION COMMISSION that PSO is authorized to increase its Oklahoma retail jurisdictional rates by $9,791,252 until the next rate review by the Commission. [See Accounting Exhibits, Attachment 1, Application Package Schedules]

IT IS FURTHER THE ORDER OF THE OKLAHOMA CORPORATION COMMISSION that a revised Cost of Service that reflects the adjustments ordered by the

Commission including rate design, revenue distribution and proof of revenue be filed with Public Utility Division before the first applicable billing cycle becomes effective based on this order.

IT IS FURTHER THE ORDER OF THE OKLAHOMA CORPORATION COMMISSION that the new depreciation rates as set forth on Attachment 2, shall be implemented effective June 1, 2007.

IT IS FURTHER THE ORDER OF THE OKLAHOMA CORPORATION COMMISSION that Attachment 3, Revenue Distribution, reflects the order of the Commission herein.

IT IS FURTHER THE ORDER OF THE OKLAHOMA CORPORATION COMMISSION that the dollar effect of the above findings and recommendations are incorporated in the attached Revenue Requirement ("Accounting") Exhibit. [See Accounting Exhibits, Attachment 1, Application Package Schedules]

IT IS FURTHER THE ORDER OF THE OKLAHOMA CORPORATION COMMISSION that the rates, charges and tariffs reflecting the terms of this Order be and the same are hereby approved and shall become effective the first billing after the Company has filed tariffs with the Commission that conform to this order and the tariffs have been approved by the Director of the Public Utility Division.

Jeff Cloud

JEFF CLOUD, Chairman

Bob Anthony

BOB ANTHONY, Vice Chairman

Jim Roth

JIM ROTH, Commissioner

DONE AND PERFORMED THIS 9 DAY OF OCTOBER 2007, BY ORDER OF THE COMMISSION:

Joyce Conner

~~PEGGY MITCHELL~~, Secretary
JOYCE CONNER, Acting Secretary

APPROVED AS TO FORM:

Jacqueline T. Miller
JACQUELINE T. MILLER
Referee

October 9, 2007
Date

PUBLIC SERVICE COMPANY OF OKLAHOMA
PUD Cause No. 200600285

Accounting Exhibits

Attachment 1
Application Package Schedules

PUBLIC SERVICE COMPANY OF OKLAHOMA
REVENUE REQUIREMENT
FOR THE TEST YEAR ENDED JUNE 30, 2006

PUD Cause No. 200600285
Final Order
Schedule B-01

	(1)	(2)	(3)	(4)	(5)
Line No.	Description	Schedule Reference	Total Company Per Books	Pro Forma Adjustment	Total Company Pro Forma
1	Rate Base	B-2	$ 1,210,623,839	$ (88,904,171)	$ 1,121,719,668
2	Rate of Return	F-1	8.01%		8.01%
3	Operating Income Requirement		96,970,970	(7,121,224)	89,849,745
4	Pro Forma Operating Income	B-2	84,126,850	(134,850)	83,991,999
5	Difference		12,844,120	(6,986,374)	5,857,746
6	Revenue Conversion Factor				1.646826
7	Change in Revenues				$ 9,646,691

PUBLIC SERVICE COMPANY OF OKLAHOMA
RATE BASE/RATE OF RETURN
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Description	(2) Schedule Reference	(3) Total Company Per Books	(4) Pro Forma Adjustment (B-3)	(5) Total Company Pro Forma	(6) Oklahoma Jurisdictional %	(7) Total Company Pro Forma Oklahoma Jurisdiction
1	Plant in service:						
2	Plant in service	C-1	$ 2,979,176,278	$ 51,551,368	$ 3,030,727,646	99.65475400%	$ 3,020,264,180
3	Construction work in progress	C-1	71,305,320	(71,305,320)	0	0.00000000%	0
4	Plant held for future use	W/P C-13	0	0	0	0.00000000%	0
5	Gross Plant	C-1	3,050,481,598	(19,753,952)	3,030,727,646	99.65475400%	3,020,264,180
6	Accumulated depreciation	D-1	(1,400,311,860)	(8,533,653)	(1,408,845,513)	99.69257935%	(1,404,514,431)
7	Net Plant		1,650,169,738	(28,287,605)	1,621,882,133	99.62189706%	1,615,749,749
8	Working capital:						
9	Cash working capital	E-1	(123,632,537)	(5,331,253)	(128,963,790)	99.68384304%	(128,556,062)
10	Prepayments (13 Mo Avg)	W/P B-5	83,878,623	(82,371,251)	1,507,372	99.65476339%	1,502,168
11	Materials, supplies and fuel inventories (13 Mo Avg)	W/P B-5	57,144,871	5,606,726	62,751,597	99.73109370%	62,582,854
12	Additions and deductions:						
13	Customer deposits (Year End))	W/P B-6	(35,440,000)	(974,638)	(36,414,638)	100.00000000%	(36,414,638)
14	Customer Advances for Construction (Year End)	W/P B-6	0	-	0	0.00000000%	0
15	Off System Trading Deposits (13 Month Avg)	W/P B-6	5,268,984	(0)	5,268,984	99.65475317%	5,250,793
16	Regulatory assets	B-3	0	-	0	0.00000000%	0
17	Other	B-3	0	(8,664,432)	(8,664,432)	99.78199379%	(8,645,543)
18	Net total investment		1,637,389,679	(120,022,453)	1,517,367,226	99.61130668%	1,511,469,321
19	Accumulated deferred income taxes	W/P J-3	(426,527,167)	31,118,282	(395,408,885)	99.64423865%	(394,002,173)
18	Excess deferred taxes	W/P J-4	0		0		0
20	Deferred investment credits (pre-1971)		(238,673)	0	(238,673)	99.66607031%	(237,876)
21	Rate base		1,210,623,839	(88,904,171)	1,121,719,668	99.59968643%	1,117,229,272
22	Net operating income (current prices)	H-1	$ 84,126,850	$ (134,850)	$ 83,991,999	99.46446754%	$ 83,542,195
23	Rate of return (current prices)		6.95%		7.49%	99.86648865%	7.48%
24	Net operating income (proposed prices)	H-1			$ 89,849,745		$ 89,490,065
25	Rate of return (proposed prices)	H-1			8.01%		8.01%

PUBLIC SERVICE COMPANY OF OKLAHOMA
RATE BASE/RATE OF RETURN
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Description	(2)	(3) Total Company Per Books	(4) Oklahoma Jurisdictional %	(5) Total Company Pro Forma Oklahoma Jurisdiction	(6) Total Company Pro Forma Oklahoma Jurisdiction	(7) Total Company Pro Forma Oklahoma Jurisdiction
1	Reconciliation to Oklahoma jurisdiction rate base on Schedule K-1:						
2	Oklahoma jurisdiction rate base, Schedule B-2						$ 1,117,229,272
3	Difference due to classification of Electric Plant Acquisition Adjustment-						
4	Specific allocation in cost of service		$ -	0.00000000%	$ -		
5	Composite allocation from above		-	0.00000000%	-		
						$ -	
6	Difference due to classification of Accumulated Amortization of Electric Plant Acquisition Adjustment-						
7	Specific allocation in cost of service		$ -	0.00000000%	$ -		
8	Composite allocation from above		-	0.00000000%	-		
						-	
9	Total difference						-
10	Oklahoma jurisdiction rate base, Schedule K-1						$ 1,117,229,272

PUD Cause No. 200600285
Final Order
Schedule B-3

PUBLIC SERVICE COMPANY OF OKLAHOMA
ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Description	(2) Adjustment Number	(3) Schedule Reference	(4) Total Company Rate Base Adjustments	(5) Oklahoma Jurisdictional %	(6) Total Company Pro Forma Oklahoma Jurisdiction
1	Plant In Service:					
2	Electric Plant in Service	1	WP C-2-1	$ -	0.00000000%	$ -
3	Construction Work In Progress	1	WP C-2-1	-	0.00000000%	-
4	Construction Work in Progress	2	WP C-2-2	-	0.00000000%	-
5	Production Plant	3	WP C-2-3	-	0.00000000%	-
6	Distribution Plant	4	WP C-2-4	-	0.00000000%	-
7	Accumulated Depreciation	3	WP D-2-1	-	0.00000000%	-
8	Accumulated Depreciation	4	WP D-2-2	(6,436,874)	99.69257935%	(6,417,086)
9	Working Capital:					
10	Fuel Inventory	5	WP B-5	2,152,206	99.94387474%	2,150,998
	Materials & Supplies					
	Prepayments					
11	Additions and Deductions:					
12	IPP - System Upgrade Credits	6	WP B-3-1	(8,664,432)	99.78199379%	(8,645,543)
13	Accumulated deferred income taxes	7	WP B-3-2	31,118,283	99.64423865%	31,007,576
14	Total Rate Base Adjustments			$ 18,169,182		$ 18,095,945

Attachment 1

PUD Cause No. 200600285
Final Order
Schedule B-3

PUBLIC SERVICE COMPANY OF OKLAHOMA
ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Description	(2) Adjustment Number	(3) Schedule Reference	(4) Total Company Rate Base Adjustments	(5) Oklahoma Jurisdictional %	(6) Total Company Pro Forma Oklahoma Jurisdiction
1	Plant In Service:					
2	Electric Plant in Service	1	WP C-2-1	$ -	0.00000000%	$ -
3	Construction Work In Progress	1	WP C-2-1	-	0.00000000%	-
4	Construction Work in Progress	2	WP C-2-2	-	0.00000000%	-
5	Production Plant	3	WP C-2-3	-	0.00000000%	-
6	Distribution Plant	4	WP C-2-4	-	0.00000000%	-
7	Accumulated Depreciation	3	WP D-2-1	-	0.00000000%	-
8	Accumulated Depreciation	4	WP D-2-2	(6,436,874)	99.69257935%	(6,417,086)
9	Working Capital:					
10	Fuel Inventory	5	WP B-5	2,152,206	99.94387474%	2,150,998
	Materials & Supplies					
	Prepayments					
11	Additions and Deductions:					
12	IPP - System Upgrade Credits	6	WP B-3-1	(8,664,432)	99.78199379%	(8,645,543)
13	Accumulated deferred income taxes	7	WP B-3-2	31,118,283	99.64423865%	31,007,576
14	Total Rate Base Adjustments			$ 18,169,182		$ 18,095,945

Attachment 1

PUD Cause No. 200600285
Final Order
Schedule B-04

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Adjustment Number	(2) Schedule Reference	(3) Description	(4) Sponsor	(5) Adjustment Amount	(6) Oklahoma Jurisdictional %	(7) Total Company Pro Forma Oklahoma Jurisdiction
			Plant in service:				
	1	WP C-2-1	To reclassify projects from CWIP that were in service at June 30, 2006 to plant in service	Aaron			
			- Plant In Service		$ -	0.00000000%	$ -
			- Construction Work In Progress		-	0.00000000%	-
	2	WP C-2-2	To exclude from rate base CWIP which is revenue producing, reimbursable or will not be in service by June 30, 2007	Aaron			
			- Construction Work In Progress		-	0.00000000%	-
	3	WP C-2-3	To reclass amounts posted incorrectly	Aaron	-	0.00000000%	-
	4	WP C-2-4	To include cost of time-of-use meters pilot program	Aaron	-	0.00000000%	-
	5	WP D-2-1	To reflect accumulated depreciation on the projects reclassified from CWIP to Plant In Service that were in service at June 30, 2006 (reference WP C-2-1) CWIP to Plant In Service that were in service at June 30, 2006.	Aaron			
			- Accumulated Depreciation		-	0.00000000%	-
	6	WP D-2-2	To increase accumulated depreciation for the Asset Retirement Obligation (ARO) liability that is recorded in FERC Account 230.	Aaron			
			- Accumulated Depreciation		(6,436,874)	99.69257935%	(6,417,086)
			Working Capital:				
	7	WP B-5	To adjust coal inventory to optimal tons	Aaron	2,152,206	99.94387474%	2,150,998
			Additions and Deductions:				
	8	WP B-3-1	To include IPP - System Upgrade Credits as a reduction to rate base. Funds must be returned to customers.	Aaron			
			- Other Rate Base Deductions		(8,664,432)	99.64423865%	(8,633,608)
	9	WP B-3-2	To include in rate base accumulated deferred income taxes	Aaron	31,118,283	99.64423865%	31,007,576

PUBLIC SERVICE COMPANY OF OKLAHOMA
Plant in Service
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) Balance 31-Dec-06	(4) Completed Const Not Classified 31-Dec-06	(5) Adjusted Balance 31-Dec-06	(6) Adjustments Schedule C-2	(7) Requested Amount
1	Electric Plant in Service	101					
2	Total Miscellaneous Intangible Plant	303	$ 55,619,706	$ -	$ 55,619,706	$ -	$ 55,619,706
3	Production						
4	Steam						
5	Land and Land Rights	310	7,391,170	-	7,391,170	-	7,391,170
6	Structures and Improvements	311	66,397,602	169,530	66,567,132	-	66,567,132
7	Boiler Plant Equipment	312	535,166,939	4,354,045	539,520,984	-	539,520,984
8	Turbogenerator Units	314	331,786,575	6,236,976	338,023,551	-	338,023,551
9	Accessory Electric Equipment	315	70,511,776	814,685	71,326,461	-	71,326,461
10	Misc. Power Plant Equipment	316	35,242,658	221,777	35,464,435	-	35,464,435
11	Asset Retirement Obligation	317	2,149,081	-	2,149,081		2,149,081
12	Total Steam Production		1,048,645,801	11,797,013	1,060,442,814	-	1,060,442,814
13	Other Production						
14	Land and Land Rights	340	62,660	-	62,660	-	62,660
15	Structures and Improvements	341	460,617	-	460,617	-	460,617
16	Fuel Holders, Producers and Access.	342	2,947,002	-	2,947,002	-	2,947,002
17	Generators	344	26,078,348	-	26,078,348	-	26,078,348
18	Accessory Electric Equipment	345	273,223	6,193	279,416	-	279,416
19	Misc. Power Plant Equipment	346	1,637,574	-	1,637,574	-	1,637,574
20	Asset Retirement Obligation	347	1,908		1,908		1,908
21	Total Other Production		31,461,332	6,193	31,467,525	-	31,467,525
22	Total Production		1,080,107,133	11,803,206	1,091,910,339	-	1,091,910,339
23	Transmission						
24	Land and Land Rights	350	30,636,492	791,076	31,427,568	-	31,427,568
25	Structures and Improvements	352	6,632,364	-	6,632,364	-	6,632,364
26	Station Equipment	353	200,192,367	14,702,392	214,894,759	-	214,894,759
27	Towers and Fixtures	354	14,056,316	-	14,056,316	-	14,056,316
28	Poles and Fixtures	355	114,632,984	6,229,930	120,862,914	-	120,862,914
29	Overhead Conductors and Devices	356	111,689,360	4,002,585	115,691,945	-	115,691,945
30	Underground Conduit	357	-	-	-	-	-
31	Underground Conductors and Devices	358	71,915	-	71,915	-	71,915
32	Total Transmission		477,911,798	25,725,983	503,637,781	-	503,637,781

PUBLIC SERVICE COMPANY OF OKLAHOMA
Plant in Service
For the Test Year Ending June 30, 2006

	(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	FERC Account Number	Balance 31-Dec-06	Completed Const Not Classified 31-Dec-06	Adjusted Balance 31-Dec-06	Adjustments Schedule C-2	Requested Amount
33	Distribution						
34	Land and Land Rights	360	7,719,014	122,541	7,841,555	-	7,841,555
35	Structures and Improvements	361	1,871,725	-	1,871,725	-	1,871,725
36	Station Equipment	362	130,389,606	3,504,071	133,893,677	-	133,893,677
37	Poles, Towers and Fixtures	364	214,727,805	6,082,839	220,810,644	-	220,810,644
38	Overhead Conductors and Devices	365	191,254,481	5,015,016	196,269,497	-	196,269,497
39	Underground Conduit	366	21,773,897	710,334	22,484,231	-	22,484,231
40	Underground Conductors and Devices	367	142,549,909	7,104,102	149,654,011	-	149,654,011
41	Line Transformers	368	207,365,418	1,581,938	208,947,356	-	208,947,356
42	Services	369	126,572,490	15,418,709	141,991,199	-	141,991,199
43	Meters	370	53,802,934	127	53,803,061	62,539	53,865,600
44	Inst on Customer Premises-Area Lights	371	30,035,633	1,756,441	31,792,074	-	31,792,074
45	Leased Property on Customer Premises	372	-	-	-	-	-
46	Street Lighting	373	39,095,998	6,780,701	45,876,699	-	45,876,699
47	Total Distribution		1,167,158,910	48,076,819	1,215,235,729	62,539	1,215,298,268
48	General						
49	Land and Land Rights	389	4,143,067	18,022	4,161,089	-	4,161,089
50	Structures and Improvements	390	33,412,164	17,730	33,429,894	-	33,429,894
51	Office Furniture and Equipment	391	27,548,992	45,826	27,594,818	-	27,594,818
52	Transportation Equipment	392	6,959,943	-	6,959,943	-	6,959,943
53	Stores Equipment	393	2,451,105	-	2,451,105	-	2,451,105
54	Tools, Shop and Garage Equipment	394	5,817,211	506,043	6,323,254	-	6,323,254
55	Laboratory Equipment	395	4,051,419	-	4,051,419	-	4,051,419
56	Power Operated Equipment	396	1,107,988	132,048	1,240,036	-	1,240,036
57	Communication Equipment	397	73,175,184	609,069	73,784,253	-	73,784,253
58	Miscellaneous Equipment	398	3,010,055	230,062	3,240,117	-	3,240,117
59	Other Tangible Property	399	529,811	-	529,811	-	529,811
60	Asset Retirement Obligation	399.1	495,814		495,814		495,814
61	Total General		162,702,753	1,558,800	164,261,553	-	164,261,553

PUBLIC SERVICE COMPANY OF OKLAHOMA
Plant in Service
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) Balance 31-Dec-06	(4) Completed Const Not Classified 31-Dec-06	(5) Adjusted Balance 31-Dec-06	(6) Adjustments Schedule C-2	(7) Requested Amount
62	Electric Plant in Service	101	2,943,500,300	87,164,808	3,030,665,107	62,539	3,030,727,646
63	Completed Plant not Classified (1)	106					
64	Production		11,803,206	(11,803,206)	-	-	-
65	Transmission		25,725,983	(25,725,983)	-	-	-
66	Distribution		48,076,819	(48,076,819)	-	-	-
67	General		1,558,800	(1,558,800)	-	-	-
68	Intangible		-	-	-	-	-
69	Total Completed Plant not Classified	106	87,164,808	(87,164,808)	-	-	-
70	Electric Plant Acquisition Adjustment	114	-	-	-	-	-
71	TOTAL ELECTRIC PLANT IN SERVICE		$ 3,030,665,108	$ (0)	$ 3,030,665,107	62,539	$ 3,030,727,646
72	Electric Plant Held for Future Use	105					
73	Production		-	-	-	-	-
74	Transmission		-	-	-	-	-
75	Distribution		-	-	-	-	-
76	Total Electric Plant Held for Future Use	105	-	-	-	-	-
77	Construction Work in Progress	107					
78	Production		-	-	-	-	-
79	Transmission		-	-	-	-	-
80	Distribution		-	-	-	-	-
81	General			-	-	-	-
82	Intangible			-	-	-	-
83	Total Construction Work in Progress	107	-	-	-	-	-
84	TOTAL ELECTRIC PLANT		$ 3,030,665,108	$ (0)	$ 3,030,665,107	$ 62,539	$ 3,030,727,646

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Plant in Service
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) Adj 1 CWIP WP C-2-1	(4) Adj 2 CWIP WP C-2-2	(5) Adj 3 Reclass WP C-2-3	(6) Adj 4 Meters WP C-2-4	(7) Total Adjustments
1	Electric Plant in Service	101					
2	Total Miscellaneous Intangible Plant	303	$ -	$ -	$ -	$ -	$ -
3	Production						
4	Steam						
5	Land and Land Rights	310	-				-
6	Structures and Improvements	311	-				-
7	Boiler Plant Equipment	312	-		-		-
8	Turbogenerator Units	314	-		-		-
9	Accessory Electric Equipment	315	-		-		-
10	Misc. Power Plant Equipment	316	-		-		-
11	Total Steam Production		-	-	-	-	-
12	Other Production						
13	Land and Land Rights	340					-
14	Structures and Improvements	341	-				-
15	Fuel Holders, Producers and Access.	342	-				-
16	Generators	344	-				-
17	Accessory Electric Equipment	345	-				-
18	Misc. Power Plant Equipment	346	-				-
19	Total Other Production		-	-	-	-	-
20	Total Production		-	-	-	-	-
21	Transmission						
22	Land and Land Rights	350	-				-
23	Structures and Improvements	352	-				-
24	Station Equipment	353	-				-
25	Towers and Fixtures	354	-				-
26	Poles and Fixtures	355	-				-
27	Overhead Conductors and Devices	356	-				-
28	Underground Conduit	357	-				-
29	Underground Conductors and Devices	358	-				-
30	Total Transmission		-	-	-	-	-

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Plant in Service
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) Adj 1 CWIP WP C-2-1	(4) Adj 2 CWIP WP C-2-2	(5) Adj 3 Reclass WP C-2-3	(6) Adj 4 Meters WP C-2-4	(7) Total Adjustments
31	Distribution						
32	Land and Land Rights	360	-				-
33	Structures and Improvements	361	-				-
34	Station Equipment	362	-				-
35	Poles, Towers and Fixtures	364	-				-
36	Overhead Conductors and Devices	365	-				-
37	Underground Conduit	366	-				-
38	Underground Conductors and Devices	367	-				-
39	Line Transformers	368	-				-
40	Services	369	-				-
41	Meters	370	-			62,539	62,539
42	Inst on Customer Premises-Area Lights	371	-				-
43	Leased Property on Customer Premises	372					-
44	Street Lighting	373	-				-
45	Total Distribution		-	-	-	62,539	62,539
46	General						
47	Land and Land Rights	389					-
48	Structures and Improvements	390					-
49	Office Furniture and Equipment	391					-
50	Transportation Equipment	392					-
51	Stores Equipment	393					-
52	Tools, Shop and Garage Equipment	394					-
53	Laboratory Equipment	395					-
54	Power Operated Equipment	396					-
55	Communication Equipment	397					-
56	Miscellaneous Equipment	398					-
57	Other Tangible Property	399					-
58	Total General		-	-	-	-	-
59	Electric Plant in Service	**101**	-	-	-	62,539	62,539

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Plant in Service
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) Adj 1 CWIP WP C-2-1	(4) Adj 2 CWIP WP C-2-2	(5) Adj 3 Reclass WP C-2-3	(6) Adj 4 Meters WP C-2-4	(7) Total Adjustments
60	Completed Plant not Classified	106					
61	Production						-
62	Transmission						-
63	Distribution						-
64	General						-
65	Intangible						-
66	Total Completed Plant not Classified	106					-
67	Electric Plant Acquisition Adjustment	114					-
68	TOTAL ELECTRIC PLANT IN SERVICE		-	-	-	62,539	62,539
69	Electric Plant Held for Future Use	105					
70	Production						-
71	Transmission						-
72	Distribution						-
73	Total Electric Plant Held for Future Use	105					-
74	Construction Work in Progress	107					
75	Production		-	-			-
76	Transmission		-	-			-
77	Distribution		-	-			-
78	General						-
79	Intangible						-
80	Total Construction Work in Progress	107	-	-	-	-	-
81	TOTAL ELECTRIC PLANT		$ -	$ -	$ -	$ 62,539	$ 62,539

<u>Testimony References</u>
Adjustments 1 through 4 to plant in service are discussed in the testimony of John O. Aaron.

Public Service Company of Oklahoma
Accumulated Provision for Depreciation, Amortization and Depletion
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) Balance 31-Dec-06	(4) Adjustments Schedule D-2	(5) Total Adjusted
1	Accumulated Provision for	108			
2	Depreciation				
3	Production Plant		$ (682,287,427)	$ (5,307,635)	$ (687,595,062)
4	Transmission Plant		(197,649,965)	(27,988)	(197,677,953)
5	Distribution Plant		(393,653,533)	(1,101,252)	(394,754,785)
6	General Plant		(97,935,627)	-	(97,935,627)
7	Total		$ (1,371,526,552)	$ (6,436,874)	$ (1,377,963,426)
8	Accumulated Provision for	111			
9	Amortization of Intangible Plant		$ (30,882,087)	-	$ (30,882,087)
10	Accumulated Provision for	115			
11	Amortization of Electric Plant				
12	Acquisition Adjustments		$ -	-	$ -
13	TOTAL ACCUMULATED PROVISION				
14	FOR DEPRECIATION AND AMORTIZATION		$ (1,402,408,639)	$ (6,436,874)	$ (1,408,845,513)

Note: Does not include accumulated provision for amortization of leased assets.

Public Service Company of Oklahoma
Adjustments to Accumulated Provision for Depreciation, Amortization and Depletion
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(2) FERC Account Number	(3) In Service Plant WP D-2-1	(4) Asset Retirement WP D-2-2	(5) Total Adjustments
1	Accumulated Provision for	108			
2	Depreciation				
3	Production Plant		$ -	$ (5,307,635)	$ (5,307,635)
4	Transmission Plant		-	(27,988)	(27,988)
5	Distribution Plant		-	(1,101,252)	(1,101,252)
6	General Plant		-		-
7	Total		-	(6,436,874)	(6,436,874)
8	Accumulated Provision for	111			
9	Amortization of Intangible Plant		-	-	-
10	Accumulated Provision for	115			
11	Amortization of Electric Plant				
12	Acquisition Adjustments		-	-	-
13	TOTAL ACCUMULATED PROVISION				
14	FOR DEPRECIATION AND AMORTIZATION		$ -	$ (6,436,874)	$ (6,436,874)

AEP - PUBLIC SERVICE COMPANY OF OKLAHOMA
LEAD/LAG STUDY RESULTS
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	Description (a)	Adjusted Test Year Amount	Prepayments	Adjusted Test Year Amount (b)	Avg. Daily Expense (c)	Revenue Lag Days (d)	Expense Lead Days (e)	Net (Lead)/Lag (f)	Working Capital Requirement (g)
1	Fuel	753,130,048	-	753,130,048	2,063,370	6.52	(34.22)	(27.70)	$ (57,155,349)
2									
3	Purchased Power	272,268,647	-	272,268,647	745,941	6.52	(33.18)	(26.66)	(19,886,800)
4									
5	Operation & Maintenance Expense	226,211,307	4,934,239	221,277,069	606,239	6.52	(34.81)	(28.29)	(17,150,488)
6									
7	Federal Income Taxes								
8	Current	15,295,169	-	15,295,169	41,905	6.52	(38.00)	(31.48)	(1,319,156)
9	Deferred	10,939,618	-	10,939,618	29,972	0.00	0.00	0.00	0
10	Total FIT	26,234,787	-	26,234,787					(1,319,156)
11									
12	Oklahoma Income Taxes								
13	Current	2,622,040	-	2,622,040	7,184	6.52	(45.75)	(39.23)	(281,815)
14	Deferred	-	-	-	-	0.00	0.00	0.00	-
15	Total SIT	2,622,040	-	2,622,040					(281,815)
16									
17	Taxes Other Than Income Taxes	38,131,839	-	38,131,839	104,471	6.52	(195.49)	(188.97)	(19,741,845)
18									
19	Interest on Customer Deposits	1,440,500	-	1,440,500	3,947	6.52	(161.37)	(154.85)	(611,127)
20									
21	Depreciation Expense	81,818,254	-	81,818,254	224,160	0.00	0.00	0.00	0
22									
23	Preferred Stock Dividends	224,344		224,344	615	6.52	(46.63)	(40.11)	(24,650)
24									
25	Interest on Long Term Debt	38,026,297		38,026,297	104,182	6.52	(69.80)	(63.28)	(6,593,041)
26									
27	Return	51,599,105	-	51,599,105	141,367	0.00	0.00	0.00	0
28									
29	Subtotal	$1,453,456,527	$ 4,934,239	$ 1,448,522,288					$ (122,764,273)
30									
31	Working Funds and Other								(6,199,517)
32									
33	Total								($128,963,790)
34									
35	* Source: WP E-1-1								

PUD Cause No. 200600285
Final Order
Schedule F-1

PUBLIC SERVICE COMPANY OF OKLAHOMA
COMPONENTS OF CAPITAL
FOR THE TEST YEAR ENDING JUNE 30 ,2006

	(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	$ 500,597,799	$149,867,164 [(1)]	$ 650,464,963	53.55%	6.32% [(1)]	3.39%
2	Preferred Stock	WP F-2	5,261,700	-	5,261,700	0.43%	4.02%	0.02%
3	Common Equity		558,468,091	568,414 [(2)]	559,036,505	46.02%	10.00% [(3)]	4.60%
4	Total Capital		$ 1,064,327,590	$150,435,578	$ 1,214,763,168	100.00%		8.01%

NOTES
(1) *Adjusted for issuance of $150MM debt in August 2006.*
(2) Adjusted to eliminate OCI charges to equity.
(3) Return on Equity prescribed in final order.

PUBLIC SERVICE COMPANY OF OKLAHOMA
TEST YEAR ACTUAL AND PRO FORMA OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Description	(2) Schedule Reference	(3) Total Company Per Books	(4) Sched. H-2 Pro Forma Adjustment	(5) Total Company Pro Forma	(6) Revenue Deficiency	(7) Pro Forma with Revenue Increase	(8) Oklahoma Jurisdictional %	(9) Total Company Pro Forma Oklahoma Jurisdiction
1	Operating Revenue		$1,464,153,206	$(995,656,729)	$ 468,496,476	$ 9,646,691	$ 478,143,167	99.66580010%	476,545,213
2	Operating Expenses:								
3	Fuel and Purchased Power	W/P H-3	985,239,061	(973,404,367)	11,834,695	0	11,834,695	99.93742551%	11,827,289
4	Other Operation and Maintenance	W/P H-3	243,981,644	(16,423,903)	227,557,741	94,066	227,651,807	99.67142673%	226,903,804
5	Other Taxes		38,823,976	(692,137)	38,131,839	0	38,131,839	99.66542657%	38,004,260
6	*Depreciation and Amortization*	I-1, I-2	84,707,282	(2,889,028)	81,818,254	0	81,818,254	99.71750925%	81,587,125
7	Operating Expenses Before Income Taxes		1,352,751,963	(993,409,434)	359,342,529	94,066	359,436,595	99.69003810%	358,322,478
8	Operating Income Before Income Taxes		111,401,243	(2,247,295)	109,153,947	9,552,625	118,706,572	99.59240883%	118,222,735
9	Income Taxes	J-1	27,274,393	(2,112,445)	25,161,948	3,694,879	28,856,827	99.56974826%	28,732,670
10	Net Operating Income		$ 84,126,850	$ (134,850)	$ 83,991,999	$ 5,857,746	$ 89,849,745	99.59968668%	$ 89,490,065
11	Rate Base	B-1	$1,210,623,839	$ (88,904,171)	$ 1,121,719,668		$1,121,719,668	99.59968643%	$ 1,117,229,272
12	Rate of Return		6.95%		7.49%		8.01%		8.01%

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

Line No.	Description (1)	Total Company Per Books (2)	WP H-2-1 Payroll Annualization (3)	WP H-2-2 AEPSC Payroll Annualization (4)	WP H-2-3 SFAS 87 Pension Expense (5)	WP H-2-4 OPEB and Pension Expense (6)
1	Operating Revenue	1,464,153,206				
2	Operating Expenses:					
3	Fuel and Purchased Power	985,239,061		18,583		
4	Other Operation and Maintenance	243,981,644	2,697,440	412,785	1,500,658	(461,878)
5	Other Taxes	38,823,976				
6	Depreciation and Amortization	84,707,282				
7	Operating Expenses Before Income Taxes	1,352,751,963	2,697,440	431,368	1,500,658	(461,878)
8	Operating Income Before Income Taxes	111,401,243	(2,697,440)	(431,368)	(1,500,658)	461,878
9	Income Taxes	27,274,393				
10	Net Operating Income	84,126,850				

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(7) WP H-2-5 SFAS 112	(8) WP H-2-6 Employee Benefits Group Ins	(9) WP H-2-7 Incentive Comp	(10) WP H-2-8 FICA Adj	(11) WP H-2-9 Interest on Customer Deposits	(12) WP H-2-10 Legislative Monitoring
1	Operating Revenue						
2	Operating Expenses:						
3	Fuel and Purchased Power						
4	Other Operation and Maintenance	1,629,646	1,318,927	(9,404,958)		1,440,500	(534,463)
5	Other Taxes				(309,788)		
6	Depreciation and Amortization						
7	Operating Expenses Before Income Taxes	1,629,646	1,318,927	(9,404,958)	(309,788)	1,440,500	(534,463)
8	Operating Income Before Income Taxes	(1,629,646)	(1,318,927)	9,404,958	309,788	(1,440,500)	534,463
9	Income Taxes						
10	Net Operating Income						

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

Line No.	Description (1)	(13) WP H-2-11 Donations & Contributions	(14) WP H-2-12 Dues & Memberships	(15) WP H-2-13 FERC Assessment	(16) WP H-2-14 Purchased Pwr Adjustment	(17) WP H-2-15 Credit Line Fees	(18) WP H-2-16 Depreciation Expense
1	Operating Revenue						
2	Operating Expenses:						
3	Fuel and Purchased Power				(260,220,000)		
4	Other Operation and Maintenance	(5,970)	(260,218)	305,829		0	
5	Other Taxes						
6	Depreciation and Amortization						(5,816,600)
7	Operating Expenses Before Income Taxes	(5,970)	(260,218)	305,829	(260,220,000)	0	(5,816,600)
8	Operating Income Before Income Taxes	5,970	260,218	(305,829)	260,220,000	(0)	5,816,600
9	Income Taxes						
10	Net Operating Income						

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

Line No.	Description (1)	(19) WP H-2-17 Amortization Expense	(20) WP H-2-18 Revenue Adjustment	(21) WP H-2-19 AEPSC Billing Adjust	(22) WP H-2-20 Rate Case Amortization	(23) WP H-2-21 Other Tax Adjustment	(24) WP H-2-22 Fuel Exp Adjustment
1	Operating Revenue		(995,656,729)				
2	Operating Expenses:						
3	Fuel and Purchased Power			(90,793)			(715,316,617)
4	Other Operation and Maintenance			(5,066,521)	136,667		
5	Other Taxes					(382,349)	
6	Depreciation and Amortization	2,481,325					
7	Operating Expenses Before Income Taxes	2,481,325	0	(5,157,315)	136,667	(382,349)	(715,316,617)
8	Operating Income Before Income Taxes	(2,481,325)	(995,656,729)	5,157,315	(136,667)	382,349	715,316,617
9	Income Taxes						
10	Net Operating Income						

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

	(1)	(25)	(26)	(27)	(28)	(29)	(30)
Line No.	Description	WP H-2-23 Factoring Expense	WP H-2-24 SPP Admin Fee	WP H-2-25 ABD Expense	WP H-2-26 RCA Rider	WP H-2-27 OCC Assessment	WP H-2-28 Transmission Expense
1	Operating Revenue						
2	Operating Expenses:						
3	Fuel and Purchased Power						
4	Other Operation and Maintenance	(1,329,936)	1,277,160	(1,377,888)	(11,825,328)	(738,614)	813,058
5	Other Taxes						
6	Depreciation and Amortization						
7	Operating Expenses Before Income Taxes	(1,329,936)	1,277,160	(1,377,888)	(11,825,328)	(738,614)	813,058
8	Operating Income Before Income Taxes	1,329,936	(1,277,160)	1,377,888	11,825,328	738,614	(813,058)
9	Income Taxes						
10	Net Operating Income						

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

Line No.	(1) Description	(31) WP H-2-29 Inventory Write Off	(32) WP H-2-30 Postage Rate Adj	(33) WP H-2-31 Environmental Adjustment	(34) WP H-2-32 Calpine Reactive Power	(35) WP H-2-33 ARO Reversal	(36) WP H-2-34 Trading Deposit Interest
1	Operating Revenue						
2	Operating Expenses:						
3	Fuel and Purchased Power				2,204,460		
4	Other Operation and Maintenance	(1,781,629)	70,586	0			3,903
5	Other Taxes						
6	Depreciation and Amortization					446,248	
7	Operating Expenses Before Income Taxes	(1,781,629)	70,586	0	2,204,460	446,248	3,903
8	Operating Income Before Income Taxes	1,781,629	(70,586)	0	(2,204,460)	(446,248)	(3,903)
9	Income Taxes						
10	Net Operating Income						

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

	(1)	(37)	(38)	(39)	(40)	(41)	(42)
Line No.	Description	WP H-2-35 IPP System Upgrade Interest	WP H-2-36 New Generation Costs	WP H-2-37 Increase Staffing	WP H-2-38 Non Utility Outside Services	WP H-2-39 Legal Exense	WP H-2-40 Advertising Expense
1	Operating Revenue						
2	Operating Expenses:						
3	Fuel and Purchased Power						
4	Other Operation and Maintenance	632,504	(958,751)	300,000	(12,769)	(104,957)	(475,990)
5	Other Taxes						
6	Depreciation and Amortization						
7	Operating Expenses Before Income Taxes	632,504	(958,751)	300,000	(12,769)	(104,957)	(475,990)
8	Operating Income Before Income Taxes	(632,504)	958,751	(300,000)	12,769	104,957	475,990
9	Income Taxes		Sch J-1 ------->				
10	Net Operating Income						

PUBLIC SERVICE COMPANY OF OKLAHOMA
Adjustments to Operating Income
For the Test Year Ending June 30, 2006

	(1)	(43)		(44)	(45)	(46
Line No.	Description	WP H-2-41 Pension Asset Alternate Recovery	WP H-2-42 Add'l Recovery due to Debt Assignment	Income Tax	Total Pro Forma Adjustments	Total Company Pro Forma
1	Operating Revenue				(995,656,729)	468,496,476
2	Operating Expenses:					
3	Fuel and Purchased Power				(973,404,367)	11,834,695
4	Other Operation and Maintenance	3,176,008	2,200,297		(16,423,903)	227,557,741
5	Other Taxes				(692,137)	38,131,839
6	Depreciation and Amortization				(2,889,028)	81,818,254
7	Operating Expenses Before Income Taxes	3,176,008	2,200,297	0	(993,409,434)	359,342,529
8	Operating Income Before Income Taxes	(3,176,008)	(2,200,297)	0	(2,247,295)	109,153,947
9	Income Taxes			(2,112,445)	(2,112,445)	25,161,948
10	Net Operating Income				(134,850)	83,991,999

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Adjustment Number	(2) Description	(3) Sponsor	(4) Adjustment Amount	(5) Final Order	(6) Revised Adjustment	(7) Oklahoma Jurisdictional %	(8) Pro Forma Oklahoma Jurisdiction
1	WP H-2-1	Increase cost of service for payroll annualization.	Aaron	2,697,440	-	2,697,440	99.7819946%	2,691,559
2	WP H-2-2	Increase cost of service related to AEPSC payroll annualization.	Aaron	431,368	-	431,368	99.7819946%	430,428
3	WP H-2-3	Increase pension expense to reflect 2006 SFAS 87 actuarial study.	McCoy	1,500,658	-	1,500,658	99.78198882%	1,497,387
4	WP H-2-4	Decrease cost of service to reflect 2006 SFAS 106 actuarial expense.	McCoy	(461,878)	-	(461,878)	99.78198882%	(460,871)
5	WP H-2-5	Increase cost of service to reflect 2006 SFAS 112 actuarial expense.	McCoy	1,629,646	-	1,629,646	99.78198882%	1,626,093
6	WP H-2-6	Increase cost of service for annualized employee benefits.	Aaron	1,318,927	-	1,318,927	99.78198882%	1,316,052
7	WP H-2-7	Decrease cost of service for incentive compensation	Aaron	(4,086,069)	(5,318,889)	(9,404,958)	99.7819946%	(9,384,455)
8	WP H-2-8	Adjust FICA expense consistent with base payroll and incentive payroll adjustments	Aaron	(84,221)	(225,567)	(309,788)	99.7819946%	(309,113)
9	WP H-2-9	Increase cost of service to include interest expense on customer deposits.	Aaron	1,418,533	21,967	1,440,500	100.00000000%	1,440,500
10	WP H-2-10	Adjust cost of service for legislative monitoring expenses.	Aaron	100,666	(635,129)	(534,463)	99.78200763%	(533,298)
11	WP H-2-11	Decrease cost of service for donations and contributions.	Aaron	(5,970)	-	(5,970)	99.78200763%	(5,957)
12	WP H-2-12	Increase cost of service for certain dues and memberships.	Aaron	165,336	(425,554)	(260,218)	99.56845932%	(259,095)
13	WP H-2-13	Increase cost of service to remove FERC assessment true-up.	Aaron	305,829	-	305,829	99.65837421%	304,784
14	WP H-2-14	Adjust cost of service for purchased power expenses.						
15		- Remove purchased power expense recovered via OCC approved FCA.	Aaron	(265,009,397)	-	(265,009,397)	99.9438774%	(264,860,667)
16		- Increase purchased power capacity costs to on-going level.	Aaron	4,789,397	-	4,789,397	99.9332909%	4,786,202

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Adjustment Number	(2) Description	(3) Sponsor	(4) Adjustment Amount	(5) Final Order	(6) Revised Adjustment	(7) Oklahoma Jurisdictional %	(8) Pro Forma Oklahoma Jurisdiction
17	WP H-2-15	Increase cost of service for Credit Line Fees.	Aaron	203,300	(203,300)	0	100.0000000%	0
18	WP H-2-16	Increase depreciation expense to proposed annual rate.	Davis	(5,816,600)	-	(5,816,600)	99.70986740%	(5,799,725)
19	WP H-2-17	Decrease amortization expense to proposed annual rate.	Aaron	2,512,966	(31,641)	2,481,325	99.78200050%	2,475,916
20	WP H-2-18	Adjust revenues in cost of service.						-
21		- Adjust retail base for weather, customer, and pro-forma	Moncrief	(20,150,068)	775,608	(19,374,460)	100.0000000%	(19,374,460)
22		- Remove retail fuel revenues included in OCC approved FCA.	Aaron	(843,902,839)	-	(843,902,839)	100.0000000%	(843,902,839)
23		- Adjust wholesale base revenue	Moncrief	1,326,156	-	1,326,156	0.0000000%	-
24		- Remove wholesale fuel revenues	Aaron	(524,449)	-	(524,449)	0.0000000%	-
25		- Adjust off-system capacity revenues for prior period	Aaron	926,399	-	926,399	99.9332909%	925,781
26		- Remove off-system revenues included in OCC approved FCA or retained by PSO	Aaron	(129,423,982)	-	(129,423,982)	99.9438774%	(129,351,346)
27		- Adjust miscellaneous revenues (forfeited discounts, misc svc, rentals, etc.)	Moncrief	(4,683,554)	-	(4,683,554)	99.3528717%	(4,653,248)
		TOTAL		(996,432,337)		(995,656,729)		(996,356,110)
28	WP H-2-19	Decrease cost of service related to AEPSC billing adjustments.	Bethel	(5,157,315)	-	(5,157,315)	99.6838430%	(5,141,009)
29	WP H-2-20	Increase amortization expense for rate case amortization related to current proceeding.	Aaron	205,000	(68,333)	136,667	100.0000000%	136,667
30	WP H-2-21	Adjust other taxes to reflect changes in revenues and rate base.	Aaron	(382,349)	-	(382,349)	99.6654266%	(381,070)
31	WP H-2-22	Eliminate fuel expense recovered via the OCC approved FAC. (Test Year fuel expense = $720,001,121; amount remaining in base rate = $4,684,504)	Aaron	(715,316,617)	-	(715,316,617)	99.9438774%	(714,915,163)
32	WP H-2-23	Annualize factoring expense based on test year ending adjusted revenue and factoring rate.	Aaron	(1,329,936)		(1,329,936)	99.6272410%	(1,324,978)
33	WP H-2-24	Increase cost of service to reflect increased SPP Administration Fees.	Aaron	1,277,160	-	1,277,160	98.2691614%	1,255,054
34	WP H-2-25	Decrease cost of service related to ABD expense adjustment.	Aaron	(1,377,888)	-	(1,377,888)	99.9313717%	(1,376,942)
35	WP H-2-26	Decrease cost of service to reflect expenses recovered through RCA rider	Aaron	(11,825,328)	-	(11,825,328)	100.0000000%	(11,825,328)
36	WP H-2-27	Decrease cost of service to reflect OCC assessment recovered through revenue rider.	Aaron	(738,614)	-	(738,614)	100.0000000%	(738,614)
37	WP H-2-28	Adjust transmission expense in cost of service						
		- Reflect increase in rate for point to point transmission service from MISO to SPP.	Aaron	595,000	-	595,000	98.2358461%	584,503
		- Remove adjustment related to prior year.	Aaron	218,058	-	218,058	98.2358461%	214,211
38	WP H-2-29	Decrease cost of service for non-recurring inventory write off	Aaron	(1,781,629)	-	(1,781,629)	99.3838690%	(1,770,652)
39	WP H-2-30	Increase cost of service to reflect postage rate increase.	Aaron	70,586	-	70,586	99.6508233%	70,339
40	WP H-2-31	Increase cost of service to reclassify environmental expenses	Aaron	8,541	(8,541)	-	99.8053018%	-
41	WP H-2-32	Increase cost of service to include Calpine payments and amortization.	Aaron	2,204,460	-	2,204,460	99.9438774%	2,203,223
42	WP H-2-33	Increase cost of service for reversal of ARO depreciation and accretion expenses.	Aaron	446,248	-	446,248	99.7098674%	444,953

PUBLIC SERVICE COMPANY OF OKLAHOMA
EXPLANATION OF ADJUSTMENTS TO OPERATING INCOME STATEMENT
FOR THE TEST YEAR ENDED JUNE 30, 2006

Line No.	(1) Adjustment Number	(2) Description	(3) Sponsor	(4) Adjustment Amount	(5) Final Order	(6) Revised Adjustment	(7) Oklahoma Jurisdictional %	(8) Pro Forma Oklahoma Jurisdiction
43	WP H-2-34	Include trading deposit interest income and expense in cost of service.	Aaron	3,903	-	3,903	100.0000000%	3,903
44	WP H-2-35	Increase cost of service to recognize annual interest on IPP System Upgrade Credits.	Aaron	632,504	-	632,504	98.2691614%	621,556
45	WP H-2-36	Adjust cost of service to reflect new generation preliminary engineering costs.	Aaron	(516,348)	(442,403)	(958,751)	99.7589508%	(956,440)
46	WP H-2-37	Increased staffing in community affairs and economic development	Aaron	300,000	-	300,000	99.7819910%	299,346
47	WP H-2-38	Remove Non Utility Outside Services		-	(12,769)	(12,769)	99.7819982%	(12,741)
48	WP H-2-39	Remove Legal Expense		-	(104,957)	(104,957)	99.7819982%	(104,728)
49	WP H-2-40	Remove Advertising Expense		-	(475,990)	(475,990)	99.7820076%	(474,952)
50	WP H-2-41	Pension Asset Alternate Recovery		-	3,176,008	3,176,008	99.78198882%	3,169,084
51	WP H-2-42	Add'l recovery due to Debt Assigned to Prepaid Pension Asset			2,200,297	2,200,297	99.78198882%	2,195,500
			Revenue	(996,432,337)	775,608	(995,656,729)		
			Expense	(990,854,633)	(2,554,801)	(993,409,434)		
			Inc Tax	0	0	(2,112,445)		
			Op Inc Net Change	(5,577,704)		(134,850)		

PUBLIC SERVICE COMPANY OF OKLAHOMA
Depreciation Expense and Depreciable Plant
For the Test Year Ending June 30, 2006
Existing Rates

PUD Cause No. 200600285
Final Order
Schedule I-1

Line No.	(1) Description	(2) Plant Account	(3) Balance 30-Jun-06	(4) Existing Rates	(5) Depreciation Accrual	(6) Operations	(7) Amount Charged to: A/C 184	(8) Inventory
1	Steam Production							
2	Land and Land Rights	310						
3	Land in Fee		5,021,779	0.00%	-	-	-	-
4	NEPS Rail Spur ROW		206,091	3.46%	7,131	7,131	-	-
5	NEPS Rail Spur Land in Fee		2,163,300	0.00%	-	-	-	-
6	Structures and Improvements	311						
7	Oil and Gas Fired Plants		33,509,454	2.48%	825,134	825,134	-	-
8	Coal Fired Plants		32,823,379	2.34%	755,982	755,982	-	-
9	Boiler Plant Equipment	312						
10	Oil and Gas Fired Plants		168,170,852	2.99%	5,017,899	5,017,899	-	-
11	Coal Fired Plants		295,906,121	2.42%	7,107,048	7,107,048	-	-
12	NEPS Rail Spur		22,359,915	3.45%	771,417		-	771,417
13	Coal Trans. Equip. (Fully Depreciated)		29,746,214	0.00%	-		-	-
14	Turbogenerator Units	314						
15	Oil and Gas Fired Plants		174,584,970	2.95%	5,137,989	5,137,989	-	-
16	Coal Fired Plants		90,041,145	2.36%	2,107,478	2,107,478	-	-
17	Accessory Electric Equipment	315						
18	Oil and Gas Fired Plants		35,068,431	2.87%	978,973	978,973	-	-
19	Coal Fired Plants		32,050,086	2.26%	721,248	721,248	-	-
20	Misc. Power Plant Equipment	316						
21	Oil and Gas Fired Plants		106,529,252	3.15%	3,293,287	3,293,287	-	-
22	Coal Fired Plants		19,985,406	2.54%	549,704	549,704	-	-
23	Short Life Items		502,703	20.00%	-	-	-	-
24	Oil and Gas Fired Plants ARO	317	1,842,756		-	-		
25	Coal Fired Plants ARO		119,306		-	-		
26	Total Steam Production		1,050,633,160	2.60%	27,273,290	26,501,873		771,417
27	Other Production							
28	Land and Land Rights	340						
29	Land in Fee		62,660	0.00%	-	-	-	-
30	Structures and Improvements	341						
31	Gas Turbine		460,617	2.44%	11,377	11,377	-	-
32	Fuel Holders, Producers and Access.	342						
33	Gas Turbine		2,947,002	3.02%	87,616	87,616	-	-
34	Generators	344	26,078,348	3.18%	829,291	829,291	-	-
35	Accessory Electric Equipment	345						
36	Gas Turbine		301,126	3.76%	11,322	11,322	-	-
37	Misc. Power Plant Equipment	346						
38	Gas Turbine		1,637,573	4.06%	60,753	60,753	-	-
39	Asset Retirement Obligation	347	1,908		-	-		
40	Total Other Production		31,489,234	3.18%	1,000,359	1,000,359		-
41	Total Production		1,082,122,394	2.61%	28,273,649	27,502,232	-	771,417

Attachment 1

PUBLIC SERVICE COMPANY OF OKLAHOMA
Depreciation Expense and Depreciable Plant
For the Test Year Ending June 30, 2006
Existing Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
						Amount Charged to:		
Line No.	Description	Plant Account	Balance 30-Jun-06	Existing Rates	Depreciation Accrual	Operations	A/C 184	Inventory
42	Transmission							
43	Land and Land Rights	350						
44	Land in Fee		2,620,845	0.00%	-	-	-	-
45	Land Rights		28,429,988	1.33%	377,688	377,688	-	-
46	Structures and Improvements	352	6,632,384	1.98%	131,302	131,302	-	-
47	Station Equipment	353	202,448,528	1.85%	3,657,300	3,657,300	-	-
48	Towers and Fixtures	354	14,056,315	1.87%	262,853	262,853	-	-
49	Poles and Fixtures	355	119,976,476	2.68%	3,101,312	3,101,312	-	-
50	Overhead Conductors and Devices	356	116,392,408	1.77%	2,015,018	2,015,018	-	-
51	Underground Conductors and Devices	358	71,915	2.22%	1,596	1,596	-	-
52	Total Transmission		490,628,839	1.95%	9,547,069	9,547,069		-
53	Distribution							
54	Land and Land Rights	360						
55	Land in Fee		6,154,070	0.00%	-	-	-	-
56	Land Rights		1,650,687	1.54%	25,156	25,156		
57	Structures and Improvements	361	1,871,725	1.43%	220,008	220,008	-	-
58	Station Equipment	362	131,154,836	1.86%	2,425,050	2,425,050	-	-
59	Poles, Towers and Fixtures	364	214,522,649	3.23%	6,712,039	6,712,039	-	-
60	Overhead Conductors and Devices	365	187,893,732	2.81%	4,855,776	4,855,776	-	-
61	Underground Conduit	366	21,317,170	2.24%	455,838	455,838		
62	Underground Conductors and Devices	367	142,906,131	1.86%	2,521,042	2,521,042		
63	Line Transformers	368	203,279,610	3.66%	7,135,065	7,135,065	-	-
64	Services	369	137,876,321	2.46%	3,168,351	3,168,351	-	-
65	Meters	370	52,707,078	3.99%	2,011,744	2,011,744	-	-
66	Inst on Customer Premises-Area Lights	371	34,136,351	7.59%	2,498,616	2,498,616		
67	Street Lighting	373	45,755,531	6.95%	3,041,433	3,041,433	-	-
68	Total Distribution		1,181,225,891	2.97%	35,070,117	35,070,117		-

PUBLIC SERVICE COMPANY OF OKLAHOMA
Depreciation Expense and Depreciable Plant
For the Test Year Ending June 30, 2006
Existing Rates

PUD Cause No. 200600285
Final Order
Schedule I-1

Line No.	(1) Description	(2) Plant Account	(3) Balance 30-Jun-06	(4) Existing Rates	(5) Depreciation Accrual	(6) Operations	(7) Amount Charged to: A/C 184	(8) Inventory
69	General							
70	Land and Land Rights	389			-			
71	Land in Fee		3,893,129	0.00%		-	-	-
	Land Rights		124,310	0.00%				
72	Structures and Improvements	390	33,567,075	2.02%	405,182	405,182	-	-
73	Office Furniture and Equipment	391						
74	Regular		28,679,219	3.18%	929,784	929,784	-	-
75	Computers		2,896,735	14.58%	417,279	417,279	-	-
76	Transportation Equipment	392	9,756,519	21.08%	960,392	709,726	(250,666)	-
77	Stores Equipment	393	2,561,104	3.06%	83,965	83,965	-	-
78	Tools, Shop and Garage Equipment	394	5,735,749	3.61%	187,892	187,892		
79	Laboratory Equipment	395	4,117,346	3.18%	140,777	140,777		
80	Power Operated Equipment	396	1,254,953	0.00%	-	-	-	-
81	Communication Equipment	397	73,382,636	4.71%	3,385,184	3,385,184	-	-
82	Miscellaneous Equipment	398	2,712,251	5.89%	140,112	140,112	-	-
83	Other Tangible Property	399						
84	Rail Maintenance Facility		529,811	1.68%	8,901	-	-	8,901
85	Asset Retirement Obligation		495,814		-	-		
86	Total General		169,706,651	3.92%	6,659,469	6,399,902	(250,666)	8,901
87	TOTAL Electric Plant in Service	101/106	2,923,683,775	2.72%	79,550,304	78,519,320	(250,666)	780,318

PUBLIC SERVICE COMPANY OF OKLAHOMA
Amortization Expense and Amortizable Rate Base
For the Test Year Ending June 30, 2006
Existing

Line No.	(1) Description	(2) Plant Account	(3) Balance 30-Jun-06	(4) Existing Rates	(5) Amortization Expense
1	Miscellaneous Intangible Plant	303			
2	Customer Information System			0.00%	127,212
3	Power Plant Monitoring System		1,767,357	0.00%	-
4	Material Management System		4,220,008	0.00%	-
5	Facilities Management		4,308,042	0.00%	-
6	Customer Accounting System		262,630	14.29%	57,330
7	Enterprise Application Solutions		39,728,501	20.00%	6,003,419
8	Integrated Fuel Management System		1,044,723	0.00%	-
9	Marketing System		670,517	0.00%	-
10	Total Misc. Intangible Plant		52,001,778	11.90%	6,187,961
11	Electric Plant Acquisition Adjustment	114			
12	Weleetka, Oklahoma		292,836	0.000%	-
13	Chelsea, Oklahoma		2,197,157	0.000%	-
14	Chelsea Municipal Authority		532,920	0.000%	-
15	Clinton Sherman Industrial Air Park		467,809	6.667%	31,641
16	Total Electric Plant Acquisition Adj.(a)		3,490,722		31,641
17	Total Rate Base Related		55,492,500		6,219,602
18	Less:				
19	(a) Recorded below the line				(31,641)
20	TOTAL AMORTIZATION EXPENSE				6,187,961

PUBLIC SERVICE COMPANY OF OKLAHOMA
Pro Forma Depreciation Expense
For the Test Year Ending June 30, 2006
Proposed Rates

Line No.	(1) Description	(2) Plant Account	(3) Pro Forma Plant	(4) Final Order Rates	(5) Depreciation Accrual	(6) Amount Charged to: Operations	(7) Clearing	(8) Inventory
1	Steam Production							
2	Land and Land Rights	310						
3	Land in Fee		$ 5,021,779	0.00%	$ -	$ -	$ -	$ -
4	NEPS Rail Spur ROW		206,091	2.30%	4,740	4,740	-	-
5	NEPS Rail Spur Land in Fee		2,163,300	0.00%	-	-	-	-
6	Structures and Improvements	311				-	-	-
7	Oil and Gas Fired Plants		33,513,356	2.35%	787,564	787,564	-	-
8	Coal Fired Plants		33,053,776	1.32%	436,310	436,310	-	-
9	Boiler Plant Equipment	312						
10	Oil and Gas Fired Plants		190,150,666	1.92%	3,650,893	3,650,893	-	-
11	Coal Fired Plants		297,473,983	1.46%	4,343,120	4,343,120	-	-
12	NEPS Rail Spur		22,359,915	1.76%	393,535		-	393,535
14	Coal Trans. Equip. (Fully Depreciated)		29,536,420	0.00%				
15	Turbogenerator Units	314						
16	Oil and Gas Fired Plants		247,271,115	2.28%	5,637,781	5,637,781	-	-
17	Coal Fired Plants		90,752,436	1.29%	1,170,706	1,170,706	-	-
18	Accessory Electric Equipment	315						
19	Oil and Gas Fired Plants		39,375,668	2.39%	941,078	941,078	-	-
20	Coal Fired Plants		31,950,792	1.29%	412,165	412,165	-	-
21	Misc. Power Plant Equipment	316						
22	Oil and Gas Fired Plants		15,309,389	3.35%	512,865	512,865	-	-
23	Coal Fired Plants		19,691,775	1.46%	287,500	287,500	-	-
24	Short Life Items		463,272	0.00%	-	-	-	-
25	Oil and Gas Fired Plants ARO		2,029,775	0.00%		-		
26	Coal Fired Plants ARO		119,306	0.00%		-		
27	Total Steam Production		1,060,442,814	1.75%	18,578,257	18,184,722	-	393,535
28	Other Production							
29	Land and Land Rights	340						
30	Land in Fee		62,660	0.00%	-	-	-	-
31	Structures and Improvements	341						
32	Gas Turbine		460,617	2.43%	11,193	11,193	-	-
33	Fuel Holders, Producers and Access.	342						
34	Gas Turbine		2,947,002	2.80%	82,516	82,516	-	-
35	Generators	344	26,078,348	2.74%	714,547	714,547	-	-
36	Accessory Electric Equipment	345						
37	Gas Turbine		279,416	2.71%	7,572	7,572	-	-
38	Misc. Power Plant Equipment	346						
39	Gas Turbine		1,637,574	2.81%	46,016	46,016	-	-
40	Asset Retirement Obligation	347	1,908	0.00%				
41	Total Other Production		31,467,524	2.74%	861,844	861,844	-	-
42	Total Production		1,091,910,337	1.78%	19,440,101	19,046,566	-	393,535

PUBLIC SERVICE COMPANY OF OKLAHOMA
Pro Forma Depreciation Expense
For the Test Year Ending June 30, 2006
Proposed Rates

Line No.	(1) Description	(2) Plant Account	(3) Pro Forma Plant	(4) Final Order Rates	(5) Depreciation Accrual	(6) Amount Charged to: Operations	(7) Clearing	(8) Inventory
43	Transmission							
44	Land and Land Rights	350						
45	Land in Fee		2,974,397	0.00%	-	-	-	-
46	Land Rights		28,453,170	1.04%	295,913	295,913	-	-
47	Structures and Improvements	352	6,632,364	1.52%	100,812	100,812	-	-
48	Station Equipment	353	214,894,759	1.55%	3,330,869	3,330,869	-	-
49	Towers and Fixtures	354	14,056,316	1.94%	272,693	272,693	-	-
50	Poles and Fixtures	355	120,862,914	2.80%	3,384,162	3,384,162	-	-
51	Overhead Conductors and Devices	356	115,691,946	2.11%	2,441,100	2,441,100	-	-
52	Underground Conductors and Devices	358	71,915	2.56%	1,841	1,841	-	-
53	Total Transmission		503,637,779	1.95%	9,827,390	9,827,390	-	-
54	Distribution							
55	Land and Land Rights	360						
56	Land in Fee		6,172,709	0.00%	-	-	-	-
57	Land Rights		1,668,846	0.85%	14,185	14,185	-	-
58	Structures and Improvements	361	1,871,725	0.36%	6,738	6,738	-	-
59	Station Equipment	362	133,893,677	1.61%	2,155,688	2,155,688	-	-
60	Poles, Towers and Fixtures	364	220,810,644	3.42%	7,551,724	7,551,724	-	-
61	Overhead Conductors and Devices	365	196,269,497	3.03%	5,946,966	5,946,966	-	-
62	Underground Conduit	366	22,484,231	2.20%	494,653	494,653		
63	Underground Conductors and Devices	367	149,654,011	1.54%	2,304,672	2,304,672		
64	Line Transformers	368	208,947,356	3.76%	7,856,421	7,856,421	-	-
65	Services	369	141,991,200	2.77%	3,933,156	3,933,156	-	-
66	Meters	370	53,865,600	3.94%	2,122,305	2,122,305	-	-
67	Inst on Customer Premises-Area Lights	371	31,792,074	6.60%	2,098,277	2,098,277		
68	Street Lighting	373	45,876,699	7.88%	3,615,084	3,615,084	-	-
69	Total Distribution		1,215,298,268	3.14%	38,099,869	38,099,869	-	-

PUBLIC SERVICE COMPANY OF OKLAHOMA
Pro Forma Depreciation Expense
For the Test Year Ending June 30, 2006
Proposed Rates

	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Description	Plant Account	Pro Forma Plant	Final Order Rates	Depreciation Accrual	Amount Charged to: Operations	Clearing	Inventory
70	General							
71	Land and Land Rights	389	-					
72	Land in Fee		4,036,779	0.00%	-	-	-	-
73	Land Rights		124,310	0.00%	-	-		
74	Structures and Improvements	390	33,429,895	0.45%	150,435	150,435	-	-
75	Office Furniture and Equipment	391	-					
76	Regular		24,268,794	6.71%	1,628,436	1,628,436	-	-
77	Computers		3,326,024	20.35%	676,846	676,846	-	-
78	Transportation Equipment	392	6,959,943	4.51%	313,893	-	313,893	-
79	Stores Equipment	393	2,451,105	3.37%	82,602	82,602	-	-
80	Tools, Shop and Garage Equipment	394	6,323,255	2.84%	179,580	179,580		
81	Laboratory Equipment	395	4,051,419	3.03%	122,758	122,758		
82	Power Operated Equipment	396	1,240,037	5.21%	64,606	-	64,606	-
83	Communication Equipment	397	73,784,253	3.73%	2,752,153	2,752,153	-	-
84	Miscellaneous Equipment	398	3,240,118	4.20%	136,085	136,085	-	-
85	Other Tangible Property	399	-					
86	Rail Maintenance Facility		529,811	1.52%	8,053	-	-	8,053
87	Asset Retirement Obligation		495,814			-		
88	Total General		164,261,556	3.72%	6,115,447	5,728,895	378,499	8,053
89	Electric Plant in Service	101	2,975,107,941	2.47%	73,482,807	72,702,720	378,499	401,588
90	Completed Construction not Classified	106						
91	Production		-	1.78%	-	-	-	-
92	Transmission		-	1.95%	-	-	-	-
93	Distribution		-	3.14%	-	-	-	-
94	General		-	3.72%	-	-	-	-
95	Intangible		-	0.00%	-	-		
96	Total Completed Const. not Classified		-		-	-	-	-
97	Construction Work In Progress							
98	Production		-	1.78%	-	-	-	-
99	Transmission		-	1.95%	-	-	-	-
100	Distribution		-	3.14%	-	-	-	-
101	General (excl. Fleet)		-	3.72%	-	-	-	-
102	Intangible		-	14.29%	-	-	-	-
103	Total Construction Work In Progress		-		-	-	-	-
104	TOTAL		$ 2,975,107,941		$ 73,482,807	$ 72,702,720	$ 378,499	$ 401,588

PUBLIC SERVICE COMPANY OF OKLAHOMA
Amortization Expense and Amortizable Rate Base
For the Test Year Ending June 30, 2006
Proposed

Line No.	(1) Description		(2) Plant Account	(3) Pro Forma Balance	(4) Proposed Rates	(5) Amortization Expense
1	Miscellaneous Intangible Plant		303			
2	Customer Information System	(a)		-	0.00%	-
3	Power Plant Monitoring System	(b)		1,767,357	0.00%	-
4	Material Management System	(b)		4,220,008	0.00%	-
5	Facilities Management	(b)		4,308,042	0.00%	-
6	Customer Accounting System	(a)		262,630	0.00%	-
7	Enterprise Application Solutions			43,346,429	20.00%	8,669,286
8	Integrated Fuel Management System	(b)		1,044,723	0.00%	-
9	Marketing System	(b)		670,517	0.00%	-
10	Total Misc. Intangible Plant			55,619,706	15.59%	8,669,286
11	Electric Plant Acquisition Adjustment		114			
12	Weleetka, Oklahoma	(b)		292,836	0.000%	-
13	Chelsea, Oklahoma	(b)		2,197,157	0.000%	-
14	Chelsea Municipal Authority	(b)		532,920	0.000%	-
15	Clinton Sherman Industrial Air Park			467,809	0.000%	-
16	Total Electric Plant Acquisition Adj.			3,490,722		-
17	Total Rate Base Related			59,110,428		8,669,286

(a) Fully amortized in Dec-05.
(b) Fully amortized prior to beginning of test year.

PUD Cause No. 200600285
Final Order
Schedule J-1 & J-2

PUBLIC SERVICE COMPANY OF OKLAHOMA
UTILITY FEDERAL
INCOME TAX COMPUTATION
FOR THE TEST YEAR ENDING JUNE 30, 2006

Line No.	Description	SCH REF	(1) TEST YEAR AMOUNT	(2) PRO FORMA ADJUSTMENTS TO REVENUE AND EXPENSES	(3) TEST YEAR PRO FORMA
1	Operating Inc Before Income Taxes	H-1	111,401,243	(2,247,296)	109,153,947
2	Less: Operating Interest	J-1-1	36,257,435	1,768,862	38,026,297
	(Net of AFUDC Debt)		75,143,808	(4,016,157)	71,127,651
3	Permanent and Flow-Through Differences				
4	50% Meal & Enter. Disallowance		235,818		235,818
5	Book Depr. on Flo Thru Basis Diff.		3,464,000	(167,000)	3,297,000
6	SFAS 106 - Post Retire Ben Medicare Subsidy		(1,987,265)		(1,987,265)
7	BIP AFUDC EQ. Amort.		97,770		97,770
8	Preferred Dividend Credit		(71,280)		(71,280)
9	Manufacturing Deduction		252,000	(702,000)	(450,000)
10	Other				0
11	Book Taxable Income		77,134,850	(4,885,157)	72,249,693
12	Overall Income Tax at 38.6792 %		29,835,143	(1,889,540)	27,945,603
13	After Tax Provisions / Adjustments				
14	Reversal of Reg Assets/Liabilities -				
15	Excess ADIT		(1,909,638)	144,447	(1,765,191)
16	Amortization of Deferred ITC		(967,269)	(51,195)	(1,018,464)
17	R&D Credit		(198,277)	198,277	0
18	Prior Period Adjustments		514,433	(514,433)	0
19	Rounding		0	0	0
20	Total		27,274,393	(2,112,445)	25,161,948

PUBLIC SERVICE COMPANY OF OKLAHOMA
PUD Cause No. 200600285

Accounting Exhibits

Attachment 2
Depreciation Rates

PUBLIC SERVICE COMPANY OF OKLAHOMA
DEPRECIATION RATES BASED ON FINAL ORDER IN CAUSE NO. PUD 200600285
ATTACHMENT 2

		Total Rate
STEAM PRODUCTION PLANT		
	NORTHEASTERN UNITS 3 AND 4	
311.0	Structures & Improvements	1.46%
312.0	Boiler Plant Equipment	1.51%
314.0	Turbogenerator Units	1.33%
315.0	Accessory Electrical Equipment	1.33%
316.0	Misc. Power Plant Equip. - Minor	0.00%
316.0	Misc. Power Plant Equip.	1.54%
	RAIL SPUR	
310.1	Rail Spur - Land Rights	2.30%
312.1	Rail Spur	1.76%
312.11	Rail Cars	0.00%
	OKLAUNION	
311.0	Structures & Improvements	1.18%
312.0	Boiler Plant Equipment	1.17%
314.0	Turbogenerator Units	1.07%
315.0	Accessory Electrical Equipment	1.12%
316.0	Misc. Power Plant Equip.	1.24%
GAS & COMBINED CYCLE PLANTS		
	COMANCHE	
311.0	Structures & Improvements	2.75%
312.0	Boiler Plant Equipment	2.97%
314.0	Turbogenerator Units	2.99%
315.0	Accessory Electrical Equipment	2.68%
316.0	Misc. Power Plant Equip.	4.14%
	NORTHEASTERN UNITS 1 AND 2	
311.0	Structures & Improvements	1.76%
312.0	Boiler Plant Equipment	1.49%
314.0	Turbogenerator Units	2.02%
315.0	Accessory Electrical Equipment	1.77%
316.0	Misc. Power Plant Equip.	3.03%
	RIVERSIDE UNITS 1 AND 2	

PUBLIC SERVICE COMPANY OF OKLAHOMA
DEPRECIATION RATES BASED ON FINAL ORDER IN CAUSE NO. PUD 200600285
ATTACHMENT 2

		Total Rate
311.0	Structures & Improvements	1.77%
312.0	Boiler Plant Equipment	1.70%
314.0	Turbogenerator Units	1.65%
315.0	Accessory Electrical Equipment	1.73%
316.0	Misc. Power Plant Equip. - Minor	0.00%
316.0	Misc. Power Plant Equip.	2.08%
	SOUTHWESTERN	
311.0	Structures & Improvements	2.50%
312.0	Boiler Plant Equipment	2.36%
314.0	Turbogenerator Units	2.31%
315.0	Accessory Electrical Equipment	2.40%
316.0	Misc. Power Plant Equip.	3.50%
	TULSA UNITS 2 AND 4	
311.0	Structures & Improvements	2.41%
312.0	Boiler Plant Equipment	2.61%
314.0	Turbogenerator Units	2.78%
315.0	Accessory Electrical Equipment	2.57%
316.0	Misc. Power Plant Equip. - Minor	0.00%
316.0	Misc. Power Plant Equip.	5.23%
	TULSA UNIT 3 (Included in Account 105 at 12/05)	
311.0	Structures & Improvements	7.66%
312.0	Boiler Plant Equipment	7.04%
314.0	Turbogenerator Units	6.89%
315.0	Accessory Electrical Equipment	6.97%
316.0	Misc. Power Plant Equip.	7.78%

PUBLIC SERVICE COMPANY OF OKLAHOMA
DEPRECIATION RATES BASED ON FINAL ORDER IN CAUSE NO. PUD 200600285
ATTACHMENT 2

		Total Rate
OTHER PRODUCTION		
	WELEETKA	
341	Structures & Improvements	2.43%
342	Fuel Holders, Producers & Accessories	2.29%
344	Generators	2.92%
345	Accessory Electrical Equip.	3.67%
346	Misc. Power Plant Equip.	2.69%
	COMANCHE	
342	Fuel Holders, Producers & Accessories	5.33%
344	Generators	2.12%
346	Misc. Power Plant Equip.	9.57%
	NORTHEASTERN UNITS 1 AND 2	
341	Structures & Improvements	3.09%
342	Fuel Holders, Producers & Accessories	1.24%
344	Generators	1.28%
345	Accessory Electrical Equip.	1.14%
346	Misc. Power Plant Equip.	0.95%
	NORTHEASTERN UNITS 3 & 4	
344	Generators	0.89%
	RIVERSIDE	
342	Fuel Holders, Producers & Accessories	1.07%
344	Generators	1.28%
345	Accessory Electrical Equip.	1.64%
	SOUTHWESTERN	
342	Fuel Holders, Producers & Accessories	1.52%
344	Generators	1.51%

PUBLIC SERVICE COMPANY OF OKLAHOMA
DEPRECIATION RATES BASED ON FINAL ORDER IN CAUSE NO. PUD 200600285
ATTACHMENT 2

		Total Rate
	TULSA	
342	Fuel Holders, Producers & Accessories	1.60%
344	Generators	1.91%
	WELEETKA	
341	Structures & Improvements	0.00%
342	Fuel Holders, Producers & Accessories	0.00%
344	Generators	1.37%
345	Accessory Electrical Equip.	0.80%
346	Misc. Power Plant Equip.	0.00%

PUBLIC SERVICE COMPANY OF OKLAHOMA
DEPRECIATION RATES BASED ON FINAL ORDER IN CAUSE NO. PUD 200600285
ATTACHMENT 2

		Total Rate
TRANSMISSION PLANT		
350.1	Land Rights	1.04%
352.0	Structures & Improvements	1.52%
353.0	Station Equipment	1.55%
354.0	Towers & Fixtures	1.94%
355.0	Poles & Fixtures	2.80%
356.0	OH Conductor & Devices	2.11%
358.0	Underground Conductor	2.56%
DISTRIBUTION PLANT		
360.1	Land Rights	0.85%
361.0	Structures & Improvements	0.36%
362.0	Station Equipment	1.61%
364.0	Poles, Towers, & Fixtures	3.42%
365.0	Overhead Conductor & Devices	3.03%
366.0	Underground Conduit	2.20%
367.0	Underground Conductor	1.54%
368.0	Line Transformers	3.76%
369.0	Services	2.77%
370.0	Meters	3.94%
371.0	Installations on Custs. Prem.	6.60%
373.0	Street Lighting & Signal Sys.	7.88%
GENERAL PLANT		
390.0	Structures & Improvements	0.45%
391.0	Office Furniture & Equipment	6.71%
391.1	Office Equipment - Computers	20.35%
392.0	Transportation Equipment	4.51%
393.0	Stores Equipment	3.37%
394.0	Tools Shop & Garage Equipment	2.84%
395.0	Laboratory Equipment	3.03%
396.0	Power Operated Equipment	5.21%
397.0	Communication Equipment	3.73%
398.0	Miscellaneous Equipment	4.20%
399	Alliance Rail	1.52%

PUBLIC SERVICE COMPANY OF OKLAHOMA
PUD Cause No. 200600285

Revenue Distribution

Attachment 3

PUBLIC SERVICE COMPANY OF OKLAHOMA
Revenue Distribution
Test Year Ending June 30, 2006

	a	b	c	d	e	f	g	h	i	j	k	l
Customer Group	Current Non-Fuel Revenue	Final Order Equalized Non-Fuel Increase	Final Order Equalized Non-Fuel % Increase	Final Order Non-Fuel Revenues	Final Order Non-Fuel % Increase	Final Order Total Fuel Revenues	Final Order Total Bill % Increase	Errata Total Bill % Increase	Final Order Current Rate of Return	Final Order Current Relative ROR	Final Order Rate of Return	Final Order Relative ROR
Residential												
Lurs	$ 4,486,472	$ 5,854,138	30.48%	$4,712,906	5.05%	$ 4,670,424	2.47%	6.52%	0.63	0.08	1.85	0.23
GC Lurs	$ 182,333	$ 230,939	26.66%	$188,032	3.13%	$ 243,772	1.34%	2.43%	1.85	0.25	2.58	0.32
RS	$ 178,231,793	$ 199,273,842	11.81%	$189,213,636	6.16%	$ 257,207,863	2.52%	5.41%	5.34	0.71	6.74	0.84
GC RS	$ 15,276,750	$ 17,925,252	17.34%	$16,192,467	5.99%	$ 26,035,345	2.22%	4.35%	4.41	0.59	5.66	0.71
Total RS	$ 198,177,348	$ 223,284,170	12.67%	$ 210,307,041	6.12%	$ 288,157,403	2.49%	5.34%	5.16	0.69	6.54	0.82
				$12,129,693								
Commercial												
GCLUGS	$ 1,062,571	$ 1,083,221	1.94%	$1,081,263	1.76%	$ 1,610,747	0.70%	3.20%	7.56	1.01	7.97	0.99
Lugs	$ 38,144,761	$ 35,537,493	-6.84%	$38,843,916	1.83%	$ 45,485,528	0.84%	7.24%	9.81	1.31	10.30	1.29
GCGS	$ 4,327,958	$ 4,253,991	-1.71%	$4,443,537	2.67%	$ 8,355,131	0.91%	4.90%	8.40	1.12	9.02	1.13
GS	$ 86,173,893	$ 85,352,448	-0.95%	$88,826,594	3.08%	$ 160,619,125	1.07%	4.80%	8.23	1.10	8.93	1.11
PL	$ 18,346,957	$ 13,677,677	-25.45%	$17,099,960	-6.80%	$ 36,988,295	-2.25%	2.45%	15.91	2.13	13.80	1.72
Ums	$ 171,326	$ 299,383	74.74%	$183,986	7.39%	$ 707,940	1.44%	2.83%	(3.44)	(0.46)	(2.31)	(0.29)
MP	$ 299,090	$ 291,266	-2.62%	$292,031	-2.36%	$ 674,334	-0.73%	3.70%	8.60	1.15	8.07	1.01
Tod	$ 36,856	$ 42,789	16.10%	0	0.00%	$ -	-100.00%	-100.00%	-	-	-	-
SL5 Total	$ 148,563,410	$ 140,538,267	-5.40%	$ 150,771,286	1.49%	$ 254,441,100	0.55%	4.96%	9.33	1.25	9.69	1.21
GCLUGS	$ 2,416	$ 5,480	126.84%	$2,670	10.53%	$ 4,174	3.86%	7.52%	(2.63)	(0.35)	(1.75)	(0.22)
Lugs	$ 44,546	$ 76,247	71.16%	$48,263	8.34%	$ 64,494	3.41%	5.87%	(0.05)	(0.01)	0.90	0.11
GCGS	$ 23,976	$ 41,730	74.05%	$22,948	-4.28%	$ 48,505	-1.42%	3.81%	(0.14)	(0.02)	(0.62)	(0.08)
GS	$ 2,979,439	$ 4,696,830	57.64%	$3,062,445	2.79%	$ 5,944,384	0.93%	4.15%	0.94	0.13	1.28	0.16
PL	$ 1,683,444	$ 2,647,096	57.24%	$1,702,554	1.14%	$ 4,778,897	0.30%	1.32%	0.84	0.11	0.98	0.12
SL4 Total	$ 4,733,820	$ 7,467,382	57.75%	$ 4,838,680	2.22%	$ 10,640,453	0.67%	2.98%	0.88	0.12	1.16	0.14
Total Commercial	$ 153,297,230	$ 148,005,649	-3.45%	$ 155,610,166	1.51%	$ 265,281,553	0.55%	4.89%	7.96	1.06	8.69	1.08
Lighting												
GSL	$ 15,356	$ 42,569	177.21%	$ 15,356	0.00%	$ 20,201	0.00%	4.32%	(0.73)	(0.10)	(0.73)	(0.09)
OL	$ 451,568	$ 702,793	55.63%	$ 496,847	10.03%	$ 943,720	3.25%	4.54%	(3.85)	(0.51)	(1.71)	(0.21)
SL	$ 6,923,092	$ 4,917,929	-28.96%	$ 6,715,399	-3.00%	$ 3,177,370	-2.06%	3.11%	14.14	1.89	13.50	1.69
MSL	$ 1,199,740	$ 5,775,128	381.36%	$ 1,199,740	0.00%	$ 2,265,089	0.00%	3.46%	(2.67)	(0.36)	(2.67)	(0.33)
Total Lighting	$ 8,589,757	$ 11,438,419	33.16%	$ 8,427,343	-1.89%	$ 6,406,379	-1.08%	3.33%	4.36	0.58	4.15	0.52
Industrial	$ 71,543,013	$ 58,674,219	-17.99%	$ 67,054,050	-6.27%	$ 253,172,192	-1.38%	0.81%	13.53%	1.81	11.61%	1.45
SL3 Total	$ 30,892,311	$ 26,801,888	-13.24%	$ 29,292,713	-5.18%	$ 94,156,632	-1.28%	0.94%	11.78	1.58	10.30	1.29
SL2 Total	$ 33,760,045	$ 26,637,900	-21.10%	$ 31,572,073	-6.48%	$ 130,404,560	-1.33%	0.75%	14.79	1.98	12.71	1.59
SL1 Total	$ 6,890,657	$ 5,234,431	-24.04%	$6,189,263	-10.18%	$ 28,611,000	-1.98%	0.65%	16.53	2.21	12.92	1.61
				$ (4,488,963)								
Total Retail	$ 431,607,347	$ 441,402,457	2.27%	$ 441,398,599	2.27%	$ 813,017,527	0.79%	3.98%	7.48	1.00	8.01	1.00
									6.36		6.81	
				$ 9,791,252					8.60		9.21	

PUBLIC SERVICE COMPANY OF OKLAHOMA
Revenue Distribution
Test Year Ending June 30, 2006

	m	n	o	p	q
Customer Group	Errata Current Relative ROR	Errata Relative ROR	Current Class % of Total Revenues	Errata Class % of Total Revenues	Final Class % of Total Revenues
Residential					
Lurs	0.01	0.35	1.04%	1.06%	1.07%
GC Lurs	0.19	0.36	0.04%	0.04%	0.04%
RS	0.68	0.80	41.29%	41.89%	42.87%
GC RS	0.55	0.67	3.54%	3.54%	3.67%
Total RS	0.65	0.78	45.92%	46.53%	47.65%
Commercial					
GCLUGS	1.02	0.89	0.25%	0.24%	0.24%
Lugs	1.35	1.41	8.84%	9.17%	8.80%
GCGS	1.15	1.17	1.00%	1.03%	1.01%
GS	1.12	1.13	19.97%	20.40%	20.12%
PL	2.27	1.89	4.25%	4.10%	3.87%
Ums	(0.61)	(0.20)	0.04%	0.04%	0.04%
MP	1.17	1.13	0.07%	0.07%	0.07%
Tod	-	-	0.01%	0.00%	0.00%
SL5 Total	1.28	1.27	34.42%	35.05%	34.16%
GCLUGS	(0.49)	(0.19)	0.00%	0.00%	0.00%
Lugs	(0.10)	0.11	0.01%	0.01%	0.01%
GCGS	(0.11)	0.05	0.01%	0.01%	0.01%
GS	0.05	0.20	0.69%	0.70%	0.69%
PL	0.04	0.11	0.39%	0.37%	0.39%
SL4 Total	0.04	0.17	1.10%	1.08%	1.10%
Total Commercial	1.21	1.25	35.52%	36.14%	35.25%
Lighting					
GSL	(0.20)	(0.09)	0.00%	0.00%	0.00%
OL	(0.69)	(0.17)	0.10%	0.11%	0.11%
SL	1.85	1.42	1.60%	1.51%	1.52%
MSL	(0.49)	(0.32)	0.28%	0.27%	0.27%
Total Lighting	0.52	0.44	1.99%	1.89%	1.91%
Industrial	12.88%	1.46			
SL3 Total	1.63	1.28	7.16%	6.68%	6.64%
SL2 Total	2.06	1.59	7.82%	7.28%	7.15%
SL1 Total	2.30	1.76	1.60%	1.48%	1.40%
Total Retail	1.00	1.00	100.00%	100.00%	100.00%